ENBRIDGE INC
Form 10-K
February 15, 2019

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

FORM 10-K

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2018
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 every Interactive Data File required to be submitted 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 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. o
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.

Large Accelerated Filer x	Accelerated Filer o
Non-Accelerated Filer o	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, 2018, was approximately US$61.1 billion.

As at February 8, 2019, the registrant had 2,022,657,570 common shares outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the proxy statement for the 2019 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
CPPIB	Canada Pension Plan Investment Board
CTS	Competitive Toll Settlement
Dawn	Dawn Hub
DCP Midstream	DCP Midstream, LLC
EBITDA	Earnings before interest, income taxes and depreciation and amortization
ECT	Enbridge Commercial Trust
EEM	Enbridge Energy Management, L.L.C.
EEP	Enbridge Energy Partners, L.P.
EGD	Enbridge Gas Distribution Inc.
EIPLP	Enbridge Income Partners LP
Enbridge	Enbridge Inc.
ENF	Enbridge Income Fund Holdings Inc.
ERII	Enbridge Renewable Infrastructure Investments S.a.r.l.
NBEUB	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
IR Plan	EGD's Incentive Rate Plan
ISO	Incentive Stock Options
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
MOLP	Midcoast Operating, L.P. and its subsidiaries

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
ROE	Return on equity
RSU	Restricted Stock Units
Sabal Trail	Sabal Trail Transmission, LLC
Sandpiper	Sandpiper Project
Seaway Pipeline	Seaway Crude Pipeline System
SEP	Spectra Energy Partners, LP
Spectra Energy	Spectra Energy Corp
Sponsored Vehicles buy-in	In the fourth quarter of 2018, Enbridge Inc. completed the buy-ins of our sponsored vehicles: Spectra Energy Partners, LP (SEP), Enbridge Energy Partners, L.P. (EEP), Enbridge Energy Management, L.L.C. (EEM) and Enbridge Income Fund Holdings Inc. (ENF), (collectively, the Sponsored Vehicles), where we acquired, in separate combination transactions, all of the outstanding equity securities of those Sponsored Vehicles not beneficially owned by us.
TCJA	Tax Cuts and Jobs Act
Texas Eastern	Texas Eastern Transmission, L.P.
the Fund	Enbridge Income Fund
the Fund and Affiliates	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. 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.

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

Although we believe these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about the following: the expected supply of and demand for crude oil, natural gas, natural gas liquids (NGL) and renewable energy; prices of crude oil, natural gas, NGL and renewable energy; exchange rates; inflation; interest rates; availability and price of labor and construction materials; operational reliability; customer and regulatory approvals; maintenance of support and regulatory approvals for our projects; anticipated in-service dates; weather; the timing and closing of dispositions; the realization of anticipated benefits and synergies of the Merger Transaction; governmental legislation; acquisitions and the timing thereof; the success of integration plans; impact of our dividend policy on our future cash flows; our credit ratings; capital project funding; expected EBITDA; expected earnings/(loss); expected earnings/(loss) per share;

expected future cash flows and estimated future dividends. Assumptions regarding the expected supply of and demand for crude oil, natural gas, NGL and renewable energy, and the prices of these commodities, are material to and underlie all forward-looking statements, as they may impact current and future levels of demand for our services. Similarly, exchange rates, inflation and interest rates impact the economies and business environments in which we operate and may impact levels of demand for our services and cost of inputs, and are therefore inherent in all forward-looking statements. Due to the interdependencies and correlation of these macroeconomic factors, the impact of any one assumption on a forward-looking statement cannot be determined with certainty, particularly with respect to the impact of the Merger Transaction on us, expected EBITDA, expected earnings/(loss), expected earnings/(loss) per share, expected future cash flows or estimated future dividends. The most relevant assumptions associated with forward-looking statements on announced projects and projects under construction, including estimated completion dates and expected capital expenditures, include the following: the availability and price of labor and construction materials; the effects of inflation and foreign exchange rates on labor and material costs; the effects of interest rates on borrowing costs; the impact of weather and customer, government and regulatory approvals on construction and in-service schedules and cost recovery regimes.

Our forward-looking statements are subject to risks and uncertainties pertaining to the realization of anticipated benefits and synergies of the Merger Transaction, operating performance, regulatory parameters, changes in regulations applicable to our business, dispositions, the transactions undertaken to simplify our corporate structure, our dividend policy, project approval and support, renewals of rights-of-way, weather, economic and competitive conditions, public opinion, changes in tax laws and tax rates, changes in trade agreements, exchange rates, interest rates, commodity prices, political decisions and supply of and demand for commodities, including but not limited to those risks and uncertainties discussed in this 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 statement made in this Annual Report on Form 10-K or otherwise, whether as a result of new information, future events or otherwise. All forward-looking statements, whether written or oral, attributable to us or persons acting on our behalf, are expressly qualified in their entirety by these cautionary statements.

PART I

ITEM 1. BUSINESS

Enbridge is one of North America's largest energy infrastructure companies 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. We safely deliver in excess of three million barrels of crude oil each day in North America through our Mainline and Express pipeline, and account for approximately 62% of United States-bound Canadian crude oil exports. We also move approximately 18% 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 1,700 megawatts (MW) of net renewable power generation capacity in North America and Europe. 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.

A more detailed description of each of our businesses and underlying assets is provided below under Business Segments.

CORPORATE VISION AND STRATEGY

VISION

Our vision is to be the leading energy infrastructure 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 and want, in the safest, most reliable and most responsible way possible.

Among our peers, we strive to be a leader in several key areas that create sustainable comparative advantage and value for shareholders including: worker and public safety, environmental protection, stakeholder relations, customer service, community investment and employee satisfaction.

STRATEGY

Last year we announced a three year plan (the Strategic Plan) focused on growing our three core business lines - Liquids Pipelines, Natural Gas Pipelines and Gas Distribution within a regulated pipeline and utility model, while improving our competitive position through streamlining our businesses and strengthening our financial position. Within each of these business lines, our assets are well positioned to provide us with the scale and diversity to compete, grow and provide the energy people need and want. Our core assets generate highly predictable cash flows and are expected to create sustainable organic growth opportunities through the expansion and extension of our existing assets.

As discussed in further detail in Part II. Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations, in 2018 we made significant progress on a number of the objectives set out in the Strategic Plan. Notably:

- we monetized approximately $7.8 billion of non-core assets, some of which were less aligned with our regulated pipelines and utilities business model;
- we strengthened our balance sheet, achieving long-term leverage targets ahead of schedule;
- we streamlined and simplified our corporate structure through buying in four publicly-traded sponsored vehicles; and

- we continued to execute on our industry-leading capital program, bringing $7 billion of new projects into service during the year and advancing our Line 3 Replacement Program (L3R Program) and other secured projects currently in progress through key regulatory milestones.

As a result of the actions we took in 2018, we are entering 2019 with a streamlined business model and organizational structure, a strong balance sheet and a renewed focus on securing additional growth.

While the relative degree of emphasis has shifted with the progress we made last year, our strategic priorities remain essentially unchanged as we seek to continue to grow the business and add value in pursuit of our longer term vision. The key priorities are summarized below.

Commitment to Safety and Operational Reliability
Safety and operational reliability remain the foundation of our Strategic Plan. Our 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 while protecting people and the environment.

Maintain a Strong Financial Position
The maintenance of our financial strength is critical to our strategy. Over the last year, execution of our funding plans together with selected asset divestitures have reduced consolidated leverage and strengthened our balance sheet.

Our financing strategies are designed to achieve strong, investment grade credit ratings to ensure that we have the financial capacity to meet our capital funding needs, and the flexibility to manage capital market disruptions and respond to opportunities as they arise. Our current secured capital program, which extends beyond 2020, can be readily financed through internally generated cash flow and available balance sheet capacity without issuance of additional common equity, and we will seek to drive attractive growth post 2020 using this “self-funded” model. For further discussion on our financing strategies, refer to Part II. Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources.

To reinforce our low-risk regulated pipeline and utility-like profile, we continue to closely monitor and manage controllable risks. This includes 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 as well as ongoing monitoring and management of credit exposures to customers, suppliers and counterparties. For further details, refer to Part II. Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

Execute Capital Program
Successful project execution is integral to our financial performance but also to the strategic positioning of our business over the long term. Our ongoing objective is to deliver projects on time, on budget and at the lowest practical cost while maintaining the highest standards for safety, quality, customer satisfaction and environmental and regulatory compliance. For a discussion of our current portfolio of capital projects, refer to Part II. Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Growth Projects - Commercially Secured Projects.

Complete Integration and Transformation
A heightened focus on efficiency and effectiveness continues to be a key priority. Given the increasingly competitive nature of our business, in 2016 we established a goal to reach top quartile cost performance while seeking opportunities to drive enhanced revenue from our operating businesses. To achieve this, we launched several projects to transform various processes, organizational capabilities and information systems infrastructure in order to improve how we do business. Several of these initiatives have been successfully completed, while others will continue into 2019 and 2020.

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A related priority for our gas distribution business is the effective integration of the operations and management of Enbridge Gas Distribution Inc. (EGD) and Union Gas Limited (Union Gas) following the amalgamation of these two large natural gas distribution utilities effective January 1, 2019. The establishment of a new five-year incentive rate making model for the combined entity provides an opportunity to increase efficiencies and enhance returns while lowering customer energy costs.

Extend Growth Post 2020

Our core assets are strategically positioned between key supply basins with strong demand pull, and are underpinned by low risk commercial structures: long-term contracts, regulated cost of service tolling frameworks, established customer bases and strong risk-adjusted returns. We will remain focused on growing post 2020 through investments in these types of assets, placing an even greater emphasis on capturing the very best of a large suite of potential organic growth opportunities with an emphasis on energy export opportunities. Opportunities will be screened, analyzed and assessed using a disciplined investment framework with the objective of ensuring effective deployment of capital to achieve attractive risk-adjusted returns.

In seeking to extend growth post 2020, we will continue to focus on maintaining our low risk, regulated pipeline and utility business model, utilizing the self-funding model described above to grow our core business, while taking a rigorous approach to capital allocation. Starting in 2020, we expect to generate $5 to $6 billion of available capital to reinvest in the business without raising external equity and maintaining a strong balance sheet. We currently see many promising organic growth opportunities in which to deploy available capital in the post 2020 period but will actively monitor the business landscape and assess these opportunities against other alternative uses for our capital on an ongoing basis in order to ensure value maximization.

MAINTAIN THE FOUNDATION

Our success in executing on our strategic priorities is very much dependent on the way in which we conduct our business and the quality and capabilities of our people. These elements provide the “foundation” required to achieve our objectives and longer term vision.

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 safety, integrity 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, which encapsulates these values.

Build and Maintain the Confidence of Stakeholders and Decisions Makers

Earning and sustaining the trust of our key stakeholders and decision makers 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 communities and other groups directly impacted by our activities 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 accountabilities and 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, and affordable energy.

We provide annual progress updates related to the above initiatives in our annual Corporate Social Responsibility and Sustainability 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 accelerated leadership programs, rigorous succession planning of critical roles, and facilitating career development and mobility throughout the enterprise. We also value diversity and have embedded inclusive practices throughout our programs and approach to people management. 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 pipelines and related terminals in Canada and the United States that transport various grades of crude oil and other liquid hydrocarbons.

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 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. We have operated, and frequently expanded, the Canadian Mainline since 1949. The Lakehead System is the portion of the mainline system in the United States. 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 Canadian Gross Domestic Product at Market Price Index published by Statistics Canada.

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, 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 index rates and the Facilities Surcharge Mechanism. Index 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 index rates, and is subject to annual adjustment on April 1.

REGIONAL OIL SANDS SYSTEM
The Regional Oil Sands System includes five intra-Alberta long haul pipelines, the Athabasca Pipeline, Waupisoo Pipeline, Woodland Pipeline, Wood Buffalo Extension/Athabasca Twin pipeline system and the Norlite Pipeline System (Norlite), as well as two large terminals: the Athabasca Terminal located north of Fort McMurray, Alberta and the Cheecham Terminal, located south of Fort McMurray, Alberta. 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 combined capacity of the intra-Alberta long haul pipelines is approximately 930,000 bpd to Edmonton and 1,370,000 bpd into Hardisty, with Norlite providing approximately 218,000 bpd of diluent capacity into the Fort McMurray region. The Woodland Pipeline and Norlite Pipeline System are joint ventures, 50/50 between us and Imperial Oil Resources Ventures Limited and ExxonMobil Canada Properties, and 70/30 with Keyera Corp. respectively. The Regional Oil Sands System is anchored by long-term agreements with multiple oil sands producers that include provisions for the recovery of some of the operating costs of this system.

GULF COAST AND MID-CONTINENT
Gulf Coast includes Seaway Crude Pipeline System (Seaway Pipeline), Flanagan South Pipeline (Flanagan South) and Spearhead Pipeline, as well as the Mid-Continent System comprised of the Cushing Terminal.

Seaway Pipeline
In 2011, we acquired a 50% interest in the 1,078-kilometer (670-mile) 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 in early 2013, increasing capacity available to shippers from an initial 150,000 bpd to approximately 400,000 bpd, depending on 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, a delivery point on the Lakehead System, 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 a capacity of 193,000 bpd.

Mid-Continent System

The Mid-Continent System is comprised of storage terminals at Cushing, Oklahoma (Cushing Terminal), consisting 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.

SOUTHERN LIGHTS PIPELINE

Southern Lights Pipeline is a 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. Southern Lights Pipeline capacity is 90% contracted with the remaining 10% of the capacity (18,000 bpd) assigned for shippers to ship uncommitted volumes.

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 Rocky Mountains 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

The Bakken System consists of the North Dakota System and the Bakken Pipeline System. The North Dakota System services the Bakken in North Dakota, and is comprised of a crude oil gathering and interstate pipeline transportation system. The gathering system provides delivery to Clearbrook for service on the Lakehead system or a variety of interconnecting pipeline and rail export facilities. The interstate portion of the system has both U.S. and Canadian components that extend from Berthold, North Dakota into Cromer, Manitoba.

Tariffs on the United States portion of the North Dakota System are governed by the 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 on the interstate pipeline system are based on long-term take-or-pay agreements with anchor shippers.

In February 2017, we closed a transaction to acquire an effective 27.6% interest in the Bakken Pipeline System, which connects the Bakken formation in North Dakota to markets in eastern PADD II and the United States Gulf Coast. The Bakken Pipeline System consists of the Dakota Access Pipeline from the Bakken area in North Dakota to Patoka, Illinois, and the Energy Transfer Crude Oil Pipeline from Patoka,

Illinois to Nederland, Texas. Initial capacity is in excess of 500,000 bpd of crude oil with the potential to be expanded through additional pumping horsepower. 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 the 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 us to become an owner (35%) in SAX, thereby forming the Illinois Extension Pipeline Company (IEPC). We have a 65% ownership in IEPC. SAX was placed into service in 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 Norman Wells (NW) System. Patoka Storage is comprised of four 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 NW System transports crude oil from Norman Wells in the Northwest Territories to Zama, Alberta and has a cost of service rate structure based on established terms with shippers.

COMPETITION
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 amongst 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.

Competition 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 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 competitors' 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. We also employ long-term agreements with shippers, which mitigates competition risk by ensuring consistent supply to our liquids pipelines network. Our current complement of growth projects to expand market access and to enhance capacity on our pipeline system are expected to provide shippers reliable and long-term competitive solutions for liquids transportation. We have a proven track record of successfully executing projects to meet the needs of our customers and 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.

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 for crude oil. 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.

Higher prices in the early part of this decade encouraged production development which pushed supply beyond demand resulting in an extended price downturn starting in 2014. By the second half of 2016, drilling technology efficiencies and innovations in North America reinvigorated production growth. Oil prices continued to strengthen into 2018 on supply concerns created by sanctions being imposed on Iran; prompting Saudi Arabia and Russia to abandon rationing targets therefore reducing earlier price gains. At the same time, global demand softened in the wake of an escalating United States-China trade dispute. This resulted in the return to crude inventory builds globally.

In Western Canada, lack of export pipeline capacity resulted in the rapid buildup of inventories and extreme discounts of Western Canadian crude; WCS discounts peaked at over US$50 per barrel against WTI in October. This, in turn, resulted in the Alberta Government entering into negotiations to purchase 7,000 rail cars and 80 engines to add about 120,000 bpd of rail export capacity for the industry by the end of 2020, and the adoption of a production curtailment policy directing the industry in the province to shut in 325,000 bpd starting January 1, 2019. The aim of this policy is to both draw down inventories by approximately 20 million barrels and return crude discounts to more historical norms. The policy calls for curtailment levels to be reduced as inventory levels ratchet down and new pipeline and rail capacity come on line. Western Canadian crude prices responded almost immediately upon the release of the curtailment adoption notice, with discounts narrowing to around US$10 per barrel. The discount at this level would imply that rail is not financially attractive, and hence frustrating the government's efforts to draw down inventories.

Notwithstanding the current price environment and Alberta policies, our mainline system has thus far continued to be highly utilized. Mainline throughput as measured at the Canada/United States border at Gretna, Manitoba saw record deliveries of 2.8 million bpd in November 2018. The mainline system continues to be subject to apportionment, 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 cost effectiveness of our mainline toll, and commercial arrangements which underpin many of the pipelines providing a significant measure of protection against volume fluctuations. 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 steep discounts for Western Canadian crude have caused some sponsors to reconsider the timing of future projects. While recently updated forecasts continue to reflect long-term supply growth from the WCSB, the projected pace of growth is slower than previous forecasts as companies continue to assess the viability of capital investments in light of the current price environment and ongoing uncertainty with respect to the timing and completion of new pipeline systems proposed by our competitors.

Over the long term, continued growth in global energy consumption is expected to be primarily driven by emerging economies in regions outside the Organization for Economic Cooperation and Development (OECD), mainly in India and China. In North America, demand growth for transportation fuels is expected to moderate due to vehicle fuel efficiencies and increasing sales of electric vehicles. Accordingly, there is a strategic opportunity to establish tide-water export facilities to service North American producers wanting access to global markets.

Global crude oil production is expected to continue to grow through 2035, primarily by North America, Brazil and Organization of Petroleum Exporting Countries (OPEC). Growth in supply from OPEC is partly due to the expected recovery of Iraqi and Libyan production. Over the longer term, North American production from tight oil plays is expected to grow as technology continues to improve well productivity and efficiencies. 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 or to United States markets.

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 markets resulted in a divergence between WTI and world pricing, resulting in lower netbacks for North American producers. 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 relative to WTI. New pipeline capacity is expected to come online in 2019, further stabilizing differentials in western Canada and the end to the government curtailment program. Canadian pipeline export capacity is expected to remain fully utilized, resulting in continued apportionment on our mainline system and incremental production utilizing non-pipeline transportation services (e.g. rail and trucks) until such time as sufficient pipeline capacity is made available. Over the longer term, however, we believe pipelines will continue to be the most reliable and cost-effective means of transportation.

Our role in helping to address the evolving supply and demand fundamentals and alleviating price discounts for producers and supply costs to refiners is through optimization of throughput on our existing liquids pipelines systems and through investment in new pipelines and related infrastructure to provide expanded transportation capacity and sustainable connectivity to alternative markets. Progress on the development and construction of our commercially secured growth projects is discussed in Part II. Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Growth Projects - Commercially Secured Projects.

GAS TRANSMISSION & MIDSTREAM

Gas Transmission and Midstream 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
US Gas Transmission includes ownership interests in Texas Eastern, Algonquin, M&N U.S., East Tennessee, Gulfstream, Sabal Trail, NEXUS, Valley Crossing, Southeast Supply Header (SESH), 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 northeastern, southern and midwestern United States.

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. We indirectly own 92% of the Algonquin natural gas transmission system.

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). We indirectly own 78% of M&N U.S.

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 2,470-kilometers (1,535-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 with 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. We indirectly own 50% of Gulfstream.

Sabal Trail is an approximately 829-kilometer (515-mile) pipeline that provides firm natural gas transportation to Florida Power & Light Company for its power generation needs and will deliver natural gas to Duke Energy Florida's natural gas plant. Facilities include a 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 enabling the access of onshore shale gas supplies once approved future expansions are completed. We indirectly own 50% of Sabal Trail.

NEXUS, which was placed into service in October 2018, is an approximately 410-kilometer (255-mile) interstate natural gas transmission system with associated compressor stations. NEXUS transports natural gas from our Texas Eastern system in Ohio to our Vector interstate pipeline in Michigan, and adds approximately 1.5 bcf/d of new capacity. Through its interconnect with Vector, NEXUS provides a connection to Dawn Hub (Dawn), the largest integrated underground storage facility in Canada and one of the largest in North America, located in southwestern Ontario adjacent to the Greater Toronto Area. We indirectly own 50% of NEXUS.

Valley Crossing, which was placed into service in October 2018, is an approximately 274-kilometer (170-mile) intrastate natural gas transmission system, with associated compressor stations. The pipeline infrastructure is located in Texas and provides market access of up to 2.6 bcf/d to the Comisión Federal de Electricidad (CFE), Mexico's state-owned utility.

SESH is an approximately 467-kilometer (290-mile) natural gas transmission system with associated compressor stations, operated jointly with Enable Gas Transmission, LLC. SESH extends from the Perryville Hub in northeastern Louisiana where the shale gas production of eastern Texas, northern Louisiana and Arkansas, along with conventional production, is reached from six major interconnections. SESH extends to Alabama, interconnecting with 14 major north-south pipelines and three high-deliverability storage facilities. We indirectly own 50% of SESH.

Vector 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. We indirectly own 60% of Vector.

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 and are generally at a higher toll than long-term contracted rates. 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 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 2,897-kilometers (1,800-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.

On July 4, 2018, we entered into agreements to sell our Canadian natural gas gathering and processing businesses, inclusive of six gas processing plants, to Brookfield Infrastructure Partners L.P. and its institutional partners. Separate agreements were entered into for those facilities currently governed by provincial regulations and those governed by federal regulations. On October 1, 2018, we closed the sale of the provincially regulated facilities and the sale of the federally regulated facilities is expected to close in mid-2019. For further information, refer to Part II. Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Asset Monetization.

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. For further information, refer to Gas Transmission and Midstream - US Gas Transmission. We indirectly own 78% of M&N Canada.

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. Canadian Gas Transmission and Midstream also provides 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
Alliance Pipeline is 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. It 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. We indirectly own 50% of Alliance Pipeline.

US MIDSTREAM
On August 1, 2018, we closed the sale of our Midcoast assets to AL Midcoast Holdings, LLC (an affiliate of ArcLight Capital Partners, LLC). For further information, refer to Part II. Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Asset Monetization. These assets consist of 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.

US Midstream still includes a 42.7% interest in each of Aux Sable Liquid Products LP and Aux Sable Midstream LLC, and a 50% interest in Aux Sable Canada LP (collectively, 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 indirectly owns approximately 38% of DCP Midstream, LP, including limited partner and general partner interests. DCP Midstream, LP is a midstream master limited partnership, with a diversified portfolio of assets, engaged in the business of gathering, compressing, treating, processing, transporting, storing and selling natural gas; producing, fractionating, transporting, storing and selling NGLs; and recovering and selling condensate. DCP Midstream, LP owns and operates more than 49 plants and approximately 99,780-kilometers (62,000-miles) of natural gas and natural gas liquids pipelines, with operations in 17 states across major producing regions.

OTHER
Other consists primarily of our offshore assets. Enbridge Offshore Pipelines is comprised of 11 active natural gas gathering and FERC regulated transmission pipelines and four active oil pipelines. 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 competition for 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 exists in all of the markets our businesses 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.

SUPPLY AND DEMAND

Our gas transmission assets make up one of the largest natural gas transportation networks in North America, driving connectivity between prolific supply basins and major demand centers within the continent. Our systems have been integral to the transition in natural gas fundamentals over the last decade, and will continue to play a part as the energy landscape evolves. Shifts in production and consumption, both domestic and foreign, will require that we continue to serve as a critical link between markets.

At the close of the last decade, natural gas production in each of the Appalachian and Permian basins was less than 5.0 bcf/d each. Today, these regions produce more than 40.0 bcf/d of natural gas on a combined basis. Improved technology and increased shale gas drilling has increased the supply of low cost natural gas. As well, there has been and continues to be a corresponding increase in demand for our natural gas infrastructure in North America. Through a series of expansions and reversals on our core systems, combined with the execution of greenfield projects and strategic acquisitions, we have been able to meet the needs of producers and consumers alike. Our United States Gas Transmission systems were initially designed to transport natural gas from the Gulf Coast to the supply starved northeast markets. Our asset base now has the capability to transport diverse supply to the northeast, southeast, midwest, and gulf coast markets on a fully subscribed and highly utilized basis.

The northeast market continues its role as a predominantly supply constrained region with steady growth. Natural gas demand in the northeast is expected to grow by 3.1 bcf/d through 2035, driven by continued commercial and residential load growth. Natural gas leads the fuel mix of the Independent System Operator New England market at more than 40 percent. The bidirectional capabilities offered by our system allow us to deliver both domestic and imported supplies to our regional customers, 75 percent of whom are local distribution companies with a contract renewal rate of 98 percent. The region has seen an increase in natural gas supply due to the development of the Marcellus and Utica shales in the Appalachia region.

Demand for natural gas in the southeast region is forecast to increase by 3.5 bcf/d through 2035. Generating capacity in Florida is expected to grow 15 percent by 2026, the majority of which is projected to be natural gas-fired. The Southeast market is linked to multiple, highly liquid supply pools that include the Marcellus and Utica shale developments, offering consistent supply and stable pricing to a growing population of end-use customers across our multiple systems under long term, utility-like arrangements.

With connectivity to Appalachian and western Canadian supply through our systems, the midwest market has access to two of the lowest cost gas producing regions on the continent. As demand in the region continues to grow by approximately 3.0 bcf/d over the next two decades, maintaining this link will remain important. Flexibility in supply for this market is especially critical to maintaining liquidity and price stability as natural gas continues to replace coal fired generation.

Gulf coast demand growth is being driven by an ongoing 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. Demand in the region is anticipated to grow by more than 6.0 bcf/d through 2035. The Gulf coast market has been the beneficiary of low cost capacity on our assets as the relationship between supply and market centers has shifted. Such cost effective capacity is difficult to access or replicate, offering existing shippers and transporters stability of capacity and utilization. Tide water market access and proximity to Mexico continue to make this region a platform of global trade as pipeline, LNG and LPG exports see strong growth. The United States exported approximately 3.0 bcf/d of natural gas from the gulf coast region at the end of 2018 with an export capacity of approximately 10.0 bcf/d scheduled to be in service by 2021.

Despite there being strong growth in both supply and demand in the United States, a lack of adequate transportation capacity has placed downward pressure on local natural gas pricing. The Appalachian Basin has seen price differentials of $1.00 to $2.00 per MMBtu relative to Henry Hub in the gulf coast over the last few years. As 3.0 bcf/d of new capacity out of the region came online in late 2018, half of which is on our newly constructed assets, the differential between northeast production and downstream markets has significantly strengthened. Unlike the dry gas production of the Marcellus, natural gas production growth in the Permian Basin is a result of robust crude oil production taking place in the region. Associated gas supplies from the region increased by approximately 4.0 bcf/d over the past two years and growth is forecasted to continue for the next decade. Until new natural gas transportation capacity begins to come online in the second half of 2019, the natural gas prices in the region will continue to remain low relative to other producing regions.

Western Canada is experiencing a similar phenomenon to that of the Permian, with the local markets experiencing very low or even negative prices for natural gas, as transportation bottlenecks continue. One of the few vital links to demand centers in the pacific northwest are our own systems in the region which operate near full capacity. As demand for supply out of the WCSB continues to grow, driven largely by NGL production and local oil sands production, the need for new natural gas and NGL infrastructure will continue to rise.

Global energy demand is expected to increase approximately 30 percent by 2035, 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 approximately 45 percent during this period as one of the world’s fastest growing energy sources. North American exports will play a significant part in meeting global demand, underscoring the ability of our assets to remain highly utilized by shippers, and highlighting the need for incremental transportation solutions across North America. In response to these global fundamentals, we believe we are well positioned to provide value-added solutions to shippers. We are responding to the need for regional infrastructure with additional investments in Canadian and United States gas transportation facilities. Progress on the development and construction of our commercially secured growth projects is discussed in Part II. Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations - Growth Projects - Commercially Secured Projects.

GAS DISTRIBUTION

Gas Distribution consists of our natural gas utility operations, the core of which are EGD and 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 an investment in Noverco Inc (Noverco).

On August 30, 2018, we received a decision from the Ontario Energy Board (OEB) approving the application to amalgamate EGD and Union Gas (Amalgamation). On October 15, 2018, we announced that we would proceed with the Amalgamation, with an expected effective date of January 1, 2019. On

January 1, 2019, the Amalgamation was completed and the amalgamated company continued as Enbridge Gas Inc.

The OEB decision also approved the rate setting mechanism for the amalgamated entity to be employed during a five-year deferred rebasing period from 2019 through 2023, after which time rates will be rebased. The decision also approved the continuation and establishment of certain deferral and variance accounts, as well as an earnings sharing mechanism that requires the amalgamated entity to share equally with customers, any earnings in excess of 150 basis points over the OEB approved return on equity (ROE).

The Amalgamation, on January 1, 2019, created the single largest natural gas utility in North America in terms of send-out volumes, and third largest in terms of number of customers. We expect that this will drive efficiencies and synergies, leverage greater supply-chain strength, create new opportunities for growth, and form a stronger platform to deliver strong, predictable returns to shareholders and superior value and service to customers.

Given the timing of the Amalgamation, this Annual Report on Form 10-K continues to provide separate descriptions of EGD and Union Gas and separate discussions of the operating and financial performance of each of those entities for the year ended December 31, 2018. Post-Amalgamation, the management and operations of EGD and Union Gas will become integrated and the operating and financial results of Enbridge Gas Inc. will reflect the combined performance of the two legacy utility operations.

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 2019, 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, 2018, EGD owned and operated a network of approximately 83,000-kilometers (51,574-miles) of mains for the distribution of natural gas, as well as the service pipes to transfer natural gas from mains to meters on customers' premises.

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

Distribution
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.

Transportation
EGD relies on its long-term contracts with Union Gas, an affiliated company under common control, for transportation of natural gas from Dawn. 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 Gas' storage pools. Key pipeline interconnects enabled EGD to deliver approximately 449 bcf of gas through EGD's distribution and transmission system in 2018.

In addition, EGD contracts for firm transportation service with TransCanada Corporation (TransCanada) to meet its annual natural gas supply requirements. The transportation service contracts are not directly linked with any particular source of natural gas supply. Separating transportation contracts from natural gas supply allows EGD flexibility in obtaining its customer's natural gas supply and accommodating the requests of its direct purchase customers for assignment of TransCanada capacity. EGD forecasts the natural gas supply needs of its customers, including the associated transportation and storage requirements.

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 southwestern Ontario, near Dawn, and have a total working capacity of approximately 109 bcf in 11 underground facilities located in depleted gas fields. 99 petajoules (PJs) of the total working capacity is available to EGD for utility operations. EGD also has storage contracts with third parties for 6 bcf of storage capacity.

UNION GAS
Union Gas is a rate regulated natural gas distribution utility that currently serves 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.

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As at December 31, 2018, Union Gas owned and operated a network of approximately 67,000-kilometers (41,632-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 three principal interrelated aspects of the natural gas distribution business in which Union Gas is directly involved: Distribution, Transportation and Storage.

Distribution

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 are underpinned by firm or interruptible service contracts.

Transportation

Union Gas’ transmission system consists of approximately 5,000-kilometers (3,107-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 1,372 bcf of gas through Union Gas’ distribution and transmission system in 2018. 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. As of November 1, 2017, the transmission system has an effective peak daily demand capacity of 7.5 bcf/d. 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 167 bcf in 25 underground facilities located in depleted gas fields. 100 PJs of the total working capacity is available to Union Gas for utility operations. Union Gas also has storage contracts with third parties for 11 bcf of storage capacity. 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 2018, Dawn provided storage, balancing, gas loans, transport, exchange and peaking services to over 195 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 four years, with the longest remaining contract term being 18 years.

NOVERCO

Noverco is a holding company that owns approximately 71% of Energir LP (Energir), 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. Energir serves approximately 520,000 residential and industrial customers and is regulated by the Quebec Régie de l’énergie and the Vermont Public Utility Commission. Noverco also holds, directly and indirectly, an investment in our common shares. We own an equity interest in Noverco through ownership of 38.9% of its common shares and an investment in its preferred 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 12,000 customers and is regulated by the New Brunswick Energy and Utilities Board (NBEUB). On December 4, 2018, we announced a definitive agreement for the sale of Enbridge Gas New Brunswick Inc. Closing of the transaction remains subject to the receipt of regulatory approvals and other customary closing conditions and is expected to occur in 2019. For further information, refer to Part II. Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Asset Monetization.

We also wholly own Gazifère, a natural gas distribution company that serves approximately 40,000 customers in western Quebec, a market not served by Energir. Gazifère is regulated by the Quebec Régie de l'énergie.

COMPETITON

EGD and Union Gas' distribution systems are regulated by the OEB and are subject to regulation in a number of areas, including rates. EGD and Union Gas are not generally subject to third-party competition within their distribution franchise area.

EGD and Union Gas compete with other forms of energy available to their customers and end-users, including electricity, coal, propane and fuel oils. Factors that influence the demand for natural gas include weather, price changes, the availability of natural gas and other forms of energy, the level of business activity, conservation, legislation, governmental regulations, the ability to convert to alternative fuels and other factors.

SUPPLY AND DEMAND

We expect that demand for natural gas in North America will continue to see low annual growth over the long term with continued growth in peak day demands. Some modest growth driven by low natural gas prices is expected to continue given the significant price advantage relative to their alternate energy options, with specific interest coming from communities that are not currently serviced by natural gas. EGD and Union Gas continue to focus on promoting conservation and energy efficiency by undertaking activities focused on reducing natural gas consumption through various demand side management programs offered across all markets.

The storage and transportation marketplace continues to respond to changing natural gas supply dynamics including a robust supply environment. In recent years, the robust North American gas supply balance, due mainly to the development of shale gas volumes including the Alberta, British Columbia, Marcellus and Utica shale areas, has resulted in lower commodity prices and narrower seasonal price spreads. Unregulated storage values are primarily determined based on the difference in value between winter and summer natural gas prices. Storage values have been relatively stable to slightly rising as the North American natural gas supply and demand slowly returned to a more balanced position.

GREEN POWER & TRANSMISSION

Green Power and Transmission consists of 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 the states of Colorado, Texas, Indiana and West Virginia. Green Power and Transmission also includes offshore wind facilities in operation and under development located in Europe.

Green Power and Transmission includes interests in more than 1,700 MW of net renewable power generation capacity. Of this amount, approximately 477 MW is generated by wind facilities located in Canada, approximately 912 MW is generated by wind facilities located in the United States, approximately 100 MW is derived from a 24.9% interest in the 400 MW Rampion Offshore Wind Project and approximately 155 MW is derived from a 25% interest in the Hohe See Offshore wind power project and its subsequent expansion, both currently under construction. The vast majority of the power produced from these wind facilities is sold under long-term power purchase agreements. Green Power and Transmission also includes three solar facilities located in Ontario and a solar facility located in Nevada, with 51 MW and 27 MW, respectively, of power generating capacity net of our partners' interests.

Green Power and Transmission also includes the Montana-Alberta Tie-Line, a 300 MW transmission line from Great Falls, Montana to Lethbridge, Alberta.

On August 1, 2018, we closed the sale of a 49% interest in all of our Canadian renewable assets, a 49% interest in two United States renewable assets and 49% of our interest in the Hohe See Offshore wind power project and its subsequent expansion, both currently under construction in Germany (collectively, the Renewable Assets). We maintain a 51% interest in the Renewable Assets and will continue to manage, operate and provide administrative services for these assets. For further information, refer to Part II. Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Asset Monetization.

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 vast majority of the revenue generated by currently operating assets is generated pursuant to long term power purchase agreements or has been substantially hedged. As such, the financial performance of these assets is not significantly impacted by fluctuating power prices arising from supply/demand imbalances or the actions of competing facilities during the term of the applicable contracts. However, the renewable energy market sector includes large utilities and small independent power producers, which are expected to aggressively compete for new project development opportunities and for the right to supply customers when contracts roll off.

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, 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.

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. 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 and improved yield factors associated with renewable energy generation. 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 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 and is expected to create further investment opportunities.

ENERGY SERVICES

The Energy Services businesses in Canada and the United States undertake physical commodity marketing activity and logistical services, and manage our volume commitments on various pipeline systems. Energy Services provides energy marketing services to North American refiners, producers and other customers.

Through wholly-owned marketing subsidiaries, Energy Services provides crude oil, natural gas, NGL and power marketing services. Energy Services transact at many North American market hubs and provide our customers with various services, including transportation, storage, supply management and product exchanges. Our Energy Services subsidiaries are primarily physical commodity marketing companies focused on servicing customers across the value chain and capturing value from quality, time and location price differentials when opportunities arise. To execute these strategies, Energy Services transports and stores on both Enbridge-owned and third party assets using a combination of contracted long-term and short-term pipeline, storage tank, rail car and truck capacity agreements.

COMPETITION

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

ELIMINATIONS AND OTHER

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 and corporate investments.

OPERATIONAL, ENVIRONMENTAL AND ECONOMIC REGULATION

LIQUIDS PIPELINES

Operational Regulation

We are subject to numerous 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.

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 has established 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 failure 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, cash flows and financial condition.

In Canada, our pipeline operations are subject to pipeline safety regulations overseen by the NEB or provincial regulators. Applicable legislation and regulations 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 been enacted. 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.

Environmental Regulation

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 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 may 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. Environmental Protection Agency 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. In addition, a number of 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. The Government of Canada has recently released the details of a federal system of carbon pricing starting in 2019. The pricing will apply to provinces and territories that are not in compliance with the federal requirements.

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 regulation 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.

GAS TRANSMISSION & MIDSTREAM

Operational Regulation

The span of regulation 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 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, the Transportation Safety Board 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 currently has a two year Settlement Agreement with its Shippers that provides for cost sharing on certain controllable expenses and sets out the regulated ROE for the two year period. The Settlement Agreement has been approved by the NEB.

Our 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.

GAS DISTRIBUTION

Operational Regulation

Our gas distribution utility operations are regulated by the OEB, the Quebec Régie de l'énergie and the NBEUB, 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 operational regulation risk. We retain dedicated professional staff and maintain strong relationships with customers, intervenors and regulators. This strong regulatory relationship continued in 2018 with the OEB's decision to approve of the application to amalgamate EGD and Union Gas in accordance with the OEB's guidance for Mergers, Acquisitions, Amalgamations and Divestitures. The decision approved a rate setting mechanism, effective January 1, 2019, to be employed during a five-year deferred rebasing period from 2019 through 2023, and allows us the opportunity to drive efficiencies and synergies.

Enbridge Gas Distribution

EGD's distribution rates, beginning in 2014 through 2018, were set under a five-year customized incentive regulation (IR) plan. The plan required EGD to update select items each year beginning in 2015 and through 2018, in order to establish final allowed revenues and rates. Under the customized IR plan, EGD shared equally with customers, earnings above the approved allowed ROE. EGD's after-tax ROE was 9.00% for 2018 and 8.78% for 2017.

Union Gas

Union Gas' distribution rates, beginning in 2014 through 2018, were set under a five-year IR plan which established 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 IR plan included an earnings sharing mechanism with customers that permitted Union Gas to fully retain the ROE from utility operations up to 9.93%, to retain 50% of any earnings between 9.93% and 10.93%, and to retain 10% of any earnings above 10.93%.

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. Environmental legislation primarily includes regulation of discharges to air, land and water; management and disposal of hazardous waste; and the assessment and management of contaminated sites.

Gas distribution system operation, as with any industrial operation, has the potential risk of abnormal or emergency conditions, or other unplanned events that could result in spills or emissions in excess of permitted levels. These events could result in injuries to workers or the public, fines, orders or charges, adverse impacts to the environment in which we operate, 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 gas distribution system operation, we also operate small oil and brine production and storage facilities in southwestern Ontario. Environmental risk associated with these facilities is the potential for unplanned releases. In the event of a release, 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 any 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 assets and facilities are subject to periodic inspection. An Annual Written Summary Report is submitted to the Ontario Ministry of Environment, Conservation and Parks (MECP), formerly the Ministry of Environment and Climate Change to demonstrate we are in good standing with our Environmental Compliance Approvals. Failure to maintain regulatory compliance could result in operational interruptions, fines, and/or orders for additional pollution control technology or environmental mitigation. As environmental requirements and regulations become more stringent, the cost to maintain compliance and the time required to obtain approvals has increased.

On July 3, 2018, the Government of Ontario issued Ontario Regulation 386/18 (the “Regulation”) which revoked the Cap and Trade program regulation and prohibits registered participants from purchasing, selling, trading or otherwise dealing with emission allowances or credits. On July 25, 2018, the Government of Ontario introduced Bill 4 to wind down the Cap and Trade program. On October 31, 2018, Bill 4, Cap and Trade Cancellation Act, 2018 (the “Act”) received Royal Assent. This Act detailed the wind down of the Ontario Cap and Trade program, effectively expunging any compliance obligation associated with greenhouse gas emissions.

Additionally, in October 2018, the federal government confirmed that Ontario will be subject to the federal government’s carbon pricing program (otherwise known as the Federal Carbon Pricing Backstop Program) (the Program). EGD and Union Gas are in the process of updating already filed rate applications for the Program, based on recent regulation updates, with the OEB. We anticipate that all costs associated with the Program, including implementation and ongoing sustainment, will be considered a pass-through cost.

As with previous years, in 2018, the EGD and Union Gas each reported GHG emissions to the Ontario MECP, 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 MECP starting 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.

EGD and Union Gas 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. Collectively, EGD and Union Gas continue to work with industry associations to refine quantification methodologies and emissions factors, as well as best management practices to minimize emissions.

EMPLOYEES

We had approximately 12,000 employees as at December 31, 2018, including approximately 8,500 employees in Canada and approximately 3,500 employees in the United States. 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, 2019. We are currently in the process of collective bargaining with 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	59	President & Chief Executive Officer
John K. Whelen	59	Executive Vice President & Chief Financial Officer
Cynthia L. Hansen	54	Executive Vice President & President, Utilities and Power Operations
D. Guy Jarvis	55	Executive Vice President & President, Liquids Pipelines
Byron C. Neiles	53	Executive Vice President, Corporate Services
Robert R. Rooney	62	Executive Vice President & Chief Legal Officer
William T. Yardley	54	Executive Vice President & President, Gas Transmission and Midstream
Vern D. Yu	52	Executive Vice President & Chief Development Officer
Allen C. Capps	48	Senior 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. Prior to that, Mr. Whelen served as Senior Vice President Corporate Development and Vice President & Treasurer. Mr. Whelen has been part of the Enbridge team since 1992 holding a number of leadership positions of increasing responsibility within the Finance function.

Cynthia L. Hansen was appointed Executive Vice President and 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 and President, Liquids Pipelines on February 27, 2017. 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 centralized capital and maintenance projects division, as well as Information Technology, Human Resources, Real Estate & Workplace Services, Supply Chain Management, and Safety, Environment, Land & Right-of-Way 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 and oversees our Public Affairs and Communications (including Corporate Social Responsibility).

William T. Yardley was named Executive Vice President and President, Gas Transmission and Midstream on February 27, 2017 coincident with the closing of the Merger Transaction. Mr. Yardley is also the President of SEP. Prior to the closing of the Sponsored Vehicle buy-ins, Mr. Yardley was also the Chairman of the Board of SEP; he now continues to serve as a Manager on the Board of Managers. 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, responsible for the identification and execution of value enhancing growth opportunities and managing capital allocation and Enbridge’s 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 Senior 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 reporting. Prior to assuming his current role on February 27, 2017, in connection with the closing of the Merger Transaction, Mr. Capps served as Vice President and Controller of Spectra Energy, where he was 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).

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Additional information about EGD and Union Gas can be found in their combined annual information form, financial statements and management's discussion and analysis (MD&A) for the year ended December 31, 2018 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 Union Gas and are publicly available on SEDAR at www.sedar.com under the continuing amalgamated company Enbridge Gas Inc. 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, 2018 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.

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, 2018 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.

DCP MIDSTREAM LP
Additional information about DCP Midstream can be found in its Annual Report on Form 10-K that will be filed with the SEC. This document contains detailed disclosure with respect to DCP Midstream, and will be publicly available on EDGAR at www.sec.gov. No part of the Form 10-K filed by DCP Midstream is, 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 U.S. L3R Program, Atlantic Bridge and the T-South Expansion. New projects may not achieve their expected investment return, which could affect our financial results, and hinder our ability to secure future projects. For additional discussion of specific proceedings that could affect our operations and financial results, refer to Part II. Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Legal and Other Updates.

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, or the network or systems of our third-party vendors, 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 and our third-party vendors 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, or those of our vendors, may become the target of cyber-attacks (including hacking, viruses or acts of terrorism) or security breaches (including employee error, malfeasance or other

breaches), which could compromise our network or systems, or those of our vendors, 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.

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.

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 of the Lakehead System, in October 2018 at the BC Pipeline

T-South system and in January 2019 at the Texas Eastern pipeline, and cannot guarantee that we will not experience catastrophic events in the future. In addition, we could be subject to significant fines and penalties from regulators in connection with any 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.

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 our 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 our Gas Distribution 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. Our Gas Distribution business has 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 we attain our respective total forecast distribution volume, our Gas Distribution business may not earn its 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. Our Gas Distribution business remains 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.

Our transformation projects may fail to fully deliver anticipated results.

We launched projects starting in 2016 to transform various processes, capabilities and reporting systems infrastructure to continuously improve effectiveness and efficiency across the organization and are subject to transformation project risk with respect to these projects. Such projects, some of which will continue into 2019 and 2020, including integration initiatives arising out of the Merger Transaction and the amalgamation of EGD and Union Gas, are subject to transformation project risk. 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.

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 and natural gas 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 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.

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.

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 an optimal amount of capital from such asset sales. In addition, the timing to close asset sales could be significantly different than our expected timeline.

We have monetized or are in the process of monetizing certain assets to execute on our strategic priority to focus on core assets and to accelerate debt reduction and provide capital. Of the $7.8 billion in announced assets sales, $5.7 billion have closed. The remaining $2.1 billion is still subject to regulatory approvals and other factors. 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 close remaining 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. If the legislation is passed in its current form, we believe it would have adverse impacts on pipeline companies, particularly in relation to the regulatory review process for proposed new projects that are “designated projects”, by making overall timelines for the development and execution of these projects longer and significantly increasing uncertainty.

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 operational regulation and failure to comply with applicable regulations could have a negative impact on our business, financial condition or results of operations.

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 our assets and operations 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. Regulators' future actions may differ from current expectations, or future legislative changes may impact the regulatory environments in which we operate. We seek to mitigate operational regulation risk by active monitoring and consulting on potential regulatory requirement changes with the respective regulators directly, 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.

Our operations are subject to economic regulation and failure to secure regulatory approval for our proposed or existing project could have a negative impact on our business, financial condition or results of operations.

Our liquids pipelines face economic regulatory risk, the risk that governments or regulatory agencies change or reject proposed or existing commercial arrangements including permits and regulatory approvals for new projects. 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 modify significantly its own long-standing policies for rate making as well as overturn long-term agreements that we have entered into with shippers or deny the approval and permits for new projects.

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 and failure to secure permits necessary for our operations 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 and permits for our operating assets or development projects. If there is a delay in obtaining any required environmental regulatory approvals or permits, 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 may have a significant effect on our earnings and cash flows.

Our insurance coverage may not be sufficient to cover our losses in the event of an accident, natural disaster or other hazardous event.

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 certain of 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.

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.

We face competition from competing carriers available to ship western Canadian liquid hydrocarbons to markets in Canada, the United States and internationally and from proposed pipelines that seek to access markets currently served by our liquids pipelines. 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. We also face competition from alternative gathering and storage facilities. 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 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. Competition in all of our businesses, including competition for new project development opportunities, could have a negative impact on our business, financial condition or results of operations.

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

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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. Refer to Part II. Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Legal and Other Updates for a discussion of legal proceedings.

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 and may cause 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 growth rate and results may be indirectly affected by commodity prices and Government policy.

Recent efforts by the Alberta Government to manage supply and inventories in Western Canada is expected to be short term in application and have negligible impact on mainline throughput, as enough inventory exists to meet refinery customer needs and service our favorable markets. 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. Sanctioned projects due to come on stream in the next 24 months, which may face delays under the Alberta curtailment program, are not as sensitive to short-term declines in crude oil prices, as investment commitments have already been made. Wide commodity price basis between Western Canada and global tidewater markets have 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 which are operating at capacity. A protracted long-term outlook for low crude oil prices could result in delay or cancellation of future projects.

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 business. 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 market 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 new United States-Mexico-Canada Agreement (USMCA) (in Canada, known as the Canada-United States-Mexico Agreement (CUSMA)) is intended to supersede the North American Free Trade Agreement (NAFTA). USMCA/CUSMA has been signed but not ratified by the legislature of each of the United States, Canada and Mexico. NAFTA provides protection against tariffs, duties and other charges or fees and assures access by the signatories. The impact of USMCA/CUSMA, if ratified, on energy markets is uncertain.

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 still uncertain. While the United States Treasury issued substantial guidance in 2018 in the form of proposed regulations, uncertainty will still exist until the proposed regulations are finalized.

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

Common Stock
Our common stock is traded on the TSX and NYSE under the symbol “ENB.” As at February 8, 2019, there were approximately 2,022,657,570 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.

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

	2018	2017
Q1	0.671	0.583
Q2	0.671	0.610
Q3	0.671	0.610
Q4	0.671	0.610

Consistent with our objective of delivering annual cash dividend increases, we announced a quarterly dividend of $0.738 per common share payable on March 1, 2019, 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 2019 annual meeting of shareholders.
Recent Sales of Unregistered Equity Securities
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. Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources - Preference Share Issuances for further discussion of the transaction.

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.

Issuer Purchases of Equity Securities
None.

Total Shareholder Return
The following graph reflects the comparative changes in the value from January 1, 2014 through December 31, 2018 of $100 invested in (1) Enbridge Inc.’s common shares traded on the TSX, (2) the S&P/TSX Composite index, (3) the S&P 500 index, (4) our United States peer group (comprising D, DTE, ET, EPD, KMI, MMP, NI, OKE, PCG, PAA, SRE and WMB) and (5) our Canadian peer group (comprising

CU, FTS, IPL, PPL and TRP). The amounts included in the table were calculated assuming the reinvestment of dividends at the time dividends were paid.

	January 1,	December 31,				
	2014	2014	2015	2016	2017	2018
Enbridge Inc.	100.00	132.30	105.29	134.79	122.93	112.74
S&P/TSX Composite	100.00	110.55	101.36	122.73	133.89	121.99
S&P 500 Index	100.00	113.69	115.26	129.05	157.22	150.33
United States Peers[1]	100.00	123.29	93.64	122.09	123.03	114.49
Canadian Peers	100.00	127.12	102.14	133.43	142.98	129.44

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,				
	2018[1]	2017[1]	2016[1]	2015	2014
(millions of Canadian dollars, except per share amounts)					
Consolidated Statements of Earnings					
Operating revenues	$46,378	$44,378	$34,560	$33,794	$37,641
Operating income	4,816	1,571	2,581	1,862	3,200
Earnings/(loss) from continuing operations	3,333	3,266	2,309	(159)	1,562
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	(451)	(407)	(240)	410	(203)
Earnings attributable to controlling interests	2,882	2,859	2,069	251	1,405
Earnings/(loss) attributable to common shareholders	2,515	2,529	1,776	(37)	1,154
Common Stock Data					
Earnings/(loss) per common share					
Basic	1.46	1.66	1.95	(0.04)	1.39
Diluted	1.46	1.65	1.93	(0.04)	1.37
Dividends paid per common share	2.68	2.41	2.12	1.86	1.40

	December 31,				
	2018[1]	2017[1]	2016[1]	2015	2014
(millions of Canadian dollars)					
Consolidated Statements of Financial Position					
Total assets[2]	$166,905	$162,093	$85,209	$84,154	$72,280
Long-term debt including capital leases, less current portion	60,327	60,865	36,494	39,391	33,423

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

2018 - Canadian Natural Gas Gathering and Processing business impairment and gain on disposition of provincially regulated assets, Midcoast Operating, L.P. impairment and loss on disposition, Line 10 impairment, and other losses on disposition.

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.

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.

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

INTRODUCTION

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

SIMPLIFICATION OF CORPORATE STRUCTURE

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

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

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

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

ASSET MONETIZATION

Renewable Assets

On August 1, 2018, we closed the sale of a 49% interest in all of our Canadian renewable assets, a 49% interest in two United States renewable assets and 49% of our interest in the Hohe See Offshore wind power project and its subsequent expansion, both concurrently under construction in Germany, (collectively, the Renewable Assets) to the Canada Pension Plan Investment Board (CPPIB). Total cash proceeds from the transaction were $1.75 billion. In addition, CPPIB will fund their pro-rata share of the remaining capital expenditures on the Hohe See Offshore wind project. We maintain a 51% interest in the Renewable Assets and will continue to manage, operate and provide administrative services for these assets.

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

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

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

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

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

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

REVISED FERC POLICY ON TREATMENT OF INCOME TAXES

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

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

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

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

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

UNITED STATES TAX REFORM

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

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

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

RESULTS OF OPERATIONS

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

EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS

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

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

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

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

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

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

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

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

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

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

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

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

- a loss of $4,391 million ($2,753 million after-tax attributable to us) and related goodwill impairment of $102 million resulting from the classification of certain assets as held for sale and the subsequent measurement at the lower of their carrying value or fair value less costs to sell, refer to Item 8. Financial Statements and Supplementary Data - Note 8. Acquisitions and Dispositions - Dispositions;
-

employee severance, transition and transformation costs of $354 million ($273 million after-tax attributable to us) in 2017, compared with $82 million in the corresponding 2016 period;

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

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

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

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

REVENUES

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

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

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

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

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

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

DIVIDENDS

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

BUSINESS SEGMENTS

LIQUIDS PIPELINES

EARNINGS BEFORE INTEREST, INCOME TAXES AND DEPRECIATION AND AMORTIZATION

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

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

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

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

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

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

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

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

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

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

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

- a gain of $72 million on sale of pipe partially offset by project wind-down costs related to EEP's Sandpiper; partially offset by
- the absence in 2017 of a $850 million gain recorded in 2016 related to the sale of non-core South Prairie Region assets.

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

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

GAS TRANSMISSION AND MIDSTREAM

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

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

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

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

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

- a net positive impact of $3,539 million related to the sale of MOLP due to the following:

the absence in 2018 of a loss of $4,391 million and related goodwill impairment of $102 million recorded in 2017 resulting from the classification of assets as held for sale and the subsequent measurement at the lower of their carrying value or fair value less costs to sell; partially offset by

  a loss of $913 million in 2018 resulting from the further revision to the fair value of the assets held for sale based on the sale price; and

a loss of $41 million in 2018 resulting from the sale of the assets.

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

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

- contributions from assets placed into service in 2018, including NEXUS, Valley Crossing, High Pine and Wyndwood pipelines;
- contributions from assets placed into service in the second half of 2017, including Sabal Trail Transmission, LLC (Sabal Trail), Access South, Adair Southwest and Lebanon Extension pipelines;
- increased fractionation margins at our Aux Sable joint venture driven by higher NGL prices and increased demand;
- favorable seasonal firm and interruptible revenues from our Alliance joint venture that resulted from wider basis differentials; and
- increased earnings from our DCP Midstream LP joint venture driven by favorable commodity prices and increased volumes.

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

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

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

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

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

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

GAS DISTRIBUTION

EARNINGS BEFORE INTEREST, INCOME TAXES AND DEPRECIATION AND AMORTIZATION

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

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

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

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

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

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

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

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

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

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

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

GREEN POWER AND TRANSMISSION

EARNINGS BEFORE INTEREST, INCOME TAXES AND DEPRECIATION AND AMORTIZATION

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

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

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

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

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

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

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

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

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

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

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

ENERGY SERVICES

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

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

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

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

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

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

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

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

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

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

ELIMINATIONS AND OTHER

LOSS BEFORE INTEREST, INCOME TAXES AND DEPRECIATION AND AMORTIZATION

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

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

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

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

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

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

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

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

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

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

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

GROWTH PROJECTS – COMMERCIALLY SECURED PROJECTS

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

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

16	Other - Canada	25	%	$0.2 billion	No significant expenditures to date	Pre-construction	2H - 2021

1 These amounts are estimates and are subject to upward or downward adjustment based on various factors. Where appropriate, the amounts reflect our share of joint venture projects.
2 Expenditures to date reflect total cumulative expenditures incurred from inception of the project up to December 31, 2018.
3 Construction of the Wisconsin portion of the project is complete as noted below. The remaining project is in pre-construction status.
4 Includes the Lakehead System Mainline Expansion - Line 61. Estimated in-service date will be adjusted to coincide with the in-service date of the U.S. L3R Program.
5 Includes the $0.1 billion Line 45 Cheecham connectivity placed into service in the second quarter of 2018.
6 Includes the US$0.2 billion Stampede Offshore oil lateral placed into service in the first quarter of 2018, the US$0.2 million Texas Eastern Appalachian Lease project placed into service in the fourth quarter of 2018, and the US$0.4 million South Texas Expansion Project and Pomelo Connector Pipeline Project placed into service in the fourth quarter of 2018.
7 Includes the $0.4 billion High Pine and the $0.2 billion Wyndwood pipeline expansion, both placed into service in the first quarter of 2018.
8 Upon closing of the sale of our Renewable Assets, our ownership interest was reduced to approximately 25%. Refer to Asset Monetization.

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

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

- Canadian Line 3 Replacement Program - replacement of the existing Line 3 crude oil pipeline between Hardisty, Alberta and Gretna, Manitoba. The Canadian L3R Program will restore the original capacity of 760,000 bpd, an increase of approximately 370,000 bpd. This will support the safety and operational reliability of the overall system, enhancing flexibility and allowing us to optimize throughput from western Canada into Superior, Wisconsin. Construction commenced in early August 2017 and is nearing completion.

- United States Line 3 Replacement Program - replacement of the existing Line 3 crude oil pipeline between Neche, North Dakota and Superior, Wisconsin. The U.S. L3R Program will support the safety and operational reliability of the mainline system, enhance system flexibility, and allow us to optimize throughput on the mainline. The L3R Program is expected to achieve the original capacity of approximately 760,000 bpd. The Wisconsin portion of the U.S. L3R Program is in service. For additional updates on the project, refer to Growth Projects - Regulatory Matters.

- Gray Oak Pipeline Project - a crude oil pipeline project connecting West Texas to destinations in the Corpus Christi and Sweeny/Freeport markets. The pipeline is a joint development with Phillips 66 and could have an ultimate capacity of approximately 900,000 bpd, subject to additional shipper commitments.

GAS TRANSMISSION AND MIDSTREAM

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

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

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

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

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

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

GREEN POWER AND TRANSMISSION

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

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

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

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

GROWTH PROJECTS - REGULATORY MATTERS

United States Line 3 Replacement Program

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

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

OTHER ANNOUNCED PROJECTS UNDER DEVELOPMENT

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

LIQUIDS PIPELINES

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

GREEN POWER AND TRANSMISSION

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

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

LIQUIDITY AND CAPITAL RESOURCES

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

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

CAPITAL MARKET ACCESS

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

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

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

Credit Facilities, Ratings and Liquidity

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

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

1 Includes facility draws, letters of credit and commercial paper issuances that are back-stopped by the credit facility.
2 Includes $253 million (US$185 million) of facilities that expire in 2020.
3 Includes $459 million (US$336 million) of facilities that expire in 2021.

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

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

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

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

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

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

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

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

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

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

During 2018, our credit ratings were affirmed as follows:

- DBRS Limited confirmed our issuer rating and medium-term notes and unsecured debentures rating of BBB (high), fixed-to-floating subordinated notes rating of BBB (low), preference share rating of Pfd-3 (high) and commercial paper rating of R-2 (high), all with stable outlooks.
- Standard & Poor’s Rating Services (S&P) affirmed our corporate credit rating and senior unsecured debt rating of BBB+, preference share rating of P-2 (low) and commercial paper rating of A-1 (low), and reaffirmed a stable outlook. S&P also affirmed our global overall short-term rating of A-2.
- Fitch Rating services affirmed long-term issuer default rating and senior unsecured debt rating of BBB+, preference share rating of BBB-, junior subordinated note rating of BBB-, and short-term and commercial paper rating of F2 with a stable rating outlook.
- On January 25, 2019 Moody’s Investor Services, Inc. upgraded our issuer and senior unsecured ratings from Baa3 to Baa2 with outlook revised to positive, upgraded our subordinated rating from Ba2 to Ba1, preference share rating from Ba2 to Ba1 and the commercial paper rating for Enbridge (U.S.) Inc. from P-3 to P-2.

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

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

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

To address this negative working capital position, we maintain significant liquidity in the form of committed credit facilities and other sources as previously discussed, which enable the funding of liabilities as they become due. As at December 31, 2018 and 2017, our net available liquidity totaled $9,409 million and

$12,959 million, respectively, on a consolidated basis. It is anticipated that any current maturities of long-term debt will be refinanced upon maturity.

SOURCES AND USES OF CASH

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

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

Operating Activities

2018

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

2017

- The growth in cash flow delivered by operations in 2017 is a reflection of the positive operating factors discussed under Results of Operations, which included contributions from new assets of approximately $2,574 million following the completion of the Merger Transaction.
- For the year ended, partially offsetting the increase in cash flows from operating activities are transaction costs in connection with the Merger Transaction, as well as employee severance costs in relation to our enterprise-wide reduction of workforce.
- Changes in operating assets and liabilities increased to $338 million from $368 million for the years ended December 31, 2017 and 2016, respectively, reflected negative working capital in each of those years. Our operating assets and liabilities fluctuate in the normal course due to various factors including fluctuations in commodity prices and activity levels within the Energy Services and Gas Distribution segments, the timing of tax payments, as well as timing of cash receipts and payments.

Investing Activities

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

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

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

2018

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

2017

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

Financing Activities

2018

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

- Repayments of maturing term notes and credits facilities, and a decrease in long-term debt issued in 2018 when compared to 2017.
- During 2018, we sold an interest in our Canadian and US renewable assets to the CPPIB. The proceeds of these dispositions and the dispositions of MOLP, the provincially regulated portion of our Canadian Natural Gas Gathering and Processing Businesses assets and international renewable assets discussed in Investing Activities above, were primarily used to repay maturing term notes and credit facilities, while proceeds from hybrid securities issued during the first half of 2018 were primarily used to repay credit facilities and to repurchase or redeem Spectra Energy Capital, LLC’s outstanding senior unsecured notes.
- Cash from financing activities further decreased as a result of decreased contributions from noncontrolling interests and redeemable noncontrolling interests. Noncontrolling interest contributions received in 2017 related to completed projects for which there were no contributions received from noncontrolling interests in 2018. In April 2017, contributions from redeemable

noncontrolling interests were received from a secondary public offering attributable to our holdings in ENF. There were no similar offerings in 2018.

- Our common share dividend payments increased in the year ended 2018, primarily due to the increase in the common share dividend rate in the first quarter of 2018, as well as an increase in the number of common shares outstanding as a result of common shares issued in connection with the Merger Transaction and the issuance of approximately 33 million common shares in December 2017 in a private placement offering.

2017

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

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

Preference Share Issuances

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

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

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

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

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

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

5 The floating quarterly dividend amount for the Series C Preference Shares was increased to $0.22685 from $0.20342 on March 1, 2018, was increased to $0.22748 from $0.22685 on June 1, 2018, was increased to $0.23934 from $0.22748 on September 1, 2018 and was increased to $0.25459 from $0.23934 on December 1, 2018, due to reset on a quarterly basis following the issuance thereof.

6

No Series D, F, H, N, or 1 Preference shares were converted on the March 1, 2018, June 1, 2018, September 1, 2018, December 1, 2018 or June 1, 2018 conversion option dates, respectively. However, the quarterly dividend amounts for Series D, F, H, N, and 1, were reset to $0.27875 from $0.25000 on March 1, 2018, $0.29306 from $0.25000 on June 1, 2018, $0.27350 from $0.25000 on September 1, 2018, $0.31788 from $0.25000 on December 1, 2018 and US$0.37182 from US$0.25000 on June 1, 2018, respectively, due to reset on every fifth anniversary thereafter.

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

Common Share Issuances

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

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

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

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

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

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

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

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

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

2 The floating dividend on the Series C Preference Shares is reset each quarter. The quarterly dividend amount of Series C increased to $0.22685 from $0.20342 on March 1, 2018, increased to $0.22748 from $0.22685 on June 1, 2018, increased to $0.23934 from $0.22748 on September 1, 2018 and increased to $0.25459 from $0.23934 on December 1, 2018.
3 The quarterly dividend amount of Series D increased to $0.27875 from $0.25000 on March 1, 2018, due to the reset of the annual dividend on every fifth anniversary of the date of issuance of the Series D Preference Shares.
4 The quarterly dividend amount of Series F increased to $0.29306 from $0.25000 on June 1, 2018, due to the reset of the annual dividend on every fifth anniversary of the date of issuance of the Series F Preference Shares.
5 The quarterly dividend amount of Series H increased to $0.27350 from $0.25000 on September 1, 2018, due to the reset of the annual dividend on every fifth anniversary of the date of issuance of the Series H Preference Shares.
6 The quarterly dividend amount of Series N increased to $0.31788 from $0.25000 on December 1, 2018, due to the reset of the annual dividend on every fifth anniversary of the date of issuance of the Series N Preference Shares.
7 The quarterly dividend amount of Series 1 increased to US$0.37182 from US$0.25000 on June 1, 2018, due to the reset of the annual dividend on every fifth anniversary of the date of issuance of the Series 1 Preference Shares.
8 The quarterly dividend amount of Series 19 increased from the first dividend of $0.26850 payable on March 1, 2018 to the regular quarterly dividend of $0.30625, effective June 1, 2018.

OFF-BALANCE SHEET ARRANGEMENTS

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

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

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

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

CONTRACTUAL OBLIGATIONS

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

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

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

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

3 Includes land leases.

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

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

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

LEGAL AND OTHER UPDATES

LIQUIDS PIPELINES

Renewal of Line 5 Easement

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

Eddystone Rail Legal Matter

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

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

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

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

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

GAS TRANSMISSION AND MIDSTREAM
Sabal Trail FERC Certificate Review
Sierra Club and two other non-governmental organizations filed a Petition for Review of Sabal Trail’s FERC certificate on September 20, 2016 in the D.C. Circuit Court of Appeals. On August 22, 2017, the D.C. Circuit issued an opinion denying one of the petitions, and granting the other petition in part, vacating the certificates, and remanding the case to FERC to supplement the environmental impact statement for the project to estimate the quantity of green-house gases to be released into the environment by the gas-fired generation plants in Florida that will consume the gas transported by Sabal Trail. The court withheld issuance of the mandate requiring vacatur of the certificate until seven days after the disposition of any timely petition for rehearing. On October 6, 2017, Sabal Trail

and FERC each filed

timely petitions for rehearing. On January 31, 2018, the court denied FERC’s and Sabal Trail’s petitions for rehearing. On February 5, 2018, FERC issued its final supplemental environmental impact statement in compliance with the D.C. Circuit decision. In addition, on February 6, 2018, FERC filed a motion with the court requesting a 45-day stay of the mandate. On March 7, 2018, the court granted FERC’s 45-day request for stay, and directed that issuance of the mandate be withheld through March 26, 2018. On March 14, 2018 FERC issued its Order on Remand Reinstating Certificate and Abandonment Authorizations which addressed the court’s ruling in the August 22, 2017 decision (March 14, 2018 Order), and on March 30, 2018 the court issued its mandate.

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

GAS DISTRIBUTION

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

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

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

OTHER LITIGATION

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

TAX MATTERS

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

CRITICAL ACCOUNTING ESTIMATES

Our consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States, which require management to make estimates, judgments and

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assumptions that affect the amounts reported in our consolidated financial statements and accompanying notes. In making judgments and estimates, management relies on external information and observable conditions, where possible, supplemented by internal analysis as required. We believe our most critical accounting policies and estimates discussed below have an impact across the various segments of our business.

Business Combinations

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

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

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

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

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

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

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

Asset Impairment
We evaluate the recoverability of our property, plant and equipment when events or circumstances such as economic obsolescence, business climate, legal or regulatory changes, or other factors indicate we may not recover the carrying amount of our assets. We continually monitor our businesses, the market and business environments to identify indicators that could suggest an asset may not be recoverable. If it is determined that the carrying value of an asset exceeds the undiscounted cash flows expected from the asset, we will assess the fair value of the asset. An impairment loss is recognized when the carrying amount of the asset exceeds its fair value as determined by quoted market prices in active markets or present value techniques. The determination of the fair value using present value techniques requires the use of projections and assumptions regarding future cash flows and weighted average cost of capital. Any changes to these projections and assumptions could result in revisions to the evaluation of the recoverability of the property, plant and equipment and the recognition of an impairment loss in the Consolidated Statements of Earnings.
Assets held for sale
We classify assets as held for sale when management commits to a formal plan to actively market an asset or a group of assets and when management believes it is probable the sale of the assets will occur within one year. We measure assets classified as held for sale at the lower of their carrying value and their estimated fair value less costs to sell.

Regulatory Accounting

Certain of our businesses are subject to regulation by various authorities, including but not limited to, the NEB, the FERC, the Alberta Energy Regulator, the NBEUB, La Régie de l'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 Generally accepted accounting principle in the United States of America (U.S. GAAP) for non-rate-regulated entities.
Key determinants in the ratemaking process are:

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

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

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

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

Depreciation

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

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

Postretirement Benefits

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

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

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

Contingent Liabilities

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

Asset Retirement Obligations

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

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

CHANGES IN ACCOUNTING POLICIES

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

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 may be 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 2.8%.

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, when applicable, to hedge against future changes to the fair value of fixed rate debt which mitigates the impact of fluctuations in the fair value of fixed rate debt via execution of fixed to floating interest rate swaps. As of December 31, 2018 we do not have any pay floating-receive fixed interest rate swaps outstanding.

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 established 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 3.2%.

We also monitor our debt portfolio mix of fixed and variable rate debt instruments to manage a consolidated portfolio of floating rate debt within the Board of Directors approved policy limit of a maximum of 30% of 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.

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 one 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 cash flow 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 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 cash flow volatility arising from market related risks to an acceptable approved risk tolerance threshold.

Effective January 1, 2018, the Board of Directors approved a change in our market risk metric to Cash Flow at Risk (CFaR). The policy change aligns the market risk metric with key result metrics in the organization.

CFaR is a statistically derived measurement used to measure the maximum cash flow loss 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 Consolidated Statements of Financial Position as at December 31, 2018. CFaR assumes that no further mitigating actions are taken to hedge or otherwise minimize exposures and the selection of a one month holding period reflects the mix of price risk sensitive assets at Enbridge. 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 CFaR policy limit for Enbridge is 3.5% of its forward 12 month normalized cash flow. At December 31, 2018 CFaR was $140M or 1.6% of estimated 12 month forward normalized cash flow.

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, 2018. 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 strong investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated through maintenance and monitoring of 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.

FAIR VALUE MEASUREMENTS

The most observable inputs available are used to estimate the fair value of 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 Board of Directors of Enbridge Inc.

Opinions on the Financial Statements and Internal Control over Financial Reporting
We have audited the accompanying consolidated statements of financial position of Enbridge Inc. and its subsidiaries (together, the Company) as of December 31, 2018 and 2017, 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, 2018, 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, 2018, 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 financial position of the Company as of December 31, 2018 and 2017, and their results of operations and their cash flows for each of the three years in the period ended December 31, 2018 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, 2018, 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 accompanying 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 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 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 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
Chartered Professional Accountants
Calgary, Alberta, Canada
February 15, 2019

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

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	2018	2017	2016
(millions of Canadian dollars, except per share amounts)			
Operating revenues			
Commodity sales	27,660	26,286	22,816
Gas distribution sales	4,360	4,215	2,486
Transportation and other services	14,358	13,877	9,258
Total operating revenues (Note 4)	46,378	44,378	34,560
Operating expenses			
Commodity costs	26,818	26,065	22,409
Gas distribution costs	2,583	2,572	1,596
Operating and administrative	6,792	6,442	4,358
Depreciation and amortization	3,246	3,163	2,240
Impairment of long-lived assets (Note 8 and Note 11)	1,104	4,463	1,376
Impairment of goodwill (Note 8 and Note 16)	1,019	102	—
Total operating expenses	41,562	42,807	31,979
Operating income	4,816	1,571	2,581
Income from equity investments (Note 13)	1,509	1,102	428
Other income/(expense)			
Net foreign currency gain/(loss)	(522)	237	91
Gain/(loss) on dispositions	(46)	16	848
Other	516	199	93
Interest expense (Note 18)	(2,703)	(2,556)	(1,590)
Earnings before income taxes	3,570	569	2,451
Income tax recovery/(expense) (Note 25)	(237)	2,697	(142)
Earnings	3,333	3,266	2,309
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	(451)	(407)	(240)
Earnings attributable to controlling interests	2,882	2,859	2,069
Preference share dividends	(367)	(330)	(293)
Earnings attributable to common shareholders	2,515	2,529	1,776
Earnings per common share attributable to common shareholders (Note 6)	1.46	1.66	1.95
Diluted earnings per common share attributable to common shareholders (Note 6)	1.46	1.65	1.93

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

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	2018	2017	2016
(millions of Canadian dollars)			
Earnings	3,333	3,266	2,309
Other comprehensive income/(loss), net of tax			
Change in unrealized loss on cash flow hedges	(153)	(21)	(138)
Change in unrealized gain/(loss) on net investment hedges	(458)	490	166
Other comprehensive income/(loss) from equity investees	38	(27)	—
Reclassification to earnings of loss on cash flow hedges	152	313	116
Reclassification to earnings of pension and other postretirement benefits amounts	12	19	17
Actuarial gain/(loss) on pension plans and other postretirement benefits	(52)	8	(34)
Foreign currency translation adjustments	4,599	(3,060)	(712)
Other comprehensive income/(loss), net of tax	4,138	(2,278)	(585)
Comprehensive income	7,471	988	1,724
Comprehensive income attributable to noncontrolling interests and redeemable noncontrolling interests	(801)	(160)	(229)
Comprehensive income attributable to controlling interests	6,670	828	1,495
Preference share dividends	(367)	(330)	(293)
Comprehensive income attributable to common shareholders	6,303	498	1,202

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

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

Year ended December 31,	2018	2017	2016
(millions of Canadian dollars, except per share amounts)			
Preference shares (Note 21)			
Balance at beginning of year	7,747	7,255	6,515
Preference shares issued	—	492	740
Balance at end of year	7,747	7,747	7,255
Common shares (Note 21)			
Balance at beginning of year	50,737	10,492	7,391
Common shares issued	—	1,500	2,241
Common shares issued in Merger Transaction (Note 8)	—	37,429	—
Shares issued on Sponsored Vehicles buy-in (Note 21)	12,727	—	—
Dividend Reinvestment and Share Purchase Plan	1,181	1,226	795
Shares issued on exercise of stock options	32	90	65
Balance at end of year	64,677	50,737	10,492
Additional paid-in capital			
Balance at beginning of year	3,194	3,399	3,301
Stock-based compensation	49	82	41
Sponsored Vehicles buy-in (Note 20)	(4,323)	—	—
Options exercised	(24)	(95)	(24)
Dilution gain on Spectra Energy Partners, LP restructuring (Note 20)	1,136	—	—
Dilution gain/(loss) and other	(111)	(192)	81
Sale of noncontrolling interest in subsidiaries (Note 20)	79	—	—
Balance at end of year	—	3,194	3,399
Retained earnings/(deficit)			
Balance at beginning of year	(2,468)	(716)	142
Earnings attributable to controlling interests	2,882	2,859	2,069
Preference share dividends	(367)	(330)	(293)
Common share dividends declared	(5,019)	(4,702)	(1,945)
Dividends paid to reciprocal shareholder	33	30	26
Modified retrospective adoption of ASC 606 Revenue from Contracts with Customers (Note 3)	(86)	—	—
Redemption value adjustment attributable to redeemable noncontrolling interests (Note 20)	(456)	292	(686)
Adjustment relating to equity method investment	—	—	(29)
Other	(57)	99	—
Balance at end of year	(5,538)	(2,468)	(716)
Accumulated other comprehensive income/(loss) (Note 23)			
Balance at beginning of year	(973)	1,058	1,632
Impact of Sponsored Vehicles buy-in	(142)	—	—
Other comprehensive income/(loss) attributable to common shareholders, net of tax	3,787	(2,031)	(574)
Balance at end of year	2,672	(973)	1,058
Reciprocal shareholding (Note 13)			
Balance at beginning of year	(102)	(102)	(83)
Change in reciprocal interest	14	—	(19)
Balance at end of year	(88)	(102)	(102)
Total Enbridge Inc. shareholders' equity	69,470	58,135	21,386
Noncontrolling interests (Note 20)			
Balance at beginning of year	7,597	577	1,300

Earnings/(loss) attributable to noncontrolling interests	334	232	(28)
Other comprehensive income/(loss) attributable to noncontrolling interests, net of tax			
Change in unrealized gain on cash flow hedges	31	15	4
Foreign currency translation adjustments	294	(431)	(44)
Reclassification to earnings of (gain)/loss on cash flow hedges	4	139	40
	329	(277)	—
Comprehensive income/(loss) attributable to noncontrolling interests	663	(45)	(28)
Noncontrolling interests resulting from Merger Transaction (Note 8)	—	8,955	—
Enbridge Energy Company, Inc. common control transaction	—	(343)	—
Distributions	(857)	(839)	(720)
Contributions	24	832	28
Deconsolidation of Sabal Trail Transmission, LLC	—	(2,318)	—
Spectra Energy Partners, LP restructuring (Note 20)	(1,486)	—	—
Sale of noncontrolling interest in subsidiaries	1,183	—	—
Purchase of noncontrolling interests on Sponsored Vehicles buy-in (Note 20)	(2,657)	—	—
Noncontrolling interests reclassified on Sponsored Vehicles buy-in	(210)	—	—
Preferred share redemption (Note 20)	(210)	—	—
Dilution gain	—	832	—
Other	(82)	(54)	(3)
Balance at end of year	3,965	7,597	577
Total equity	73,435	65,732	21,963
Dividends paid per common share	2.68	2.41	2.12

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

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	2018	2017	2016
(millions of Canadian dollars)			
Operating activities			
Earnings	3,333	3,266	2,309
Adjustments to reconcile earnings to net cash provided by operating activities:			
Depreciation and amortization	3,246	3,163	2,240
Deferred income tax (recovery)/expense	(148)	(2,877)	43
Changes in unrealized (gain)/loss on derivative instruments, net (Note 24)	903	(1,242)	(509)
Earnings from equity investments	(1,509)	(1,102)	(656)
Distributions from equity investments	1,539	1,264	827
Impairment of long-lived assets	1,104	4,463	1,620
Impairment of goodwill	1,019	102	—
(Gain)/loss on dispositions	8	(120)	(848)
Other	92	79	547
Changes in operating assets and liabilities (Note 27)	915	(338)	(368)
Net cash provided by operating activities	10,502	6,658	5,205
Investing activities			
Capital expenditures	(6,806)	(8,287)	(5,128)
Long-term investments	(1,312)	(3,586)	(514)
Distributions from equity investments in excess of cumulative earnings	1,277	125	—
Additions to intangible assets	(540)	(789)	(127)
Acquisitions	—	—	(644)
Cash acquired in Merger Transaction (Note 8)	—	682	—
Proceeds from dispositions	4,452	628	1,379
Reimbursement of capital expenditures	—	212	—
Other	(88)	(22)	(118)
Net cash used in investing activities	(3,017)	(11,037)	(5,152)
Financing activities			
Net change in short-term borrowings (Note 18)	(420)	721	(248)
Net change in commercial paper and credit facility draws	(2,256)	(1,249)	(2,297)
Debenture and term note issues, net of issue costs	3,537	9,483	4,080
Debenture and term note repayments	(4,445)	(5,054)	(1,946)
Sale of noncontrolling interest in subsidiary	1,289	—	—
Purchase of interest in consolidated subsidiary	—	(227)	—
Contributions from noncontrolling interests	24	832	28
Distributions to noncontrolling interests	(857)	(919)	(720)
Contributions from redeemable noncontrolling interests	70	1,178	591
Distributions to redeemable noncontrolling interests	(325)	(247)	(202)
Sponsored Vehicle buy-in cash payment	(64)	—	—
Preference shares issued	—	489	737
Redemption of preferred shares	(210)	—	—
Common shares issued	21	1,549	2,260
Preference share dividends	(364)	(330)	(293)
Common share dividends	(3,480)	(2,750)	(1,150)
Other	(23)	—	—
Net cash (used in)/provided by financing activities	(7,503)	3,476	840
Effect of translation of foreign denominated cash and cash equivalents and restricted cash	68	(72)	(19)
Net increase/(decrease) in cash and cash equivalents and restricted cash	50	(975)	874

Cash and cash equivalents and restricted cash at beginning of year	587	1,562	688
Cash and cash equivalents and restricted cash at end of year	637	587	1,562
Supplementary cash flow information			
Cash paid for income taxes	277	172	194
Cash paid for interest, net of amount capitalized	2,508	2,668	1,820
Property, plant and equipment non-cash accruals	847	889	773

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

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ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	2018	2017
(millions of Canadian dollars; number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents (Note 2)	518	480
Restricted cash	119	107
Accounts receivable and other (Note 9)	6,517	7,053
Accounts receivable from affiliates	79	47
Inventory (Note 10)	1,339	1,528
	8,572	9,215
Property, plant and equipment, net (Note 11)	94,540	90,711
Long-term investments (Note 13)	16,707	16,644
Restricted long-term investments (Note 14)	323	267
Deferred amounts and other assets	8,558	6,442
Intangible assets, net (Note 15)	2,372	3,267
Goodwill (Note 16)	34,459	34,457
Deferred income taxes (Note 25)	1,374	1,090
Total assets	166,905	162,093
Liabilities and equity		
Current liabilities		
Short-term borrowings (Note 18)	1,024	1,444
Accounts payable and other (Note 17)	9,836	9,478
Accounts payable to affiliates	40	157
Interest payable	669	634
Environmental liabilities	27	40
Current portion of long-term debt (Note 18)	3,259	2,871
	14,855	14,624
Long-term debt (Note 18)	60,327	60,865
Other long-term liabilities	8,834	7,510
Deferred income taxes (Note 25)	9,454	9,295
	93,470	92,294
Commitments and contingencies (Note 29)		
Redeemable noncontrolling interests (Note 20)	—	4,067
Equity		
Share capital (Note 21)		
Preference shares	7,747	7,747
Common shares (2,022 and 1,695 outstanding at December 31, 2018 and December 31, 2017, respectively)	64,677	50,737
Additional paid-in capital	—	3,194
Deficit	(5,538)	(2,468)
Accumulated other comprehensive income/(loss) (Note 23)	2,672	(973)
Reciprocal shareholding	(88)	(102)
Total Enbridge Inc. shareholders’ equity	69,470	58,135
Noncontrolling interests (Note 20)	3,965	7,597
	73,435	65,732
Total liabilities and equity	166,905	162,093

Variable Interest Entities (Note 12).
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.

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, Gulf Coast and Mid-Continent, Southern Lights Pipeline, Express-Platte System, Bakken System, and Feeder Pipelines and Other.

GAS TRANSMISSION AND MIDSTREAM
Gas Transmission and Midstream consists of investments in natural gas pipelines and gathering and processing facilities in Canada and the United States. 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 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 natural gas distribution activities in Quebec and New Brunswick and an investment in Noverco Inc. (Noverco).

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 in operation and 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 the impact of foreign exchange hedge settlements, which are not allocated to business segments. Also included in Eliminations and Other are new business development activities, general corporate investments and a portion of the synergies achieved thus far related to the integration of corporate functions due to the Merger Transaction, as defined in Acquisition of Spectra Energy Corp.

SPONSORED VEHICLES BUY-IN

In the fourth quarter of 2018, Enbridge completed the buy-ins of our sponsored vehicles: Spectra Energy Partners, LP (SEP), Enbridge Energy Partners, L.P. (EEP), Enbridge Energy Management, L.L.C. (EEM) and Enbridge Income Fund Holdings Inc. (ENF), (referred to herein collectively as the Sponsored Vehicles) in a series of combination transactions, through which we acquired all of the outstanding equity securities of the Sponsored Vehicles not beneficially owned by us (collectively, the Sponsored Vehicles buy-in). Please refer to Note 20 - Noncontrolling Interests for further discussion of the transactions.

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 common stock for each share of Spectra Energy common stock that they owned, resulting in us acquiring 100% ownership of Spectra Energy. Please refer to Note 8 - Acquisitions and Dispositions for further discussion of the transaction.

DISPOSITIONS

During the years ended December 31, 2018 and 2017, we have disposed of a number of our non-core assets. Please refer to Note 8 - Acquisitions and Dispositions for further discussion of these transactions.

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 7); purchase price allocations (Note 8); unbilled revenues; depreciation rates and carrying value of property, plant and equipment (Note 11); amortization rates of intangible assets (Note 15); measurement of goodwill (Note 16); fair value of asset retirement obligations (ARO) (Note 19); valuation of stock-based compensation (Note 22); fair value of financial instruments (Note 24); provisions for income taxes (Note 25); assumptions used to measure retirement and other postretirement benefit obligations (OPEB) (Note 26); commitments and contingencies (Note 29); and estimates of losses related to environmental remediation obligations (Note 29). Actual results could differ from these estimates.

Certain comparative figures in our Consolidated Statements of Cash Flows have been reclassified to conform to the current year's presentation. 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. Net cash provided by financing activities in the Consolidated Statements of Cash Flows for the year ended December 31, 2016 have decreased by $0.3 billion 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 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, if 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 is applied, where an investor holding the majority voting rights consolidates the entity.

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 for comparative periods. Redeemable noncontrolling interests on the Consolidated Statements of Financial Position as at December 31, 2017 are recognized 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 (NBEUB), 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 7).

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, 2018, 2017 and 2016, cash received net of revenue recognized for contracts under make-up rights and similar deferred revenue arrangements was $208 million, $196 million, and $249 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.

Our Energy Services segment enters into commodity purchase and sale arrangements that are recorded gross because the related contracts are not held for trading purposes and we are acting as the principal in the transactions. 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 have readily determinable fair values as other investments measured at fair value measurement alternative and 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 impairment each reporting period. Equity investments with readily determinable fair values are measured at fair value through net income. Dividends received from investments in equity securities are recognized in earnings when the right to receive payment is established.

Investments in debt securities are classified either as available for sale securities measured at fair value through OCI or as held to maturity securities measured at amortized cost.

NONCONTROLLING INTERESTS
Noncontrolling interests represent ownership interests attributable to third parties in certain consolidated subsidiaries. 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 as at December 31, 2017, within the mezzanine section of the Consolidated Statements of Financial Position between long-term liabilities and equity.

Enbridge Income Fund (The Fund)'s noncontrolling interest holders had the option to redeem the Fund trust units for cash, subject to certain limitations. Redeemable noncontrolling interests as at December 31, 2017 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 and up until redeemable noncontrolling interest repurchase date, 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 for comparative periods.

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. From January 1, 2017 through July 3, 2018, emission allowances, which are recorded at their original cost, were 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 of the goodwill balance on April 1.

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.

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

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 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

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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. ARO 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 2018) 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.

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

There were no changes in accounting policies during the year ended December 31, 2018.

ADOPTION OF NEW ACCOUNTING STANDARDS

Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income

Effective January 1, 2018, we adopted Accounting Standards Update (ASU) 2018-02 to address a specific consequence of the Tax Cuts and Jobs Act (TCJA or United States Tax Reform) enacted by the United States federal government on December 22, 2017. The amendments in this accounting update allowed a reclassification from accumulated other comprehensive income (AOCI) to retained earnings for stranded tax effects resulting from the TCJA. The amendments eliminated the stranded tax effects recognized as a result of the reduction of the historical United States federal corporate income tax rate to the newly enacted United States federal corporate income tax rate. The adoption of this accounting update did not have a material impact on our consolidated financial statements.

Clarifying Guidance on the Application of Modification Accounting on Stock Compensation

Effective January 1, 2018, we adopted ASU 2017-09 and applied the standard on a prospective basis. The new standard was issued to clarify the scope of modification accounting. Under the new guidance, modification accounting is required for all changes to share-based payment awards, unless all of the following conditions 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 adoption of this accounting update did not, and is not expected to have a material impact on our consolidated financial statements.

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

Effective January 1, 2018, we adopted ASU 2017-07 which was issued 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 other postretirement plans. Upon adoption of this accounting update, our Consolidated Statements of Earnings presents the current service cost within Operating and administrative expenses and the other components of net benefit cost within Other income/(expense). Previously, all components of net benefit cost were presented within Operating and administrative expenses. In addition, only the service cost component of net benefit cost will be capitalized on a prospective basis. The adoption of this accounting update did not, and is not expected to have a material impact on our consolidated financial statements.

Clarifying Guidance on Derecognition and Partial Sales of Nonfinancial Assets

Effective January 1, 2018, we adopted ASU 2017-05 on a modified retrospective basis. The new standard 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 adoption of this accounting update did not have a material impact on our consolidated financial statements.

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

Effective January 1, 2018, we adopted ASU 2016-18 on a retrospective basis. The new standard clarifies guidance on the classification and presentation of changes in restricted cash and restricted cash equivalents within the statement of cash flows. The amendments require 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. For current and comparative

periods, we amended the presentation in the Consolidated Statements of Cash Flows to include restricted cash and restricted cash equivalents with cash and cash equivalents.

Simplifying Cash Flow Classification
Effective January 1, 2018, we adopted ASU 2016-15 on a retrospective basis. The new standard reduces diversity in practice of how certain cash receipts and cash payments are classified in the Consolidated Statements of Cash Flows. The new guidance addresses eight specific presentation issues. We assessed each of the eight specific presentation issues and the adoption of this ASU did not have a material impact on our consolidated financial statements.

Recognition and Measurement of Financial Assets and Liabilities
Effective January 1, 2018, we adopted ASU 2016-01 on a prospective basis. The new standard addresses 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 assets and liabilities is measured using the exit price notion. The adoption of this accounting update did not have a material impact on our consolidated financial statements.

Revenue from Contracts with Customers
Effective January 1, 2018, we adopted ASU 2014-09 on a modified retrospective basis to contracts that were not complete at the date of initial application. The new standard was issued 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 previous standards.

In adopting Accounting Standards Codification (ASC) 606, we applied the practical expedient for contract modifications whereby contracts that were modified before January 1, 2018 were not retrospectively restated. Instead, the aggregate effect of all contract modifications occurring before that time has been reflected when identifying satisfied and unsatisfied performance obligations, determining the transaction price and allocating the transaction price to satisfied and unsatisfied performance obligations.
Revenue was previously recognized for a certain contract within the Liquids Pipelines business unit using a formula-based method. Under the new revenue standard, revenue is recognized on a straight-line basis over the term of the agreement in order to reflect the fulfillment of our performance obligation to provide up to a specified volume of pipeline capacity throughout the term of the contract.

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 (CIACs) were previously recorded as reductions of property, plant and equipment regardless of whether the amounts were imposed by regulation or arose from negotiations with customers. Under the new revenue standard, CIACs which are negotiated as part of an agreement to provide transportation and other services to a customer are deemed to be advance payments for future services and are recognized as revenue when those future services are provided. Accordingly, negotiated CIACs are accounted for as deferred revenue and recognized as revenue over the term of the associated revenue contract. Amounts which are required to be collected from the customer based on requirements of the regulator continue to be accounted for as reductions of property, plant and equipment.

The below table presents the cumulative, immaterial effect of the adoption of ASC 606 on our

Consolidated Statement of Financial Position as at January 1, 2018 on each affected financial statement line item. For the year ended December 31, 2018, the effect of the adoption of ASC 606 on our Consolidated Statement of Earnings was not material.

	Balance at December 31, 2017	Adjustments Due to ASC 606	Balance at January 1, 2018
(millions of Canadian dollars)			
Assets			
Deferred amounts and other assets	6,442	(170)	6,272
Property, plant and equipment, net	90,711	112	90,823
Liabilities and equity			
Accounts payable and other	9,478	62	9,540
Other long-term liabilities	7,510	66	7,576
Deferred income taxes	9,295	(62)	9,233
Redeemable noncontrolling interests	4,067	(38)	4,029
Deficit	(2,468)	(86)	(2,554)

The following ASU's have been issued, but not yet adopted

Clarifying Interaction between Collaborative Arrangements and Revenue from Contracts with Customers
In November 2018, ASU 2018-18 was issued to provide clarity on when transactions between entities in a collaborative arrangement should be accounted for under the new revenue standard, ASC 606. In determining whether transactions in collaborative arrangements should be accounted under the revenue standard, the update specifies that entities shall apply unit of account guidance to identify distinct goods or services and whether such goods and services are separately identifiable from other promises in the contract. ASU 2018-18 also precludes entities from presenting transactions with a collaborative partner which are not in scope of the new revenue standard together with revenue from contracts with customers. The accounting update is effective January 1, 2020 and early adoption is permitted. We are currently assessing the impact of the new standard on our consolidated financial statements.

Improvements to Related Party Guidance for Variable Interest Entities
ASU 2018-17 was issued in October 2018 to improve the related party guidance on determining whether fees paid to decision makers and service providers ("decision-maker fees") are variable interests. Under the new guidance, reporting entities must consider indirect interests held through related parties in common control arrangements on a proportionate basis, rather than as the equivalent of a direct interest in its entirety, when determining if a decision maker's fees constitute a variable interest. The accounting update is effective January 1, 2020 and must be applied on a retrospective basis. We are currently assessing the impact of the new standard on our consolidated financial statements.

Amended Guidance on Cloud Computing Arrangements
In August 2018, ASU 2018-15 was issued to provide guidance on the accounting for implementation costs incurred in a cloud computing arrangement (CCA) that is a service contract. The amendment aligns the accounting for costs incurred to implement a CCA that is a service arrangement with the guidance on capitalizing costs associated with developing or obtaining internal-use software. Additionally, ASU 2018-15 specifies that an entity would apply ASC 350-40, Internal-use software, to determine which implementation costs related to a hosting arrangement that is a service contract should be capitalized and which should be expensed. Furthermore, the amendments in the update require capitalized costs be amortized on a straight-line basis generally over the term of the arrangement and presented in the same income statement line as fees paid for the hosting service. The new standard also requires that the balance sheet presentation of capitalized implementation costs to be the same as that of the prepayment of fees related to the hosting arrangement, as well as similar consistency in classifications from a cash flow statement perspective. ASU 2018-15 is effective January 1, 2020 and we have elected to early adopt

the standard as of January 1, 2019, as permitted. We do not expect the adoption of this accounting update to have a material impact on our consolidated financial statements.

Disclosure Effectiveness
In August 2018, the Financial Accounting Standards Board issued two amendments as a part of its disclosure framework project aimed to improve the effectiveness of disclosures in the notes to financial statements.

ASU 2018-14 was issued in August 2018 to improve disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans. The amendment modifies the current guidance by adding and removing several disclosure requirements while also clarifying the guidance on current disclosure requirements. ASU 2018-14 is effective January 1, 2021 and entities are permitted to adopt the standard early. We are currently assessing the impact of the new standard on our consolidated financial statements.

ASU 2018-13 was issued to improve the disclosure requirements for fair value measurements by eliminating and modifying some disclosures, while also adding new disclosures. This update is effective January 1, 2020, however entities are permitted to early adopt the eliminated or modified disclosures. We are currently assessing the impact of the new standard on our 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 amendments allow 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, with early adoption permitted, and is to be applied on a modified retrospective basis. Based upon our current assessment, we do not expect the standard to have a material impact on our consolidated financial statements.

In October 2018, ASU 2018-16 was issued to permit the use of the Overnight Index Swap rate based on the Secured Overnight Financing Rate as a U.S. benchmark interest rate for hedge accounting purposes. ASU 2018-16 is effective concurrently with ASU 2017-12.

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 do not expect the adoption of this accounting update to 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 will recognize 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.

Further, ASU 2018-19 was issued in November 2018 to clarify that operating lease receivables should be accounted for under the new leases standard, ASC 842, and are not within the scope of ASC 326, Financial Instrument - Credit Losses. Both accounting updates are effective January 1, 2020. We are currently assessing the impact of the new standard on our consolidated financial statements.

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 statements 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. The new standard became effective January 1, 2019 and in adopting ASC 842, we have applied the package of practical expedients offered in connection with this update. Application of the package of practical expedients permits entities not to reassess a) whether any expired or existing contracts contain leases in accordance with the new guidance, b) lease classifications, and c) whether initial direct costs capitalized under current guidance continue to meet the definition of initial direct costs under the new guidance. Under the new lease guidance, we have also decided to elect, by class of underlying asset, to not separate non-lease components from the associated lease components of our lessee contract and account for both components as a single lease component.

ASU 2018-01 was issued in January 2018 to address stakeholder concerns about the costs and complexity of complying with the transition provisions of the new lease requirements as they relate to land easements. The amendments provide an optional transition practical expedient to not evaluate existing or expired land easements that were not previously accounted for as leases under existing guidance. We have elected this practical expedient in connection with the adoption of the new lease requirements.

In July 2018, ASU 2018-11 was issued to address additional stakeholder concerns regarding the unanticipated costs and complexities associated with the modified retrospective transition method as well as the requirement for lessors to separate components of a contract. Under the new guidance, entities are provided with an additional transition method which allows entities to apply the new standard at the date of adoption and to elect not to recast comparative periods presented. This amendment also permits lessors to combine associated lease and non-lease components within a contract for operating leases when certain conditions are met. We have elected both of these practical expedients in the adoption of the new lease standard.

We have identified all lease contracts existing as at November 30, 2018 and have performed detailed evaluations of those lease contracts under the requirements of the transitional guidance. We estimate that we will recognize right-of-use lease assets and related lease liabilities for existing operating leases where we are the lessee in the range of $750 million to $900 million, with no impact to our Consolidated Statements of Earnings or Consolidated Statements of Cash Flows. This estimate represents the net present value of future lease payments payable under operating lease contracts we had entered into as at November 30, 2018, and that have commenced or are scheduled to commence by January 1, 2019. We do not expect any adjustments will be made to our accounting for existing lessor contracts as a result of implementing this new standard.

4. REVENUE

REVENUE FROM CONTRACTS WITH CUSTOMERS
Major Products and Services

Year ended December 31, 2018	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution	Green Power and Transmission	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Transportation revenue	8,488	3,928	875	—	—	—	13,291
Storage and other revenue	101	222	196	—	—	—	519
Gas gathering and processing revenue	—	815	—	—	—	—	815
Gas distribution revenue	—	—	4,376	—	—	—	4,376
Electricity and transmission revenue	—	—	—	559	—	—	559
Commodity sales	—	1,590	—	—	—	—	1,590
Total revenue from contracts with customers	8,589	6,555	5,447	559	—	—	21,150
Commodity sales	—	—	—	—	26,070	—	26,070
Other revenue[1]	(894)	6	9	8	4	25	(842)
Intersegment revenue	384	10	14	—	154	(562)	—
Total revenue	8,079	6,571	5,470	567	26,228	(537)	46,378

1 Includes mark-to-market gains/(losses) from our hedging program.

We disaggregate revenue into categories which represent our principal performance obligations within each business segment because these revenue categories represent the most significant revenue streams in each segment and consequently are considered to be the most relevant revenue information for management to consider in evaluating performance.

Contract Balances

	Receivables	Contract Assets	Contract Liabilities
(millions of Canadian dollars)			
Balance as at January 1, 2018	2,475	290	992
Balance as at December 31, 2018	1,929	191	1,245

Contract receivables represent the amount of receivables derived from contracts with customers. The decrease in contract receivables for the year ended December 31, 2018, is primarily attributed to the sale of Midcoast Operating, L.P. and its subsidiaries to AL Midcoast Holdings, LLC (an affiliate of ArcLight Capital Partners, LLC), refer to Note 8 - Acquisitions and Dispositions for further discussion.

Contract assets represent the amount of revenue which has been recognized in advance of payments received for performance obligations we have fulfilled (or partially fulfilled) and prior to the point in time at which our right to the payment is unconditional. Amounts included in contract assets are transferred to accounts receivable when our right to the consideration becomes unconditional.

Contract liabilities represent payments received for performance obligations which have not been fulfilled. Contract liabilities primarily relate to make-up rights and deferred revenue. Revenue recognized during the year ended December 31, 2018 included in contract liabilities at the beginning of the period is $183 million. Increases in contract liabilities from cash received, net of amounts recognized as revenue during the year ended December 31, 2018 were $449 million.

Performance Obligations

Segment	Nature of Performance Obligation
Liquids Pipelines	• Transportation and storage of crude oil and NGLs • Sale of crude oil, natural gas and NGLs
Gas Transmission and Midstream	• Transportation, storage, gathering, compression and treating of natural gas • Transportation of NGLs • Supply and delivery of natural gas
Gas Distribution	• Transportation of natural gas • Storage of natural gas
Green Power and Transmission	• Generation and transmission of electricity • Delivery of electricity from renewable energy generation facilities

There was no material revenue recognized in the year ended December 31, 2018 from performance obligations satisfied in previous periods.

Payment Terms

Payments are received monthly from customers under long-term transportation, commodity sales, and gas gathering and processing contracts. Payments from Gas Distribution customers are received on a continuous basis based on established billing cycles.

Certain contracts in the United States offshore business provide for us to receive a series of fixed monthly payments (FMPs) for a specified period which is less than the period during which the performance obligations are satisfied. As a result, a portion of the FMPs is recorded as a contract liability. The FMPs are not considered to be a financing arrangement because the payments are scheduled to match the production profiles of offshore oil and gas fields, which generate greater revenue in the initial years of their productive lives.

Revenue to be Recognized from Unfulfilled Performance Obligations

Total revenue from performance obligations expected to be fulfilled in future periods is $67.4 billion, of which $7.1 billion is expected to be recognized during the year ending December 31, 2019.

The revenues excluded from the amounts above based on optional exemptions available under ASC 606, as explained below, represent a significant portion of our overall revenues and revenues from contracts with customers. Certain revenues such as flow-through operating costs charged to shippers are recognized at the amount for which we have the right to invoice our customers and are excluded from the amounts for revenue to be recognized in the future from unfulfilled performance obligations above. Variable consideration is excluded from the amounts above due to the uncertainty of the associated consideration, which is generally resolved when actual volumes and prices are determined. For example, we consider interruptible transportation service revenues to be variable revenues since volumes cannot be estimated. Additionally, the effect of escalation on certain tolls which are contractually escalated for inflation has not been reflected in the amounts above as it is not possible to reliably estimate future inflation rates. Revenues for periods extending beyond the current rate settlement term for regulated contracts where the tolls are periodically reset by the regulator are excluded from the amounts above since future tolls remain unknown. Finally, revenues from contracts with customers which have an original expected duration of one year or less are excluded from the amounts above.

SIGNIFICANT JUDGMENTS MADE IN RECOGNIZING REVENUE

Long-Term Transportation Agreements

For long-term transportation agreements, significant judgments pertain to the period over which revenue is recognized and whether the agreement provides for make-up rights for the shippers. Transportation revenue earned from firm contracted capacity arrangements is recognized ratably over the contract period. Transportation revenue from interruptible or volumetric-based arrangements is recognized when services are performed.

Estimates of Variable Consideration

Revenue from arrangements subject to variable consideration is recognized only to the extent that it is probable that a significant reversal in the amount of cumulative revenue recognized will not occur when the uncertainty associated with the variable consideration is subsequently resolved. Uncertainties associated with variable consideration relate principally to differences between estimated and actual volumes and prices. These uncertainties are resolved each month when actual volumes are sold or transported and actual tolls and prices are determined.

Recognition and Measurement of Revenue

Year ended December 31, 2018	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution	Green Power and Transmission	Energy Services	Consolidated
(millions of Canadian dollars)						
Revenue from products transferred at a point in time[1]	—	1,590	68	—	—	1,658
Revenue from products and services transferred over time[2]	8,589	4,965	5,379	559	—	19,492
Total revenue from contracts with customers	8,589	6,555	5,447	559	—	21,150

1 Revenue from sales of crude oil, natural gas and NGLs.

2 Revenue from crude oil and natural gas pipeline transportation, storage, natural gas gathering, compression and treating, natural gas distribution, natural gas storage services and electricity sales.

Performance Obligations Satisfied at a Point in Time

Revenue from commodity sales where the commodity sold is not immediately consumed prior to use is recognized at the point in time when the contractually specified volume of the commodity has been delivered, as control over the commodity transfers to the customer upon delivery.

Performance Obligations Satisfied Over Time

For arrangements involving the transportation and sale of petroleum products and natural gas where the transportation services or commodities are simultaneously received and consumed by the shipper or customer, we recognize revenue over time using an output method based on volumes of commodities delivered or transported. The measurement of the volumes transported or delivered corresponds directly to the benefits received by the shippers or customers during that period.

Determination of Transaction Prices

Prices for gas processing and transportation services are determined based on the capital cost of the facilities, pipelines and associated infrastructure required to provide such services plus a rate of return on capital invested that is determined either through negotiations with customers or through regulatory processes for those operations that are subject to rate regulation.

Prices for commodities sold are determined by reference to market price indices plus or minus a negotiated differential and in certain cases a marketing fee.

Prices for natural gas sold and distribution services provided by regulated natural gas distribution operations are prescribed by regulation.

5. SEGMENTED INFORMATION

Segmented information for the years ended December 31, 2018, 2017 and 2016 are as follows:

Year ended December 31, 2018	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution	Green Power and Transmission	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues	8,079	6,571	5,470	567	26,228	(537)	46,378
Commodity and gas distribution costs	(16)	(1,481)	(2,748)	(7)	(25,689)	540	(29,401)
Operating and administrative	(3,124)	(2,102)	(1,111)	(157)	(73)	(225)	(6,792)
Impairment of long-lived assets	(180)	(914)	—	(4)	—	(6)	(1,104)
Impairment of goodwill	—	(1,019)	—	—	—	—	(1,019)
Income/(loss) from equity investments	577	930	11	(28)	18	1	1,509
Other income/(expense)	(5)	349	89	(2)	(2)	(481)	(52)
Earnings/(loss) before interest, income tax expense, and depreciation and amortization	5,331	2,334	1,711	369	482	(708)	9,519
Depreciation and amortization							(3,246)
Interest expense							(2,703)
Income tax expense							(237)
Earnings							3,333
Capital expenditures[1]	3,102	2,644	1,066	33	—	27	6,872
Total assets	68,798	60,559	25,748	5,716	1,042	5,042	166,905

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
	6,395	(1,269)	1,390	372	(263)	(337)	6,288

Earnings/(loss) before interest, income tax expense, and depreciation and amortization							
Depreciation and amortization							(3,163)
Interest expense							(2,556)
Income tax recovery							2,697
Earnings							3,266
Capital expenditures[1]	2,799	4,016	1,177	321	1	108	8,422
Total assets	63,881	60,745	25,956	6,289	2,514	2,708	162,093

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Year ended December 31, 2016	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution	Green Power and Transmission	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues	8,176	2,877	2,976	502	20,364	(335)	34,560
Commodity and gas distribution costs	(12)	(2,206)	(1,653)	5	(20,473)	334	(24,005)
Operating and administrative	(2,908)	(446)	(553)	(173)	(63)	(215)	(4,358)
Impairment of long-lived assets	(1,365)	(11)	—	—	—	—	(1,376)
Income/(loss) from equity investments	194	223	12	2	(3)	—	428
Other income/(expense)	841	27	49	8	(8)	115	1,032
Earnings/(loss) before interest, income tax expense, and depreciation and amortization	4,926	464	831	344	(183)	(101)	6,281
Depreciation and amortization							(2,240)
Interest expense							(1,590)
Income tax expense							(142)
Earnings							2,309
Capital expenditures[1]	3,957	176	713	251	—	32	5,129

1 Includes allowance for equity funds used during construction.

The measurement basis for preparation of segmented information is consistent with the significant accounting policies (Note 2).

No non-affiliated customer exceeds 10% of our third-party revenues for the year ended December 31, 2018. Our largest non-affiliated customer accounted for approximately 11.8%, and 18.0% of our third-party revenues for the years ended December 31, 2017 and 2016, respectively. A second customer accounted for approximately 10.4% of our third-party revenues for the year ended December 31, 2016. Revenues from these two customers are primarily reported in the Energy Services segment.

GEOGRAPHIC INFORMATION

Revenues[1]

Year ended December 31,	2018	2017	2016
(millions of Canadian dollars)			
Canada	19,023	18,076	12,470
United States	27,355	26,302	22,090
	46,378	44,378	34,560

1 Revenues are based on the country of origin of the product or service sold.

Property, Plant and Equipment[1]

December 31,	2018	2017

(millions of Canadian dollars)		
Canada	44,716	46,025
United States	49,824	44,686
	94,540	90,711

1 Amounts are based on the location where the assets are held.

6. EARNINGS PER COMMON SHARE

BASIC

Earnings per common share is calculated by dividing earnings attributable to common shareholders by the weighted average number of common shares outstanding. The weighted average number of common shares outstanding has been reduced by our pro-rata weighted average interest in our own common shares of 12 million as at December 31, 2018, and 13 million as at December 31, 2017 and 2016, resulting from our reciprocal investment in Noverco.

DILUTED
The treasury stock method is used to determine the dilutive impact of stock options. This method assumes any proceeds from the exercise of stock options would be used to purchase common shares at the average market price during the period.

Weighted average shares outstanding used to calculate basic and diluted earnings per share are as follows:

December 31,	2018	2017	2016
(number of shares in millions)			
Weighted average shares outstanding	1,724	1,525	911
Effect of dilutive options	3	7	7
Diluted weighted average shares outstanding	1,727	1,532	918

For the years ended December 31, 2018, 2017 and 2016, 26,837,822, 14,271,615 and 10,803,672, respectively, of anti-dilutive stock options with a weighted average exercise price of $50.38, $56.71 and $52.92, respectively, were excluded from the diluted earnings per common share calculation.

7. REGULATORY MATTERS

GENERAL INFORMATION ON RATE REGULATION AND ITS ECONOMIC EFFECTS
We record assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for non-regulated entities. See Note 2 - Significant Accounting Policies for further discussion.

A number of our businesses are subject to regulation by the NEB. We also collect and set aside funds to cover future pipeline abandonment costs for all NEB regulated pipelines as a result of the NEB’s regulatory requirements under LMCI (Note 14). Amounts expected to be paid to cover future abandonment costs are recognized as long-term regulatory liabilities. Our significant regulated businesses and other related accounting impacts, are described below.

Liquids Pipelines
Canadian Mainline
Canadian Mainline includes the Canadian portion of the mainline system and is subject to regulation by the NEB. Canadian Mainline tolls (excluding Lines 8 and 9) are currently governed by the 10-year CTS, which establishes a Canadian Local Toll for all volumes shipped on the Canadian Mainline and an International Joint Tariff for all volumes shipped from western Canadian receipt points to delivery points on the Lakehead System and delivery points on the Canadian Mainline downstream of the Lakehead System. The CTS was negotiated with shippers in accordance with NEB guidelines, was approved by the NEB in June 2011 and took effect July 1, 2011. Under the CTS, a regulatory asset is recognized to offset deferred income taxes as a NEB rate order governing flow-through income tax treatment permits future recovery. No other material regulatory assets or liabilities are recognized under the terms of the CTS.

Southern Lights Pipeline

The United States portion of the Southern Lights Pipeline is regulated by the FERC and the Canadian portion of the Southern Lights Pipeline is regulated by the NEB. Shippers on the Southern Lights Pipeline are subject to long-term transportation contracts under a cost-of-service toll methodology. Toll adjustments are filed annually with the regulators. Tariffs provide for recovery of allowable operating and debt financing costs, plus a pre-determined after-tax rate of return on equity (ROE) of 10%. Southern Lights Pipeline tolls are based on a deemed 70% debt and 30% equity structure.

Gas Transmission and Midstream

British Columbia (BC) Pipeline and BC Field Services

Under the current NEB-authorized rate structure for BC Pipeline, income tax costs are recovered in tolls based on the current income tax payable and do not include accruals for deferred income tax. However, as income taxes become payable as a result of the reversal of the temporary differences that created the deferred income taxes, it is expected that tolls will be adjusted to recover these taxes. Since most of these temporary differences are related to property, plant and equipment costs, this recovery is expected to occur over the life of those assets.

On July 4, 2018, we entered into agreements to sell our Canadian natural gas gathering and processing businesses (Note 8). On October 1, 2018, we closed the sale of the provincially regulated facilities. The sale of the federally regulated facilities is expected to close in mid-2019.

Spectra Energy Partners, LP

SEP's gas transmission and storage services are regulated by the FERC. Current rates are governed by the applicable FERC-approved natural gas tariff while fee-based gathering services are governed by the applicable state oil and gas commissions.

For information related to regulatory assets acquired in the Merger Transaction for Union Gas, BC Pipelines, BC Field Services and SEP, refer to Note 8 - Acquisitions and Dispositions.

Gas Distribution

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

The OEB decision also approved the rate setting mechanism for the amalgamated entity to be employed during a five-year deferred rebasing period from 2019 through 2023, after which time rates will be rebased. The decision also approved the continuation and establishment of certain deferral and variance accounts, as well as an earnings sharing mechanism that requires the amalgamated entity to share equally with customers, any earnings in excess of 150 basis points over the OEB approved ROE.

Enbridge Gas Distribution Inc.

EGD’s gas distribution operations are regulated by the OEB. Rates for the years ended December 31, 2018 and 2017 were set in accordance with parameters established by the customized incentive rate plan (IR Plan). The customized IR Plan, inclusive of the requested capital investment amounts and an incentive mechanism providing the opportunity to earn above the allowed ROE, was approved, with modifications, by the OEB in 2014. The approved customized IR Plan is for establishing rates for 2014 through 2018.

As part of the customized IR Plan, the OEB approved the adoption of a new approach for determining net salvage percentages to be included within EGD’s approved depreciation rates, as compared with the traditional approach previously employed. The new approach results in lower net salvage percentages for EGD, and therefore lowers depreciation rates and future removal and site restoration reserves. The customized IR Plan also includes an earnings sharing mechanism, whereby any return over the allowed rate of return for a given year under the customized IR Plan will be shared equally with customers. Within annual rate proceedings for 2015 through 2018, the customized IR plan requires allowed revenues, and corresponding rates, to be updated annually for select items.

EGD’s after-tax rate of return on common equity embedded in rates was 9.0% and 8.8% for the years ended December 31, 2018 and 2017, respectively, based on a 36% deemed common equity component of capital for regulatory purposes, in both years.

Union Gas Limited

Union Gas is regulated by the OEB. Union Gas's distribution rates beginning January 1, 2014 are set under a five-year incentive regulation framework. The incentive regulation 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 incentive regulation framework includes an earnings sharing mechanism that permits Union Gas to fully retain the return on common equity from utility operations up to 9.93%, share 50% of any earnings between 9.93% and 10.93% with customers, and share 90% of any earnings above 10.93% with customers. Union Gas's approved after-tax return on common equity is fixed at 8.93% for the five-year incentive regulation term.

Enbridge Gas New Brunswick Inc.

Enbridge Gas New Brunswick Inc. is regulated by the EUB. The current rates are set, as prescribed by legislation for 2018 and 2019. In 2020 all rates will be set by cost-of-service methodology. On December 4, 2018, we announced that we entered into a definitive agreement for the sale of Enbridge Gas New Brunswick Inc. (Note 8). Closing of the transaction remains subject to the receipt of regulatory approvals and other customary closing conditions expected to occur in 2019. As such, we classified Enbridge Gas New Brunswick Inc. assets as held for sale and measured them at the lower of their carrying value or fair value less costs to sell. As the carrying value does not exceed the fair value, no impairment has been recorded for the year ended December 31, 2018.

FINANCIAL STATEMENT EFFECTS

Accounting for rate-regulated activities has resulted in the recognition of the following significant regulatory assets and liabilities:

December 31,	Recovery/Refund Period Ends	2018	2017
(millions of Canadian dollars)			
Regulatory assets/(liabilities)			
Liquids Pipelines			
Deferred income taxes	Various	1,673	1,492
Tolling deferrals	Various	(28)	(34)
Recoverable income taxes	Through 2030	27	46
Pipeline future abandonment costs[1]	Various	(201)	(141)
Gas Transmission and Midstream			
Deferred income taxes	Various	826	717
Regulatory liability related to income taxes[2]	Various	(912)	(1,078)
Other	Various	94	(16)
Gas Distribution			
Deferred income taxes	Various	1,132	1,000
Purchased gas variance[3]	Various	197	51
Pension plans and OPEB[4]	Through 2033	118	102
Constant dollar net salvage adjustment	2018	6	38
Future removal and site restoration reserves[5]	Various	(1,107)	(1,066)
Site restoration clearance adjustment	Various	—	(31)
Other	Various	(4)	31

1 Funds collected are included in Restricted long-term investments (Note 14).

2 Relates to the establishment of a regulatory liability as a result of the United States tax reform legislation enacted December 22, 2017.

3 Purchase gas variance is the difference between the actual cost and the approved cost of natural gas reflected in rates. EGD and Union Gas have been granted OEB approval to refund this balance to, or to collect this balance from, customers on a rolling 12-month basis via the Quarterly Rate Adjustment Mechanism process.

4 The balances are excluded from the rate base and do not earn an ROE.

5 Future removal and site restoration reserves result from amounts collected from customers by the Company, with the approval of the OEB, to fund future costs for removal and site restoration relating to property, plant and equipment. These costs are collected as part of depreciation charged on property, plant and equipment that is recorded in rates. The balance represents the amount that the Company has collected from customers, net of actual costs expended on removal and site restoration. The settlement of this balance will occur over the long-term as future removal and site restoration costs are incurred. In the absence of rate regulation accounting, costs incurred for removal and site restoration would be charged to earnings as incurred with recognition of revenue for amounts previously collected.

OTHER ITEMS AFFECTED BY RATE REGULATION

Allowance for Funds Used During Construction and Other Capitalized Costs

Under the pool method prescribed by certain regulators, it is not possible to identify the carrying value of the equity component of AFUDC or its effect on depreciation. Similarly, gains and losses on the retirement of certain specific fixed assets in any given year cannot be identified or quantified.

Operating Cost Capitalization

With the approval of regulators, certain 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. In the absence of rate regulation, a portion of such operating costs would be charged to earnings in the year incurred.

EGD entered into a services contract relating to asset management initiatives. The majority of the costs, primarily consulting fees, are being capitalized to gas mains in accordance with regulatory approval. As at December 31, 2018 and 2017, the net book value of these costs included in gas mains in Property, plant and equipment, net was $110 million and $118 million, respectively. In the absence of rate regulation accounting, some of these costs would be charged to earnings in the year incurred.

8. ACQUISITIONS AND DISPOSITIONS

ACQUISITIONS

Spectra Energy Corp

On February 27, 2017, Enbridge and Spectra Energy combined in 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 common stock for each share of Spectra Energy common stock that they owned, giving us 100% ownership of Spectra Energy.

Consideration offered to complete the Merger Transaction included 691 million common shares of Enbridge at US$41.34 per share, based on the February 24, 2017 closing price on the New York Stock Exchange (NYSE), for a total value of $37,429 million in common shares issued to Spectra Energy shareholders, plus approximately $3 million in cash in lieu of any fractional shares, and 3.5 million share options with a fair value of $77 million, that were exchanged for Spectra Energy's outstanding stock compensation awards.

Spectra Energy, through its subsidiaries and equity affiliates, owns and operates a large and diversified portfolio of complementary natural gas-related energy assets and is one of North America's leading natural gas infrastructure companies. 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 brings together two highly complementary platforms to create North America's largest energy infrastructure company and meaningfully enhances customer optionality, positioning us for long-term growth opportunities, and strengthening our balance sheet.

The Merger Transaction has been accounted for as a business combination under the acquisition method of accounting as prescribed by Accounting Standards Codification (ASC) 805 Business Combinations. The acquired tangible and intangible assets and assumed liabilities are recorded at their estimated fair values at the date of acquisition.

The purchase price allocation has been completed as at December 31, 2017, along with the allocation of goodwill to reporting units (Note 16). Our reporting units are equivalent to our identified segments with the exception of the Gas Transmission and Midstream segment, which is composed of two reporting units: gas transmission and gas midstream.

The following table summarizes the estimated fair values that were assigned to the net assets of Spectra Energy:

February 27,	2017
(millions of Canadian dollars)	
Fair value of net assets acquired:	
Current assets (a)	2,432
Property, plant and equipment, net (b)	33,555
Restricted long-term investments	144
Long-term investments (c)	5,000
Deferred amounts and other assets (d)	2,390
Intangible assets, net (e)	1,288
Current liabilities (a)	(3,982)
Long-term debt (d)	(21,444)
Other long-term liabilities	(1,983)
Deferred income taxes (b)	(7,670)
Noncontrolling interests (f)	(8,877)
	853
Goodwill (g)	36,656
	37,509
Purchase price:	
Common shares	37,429
Cash	3
Fair value of outstanding earned stock compensation awards recorded in Additional paid-in capital	77
	37,509

a) Accounts receivable is comprised primarily of customer trade receivables and natural gas imbalances. As such, the fair value of accounts receivable approximates the net carrying value of $1,174 million. The gross amount due of $1,190 million, of which $16 million is not expected to be collected, is included in current assets.

During the fourth quarter of 2017, we identified certain transactions that were not reflected in the purchase price equation. This resulted in a $67 million and $548 million increase in current assets and current liabilities, respectively, and a $481 million decrease in long-term debt.

b) We have applied the valuation methodologies described in ASC 820 Fair Value Measurements and Disclosures, to value the property, plant and equipment purchased. The fair value of Spectra Energy's rate-regulated property, plant and equipment was determined using a market participant perspective, which is their carrying amount. The fair value of the remaining non-regulated property, plant and equipment was determined primarily using variations of the income approach, which is based on the present value of the future after-tax cash flows attributable to each non-regulated asset. Some of the more significant assumptions inherent in the development of the values, from the perspective of a market participant, include, but are not limited to, the amount and timing of projected future cash flows (including revenue and profitability); the discount rate selected to measure the risks inherent in the future cash flows; the assessment of the asset's life cycle; the competitive trends impacting the asset; and customer turnover.

During the third quarter of 2017, Spectra Energy's right-of-way agreements were reclassified from intangible assets to property, plant and equipment to conform the presentation of these agreements with our accounting policy pertaining to rights-of-way. The purchase price allocation above reflects this reclassification, which amounted to $830 million as at February 27, 2017. There is no change in the amortization period for the right-of-way agreements as a result of this reclassification.

During the fourth quarter of 2017, we finalized our fair value measurement of the BC Pipeline & Field Services businesses, which resulted in decreases to property, plant and equipment of $1,955 million and deferred income tax liabilities of $661 million as at February 27, 2017.

c) Long-term investments represent Spectra Energy's 50% equity investment in DCP Midstream LLC (DCP Midstream), Gulfstream Natural Gas System, L.L.C., Nexus Gas Transmission, LLC (Nexus), Steckman Ridge LP, Islander East Pipeline Company, L.L.C., Southeast Supply Header L.L.C., and 20% equity interest in PennEast Pipeline Company LLC (PennEast). The fair value of these investments was determined using an income approach.

d) Fair value of long-term debt was determined based on the current underlying Government of Canada and United States Treasury interest rates on the corresponding bonds, as well as an implied credit spread based on current market conditions and resulted in an increase in the book value of debt of $1.5 billion. The fair value adjustment to long-term debt related to rate-regulated entities of $629 million also results in a regulatory offset in Deferred amounts and other assets in the Consolidated Statements of Financial Position.

During the fourth quarter of 2017, deferred amounts and other assets decreased by $530 million as at February 27, 2017 due to the finalization of BC Pipelines & Field Services' fair value measurement, as discussed under (b) above.

During the fourth quarter of 2017, we identified certain transactions that were not reflected in the purchase price equation. This resulted in a $481 million decrease in long-term debt, as discussed under (a) above.

e) Intangible assets primarily consist of customer relationships in the non-regulated business, which represent the underlying relationship from long-term agreements with customers that are capitalized upon acquisition, determined using the income approach. Intangible assets are amortized on a straight-line basis over their expected lives.

During the third quarter of 2017, intangible assets decreased by $830 million as at February 27, 2017 due to a reclassification to property, plant and equipment, as discussed under (b) above.

The fair value of intangible assets acquired through the Merger Transaction, by major classes is as follows:

As at February 27, 2017	Weighted Average Amortization Rate		Fair Value
(millions of Canadian dollars)			
Customer relationships[1]	3.7	%	739
Project agreement[2]	4.0	%	105
Software	11.1	%	329
Other	4.2	%	115
			1,288

1 Represents customer relationships in the non-regulated business, which were capitalized upon acquisition.

2 Represents a project agreement between SEP, NextEra Energy, Inc., Duke Energy Corporation (Duke Energy) and Williams Partners L.P. In accordance with the agreement, payments will be made, based on our proportional ownership interest in Sabal Trail Transmission, LLC (Sabal Trail), as certain milestones of the project are met. Amortization of the intangible asset began on July 3, 2017, when Sabal Trail was placed into service (Note 13).

f) The fair value of Spectra Energy's noncontrolling interests includes approximately 78.4 million SEP common units outstanding to the public, valued at the February 24, 2017 closing price of US$44.88 per common unit on the NYSE, and units held by third parties in Maritimes & Northeast Pipeline, L.L.C., Sabal

Trail and Algonquin Gas Transmission, L.L.C., valued based on the

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underlying net assets of each reporting unit and preferred stock held by third parties in Union Gas and Westcoast Energy Inc.

During the third quarter of 2017, we finalized our fair value measurement of Sabal Trail, which resulted in an increase to noncontrolling interests of $85 million as at February 27, 2017.

g) We recorded $36.7 billion in goodwill, which is primarily related to expected synergies from the Merger Transaction. The goodwill balance recognized is not deductible for tax purposes. Factors that contributed to the goodwill include the opportunity to expand our natural gas pipelines segment, the potential for cost and supply chain optimization synergies, existing assembled assets and work force that cannot be duplicated at the same cost by a new entrant, franchise rights and other intangibles not separately identifiable because they are inextricably linked to the provision of regulated utility service and the enhanced scale and geographic diversity which provide greater optionality and platforms for future growth.

During the third quarter of 2017, goodwill increased by $85 million as at February 27, 2017 due to the finalization of the fair value measurement of Sabal Trail as discussed under (f) above.

During the fourth quarter of 2017, goodwill increased by $1,824 million as at February 27, 2017 due to the finalization of the fair value measurement of BC Pipelines & Field Services as discussed under (b) above.

Acquisition-related expenses incurred were approximately $231 million. Costs incurred for the years ended December 31, 2017 and 2016 of $180 million and $51 million, respectively, are included in Operating and administrative expense in the Consolidated Statements of Earnings.

Upon completion of the Merger Transaction, we began consolidating Spectra Energy. Since the closing date of February 27, 2017 through December 31, 2017, Spectra Energy has generated approximately $5,740 million in revenues and $2,574 million in earnings.

Our supplemental pro forma consolidated financial information for the years ended December 31, 2017 and 2016, including the results of operations for Spectra Energy as if the Merger Transaction had been completed on January 1, 2016 are as follows:

Year ended December 31,	2017	2016
(unaudited; millions of Canadian dollars)		
Revenues	45,669	40,934
Earnings attributable to common shareholders[1]	2,902	2,820

1 Merger Transaction costs of $180 million (after-tax $131 million) were excluded from earnings for the year ended December 31, 2017.

Tupper Main and Tupper West

On April 1, 2016, we acquired the Tupper Main and Tupper West gas plants and associated pipelines (the Tupper Plants) located in northeastern BC for cash consideration of $539 million. The purchase price for the Tupper Plants was equal to the fair value of identifiable net assets acquired and accordingly, we did not recognize any goodwill as part of the acquisition. Transaction costs incurred by us totaled approximately $1 million and are included in Operating and administrative expense in the Consolidated Statements of Earnings. The Tupper Plants are a part of our Gas Transmission and Midstream segment.

Since the closing date through December 31, 2016, the Tupper Plants generated approximately $33 million in revenues and $22 million in earnings before interest and income taxes. If the acquisition had closed on January 1, 2016, the Consolidated Statements of Earnings for the year ended December 31, 2016 would have shown revenues of $44 million and earnings before interest and income taxes of $28 million.

The final purchase price allocation was as follows:

April 1,	2016
(millions of Canadian dollars)	
Fair value of net assets acquired:	
Property, plant and equipment	288
Intangible assets	251
	539
Purchase price:	
Cash	539

In 2018, the assets of the Tupper Plants were subsequently reclassified to assets held for sale and sold as part of the provincially regulated assets of the Canadian Natural Gas Gathering and Processing transaction. See Assets Held for Sale section below for further details of the transaction.

OTHER ACQUISITIONS

Chapman Ranch Wind Project

On September 9, 2016, we acquired a 100% interest in the 249 megawatt (MW) Chapman Ranch Wind Project (Chapman Ranch) located in Texas for cash consideration of $65 million (US$50 million), of which $62 million (US$48 million) was allocated to property, plant and equipment and the balance allocated to Intangible assets. On November 2, 2016, we invested a further $40 million (US$30 million) in Chapman Ranch, of which $23 million (US$17 million) was related to Property, plant and equipment and the balance related to Intangible assets. There would have been no effect on our earnings if the transaction had occurred on January 1, 2016 as the project was under construction and had not generated revenues to date. Chapman Ranch is a part of our Green Power and Transmission segment.

New Creek Wind Project

In November 2015, we acquired a 100% interest in the 103 MW New Creek Wind Project (New Creek) for cash consideration of $48 million (US$36 million), with $35 million (US$26 million) of the purchase price allocated to Property, plant and equipment and the balance allocated to Intangible assets. New Creek was placed into service in December 2016 and is a part of our Green Power and Transmission segment.

Midstream Business

On February 27, 2015, EEP acquired, through its partially-owned subsidiary, Midcoast Energy Partners, L.P. (MEP), the midstream business of New Gulf Resources, LLC located in Texas for $106 million (US$85 million) in cash and a contingent future payment of up to $21 million (US$17 million). The acquisition consisted of a natural gas gathering system that is in operation and is a part of our Gas Transmission and Midstream segment. Of the purchase price, we allocated $69 million (US$55 million) to Property, plant and equipment and the balance to Intangible assets. In 2016, we determined that the likelihood of making any future contingent payments was remote.

ASSETS HELD FOR SALE

Enbridge Gas New Brunswick

In December 2018, we entered into an agreement for the sale of Enbridge Gas New Brunswick Limited Partnership and Enbridge Gas New Brunswick Inc. (collectively, EGNB) to Liberty Utilities (Canada) LP, a wholly-owned subsidiary of Algonquin Power and Utilities Corp., for a cash purchase price of $331 million. EGNB operates and maintains natural gas distribution pipelines in southern New Brunswick, and its related assets are included in our Gas Distribution segment. Subject to certain regulatory approvals and customary closing conditions, the transaction is expected to close in 2019.

As these assets represented a portion of a reporting unit, we allocated a portion of the goodwill of the reporting unit to these assets using a relative fair value approach. As such, we have classified EGNB assets and an allocated goodwill of $133 million as held for sale and measured them at the lower of their carrying value or fair value less costs to sell. As the carrying value does not exceed the fair value, no impairment has been recorded for the year ended December 31, 2018.

Canadian Natural Gas Gathering and Processing Businesses
On July 4, 2018, we entered into agreements to sell our Canadian natural gas gathering and processing businesses to Brookfield Infrastructure Partners L.P. and its institutional partners for a cash purchase price of approximately $4.3 billion, subject to customary closing adjustments. Separate agreements were entered into for those facilities currently governed by provincial regulations and those governed by federal regulations (collectively, Canadian Natural Gas Gathering and Processing Businesses assets). On October 1, 2018, we closed the sale of the provincially regulated facilities for proceeds of approximately $2.5 billion. These assets were included within our Gas Transmission and Midstream segment. Please see Dispositions discussion below for further details regarding the transaction.

As at December 31, 2018, the net assets of the federally regulated facilities of our Canadian Natural Gas Gathering and Processing Business remain classified as held for sale, including $55 million of allocated goodwill. The sale of the federally regulated facilities is expected to close in mid-2019 for proceeds of approximately $1.8 billion.

In addition, upon classifying the Canadian Natural Gas Gathering and Processing Businesses assets as held for sale in the third quarter of 2018, as these assets represented a portion of a reporting unit, we allocated a portion of the goodwill of the reporting unit to these assets using a relative fair value approach. As a result of the goodwill allocation, the carrying value of Canadian Natural Gas Gathering and Processing Businesses assets is greater than the sale price consideration less the cost to sell. Therefore, we recorded a goodwill impairment of $1,019 million on the Consolidated Statements of Earnings for the year ended December 31, 2018. The held for sale classification represented a triggering event and required us to perform a goodwill impairment test for the related reporting unit. The results of the test did not indicate any additional goodwill impairment.

Line 10 Crude Oil Pipeline
In the first quarter of 2018, we satisfied the condition as set out in our agreements for the sale of our Line 10 crude oil pipeline (Line 10), which originates near Hamilton, Ontario and terminates at West Seneca, New York. Our subsidiaries, Enbridge Pipelines Inc. and EEP, own the Canadian and United States portions of Line 10, respectively, and the related assets are included in our Liquids Pipeline segment.

We expect to close the sale of Line 10 within one year, subject to regulatory approval and certain closing conditions. As such, during the first quarter of 2018, we classified Line 10 assets as held for sale and measured them at the lower of their carrying value or fair value less costs to sell, which resulted in a loss of $154 million ($95 million after-tax attributable to us) included within Asset impairment on the Consolidated Statements of Earnings for the year ended December 31, 2018.

St. Lawrence Gas Company, Inc.
In August 2017, we entered into an agreement to sell the issued and outstanding shares of St. Lawrence Gas Company, Inc. (St. Lawrence Gas) for cash proceeds of approximately $96 million (US$70 million). Subject to regulatory approval and certain pre-closing conditions, the transaction is expected to close in 2019. As at December 31, 2018 and 2017, St. Lawrence Gas, which is a part of our Gas Distribution segment, was classified as held for sale in the Consolidated Statements of Financial Position.

The table below summarizes the presentation of net assets held for sale in our Consolidated Statements of Financial Position.

(millions of Canadian dollars)	December 31, 2018	December 31, 2017
Accounts receivable and other (current assets held for sale)	117	424
Deferred amounts and other assets (long-term assets held for sale)[1]	2,383	1,190
Accounts payable and other (current liabilities held for sale)	(63)	(315)
Other long-term liabilities (long-term liabilities held for sale)	(96)	(34)
Net assets held for sale	2,341	1,265

1 Included within Deferred amounts and other assets at December 31, 2018 and 2017 respectively is property, plant and equipment of $2.1 billion and $1.1 billion.

DISPOSITIONS

Canadian Natural Gas Gathering and Processing Businesses

On October 1, 2018, we closed the sale of the provincially regulated facilities of the Canadian Natural Gas Gathering and Processing Businesses assets for proceeds of approximately $2.5 billion. After closing adjustments, a gain on disposal of $34 million before tax was included in Other income/(expense) in the Consolidated Statements of Earnings. Please see Assets Held for Sale discussion above for further details regarding the transaction.

Renewable Assets

On August 1, 2018, we closed the sale of a 49% interest in all of our Canadian renewable assets, a 49% interest in two United States renewable assets and 49% of our interest in the Hohe See Offshore wind power project and its subsequent expansion, both concurrently under construction in Germany, (collectively, the Renewable Assets) to the Canada Pension Plan Investment Board (CPPIB). Total cash proceeds from the transaction were $1.75 billion. In addition, CPPIB will fund their pro-rata share of the remaining capital expenditures on the Hohe See Offshore wind power project. We maintain a 51% interest in the Renewable Assets and will continue to manage, operate and provide administrative services for these assets.

A loss on disposal of $20 million (€14 million) was included in Other income/(expense) in the Consolidated Statements of Earnings for the sale of 49% of our interest in the Hohe See Offshore wind power project and its subsequent expansion. Subsequent to the sale, the remaining interests in these assets continue to be accounted for as an equity method investment, and are a part of our Green Power and Transmission segment.

Gains of $62 million and $17 million (US$13 million) were included in Additional paid-in capital in the Consolidated Statements of Financial Position for the sale of 49% interest in the Canadian and United States renewable assets, respectively. Subsequent to the sale, because we maintained a controlling interest, these assets continue to be consolidated and are a part of our Green Power and Transmission segment. In addition, we recognized noncontrolling interests in our Consolidated Statements of Financial Position as at December 31, 2018 to reflect the interests that we do not hold (Note 20).

Also, a deferred income tax recovery of $267 million ($196 million attributable to us) was recorded in the year ended December 31, 2018 as a result of the agreement entered into during the second quarter of 2018 for the Renewable Assets (Note 25).

In connection with our sale of the Renewable Assets, we have new consolidated and unconsolidated VIEs (Note 12).

Midcoast Operating, L.P.

On August 1, 2018, we closed the sale of Midcoast Operating, L.P. and its subsidiaries (collectively, MOLP) to AL Midcoast Holdings, LLC (an affiliate of ArcLight Capital Partners, LLC) for total cash proceeds of $1.4 billion (US$1.1 billion). After closing adjustments recorded in the fourth quarter of 2018, a loss on disposal of $41 million (US$32 million) was included in Other income/(expense) in the

Consolidated Statements of Earnings. MOLP conducted our United States natural gas and natural gas liquids gathering, processing, transportation and marketing businesses, and was a part of our Gas Transmission and Midstream segment.

Upon closing of the sale, we also recorded a liability of $387 million (US$298 million) for future volume commitments retained by us. The associated loss is included in the loss on disposal of $41 million discussed above. As at December 31, 2018, $79 million (US$58 million) and $296 million (US$216 million) were included in Accounts payable and other and Other long-term liabilities, respectively, on the Consolidated Statements of Financial Position.

In the second quarter of 2018, our equity method investment in the Texas Express NGL pipeline system, together with the MOLP assets that have been held for sale since December 31, 2017, also met the conditions for assets held for sale. The $447 million carrying value of Texas Express NGL pipeline system equity investment and an allocated goodwill of $262 million, were included within the disposal group as at June 30, 2018 and subsequently disposed on August 1, 2018.

In the first quarter of 2018, as a result of entering into a definitive sales agreement, the fair value of the assets held for sale as at March 31, 2018 were revised based on the sale price. Accordingly, we recorded a loss of $913 million ($701 million after-tax). This loss has been included within Asset impairment on the Consolidated Statements of Earnings for the year ended December 31, 2018.

Previously as at December 31, 2017, we classified these assets as held for sale and measured them at the lower of their carrying value or fair value less costs to sell, which resulted in an asset impairment loss of $4.4 billion ($2.8 billion after-tax) and a related goodwill impairment of $102 million, which were included in the Consolidated Statement of Earnings for the year ended December 31, 2017.

Sandpiper Project

During the years ended December 31, 2018 and 2017, we sold unused pipe related to the Sandpiper Project (Sandpiper) for cash proceeds of approximately $38 million (US$30 million) and $148 million (US$111 million), respectively. Gains on disposal of $29 million (US$22 million) and $83 million (US$63 million) before tax were included in Operating and administrative expense in the Consolidated Statements of Earnings for the years ended December 31, 2018 and 2017, respectively. These assets were a part of our Liquids Pipelines segment.

Olympic Pipeline

On July 31, 2017, we completed the sale of our interest in Olympic Pipeline for cash proceeds of approximately $203 million (US$160 million). A gain on disposal of $27 million (US$21 million) before tax was included in Other income/(expense) in the Consolidated Statements of Earnings. This interest was a part of our Liquids Pipelines segment.

Ozark Pipeline

In 2016, we classified the Ozark Pipeline assets as held for sale. On March 1, 2017, we completed the sale of the Ozark Pipeline assets to a subsidiary of MPLX LP for cash proceeds of approximately $294 million (US$220 million), including reimbursement of costs. A gain on disposal of $14 million (US$10 million) before tax was included in Operating and administrative expense in the Consolidated Statements of Earnings. These assets were a part of our Liquids Pipelines segment.

South Prairie Region

On December 1, 2016, we completed the sale of the South Prairie Region assets for cash proceeds of approximately $1.1 billion. A gain on disposal of $850 million before tax was included in Other income/(expense) in the Consolidated Statements of Earnings. These assets were a part of our Liquids Pipelines segment.

OTHER DISPOSITIONS

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In December 2016, we sold other miscellaneous non-core assets for cash proceeds of approximately $286 million.

9. ACCOUNTS RECEIVABLE AND OTHER

December 31,	2018	2017
(millions of Canadian dollars)		
Trade receivables and unbilled revenues[1]	4,711	5,325
Short-term portion of derivative assets	498	296
Other	1,308	1,432
	6,517	7,053

1 Net of allowance for doubtful accounts of $64 million and $50 million as at December 31, 2018 and 2017, respectively.

During 2017, in conjunction with its restructuring actions (Note 20), EEP terminated a receivable purchase agreement with a special purpose entity wholly-owned by us.

10. INVENTORY

December 31,	2018	2017
(millions of Canadian dollars)		
Natural gas	776	695
Crude oil	482	744
Other commodities	81	89
	1,339	1,528

Adjustments of $93 million, nil and nil were included in Commodity costs on the Consolidated Statements of Earnings for the years ended December 31, 2018, 2017 and 2016, respectively, to reduce inventory to market value.

11. PROPERTY, PLANT AND EQUIPMENT

December 31,	Weighted Average Depreciation Rate	2018	2017
(millions of Canadian dollars)			
Pipelines	2.6%	50,078	47,720
Pumping equipment, buildings, tanks and other	3.0%	16,935	16,610
Land and right-of-way[1]	2.7%	2,603	2,538
Gas mains, services and other	3.2%	17,474	17,026
Compressors, meters and other operating equipment	1.7%	5,893	5,774
Processing and treating plants	1.5%	1,634	1,440
Storage	1.9%	1,713	1,545
Wind turbines, solar panels and other	4.2%	5,063	4,804
Power transmission	2.6%	383	365
Vehicles, office furniture, equipment and other buildings and improvements	5.9%	630	390
Under construction	—	9,778	7,601
Total property, plant and equipment[2]		112,184	105,813
Total accumulated depreciation		(17,644)	(15,102)
Property, plant and equipment, net		94,540	90,711

1 The measurement of weighted average depreciation rate excludes non-depreciable assets.
2 Certain assets were reclassified as held for sale as at December 31, 2018 and December 31, 2017 (Note 8).

Depreciation expense for the years ended December 31, 2018, 2017 and 2016 was $2.9 billion, $2.9 billion and $2.0 billion, respectively.

IMPAIRMENT

Northern Gateway Project

On November 29, 2016, the Canadian Federal Government directed the NEB to dismiss our Northern Gateway Project application and the Certificates of Public Convenience and Necessity have been rescinded. In consultation with potential shippers and Aboriginal equity partners, we assessed this decision and concluded that the project cannot proceed as envisioned. After taking into consideration the amount recoverable from potential shippers on the Northern Gateway Project, we recognized an impairment of $373 million ($272 million after-tax), which is included in Impairment of property, plant and equipment in the Consolidated Statements of Earnings. This impairment loss is based on the full carrying value of the assets, which have an estimated fair value of nil, and are a part of our Liquids Pipelines segment.

Sandpiper Project

On September 1, 2016, we announced that EEP applied for the withdrawal of regulatory applications pending with the Minnesota Public Utilities Commission for Sandpiper. In connection with this announcement and other factors, we evaluated Sandpiper for impairment. As a result, we recognized an impairment loss of $992 million ($81 million after-tax attributable to us) for the year ended December 31, 2016, which is included in Impairment of property, plant and equipment in the Consolidated Statements of Earnings. Sandpiper is a part of our Liquids Pipelines segment. The estimated remaining fair value of Sandpiper was based on the estimated price that would be received to sell unused pipe, land and other related equipment in its current condition, considering the current market conditions for sale of these assets at the time. The valuation considered a range of potential selling prices from various alternatives that could be used to dispose of these assets. The estimated fair value, with the exception of $3 million in land, was reclassified into Deferred amounts and other assets in the Consolidated Statements of Financial Position as at December 31, 2016. During 2017, we disposed of substantially all of the remaining Sandpiper assets (Note 8).

Other

For the year ended December 31, 2016, we recorded impairment charges of $11 million related to EEP's non-core trucking assets and related facilities, which are a part of our Gas Transmission and Midstream segment.

Impairment charges were based on the amount by which the carrying values of the assets exceeded fair value, determined using expected discounted future cash flows, and such charges are included in Impairment of property, plant and equipment on the Consolidated Statements of Earnings.

12. VARIABLE INTEREST ENTITIES

CONSOLIDATED VARIABLE INTEREST ENTITIES

Enbridge Canadian Renewable LP (ECRLP)

To facilitate the sale on August 1, 2018 of the Renewable Assets (Note 8), we and our subsidiaries transferred our Canadian renewable assets to a newly formed partnership, ECRLP. Subsequently, a 49% interest in ECRLP was sold to CPPIB. ECRLP is a VIE as its limited partners do not have substantive kick-out rights or participating rights. Because we have the power to direct the activities of ECRLP, we are exposed to potential losses, and we have the right to receive benefits from ECRLP, we are considered the primary beneficiary.

Enbridge Energy Partners, L.P.

EEP is a Delaware limited partnership and is considered a VIE as its limited partners do not have substantive kick-out rights or participating rights. Through our wholly-owned subsidiary, Enbridge Energy Company, Inc. (EECI), we have the power to direct EEP's activities and have a significant impact on

EEP’s economic performance. Along with an economic interest held through an indirect common interest and general partner interest through EECI, and through our 100% ownership of EECI, we are the primary beneficiary of EEP. As at December 31, 2017, our economic interest in EEP was 34.6% and the public owned the remaining interests in EEP. As at December 31, 2018, subsequent to the Sponsored Vehicles buy-in (Note 20), our interest in EEP was 100%.

Enbridge Income Fund
The Fund is an unincorporated open-ended trust established by a trust indenture under the laws of the Province of Alberta and is considered a VIE by virtue of its capital structure. We are the primary beneficiary of the Fund through our 100% direct common interest in the Fund. We also serve in the capacity of Manager of the Fund and Affiliates. As at December 31, 2017, our combined economic interest and direct common interest in the Fund were 82.5% and 29.4%, respectively. As at December 31, 2018, subsequent to the Sponsored Vehicles buy-in (Note 20), our interest in the Fund was 100%.

Enbridge Commercial Trust (ECT)
We have the ability to appoint the majority of the trustees to ECT’s Board of Trustees, resulting in a lack of decision making ability for the holders of the common trust units of ECT. As a result, ECT is considered to be a VIE and although we do not have a common equity interest in ECT, we are considered to be the primary beneficiary of ECT. We also serve in the capacity of Manager of ECT, as part of the Fund and Affiliates.

Enbridge Income Partners LP (EIPLP)
EIPLP, formed in 2002, is involved in the generation, transportation and storage of energy through interests in its Liquids Pipelines business, including the Canadian Mainline, the Regional Oil Sands System, a 50.0% interest in the Alliance Pipeline, which transports natural gas, and its renewable and alternative power generation facilities. EIPLP is a partnership between a direct wholly-owned subsidiary of Enbridge and ECT. EIPLP is considered a VIE as its limited partners lack substantive kick-out rights and participating rights. Through a majority ownership of EIPLP’s General Partner, 100% ownership of Enbridge Management Services Inc. (a service provider for EIPLP), and a direct common interest in EIPLP, we have the power to direct the activities that most significantly impact EIPLP’s economic performance and have the obligation to absorb losses and the right to receive residual returns that are potentially significant to EIPLP, making us the primary beneficiary of EIPLP. As at December 31, 2017, our economic interest and direct common interest in EIPLP were 73.5% and 53.1%, respectively. As at December 31, 2018, subsequent to the Sponsored Vehicles buy-in (Note 20), our interest in EIPLP was 100%.

Green Power and Transmission
Through various subsidiaries, we have a majority ownership interest in Magic Valley, Wildcat, Keechi Wind Project (Keechi), New Creek and Chapman Ranch wind facilities. These wind facilities are considered VIEs due to the members’ lack of substantive kick-out rights and participating rights. We are the primary beneficiary of these VIEs by virtue of our voting rights, our power to direct the activities that most significantly impact the economic performance of the wind facilities, and our obligation to absorb losses.

Enbridge Holdings (DakTex) L.L.C.
Enbridge Holdings (DakTex) L.L.C. (DakTex) is owned 75% by a wholly-owned subsidiary of Enbridge and 25% by EEP, through which we have an effective 27.6% interest in the equity investment, Bakken Pipeline System (Note 13). EEP is the primary beneficiary because it has the power to direct DakTex’s activities that most significantly impact its economic performance. We consolidate EEP and by extension also consolidate DakTex.

Spectra Energy Partners, LP
SEP is a natural gas and crude oil infrastructure master limited partnership and is considered a VIE as its limited partners do not have substantive kick-out rights or participating rights. We are the primary

beneficiary of SEP because we have the power to direct SEP's activities that most significantly impact its economic performance. We acquired a 75% ownership in SEP through the Merger Transaction in 2017. As at December 31, 2018, subsequent to the Sponsored Vehicles buy-in (Note 20), our interest in SEP was 100%.

Valley Crossing Pipeline, LLC

Valley Crossing Pipeline, LLC (Valley Crossing), a wholly-owned subsidiary of Enbridge, has constructed a natural gas pipeline to transport natural gas within Texas. The pipeline was placed into service in October 2018. Following the completion of the pipeline construction and beginning of the long term transportation services agreement, Valley Crossing was concluded to have sufficient equity at risk to finance its activities without additional subordinated financial support and thus is no longer a VIE after October 2018.

Other Limited Partnerships

By virtue of a lack of substantive kick-out rights and participating rights, substantially all limited partnerships wholly-owned by us and/or our subsidiaries are considered VIEs. As these entities are 100% owned and directed by us with no third parties having the ability to direct any of the significant activities, we are considered the primary beneficiary.

The following table includes assets to be used to settle liabilities of our consolidated VIEs and liabilities of our consolidated VIEs for which creditors do not have recourse to our general credit as the primary beneficiary. These assets and liabilities are included in the Consolidated Statements of Financial Position.

December 31,	2018	2017
(millions of Canadian dollars)		
Assets		
Cash and cash equivalents	506	368
Restricted cash	27	—
Accounts receivable and other	2,073	2,132
Accounts receivable from affiliates	5	3
Inventory	244	220
	2,855	2,723
Property, plant and equipment, net	72,737	68,685
Long-term investments	6,481	6,258
Restricted long-term investments	244	206
Deferred amounts and other assets	3,156	2,921
Intangible assets, net	317	296
Goodwill	29	29
Deferred income taxes	131	145
	85,950	81,263
Liabilities		
Short-term borrowings	275	485
Accounts payable and other	2,925	2,859
Accounts payable to affiliates	4	131
Interest payable	303	312
Environmental liabilities	22	35
Current portion of long-term debt	1,034	2,129
	4,563	5,951
Long-term debt	29,577	31,469
Other long-term liabilities	5,074	4,301
Deferred income taxes	6,911	3,010
	46,125	44,731
Net assets before noncontrolling interests	39,825	36,532

We do not have an obligation to provide financial support to any of the consolidated VIEs.

UNCONSOLIDATED VARIABLE INTEREST ENTITIES

We currently hold several equity investments in limited partnerships that are assessed to be VIEs due to limited partners not having substantive kick-out rights or participating rights. We have determined that we do not have the power to direct the activities of the VIEs that most significantly impact the VIEs' economic performance. Specifically, the power to direct the activities of a majority of these VIEs is shared amongst the partners. Each partner has representatives that make up an executive committee who makes significant decisions for the VIE and none of the partners may make major decisions unilaterally.

The carrying amount of our interest in VIEs that are unconsolidated and our estimated maximum exposure to loss as at December 31, 2018 and 2017 is presented below.

December 31, 2018	Carrying Amount of Investment in VIE	Enbridge's Maximum Exposure to Loss
(millions of Canadian dollars)		
Aux Sable Liquid Products L.P.[1]	311	375
Eolien Maritime France SAS[2]	68	784
Enbridge Renewable Infrastructure Investments S.a.r.l.[3, 9]	127	3,250
Illinois Extension Pipeline Company, L.L.C.[4]	724	724
Nexus Gas Transmission, LLC[5]	1,757	2,668
PennEast Pipeline Company, LLC[6]	97	385
Rampion Offshore Wind Limited[7]	638	648
Vector Pipeline L.P.[8]	198	301
Other[4]	27	27
	3,947	9,162

December 31, 2017	Carrying Amount of Investment in VIE	Enbridge's Maximum Exposure to Loss
(millions of Canadian dollars)		
Aux Sable Liquid Products L.P.	300	361
Eolien Maritime France SAS	69	754
Hohe See Offshore Wind Project[9]	763	2,484
Illinois Extension Pipeline Company, L.L.C.	686	686
Nexus Gas Transmission, LLC	834	1,678
PennEast Pipeline Company, LLC	69	345
Rampion Offshore Wind Limited	555	679
Sabal Trail Transmissions, LLC	2,355	2,529
Vector Pipeline L.P.	169	278
Other	21	21
	5,821	9,815

1 At December 31, 2018, the maximum exposure to loss includes a guarantee by us for our respective share of the VIE's borrowing on a bank credit facility.

2 At December 31, 2018, the maximum exposure to loss includes the portion of our parental guarantee that has been committed in project construction contracts in which we would be liable for in the event of default by the VIE and an outstanding affiliate loan receivable for $202 million held by us.

3

At December 31, 2018, the maximum exposure to loss includes the portion of our parental guarantee that has been committed in project construction contracts in which we would be liable for in the event of default by the VIE.

4 At December 31, 2018, the maximum exposure to loss is limited to our equity investment as these companies are in operation and self-sustaining.

5 At December 31, 2018, the maximum exposure to loss includes the remaining expected contributions to the joint venture and parental guarantees for our portion of capacity lease agreements.

6 At December 31, 2018 the maximum exposure to loss includes the remaining expected contributions to the joint venture.

7 At December 31, 2018, the maximum exposure to loss includes the portion of our parental guarantee that has been committed in project contracts in which we would be liable for in the event of default by the VIE.

8 At December 31, 2018 the maximum exposure to loss includes the carrying value of an outstanding affiliate loan receivable for $102 million held by us.

9 As at December 31, 2018, the carrying amount of investment and maximum exposure to loss related to Hohe See Offshore Wind Project are included in the amounts shown for ERII.

We do not have an obligation to and did not provide any additional financial support to the VIEs during the years ended December 31, 2018 and 2017.

Enbridge Renewable Infrastructure Investments S.a.r.l. (ERII)
To facilitate the sale on August 1, 2018 of the Renewable Assets (Note 8), we transferred our interest in the Hohe See Offshore wind facilities and its subsequent expansion to a newly formed entity, ERII. Subsequently, a 49% interest in ERII was sold to CPPIB. ERII is a VIE due to insufficient equity at risk to finance its activities. We are not the primary beneficiary of ERII since the power to direct the activities of ERII that most significantly impacts its economic performance is shared. We account for ERII by using the equity method as we retain significant influence through a 51% voting interest in substantive decisions.

Sabal Trail Transmission, LLC
SEP owns a 50% interest in Sabal Trail, a joint venture that operates a pipeline originating in Alabama that transports natural gas to Florida and has been classified as a variable interest entity.

On April 30, 2018, Sabal Trail issued US$500 million in aggregate principal amount of 4.25% senior notes due in 2028, US$600 million in aggregate principal amount of 4.68% senior notes due in 2038 and US$400 million in aggregate principal amount of 4.83% senior notes due in 2048. Sabal Trail distributed net proceeds from the offering to the members as a partial reimbursement of construction and development costs incurred by the members. The net distribution made to SEP was US$744 million and was used to pay down indebtedness and is included within Distributions from equity investments in excess of cumulative earnings on the Consolidated Statements of Cash Flows for the year ended December 31, 2018. These events triggered reconsideration and as a result, it was concluded that Sabal Trail was no longer a VIE as of June 30, 2018 due to sufficient equity at risk to finance its activities.

13. LONG-TERM INVESTMENTS

December 31,	Ownership Interest	2018	2017
(millions of Canadian dollars)			
EQUITY INVESTMENTS			
Liquids Pipelines			
Bakken Pipeline System[1]	27.6%	2,039	1,938
Seaway Crude Pipeline System	50.0%	3,113	2,882
Illinois Extension Pipeline Company, L.L.C.[2]	65.0%	724	686
Other	30.0% - 43.8%	97	87
Gas Transmission and Midstream			
Alliance Pipeline[3]	50.0%	368	375
Aux Sable	42.7% - 50.0%	311	300
DCP Midstream, LLC[4]	50.0%	2,368	2,143
Gulfstream Natural Gas System, L.L.C.[4]	50.0%	1,289	1,205
Nexus Gas Transmission, LLC[4]	50.0%	1,757	834
Offshore - various joint ventures	22.0% - 74.3%	400	389
PennEast Pipeline Company LLC[4]	20.0%	97	69
Sabal Trail Transmission, LLC[5]	50.0%	1,586	2,355
Southeast Supply Header L.L.C.[4]	50.0%	519	486
Steckman Ridge LP[4]	49.5%	237	221
Texas Express Pipeline[6]	35.0%	—	430
Vector Pipeline L.P.	60.0%	198	169
Other[4]	33.3% - 50.0%	6	34
Gas Distribution			
Noverco Common Shares	38.9%	—	—
Other[4]	50.0%	15	15
Green Power and Transmission			
Eolien Maritime France SAS	50.0%	68	69
Enbridge Renewable Infrastructure Investments S.a.r.l.[7]	25.5%	127	763
Rampion Offshore Wind Project	24.9%	638	555
Other	19.0% - 50.0%	72	95
Eliminations and Other			
Other	19.0% - 42.7%	10	26
OTHER LONG-TERM INVESTMENTS			
Gas Distribution			
Noverco Preferred Shares		478	371
Green Power and Transmission			
Emerging Technologies and Other		80	80
Eliminations and Other			
Other		110	67
		16,707	16,644

1 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) for a purchase price of $2 billion (US$1.5 billion). The Bakken Pipeline System was placed into service on June 1, 2017. For details regarding our funding arrangement, refer to Note 20 - Noncontrolling Interests.

2 Owns the Southern Access Extension Project.

3 Certain assets of the Alliance Pipeline are pledged as collateral to Alliance Pipeline lenders.

4 On February 27, 2017, we acquired Spectra Energy's interests in DCP Midstream, Gulfstream Natural Gas System, L.L.C, Nexus, PennEast, Southeast Supply Header L.L.C., Steckman Ridge LP and other equity investments as part

of the Merger Transaction (Note 8).

5 On February 27, 2017, we acquired Spectra Energy's consolidated interest in Sabal Trail as part of the Merger Transaction (Note 8). On July 3, 2017, Sabal Trail was placed into service and the assets, liabilities, and noncontrolling interests were deconsolidated as at the in-service date.

6 On August 1, 2018 the sale of Midcoast Operating, L.P. and its subsidiaries closed. Upon closing of the sale, our interest in the Texas Express NGL pipeline system was sold along with the MOLP assets. The carrying value of $447 million of our equity method investment in the Texas Express NGL pipeline system was included within the disposal group of the transaction. For further details on the sale transaction please refer to Note 8 - Acquisitions and Dispositions.

7 On February 8, 2017, we acquired an effective 50% interest in EnBW Hohe See GmbH & Co. KG. On August 1, 2018 we transferred our interest in the Hohe See Offshore wind facilities and its subsequent expansion to a newly formed entity, ERII. Subsequently, we sold a 49% interest in ERII to CPPIB, reducing our interest in the project to 25.5%.

Equity investments include the unamortized excess of the purchase price over the underlying net book value of the investees' assets at the purchase date. As at December 31, 2018, this comprised of $2.2 billion in Goodwill and $706 million in amortizable assets. As at December 31, 2017, this comprised of $2.0 billion in Goodwill and $643 million in amortizable assets.

For the years ended December 31, 2018, 2017 and 2016, dividends received from equity investments were $2.8 billion, $1.4 billion and $825 million, respectively.

Summarized combined financial information of our interest in unconsolidated equity investments (presented at 100%) is as follows:

	Year Ended December 31,								
	2018			2017			2016		
	Seaway	Other	Total	Seaway	Other	Total	Seaway	Other	Total
(millions of Canadian dollars)									
Operating revenues	966	18,251	19,217	959	15,254	16,213	938	3,164	4,102
Operating expenses	212	15,422	15,634	286	12,911	13,197	293	3,051	3,344
Earnings/(loss)	646	2,308	2,954	672	2,056	2,728	643	(2)	641
Earnings attributable to controlling interests	323	1,059	1,382	336	926	1,262	322	147	469

	December 31, 2018			December 31, 2017		
	Seaway	Other	Total	Seaway	Other	Total
(millions of Canadian dollars)						
Current assets	113	3,176	3,289	106	3,432	3,538
Non-current assets	3,585	45,531	49,116	3,329	41,697	45,026
Current liabilities	123	5,413	5,536	143	3,311	3,454
Non-current liabilities	16	15,859	15,875	13	13,582	13,595
Noncontrolling interests	—	3,479	3,479	—	3,191	3,191

Sabal Trail Transmission, LLC

On July 3, 2017, Sabal Trail was placed into service. In accordance with the Sabal Trail LLC Agreement, upon the in-service date, the power to direct Sabal Trail's activities became shared with its members. We are no longer the primary beneficiary and deconsolidated the assets, liabilities and noncontrolling interests related to Sabal Trail as at the in-service date.

At deconsolidation, our 50% interest in Sabal Trail was recorded at its fair value of $2.3 billion (US$1.9 billion), which approximated its carrying value as a long-term equity investment. As a result, there was no gain or loss recognized for the year ended December 31, 2017 related to the remeasurement of the retained equity interest to its fair value. The fair value was determined using the income approach which is based on the present value of the future cash flows.

Noverco Inc.

As at December 31, 2018 and 2017, we owned an equity interest in Noverco through ownership of 38.9% of its common shares and an investment in preferred shares. The preferred shares are entitled to a cumulative preferred dividend based on the average yield of Government of Canada bonds maturing in 10 years plus a margin of 4.38%.

As at December 31, 2018 and 2017, Noverco owned an approximate 1.4% and 1.9% reciprocal shareholding in our common shares, respectively. Noverco sold 4.4 million common shares in December

2018 and purchased 1.2 million common shares in February 2016. Shares purchased and sold were treated as treasury stock on the Consolidated Statements of Changes in Equity.

As a result of Noverco's reciprocal shareholding in our common shares, as at December 31, 2018 and 2017, we had an indirect pro-rata interest of 0.5% and 0.7%, respectively, in our own shares. Both the equity investment in Noverco and shareholders' equity have been reduced by the reciprocal shareholding of $88 million and $102 million as at December 31, 2018 and 2017. Noverco records dividends paid from us as dividend income and we eliminate these dividends from our equity earnings of Noverco. We record our pro-rata share of dividends paid by us to Noverco as a reduction of dividends paid and an increase in our investment in Noverco.

14. RESTRICTED LONG-TERM INVESTMENTS

Effective January 1, 2015, we began collecting and setting aside funds to cover future pipeline abandonment costs for all NEB regulated pipelines as a result of the NEB's regulatory requirements under LMCI. The funds collected are held in trusts in accordance with the NEB decision. The funds collected from shippers are reported within Transportation and other services revenues on the Consolidated Statements of Earnings and Restricted long-term investments on the Consolidated Statements of Financial Position. Concurrently, we reflect the future abandonment cost as an increase to Operating and administrative expense on the Consolidated Statements of Earnings and Other long-term liabilities on the Consolidated Statements of Financial Position.

We routinely invest excess cash and various restricted balances in securities such as commercial paper, bankers acceptances, corporate debt securities, Canadian equity securities, treasury bills and money market securities in the United States and Canada.

As at December 31, 2018 and 2017, we had restricted long-term investments held in trust and classified as available for sale or held to maturity of $323 million and $267 million, respectively. We had estimated future abandonment costs related to LMCI of $212 million and $151 million as at December 31, 2018 and 2017, respectively.

15. INTANGIBLE ASSETS

The following table provides the weighted average amortization rate, gross carrying value, accumulated amortization and net carrying value for each of our major classes of intangible assets:

December 31, 2018[1]	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Customer relationships	5.0 %	762	70	692
Power purchase agreements	4.4 %	96	21	75
Project agreement[2]	4.0 %	164	10	154
Software	11.4 %	1,827	814	1,013
Other intangible assets	4.1 %	508	70	438
		3,357	985	2,372

December 31, 2017[1]	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Customer relationships	3.5 %	967	41	926
Power purchase agreements	3.5 %	99	17	82
Project agreement[2]	4.0 %	150	3	147
Software	11.3 %	1,760	714	1,046
Other intangible assets[3]	4.4 %	1,162	96	1,066
		4,138	871	3,267

1 Certain assets were reclassified as held for sale as at December 31, 2018 and December 31, 2017 (Note 8).
2 Represents a project agreement acquired from the Merger Transaction (Note 8).
3 The measurement of weighted average amortization rate excludes non-depreciable intangible assets.

For the years ended December 31, 2018, 2017 and 2016, our amortization expense related to intangible assets totaled $281 million, $280 million and $177 million, respectively. The following table presents our forecast of amortization expense associated with existing intangible assets for the years indicated as follows:

	2019	2020	2021	2022	2023
Forecast of amortization expense (millions of Canadian dollars)	278	251	227	205	186

16. GOODWILL

(millions of Canadian dollars)	Liquids Pipelines	Gas Transmission & Midstream	Gas Distribution	Green Power and Transmission	Energy Services	Eliminations and Other	Consolidated
Gross Cost							
Balance at January 1, 2017	59	457	7	—	2	13	538
Acquired in Merger Transaction (Note 8)	8,070	22,914	5,672	—	—	—	36,656
Sabal Trail deconsolidation (Note 13)	—	(966)	—	—	—	—	(966)
Disposition	(29)	—	—	—	—	—	(29)
Foreign exchange and other	(314)	(866)	—	—	—	—	(1,180)
Balance at December 31, 2017	7,786	21,539	5,679	—	2	13	35,019
Disposition	—	(628)	—	—	—	—	(628)
Allocation to assets held for sale	—	(55)	(133)	—	—	—	(188)
Foreign exchange and other	538	1,482	(183)	—	—	—	1,837
Balance at December 31, 2018	8,324	22,338	5,363	—	2	13	36,040
Accumulated Impairment							
Balance at January 1, 2017	—	(440)	(7)	—	—	(13)	(460)
Impairment	—	(102)	—	—	—	—	(102)
Balance at December 31, 2017	—	(542)	(7)	—	—	(13)	(562)
Impairment	—	(1,019)	—	—	—	—	(1,019)
Balance at December 31, 2018	—	(1,561)	(7)	—	—	(13)	(1,581)
Carrying Value							
Balance at December 31, 2017	7,786	20,997	5,672	—	2	—	34,457
Balance at December 31, 2018	8,324	20,777	5,356	—	2	—	34,459

IMPAIRMENT

Gas Transmission and Midstream

Canadian Natural Gas Gathering and Processing Businesses

During the year ended December 31, 2018, we recorded a goodwill impairment charge of $1,019 million related to our Canadian Natural Gas Gathering and Processing Businesses assets which were classified as held for sale in the third quarter. The provincially regulated assets were subsequently sold in the fourth quarter (Note 8). As these assets represented a portion of a reporting unit, we allocated a portion of the goodwill of the reporting unit to these assets using a relative fair value approach. In connection with the write-down of the carrying values of the assets held for sale to its sale price consideration less costs to sell, the related goodwill was impaired. We also performed a goodwill impairment test for the related reporting unit resulting in no additional impairment charge.

US Midstream

During the year ended December 31, 2017, we recorded a goodwill impairment charge of $102 million related to certain assets in our Gas Transmission and Midstream segment classified as held for sale (Note 8). Goodwill was allocated to certain disposal groups qualifying as a business based on a relative fair value approach. In connection with the write-down of the carrying values of the assets held for sale to its fair value less costs to sell, the related goodwill was impaired. The fair value of these assets were estimated using the discounted cash flow method, which was negatively impacted by prolonged decline in commodity prices and deteriorating business performance. We also performed goodwill impairment testing on the associated gas midstream reporting unit resulting in no additional impairment charge.

The estimate of the gas midstream reporting unit's fair value required the use of significant unobservable inputs representative of a Level 3 fair value measurement, including assumptions related to the future performance of the reporting unit.

DISPOSITIONS

In 2018, we derecognized $262 million of goodwill on the disposition of Midcoast Operating, L.P. and its subsidiaries and $366 million on the disposition of the provincially regulated facilities of our Canadian Natural Gas Gathering and Processing Business (Note 8).

In 2017, we derecognized $29 million of goodwill on the disposition of Olympic Pipeline (Note 8).

ASSETS HELD FOR SALE

As at December 31, 2018, the net assets of the federally regulated facilities of our Canadian Natural Gas Gathering and Processing Business remain classified as held for sale, including $55 million of allocated goodwill. In addition, as at December 31, 2018, the net assets of EGNB were also classified as held for sale, including $133 million of allocated goodwill.

ACQUISITIONS

In 2017, we recognized $36.7 billion of goodwill on the Merger Transaction (Note 8).

17. ACCOUNTS PAYABLE AND OTHER

December 31,	2018	2017
(millions of Canadian dollars)		
Trade payables and operating accrued liabilities	4,604	5,135
Construction payables and contractor holdbacks	804	706
Current derivative liabilities	1,234	1,130
Dividends payable	1,539	1,169
Taxes payable	801	522
Other	854	816
	9,836	9,478

18. DEBT

December 31, (millions of Canadian dollars)	Weighted Average Interest Rate		Maturity	2018	2017
Enbridge Inc.					
United States dollar term notes[1]	4.1	%	2022-2046	6,419	5,889
Medium-term notes[2]	4.3	%	2019-2064	7,323	5,698
Fixed-to-floating subordinated term notes[3,4]	5.9	%	2077-2078	6,771	3,843
Floating rate notes[5]			2019-2020	2,389	2,254
Commercial paper and credit facility draws[6]	2.2	%	2019-2023	1,999	2,729
Other[7]				—	3
Enbridge (U.S.) Inc.					
Commercial paper and credit facility draws[8]	3.5	%	2020	1,065	490
Enbridge Energy Partners, L.P.					
Senior notes[9]	6.2	%	2019-2045	6,214	6,328
Junior subordinated notes[10]			2067	546	501
Commercial paper and credit facility draws[11]	3.3	%	2022	1,044	1,820
Enbridge Gas Distribution Inc.					
Medium-term notes	4.5	%	2020-2050	3,695	3,695
Debentures	9.9	%	2024	85	85
Commercial paper and credit facility draws	2.3	%	2020	750	960
Enbridge Income Fund					
Medium-term notes[2]				—	1,750
Commercial paper and credit facility draws				—	755
Enbridge Pipelines (Southern Lights) L.L.C.					
Senior notes[12]	4.0	%	2040	1,257	1,207
Enbridge Pipelines Inc.					
Medium-term notes[13]	4.3	%	2019-2046	4,225	4,525
Debentures	8.2	%	2024	200	200
Commercial paper and credit facility draws[14]	2.4	%	2020	2,200	1,438
Other[7]				4	4
Enbridge Southern Lights LP					
Senior notes	4.0	%	2040	289	315
Midcoast Energy Partners, L.P.					
Senior notes[15]				—	501
Spectra Energy Capital[16]					
Senior notes[17]	7.1	%	2032-2038	236	1,665
Spectra Energy Partners, LP[16]					
Senior secured notes[18]	6.1	%	2020	150	138
Senior notes[19]	4.3	%	2020-2048	8,249	7,192
Floating rate notes[20]			2020	546	501
Commercial paper and credit facility draws[21]	3.2	%	2022	2,065	2,824
Union Gas Limited[16]					
Medium-term notes	4.1	%	2021-2047	3,290	3,490
Senior debentures				—	75
Debentures	8.7	%	2025	125	250
Commercial paper and credit facility draws	2.3	%	2021	275	485
Westcoast Energy Inc.[16]					
Senior secured notes	6.2	%	2019	33	66
Medium-term notes	4.7	%	2019-2041	2,175	2,177

Debentures	8.6	%	2020-2026	375	525
Fair value adjustment - Spectra Energy acquisition				964	1,114
Other[22]				(348)	(312)
Total debt				64,610	65,180
Current maturities				(3,259)	(2,871)
Short-term borrowings[23]				(1,024)	(1,444)
Long-term debt				60,327	60,865

1 2018 - US$4,700 million; 2017 - US$4,700 million.

2 On December 21, 2018, Enbridge and Enbridge Income Fund (the Fund) completed a transaction to exchange certain series of the Fund's outstanding medium-term notes (Legacy Fund Notes) for an equal principal amount of newly issued medium term notes of Enbridge, having financial terms that are the same as the financial terms of the Fund Notes. See Debt Exchange discussion below.

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3 2018 - $2,400 million and US$3,200 million; 2017 - $1,650 million and US$1,750 million. For the initial 10 years, the notes carry a fixed interest rate. Subsequently, the interest rate will be floating and set to equal the three-month Bankers' Acceptance Rate or London Interbank Offered Rate (LIBOR) plus a margin.
4 The notes would be converted automatically into Conversion Preference Shares in the event of bankruptcy and related events.
5 2018 - $750 million and US$1,200 million; 2017 - $750 million and US$1,200 million. Carries an interest rate equal to the three-month Bankers' Acceptance Rate plus a margin of 59 basis points or LIBOR plus a margin of 40 or 70 basis points.
6 2018 - $1,906 million and US$69 million; 2017 - $1,593 million and US$907 million.
7 Primarily capital lease obligations.
8 2018 - US$780 million; 2017 - US$391 million.
9 2018 - US$4,550 million; 2017 - US$5,050 million.
10 2018 - US$400 million; 2017 - US$400 million. Carries an interest rate equal to the three-month LIBOR plus a margin of 379.75 basis points.
11 2018 - US$764 million; 2017 - US$1,453 million.
12 2018 - US$920 million; 2017 - US$963 million.
13 Included in medium-term notes is $100 million with a maturity date of 2112.
14 2018 - $1,905 million and US$216 million; 2017 - $1,080 million and US$286 million.
15 2017 - US$400 million.
16 Debt acquired in conjunction with the Merger Transaction (Note 8).
17 2018 - US$173 million; 2017 - US$1,329 million.
18 2018 - US$110 million; 2017 - US$110 million.
19 2018 - US$6,040 million; 2017 - US$5,740 million.
20 2018 - US$400 million; 2017 - US$400 million. Carries an interest rate equal to the three-month LIBOR plus a margin of 70 basis points.
21 2018 - US$1,512 million; 2017 - US$2,254 million.
22 Primarily debt discount and debt issue costs.
23 Weighted average interest rate - 2.3%; 2017 - 1.4%.

SECURED DEBT

Senior secured notes, totaling $183 million as at December 31, 2018, includes project financings for M&N Canada and Express-Platte System. Ownership interests in M&N Canada and certain of its accounts, revenues, business contracts and other assets are pledged as collateral. Express-Platte System notes payable are secured by the assignment of the Express-Platte System transportation receivables and by the Canadian portion of the Express-Platte pipeline system assets.

CREDIT FACILITIES

The following table provides details of our committed credit facilities at December 31, 2018:

December 31,	Maturity	2018 Total Facilities	Draws[1]	Available
(millions of Canadian dollars)				
Enbridge Inc.	2019-2023	5,751	2,008	3,743
Enbridge (U.S.) Inc.	2020	1,932	1,065	867
Enbridge Energy Partners, L.P.[2]	2022	2,493	1,044	1,449
Enbridge Gas Distribution Inc.	2019-2020	1,018	760	258
Enbridge Pipelines Inc.	2020	3,000	2,200	800
Spectra Energy Partners, LP[3,4]	2022	3,414	2,065	1,349
Union Gas Limited[4]	2021	700	275	425
Total committed credit facilities		18,308	9,417	8,891

1 Includes facility draws, letters of credit and commercial paper issuances that are back-stopped by the credit facility.
2 Includes $253 million (US$185 million) of facilities that expire in 2020.
3 Includes $459 million (US$336 million) of facilities that expire in 2021.
4 Committed credit facilities acquired in conjunction with the Merger Transaction (Note 8).

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

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

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

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

Westcoast Energy Inc. terminated an unutilized $400 million credit facility, which was scheduled to mature in 2021. The facility was acquired in conjunction with the Merger Transaction.

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

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

Credit facilities carry a weighted average standby fee of 0.2% per annum on the unused portion and draws bear interest at market rates. Certain credit facilities serve as a back-stop to the commercial paper programs and we have the option to extend such facilities, which are currently set to mature from 2020 to 2023.

As at December 31, 2018 and 2017, commercial paper and credit facility draws, net of short-term borrowings and non-revolving credit facilities that mature within one year of $7,967 million and $10,055 million, respectively, are supported by the availability of long-term committed credit facilities and therefore have been classified as long-term debt.

LONG-TERM DEBT ISSUANCES

The following are long-term debt issuances made during 2018 and 2017, excluding the debt exchange discussed below:

Company	Issue Date		Principal Amount
(millions of Canadian dollars unless otherwise stated)			
Enbridge Inc.			
	March 2018	Fixed-to-floating rate subordinated notes due March 2078[1]	US$850
	April 2018	Fixed-to-floating rate subordinated notes due April 2078[2]	$750
	April 2018	Fixed-to-floating rate subordinated notes due April 2078[3]	US$600
	May 2017	Floating rate notes due May 2019[4]	$750
	June 2017	3.19% medium-term notes due December 2022	$450
	June 2017	3.20% medium-term notes due June 2027	$450
	June 2017	4.57% medium-term notes due March 2044	$300
	June 2017	Floating rate notes due June 2020[5]	US$500
	July 2017	2.90% senior notes due July 2022	US$700
	July 2017	3.70% senior notes due July 2027	US$700
	July 2017	Fixed-to-floating rate subordinated	US$1,000

		notes due July 2077[6]	
	September 2017	Fixed-to-floating rate subordinated notes due September 2077[7]	$1,000
	October 2017	Fixed-to-floating rate subordinated notes due September 2077[7]	$650
	October 2017	Floating rate notes due January 2020[8]	US$700
Enbridge Gas Distribution Inc.			
	November 2017	3.51% medium-term notes due November 2047	$300
Spectra Energy Partners, LP			
	January 2018	3.50% senior notes due January 2028[9]	US$400
	January 2018	4.15% senior notes due January 2048[9]	US$400
	June 2017	Floating rate notes due June 2020[10]	US$400
Union Gas Limited			
	November 2017	2.88% medium-term notes due November 2027	$250
	November 2017	3.59% medium-term notes due November 2047	$250

1 Notes mature in 60 years and are callable on or after year 10. For the initial 10 years, the notes carry a fixed interest rate of 6.25%. Subsequently, the interest rate will be set to equal the three-month LIBOR plus a margin of 364 basis points from years 10 to 30, and a margin of 439 basis points from years 30 to 60.

2 Notes mature in 60 years and are callable on or after year 10. For the initial 10 years, the notes carry a fixed interest rate of 6.625%. Subsequently, the interest rate will be set to equal the Canadian Dollar Offered Rate plus a margin of 432 basis points from years 10 to 30, and a margin of 507 basis points from years 30 to 60.

3 Notes mature in 60 years and are callable on or after year five. For the initial five years, the notes carry a fixed interest rate of 6.375%. Subsequently, the interest rate will be set to equal the three-month LIBOR plus a margin of

359 basis points from years five to 10, a margin of 384 basis points from years 10 to 25, and a margin of 459 basis points from years 25 to 60.

4 Carries an interest rate equal to the three-month Bankers' Acceptance Rate plus 59 basis points.

5 Carries an interest rate equal to the three-month LIBOR plus 70 basis points.

6 Matures in 60 years and are callable on or after year 10. For the initial 10 years, the notes carry a fixed interest rate of 5.5%. Subsequently, the interest rate will be set to equal the three-month LIBOR plus a margin of 342 basis points from year 10 to 30, and a margin of 417 basis points from year 30 to 60.

7 Matures in 60 years and are callable on or after year 10. For the initial 10 years, the notes carry a fixed interest rate of 5.4%. Subsequently, the interest rate will be set to equal the three-month Bankers' Acceptance Rate plus a margin of 325 basis points from year 10 to 30, and a margin of 400 basis points from year 30 to 60.

8 Carries an interest rate equal to the three-month LIBOR plus 40 basis points.

9 Issued through Texas Eastern Transmission, L.P. (Texas Eastern), a wholly-owned operating subsidiary of SEP.

10 Carries an interest rate equal to the three-month LIBOR plus 70 basis points.

LONG-TERM DEBT REPAYMENTS

The following are long-term debt repayments during 2018 and 2017, excluding the debt exchange discussed below:

Company	Retirement/Repayment Date		Principal Amount	Cash Consideration[1]
(millions of Canadian dollars unless otherwise stated)				
Enbridge Inc.				
	March 2017	Floating rate notes	$500	

April 2017	5.60% medium-term notes	US$400
June 2017	Floating rate notes	US$500
Enbridge Energy Partners, L.P.		
April 2018	6.50% senior notes	US$400
October 2018	7.00% senior notes	US$100
Enbridge Gas Distribution Inc.		
April 2017	1.85% medium-term notes	$300
December 2017	5.16% medium-term notes	$200
Enbridge Income Fund		
December 2018	4.00% medium-term notes	$125
June 2017	5.00% medium-term notes	$100
December 2017	2.92% medium-term notes	$225
Enbridge Pipelines (Southern Lights) L.L.C.		
June and December 2018	3.98% medium-term notes due June 2040	US$43
June and December 2017	3.98% medium-term note due June 2040	US$37
Enbridge Pipelines Inc.		
November 2018	6.62% medium-term notes	$170
November 2018	6.62% medium-term notes	$130
Enbridge Southern Lights LP		
January, July and December 2018	4.01% medium-term notes due June 2040	$27
June 2017		$7

	4.01% medium-term notes due June 2040		
Midcoast Energy Partners, L.P.			
Redemption			
July 2018[2]	3.56% senior notes due September 2019	US$75	US$76
July 2018[2]	4.04% senior notes due September 2021	US$175	US$182
July 2018[2]	4.42% senior notes due September 2024	US$150	US$161
Spectra Energy Capital, LLC			
Repurchase via Tender Offer			
March 2018[2]	6.75% senior unsecured notes due 2032	US$64	US$80
March 2018[2]	7.50% senior unsecured notes due 2038	US$43	US$59
July 2017[3]	Senior notes carrying interest ranging from 3.3% to 7.5% due 2018 to 2038	US$761	US$857
Redemption			
March 2018[2]	5.65% senior unsecured notes due 2020	US$163	US$172
March 2018[2]	3.30% senior unsecured notes due 2023	US$498	US$508
July and September 2017[3]	8.00% senior notes due 2019	US$500	US$581
Repayment			
April 2018	6.20% senior notes	US$272	
July 2018		US$118	

	6.75% senior notes	
Spectra Energy Partners, LP		
September 2018	2.95% senior notes	US$500
September 2017	6.00% senior notes	US$400
June and December 2017	7.39% subordinated secured notes	US$12
Union Gas Limited		
April 2018	5.35% medium-term notes	$200
August 2018	8.75% debentures	$125
October 2018	8.65% senior debentures	$75
November 2017	9.70% debentures	$125
Westcoast Energy Inc.		
May and November 2018	6.90% senior secured notes due 2019	$26
May and November 2018	4.34% senior secured notes due 2019	$9
September 2018	8.50% debenture	$150
May and November 2017	6.90% senior secured notes due 2019	$26
May and November 2017	4.34% senior secured notes due 2019	$24

1 Cash consideration disclosed for repayments where the cash paid differs from the principal amount.

2 The loss on debt extinguishment of $64 million (US$50 million), net of the fair value adjustment recorded upon completion of the Merger Transaction, was reported within Interest expense in the Consolidated Statements of Earnings.

3 The loss on debt extinguishment of $50 million (US$38 million), net of the fair value adjustment recorded upon completion of the Merger Transaction, was reported within Interest expense in the Consolidated Statements of Earnings.

DEBT EXCHANGE

On December 21, 2018, Enbridge and the Fund completed a transaction to exchange certain series of the Legacy Fund Notes for an equal principal amount of newly issued medium term notes of Enbridge (Enbridge Notes), having financial terms that are the same as the financial terms of the Fund Notes.

The following Enbridge Notes were issued in exchange for the previously held Fund Notes:

- Enbridge 4.10% medium-term notes, due February 22, 2019 issued in exchange for Fund 4.10% medium-term notes, due February 22, 2019 with a principal amount of $300 million;
- Enbridge 4.85% medium-term notes, due November 12, 2020 issued in exchange for Fund 4.85% medium-term notes, due November 12, 2020 with a principal amount of $100 million;
- Enbridge 4.85% medium-term notes, due February 22, 2022 issued in exchange for Fund 4.85% medium-term notes, due February 22, 2022 with a principal amount of $200 million;
- Enbridge 3.94% medium-term notes, due January 13, 2023 issued in exchange for Fund 3.94% medium-term notes, due January 13, 2023 with a principal amount of $275 million;
- Enbridge 3.95% medium-term notes, due November 19, 2024 issued in exchange for Fund 3.95% medium-term notes, due November 19, 2024 with a principal amount of $500 million; and
- Enbridge 4.87% medium-term notes, due November 21, 2044 issued in exchange for Fund 4.87% medium-term notes, due November 21, 2044 with a principal amount of $250 million.

DEBT COVENANTS

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

INTEREST EXPENSE

Year ended December 31,	2018	2017	2016
(millions of Canadian dollars)			
Debentures and term notes	3,011	3,011	1,714
Commercial paper and credit facility draws	171	206	197
Amortization of fair value adjustment - Spectra Energy acquisition	(131)	(270)	—
Capitalized	(348)	(391)	(321)
	2,703	2,556	1,590

19. ASSET RETIREMENT OBLIGATIONS

Our ARO relate mostly to the retirement of pipelines, renewable power generation assets, obligations related to right-of way agreements and contractual leases for land use.

The liability for the expected cash flows as recognized in the financial statements reflected discount rates ranging from 1.8% to 9.0%.

A reconciliation of movements in our ARO liabilities is as follows:

December 31,	2018	2017
(millions of Canadian dollars)		
Obligations at beginning of year	793	232
Liabilities acquired	—	546
Liabilities disposed	(13)	—
Liabilities incurred	145	—
Liabilities settled	(21)	(22)
Change in estimate	29	18
Foreign currency translation adjustment	22	(12)
Accretion expense	34	31
Obligations at end of year	989	793
Presented as follows:		
Accounts payable and other	6	2
Other long-term liabilities	983	791
	989	793

20. NONCONTROLLING INTERESTS

NONCONTROLLING INTERESTS

The following table provides additional information regarding Noncontrolling interests as presented in our Consolidated Statements of Financial Position:

December 31,	2018	2017
(millions of Canadian dollars)		
Algonquin Gas Transmission, L.L.C[1]	518	476
Enbridge Energy Management, L.L.C.[2]	—	34
Enbridge Energy Partners, L.P.[3]	—	138
Enbridge Gas Distribution Inc.[4]	—	100
Maritimes & Northeast Pipeline, L.L.C[1]	613	572
Renewable energy assets[5]	1,961	806
Spectra Energy Partners, LP[6]	—	4,335
Union Gas Limited[7]	—	110
Westcoast Energy Inc.[8]	841	1,005
Other[9]	32	21
	3,965	7,597

1 Represents subsidiaries of SEP and the interests in these subsidiaries held by third parties.

2 On December 20, 2018, we executed the definitive agreement with EEM and acquired all of the publicly held shares of EEM not already owned by us or our subsidiaries. As at December 31, 2017, the balance represented 88.3% interest in EEM held by public shareholders.

3 On December 20, 2018, we executed the definitive agreement with EEP and acquired all of the publicly held Class A common units of EEP not already owned by us or our subsidiaries. As at December 31, 2017, the balance represented 68.2% interest in EEP held by public unitholders.

4 On November 29, 2018, EGD redeemed all of its four million cumulative redeemable preferred shares held by third parties. As at December 31, 2017, the balance of these preferred shares was $100 million.

5 On August 1, 2018, we closed the sale of 49% of our interest in the Renewable Assets (Note 8). The remaining balance represents the tax equity investors' interests in Magic Valley, Wildcat, Keechi, New Creek and Chapman Ranch wind facilities, which are accounted for using the HLBV method, with an additional 20.0% noncontrolling interest in each of the Magic Valley and Wildcat wind facilities held by third parties as at December 31, 2018 and 2017.

6 On December 17, 2018, we closed the definitive agreement with SEP and acquired all of the publicly listed common units of SEP not already owned by us or our subsidiaries. As at December 31, 2017, the balance represented 25.7% interest in SEP held by public unitholders.

7 On November 29, 2018, Union Gas redeemed all of its four million cumulative redeemable preferred shares held by third parties. As at December 31, 2017, the balance of these preferred shares was $110 million.

8 Represents the 16.6 million cumulative redeemable preferred shares and 12 million cumulative first preferred shares as at December 31, 2018 and 2017 held by third parties in Westcoast Energy Inc., and the 22.0% interest in Maritimes & Northeast Pipeline Limited Partnership held by third parties as at December 31, 2018 and 2017.

9 Represents subsidiary of EEP and the interests in this subsidiary held by third parties.

United States Sponsored Vehicles Buy-in

On August 24, 2018, we entered into a definitive agreement with SEP under which we agreed to acquire all of the outstanding public common units of SEP not already owned by us or our subsidiaries on the basis of 1.111 of our common shares for each common unit of SEP. Upon the closing of the transaction on December 17, 2018, we acquired all of the public common units of SEP and SEP became an indirect, wholly-owned subsidiary of Enbridge. The transaction is valued at $3.9 billion based on the closing price of our common shares on the New York Stock Exchange on December 14, 2018. As a result of this buy-in, we recorded a decrease in Noncontrolling interests, Additional paid-in capital and Deferred income tax liabilities of $3.0 billion, $642 million and $167 million, respectively.

On September 17, 2018, we entered into definitive agreements with each of EEP and EEM under which we agreed to acquire all of the outstanding public class A common units of EEP and all of the outstanding public listed shares of EEM not already owned by us or our subsidiaries. Under the agreements, EEP public unitholders will receive 0.335 of our common shares for each class A common unit of EEP, and

EEM public shareholders will receive 0.335 of our common shares for each listed share of EEM. Upon the closing of the respective transactions on December 20, 2018, we acquired all of the public Class A common units of EEP and shares of EEM, and both EEP and EEM became indirect, wholly-owned subsidiaries of Enbridge. The EEP and EEM transactions are valued at $3.0 billion and $1.3 billion, respectively, based on the closing price of our common shares on the New York Stock Exchange on December 19, 2018. As a result of the buy-ins, collectedly for EEP and EEM, we recorded an increase in Noncontrolling interests and a decrease in Additional paid-in capital and Deferred income tax liabilities of $185 million, $3.7 billion and $707 million, respectively.

For discussion on the roll-up of ENF, refer to Canadian Sponsored Vehicles Buy-in under Redeemable Noncontrolling Interests below.

Renewable Assets

On August 1, 2018, we closed the sale of a 49% interest in all of our Canadian renewable assets and a 49% interest in two United States renewable assets to CPPIB (Note 8). As a result, we recorded an increase in Noncontrolling interests, Additional paid-in capital and Deferred income tax liabilities of $1,183 million, $79 million and $27 million, respectively, in the third quarter of 2018. For 2018, CPPIB's distributions and allocation of earnings were not proportionate to its ownership.

SEP Incentive Distribution Rights

As at December 31, 2017, we collectively owned a 75% ownership interest in SEP, together with 100% of SEP's incentive distribution rights (IDRs). On January 22, 2018, Enbridge and SEP announced the execution of a definitive agreement, resulting in us converting all of our 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 were eliminated. In the first quarter of 2018, we held a non-economic general partner interest in SEP and owned approximately 403 million SEP common units, representing approximately 83% of SEP's outstanding common units. As a result of this restructuring, we recorded a decrease in Noncontrolling interests of $1.5 billion and increases in Additional paid-in capital and Deferred income tax liabilities of $1.1 billion and $333 million, respectively. Subsequently in 2018, we acquired all of the outstanding common units of SEP (refer to United States Sponsored Vehicles Buy-in above).

Enbridge Energy Partners, L.P.

United States Sponsored Vehicle Strategy

On April 28, 2017, we completed a strategic review of EEP and took the actions described below. As a result of these actions, we recorded an increase in Noncontrolling interests of $458 million, inclusive of foreign currency translation adjustments, and a decrease in Additional paid-in capital of $421 million, net of deferred income taxes of $253 million.

Acquisition of Midcoast Assets and Privatization of MEP

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

On June 28, 2017, we acquired, through a wholly-owned subsidiary, all of EEP’s interest in the Midcoast 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, 100% of the Midcoast gas gathering and processing business was owned by us and subsequently sold on August 1, 2018 (see Note 8 - Acquisitions and Dispositions for further details).

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. We also irrevocably

waived all of our rights associated with our ownership of 66.1 million Class D units and 1,000 Incentive Distribution Units 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. Further, in conjunction with the restructuring actions, EEP terminated a receivable purchase agreement with a special purpose entity wholly-owned by us.

Finalization of Bakken Pipeline System Joint Funding Agreement
On April 27, 2017, we entered into a joint funding arrangement with EEP. Pursuant to this joint funding arrangement, we own 75% and EEP owns 25% of the combined 27.6% effective interest in the Bakken Pipeline System. Under this arrangement, EEP retains a five-year option to acquire an additional 20% interest in the Bakken Pipeline System. Upon the execution of the 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.

REDEEMABLE NONCONTROLLING INTERESTS
The following table presents additional information regarding Redeemable noncontrolling interests as presented in our Consolidated Statements of Financial Position:

Year ended December 31,	2018	2017	2016
(millions of Canadian dollars)			
Balance at beginning of year	4,067	3,392	2,141
Earnings attributable to redeemable noncontrolling interests	117	175	268
Other comprehensive income/(loss), net of tax			
Change in unrealized loss on cash flow hedges	3	(21)	(17)
Other comprehensive loss from equity investees	14	—	—
Reclassification to earnings of loss on cash flow hedges	—	57	9
Foreign currency translation adjustments	4	(6)	(3)
Other comprehensive income/(loss), net of tax	21	30	(11)
Distributions to unitholders	(300)	(247)	(202)
Contributions from unitholders	70	1,178	591
Modified retrospective adoption of accounting standard (note 3)	(38)	—	—
Net dilution gain/(loss)	76	(169)	(81)
Redemption value adjustment	456	(292)	686
Sponsored vehicle buy-in[1]	(4,469)	—	—
Balance at end of year	—	4,067	3,392

1. On November 8, 2018, we executed the definitive agreement with ENF and acquired all of the publicly held shares of ENF not already owned by us or our subsidiaries.

Canadian Sponsored Vehicle Buy-in
On September 17, 2018, we entered into a definitive agreement with ENF under which we would acquire all of the outstanding public common shares of ENF not already owned by us or our subsidiaries on the basis of 0.735 of our common shares and cash of $0.45 for each common share of ENF. Upon the closing of the transaction on November 8, 2018, we acquired all of the public common shares of ENF and ENF become a wholly-owned subsidiary of Enbridge. The transaction, excluding the cash component, is valued at $4.5 billion based on the closing price of our common shares on the Toronto Stock Exchange on November 7, 2018. As a result of this buy-in, we recorded a decrease in Redeemable noncontrolling interests and Additional paid-in capital of $4.5 billion and $25 million, respectively, with nil deferred tax impact.
As at December 31, 2017 and 2016, Redeemable Noncontrolling Interest represented 56.5% and 45.6%, respectively, of interests in the Fund’s trust units that are held by third parties.

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21. SHARE CAPITAL

Our authorized share capital consists of an unlimited number of common shares with no par value and an unlimited number of preference shares.

COMMON SHARES

December 31,	2018 Number of Shares	Amount	2017 Number of Shares	Amount	2016 Number of Shares	Amount
(millions of Canadian dollars; number of shares in millions)						
Balance at beginning of year	1,695	50,737	943	10,492	868	7,391
Common shares issued[1]	—	—	33	1,500	56	2,241
Common shares issued in Merger Transaction (Note 8)	—	—	691	37,429	—	—
Common shares issued in Sponsored Vehicle buy-in (SEP) (Note 20)	91	3,888	—	—	—	—
Common shares issued in Sponsored Vehicle buy-in (EEP) (Note 20)	72	3,042	—	—	—	—
Common shares issued in Sponsored Vehicle buy-in (EEM) (Note 20)	30	1,267	—	—	—	—
Common shares issued in Sponsored Vehicle buy-in (ENF) (Note 20)	104	4,530	—	—	—	—
Dividend Reinvestment and Share Purchase Plan	28	1,181	25	1,226	16	795
Shares issued on exercise of stock options	2	32	3	90	3	65
Balance at end of year	2,022	64,677	1,695	50,737	943	10,492

1 Gross proceeds of nil, $1.5 billion and $2.3 billion for the years ended December 31, 2018, 2017 and 2016, respectively; net issuance costs of nil, nil and $59 million for the years ended December 31, 2018, 2017 and 2016, respectively.

PREFERENCE SHARES

December 31,	2018 Number of Shares	2018 Amount	2017 Number of Shares	2017 Amount	2016 Number of Shares	2016 Amount
(millions of Canadian dollars; number of shares in millions)						
Preference Shares, Series A	5	125	5	125	5	125
Preference Shares, Series B	18	457	18	457	20	500
Preference Shares, Series C	2	43	2	43	—	—
Preference Shares, Series D	18	450	18	450	18	450
Preference Shares, Series F	20	500	20	500	20	500
Preference Shares, Series H	14	350	14	350	14	350
Preference Shares, Series J	8	199	8	199	8	199
Preference Shares, Series L	16	411	16	411	16	411
Preference Shares, Series N	18	450	18	450	18	450
Preference Shares, Series P	16	400	16	400	16	400
Preference Shares, Series R	16	400	16	400	16	400
Preference Shares, Series 1	16	411	16	411	16	411
Preference Shares, Series 3	24	600	24	600	24	600
Preference Shares, Series 5	8	206	8	206	8	206
Preference Shares, Series 7	10	250	10	250	10	250
Preference Shares, Series 9	11	275	11	275	11	275
Preference Shares, Series 11	20	500	20	500	20	500
Preference Shares, Series 13	14	350	14	350	14	350
Preference Shares, Series 15	11	275	11	275	11	275
Preference Shares, Series 17	30	750	30	750	30	750
Preference Shares, Series 19	20	500	20	500	—	—
Issuance costs		(155)		(155)		(147)
Balance at end of year		7,747		7,747		7,255

Characteristics of the preference shares are as follows:

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

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

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

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

4

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

5 The floating quarterly dividend amount for the Series C Preference Shares was increased to $0.22685 from $0.20342 on March 1, 2018, was increased to $0.22748 from $0.22685 on June 1, 2018, was increased to $0.23934 from $0.22748 on September 1, 2018 and was increased to $0.25459 from $0.23934 on December 1, 2018, due to reset on a quarterly basis following the issuance thereof.

6 No Series D, F, H, N, or 1 Preference shares were converted on the March 1, 2018, June 1, 2018, September 1, 2018, December 1, 2018 or June 1, 2018 conversion option dates, respectively. However, the quarterly dividend amounts for Series D, F, H, N, and 1, were increased to $0.27875 from $0.25000 on March 1, 2018, $0.29306 from $0.25000 on June 1, 2018, $0.27350 from $0.25000 on September 1, 2018, $0.31788 from $0.25000 on December 1, 2018 and US$0.37182 from US$0.25000 on June 1, 2018, respectively, due to reset on every fifth anniversary thereafter.

DIVIDEND REINVESTMENT AND SHARE PURCHASE PLAN

On November 2, 2018, we announced the suspension of our DRIP, effective immediately. Prior to the announcement, our shareholders were able to participate in the DRIP, which enabled participants to reinvest their dividends in our common shares at a 2% discount to market price and to make additional optional cash payments to purchase common shares at the market price, free of brokerage or other charges. Refer to Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Share Issuances for details on dividends paid.

SHAREHOLDER RIGHTS PLAN

The Shareholder Rights Plan is designed to encourage the fair treatment of shareholders in connection with any takeover offer for us. Rights issued under the plan become exercisable when a person and any related parties acquires or announces its intention to acquire 20% or more of our outstanding common shares without complying with certain provisions set out in the plan or without approval of our Board of Directors. Should such an acquisition occur, each rights holder, other than the acquiring person and related parties, will have the right to purchase our common shares at a 50% discount to the market price at that time.

22. STOCK OPTION AND STOCK UNIT PLANS

We maintain four long-term incentive compensation plans: the ISO Plan, the Performance Stock Options (PSO) Plan, the Performance Stock Units (PSU) Plan and the RSU Plan. A maximum of 60 million common shares were reserved for issuance under the 2002 ISO Plan, of which 50 million have been issued to date. A further 71 million common shares have been reserved for issuance under the 2007 ISO and PSO Plans, of which 17 million have been issued to date. The PSU and RSU Plans grant notional units as if a unit was one Enbridge common share and are payable in cash.

Prior to the Merger Transaction, Spectra Energy had a long-term incentive plan providing for the granting of stock options, restricted and unrestricted stock awards and units, and other equity-based awards. Upon closing of the Merger Transaction, Enbridge replaced existing Spectra Energy share-based payment awards with awards that will be settled in shares of Enbridge, with Spectra Energy's cash-settled phantom awards included in the fair value of the net assets acquired (Note 8).

Total stock-based compensation expense recorded for the years ended December 31, 2018, 2017 and 2016 was $106 million, $165 million and $130 million, respectively. Disclosure of activity and assumptions for material stock-based compensation plans are included below.

INCENTIVE STOCK OPTIONS

Key employees are granted ISOs to purchase common shares at the market price on the grant date. ISOs vest in equal annual installments over a four-year period and expire 10 years after the issue date.

December 31, 2018	Number	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (years)	Aggregate Intrinsic Value
(options in thousands; intrinsic value in millions of Canadian dollars)				
Options outstanding at beginning of year	34,366	45.41		
Options granted	5,775	32.32		
Options exercised[1]	(2,519)	27.11		
Options cancelled or expired	(3,235)	44.11		
Options outstanding at end of year	34,387	43.47	6.1	108
Options vested at end of year[2]	21,064	43.48	4.7	84

1 The total intrinsic value of ISOs exercised during the years ended December 31, 2018, 2017 and 2016 was $42 million, $62 million and $123 million, respectively, and cash received on exercise was $15 million, $17 million and $37 million, respectively.

2 The total fair value of ISOs vested during the years ended December 31, 2018, 2017 and 2016 was $36 million, $44 million and $36 million, respectively.

Weighted average assumptions used to determine the fair value of ISOs granted using the Black-Scholes-Merton option pricing model are as follows:

Year ended December 31,	2018	2017	2016
Fair value per option (Canadian dollars)[1]	3.86	6.00	7.37
Valuation assumptions			
Expected option term (years)[2]	5	5	5
Expected volatility[3]	21.9%	20.4%	25.1%
Expected dividend yield[4]	6.4%	4.4%	4.4%
Risk-free interest rate[5]	2.2%	1.2%	0.8%

1 Options granted to United States employees are based on NYSE prices. The option value and assumptions shown are based on a weighted average of the United States and the Canadian options. The fair values per option for the years ended December 31, 2018, 2017 and 2016 were $3.75, $5.66 and $7.01, respectively, for Canadian employees and US$3.30, US$5.72 and US$6.60, respectively, for United States employees.

2 The expected option term is six years based on historical exercise practice and three years for retirement eligible employees.

3 Expected volatility is determined with reference to historic daily share price volatility and consideration of the implied volatility observable in call option values near the grant date.

4 The expected dividend yield is the current annual dividend at the grant date divided by the current stock price.

5 The risk-free interest rate is based on the Government of Canada's Canadian Bond Yields and the United States Treasury Bond Yields.

Compensation expense recorded for the years ended December 31, 2018, 2017 and 2016 for ISOs was $28 million, $40 million and $43 million, respectively. As at December 31, 2018, unrecognized compensation expense related to non-vested stock-based compensation arrangements granted under the ISO Plan was $23 million. The expense is expected to be fully recognized over a weighted average period of approximately two years.

RESTRICTED STOCK UNITS

We have a RSU Plan where cash awards are paid to certain of our employees following a 35-month maturity period. RSU holders receive cash equal to our weighted average share price for 20 days prior to the maturity of the grant multiplied by the units outstanding on the maturity date.

December 31, 2018	Number	Weighted Average Remaining Contractual Life (years)	Aggregate Intrinsic Value
(units in thousands; intrinsic value in millions of Canadian dollars)			
Units outstanding at beginning of year	1,693		
Units granted	542		
Units cancelled	(191)		
Units matured[1]	(971)		
Dividend reinvestment	140		
Units outstanding at end of year	1,213	1.3	52

1 The total amount paid during the years ended December 31, 2018, 2017 and 2016 for RSUs was $41 million, $39 million and $56 million, respectively.

Compensation expense recorded for the years ended December 31, 2018, 2017 and 2016 for RSUs was $32 million, $46 million and $51 million, respectively. As at December 31, 2018, unrecognized compensation expense related to non-vested units granted under the RSU Plan was $26 million. The expense is expected to be fully recognized over a weighted average period of approximately two years.

23. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME/(LOSS)

Changes in AOCI attributable to our common shareholders for the years ended December 31, 2018, 2017 and 2016 are as follows:

	Cash Flow Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Adjustment	Total
(millions of Canadian dollars)						
Balance at January 1, 2018	(644)	(139)	77	10	(277)	(973)
Other comprehensive income/(loss) retained in AOCI	(244)	(509)	4,301	16	(85)	3,479
Other comprehensive (income)/loss reclassified to earnings						
Interest rate contracts[1]	157	—	—	—	—	157
Commodity contracts[2]	(1)	—	—	—	—	(1)
Foreign exchange contracts[3]	7	—	—	—	—	7
Other contracts[4]	22	—	—	—	—	22
Amortization of pension and OPEB actuarial loss and prior service costs[5]	—	—	—	—	16	16
	(59)	(509)	4,301	16	(69)	3,680
Tax impact						
Income tax on amounts retained in AOCI	57	50	—	8	33	148
Income tax on amounts reclassified to earnings	(37)	—	—	—	(4)	(41)
	20	50	—	8	29	107
Sponsored Vehicles buy-in[6]	(87)	—	(55)	—	—	(142)
Balance at December 31, 2018	(770)	(598)	4,323	34	(317)	2,672

(millions of Canadian dollars)	Cash Flow Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Adjustment	Total
Balance at January 1, 2017	(746)	(629)	2,700	37	(304)	1,058
Other comprehensive income/(loss) retained in AOCI	1	478	(2,623)	(11)	18	(2,137)
Other comprehensive (income)/loss reclassified to earnings						
Interest rate contracts[1]	207	—	—	—	—	207
Commodity contracts[2]	(7)	—	—	—	—	(7)
Foreign exchange contracts[3]	(6)	—	—	—	—	(6)
Other contracts[4]	(6)	—	—	—	—	(6)
Amortization of pension and OPEB actuarial loss and prior service costs[5]	—	—	—	—	41	41
	189	478	(2,623)	(11)	59	(1,908)
Tax impact						
Income tax on amounts retained in AOCI	(16)	12	—	(16)	(10)	(30)
Income tax on amounts reclassified to earnings	(71)	—	—	—	(22)	(93)
	(87)	12	—	(16)	(32)	(123)
Balance at December 31, 2017	(644)	(139)	77	10	(277)	(973)

(millions of Canadian dollars)	Cash Flow Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Adjustment	Total
Balance at January 1, 2016	(688)	(795)	3,365	37	(287)	1,632
Other comprehensive income/(loss) retained in AOCI	(216)	171	(665)	(5)	(45)	(760)
Other comprehensive (income)/loss reclassified to earnings						
Interest rate contracts[1]	147	—	—	—	—	147
Commodity contracts[2]	(11)	—	—	—	—	(11)
Foreign exchange contracts[3]	1	—	—	—	—	1
Other contracts[4]	(18)	—	—	—	—	(18)
Amortization of pension and OPEB actuarial loss and prior service costs[5]	—	—	—	—	21	21
	(97)	171	(665)	(5)	(24)	(620)
Tax impact						
Income tax on amounts retained in AOCI	91	(5)	—	5	11	102
Income tax on amounts reclassified to earnings	(52)	—	—	—	(4)	(56)
	39	(5)	—	5	7	46
Balance at December 31, 2016	(746)	(629)	2,700	37	(304)	1,058

1 Reported within Interest expense in the Consolidated Statements of Earnings.
2 Reported within Commodity costs in the Consolidated Statements of Earnings.
3 Reported within Other income/(expense) in the Consolidated Statements of Earnings.
4 Reported within Operating and administrative expense in the Consolidated Statements of Earnings.
5 These components are included in the computation of net benefit costs and are reported within Operating and administrative expense in the Consolidated Statements of Earnings.

6 Represents the historical noncontrolling interests and redeemable noncontrolling interests related to the Sponsored Vehicles reclassified to AOCI, upon the completion of the buy-in.

24. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET RISK
Our earnings, cash flows and OCI are subject to movements in foreign exchange rates, interest rates, commodity prices and our share price (collectively, market risks). Formal risk management policies, processes and systems have been designed to mitigate these risks.

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 may be 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 2.8%.

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, when applicable, to hedge against future changes to the fair value of fixed rate debt which mitigates the impact of fluctuations in the fair value of fixed rate debt via execution of fixed to floating interest rate swaps. As of December 31, 2018, we do not have any pay floating-receive fixed interest rate swaps outstanding.

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 established 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 3.2%.

We also monitor our debt portfolio mix of fixed and variable rate debt instruments to manage a consolidated portfolio of floating rate debt within the Board of Directors approved policy limit of a maximum of 30% of 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.

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 one form of stock-based compensation, restricted share units. We use a combination of qualifying and non-qualifying derivative instruments to manage equity price risk.

TOTAL DERIVATIVE INSTRUMENTS
The following table summarizes the Consolidated Statements of Financial Position location and carrying value of our derivative instruments.

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 those circumstances. The following table summarizes the maximum potential settlement amounts in the event of these specific circumstances. All amounts are presented gross in the Consolidated Statements of Financial Position.

December 31, 2018	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment Hedges	Derivative Instruments Used as Fair Value Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)							
Accounts receivable and other							
Foreign exchange contracts	—	—	—	47	47	(37)	10
Interest rate contracts	22	—	—	—	22	(2)	20
Commodity contracts	2	—	—	427	429	(114)	315
	24	—	—	474	498	(153)	345
Deferred amounts and other assets							
Foreign exchange contracts	23	—	—	39	62	(39)	23
Interest rate contracts	5	—	—	—	5	—	5
Commodity contracts	19	—	—	33	52	(21)	31
	47	—	—	72	119	(60)	59
Accounts payable and other							
Foreign exchange contracts	(5)	—	—	(610)	(615)	37	(578)
Interest rate contracts	(163)	—	—	(178)	(341)	2	(339)
Commodity contracts	—	—	—	(273)	(273)	114	(159)
Other contracts	(1)	—	—	(4)	(5)	—	(5)
	(169)	—	—	(1,065)	(1,234)	153	(1,081)
Other long-term liabilities							
Foreign exchange contracts	(1)	(15)	—	(2,196)	(2,212)	39	(2,173)
Interest rate contracts	(201)	—	—	—	(201)	—	(201)
Commodity contracts	—	—	—	(178)	(178)	21	(157)
Other contracts	(1)	—	—	(1)	(2)	—	(2)
	(203)	(15)	—	(2,375)	(2,593)	60	(2,533)
Total net derivative asset/(liability)	17	(15)	—	(2,720)	(2,718)	—	(2,718)

Foreign exchange contracts							
Interest rate contracts	(337)	—	—	(178)	(515)	—	(515)
Commodity contracts	21	—	—	9	30	—	30
Other contracts	(2)	—	—	(5)	(7)	—	(7)
	(301)	(15)	—	(2,894)	(3,210)	—	(3,210)

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December 31, 2017	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment Hedges	Derivative Instruments Used as Fair Value Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)							
Accounts receivable and other							
Foreign exchange contracts	1	4	—	138	143	(83)	60
Interest rate contracts	6	—	2	—	8	(3)	5
Commodity contracts	2	—	—	143	145	(64)	81
	9	4	2	281	296	(150)	146
Deferred amounts and other assets							
Foreign exchange contracts	1	1	—	143	145	(125)	20
Interest rate contracts	7	—	6	—	13	(2)	11
Commodity contracts	17	—	—	6	23	(19)	4
	25	1	6	149	181	(146)	35
Accounts payable and other							
Foreign exchange contracts	(5)	(42)	—	(312)	(359)	83	(276)
Interest rate contracts	(140)	—	(6)	(183)	(329)	3	(326)
Commodity contracts	—	—	—	(439)	(439)	64	(375)
Other contracts	(1)	—	—	(2)	(3)	—	(3)
	(146)	(42)	(6)	(936)	(1,130)	150	(980)
Other long-term liabilities							
Foreign exchange contracts	(4)	(9)	—	(1,299)	(1,312)	125	(1,187)
Interest rate contracts	(38)	—	(2)	—	(40)	2	(38)
Commodity contracts	—	—	—	(186)	(186)	19	(167)
Other contracts	(1)	—	—	—	(1)	—	(1)
	(43)	(9)	(2)	(1,485)	(1,539)	146	(1,393)
Total net derivative asset/(liability)							
	(7)	(46)	—	(1,330)	(1,383)	—	(1,383)

Foreign exchange contracts							
Interest rate contracts	(165)	—	—	(183)	(348)	—	(348)
Commodity contracts	19	—	—	(476)	(457)	—	(457)
Other contracts	(2)	—	—	(2)	(4)	—	(4)
	(155)	(46)	—	(1,991)	(2,192)	—	(2,192)

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The following table summarizes the maturity and notional principal or quantity outstanding related to our derivative instruments.

	2018						2017
As at December 31,	2019	2020	2021	2022	2023	Thereafter	Total
Foreign exchange contracts - United States dollar forwards - purchase (millions of United States dollars)	925	1	—	—	—	—	759
Foreign exchange contracts - United States dollar forwards - sell (millions of United States dollars)	4,969	4,893	3,608	1,944	1,804	1,857	16,167
Foreign exchange contracts - British pound (GBP) forwards - purchase (millions of GBP)	—	—	—	—	—	—	18
Foreign exchange contracts - GBP forwards - sell (millions of GBP)	89	25	27	28	29	120	318
Foreign exchange contracts - Euro forwards - purchase (millions of Euro)	226	—	—	—	—	—	655
Foreign exchange contracts - Euro forwards - sell (millions of Euro)	—	23	94	94	92	606	1,262
Foreign exchange contracts - Japanese yen forwards - purchase (millions of yen)	32,662	—	—	20,000	—	—	52,662
Interest rate contracts - short-term pay fixed rate (millions of Canadian dollars)	8,616	6,243	4,188	412	49	156	7,138
Interest rate contracts - long-term receive fixed rate (millions of Canadian dollars)	—	—	—	—	—	—	4,196
Interest rate contracts - long-term pay fixed rate (millions of Canadian dollars)	3,777	3,185	1,596	—	—	—	5,402
Equity contracts (millions of Canadian dollars)	35	20	—	—	—	—	90
Commodity contracts - natural gas (billions of cubic feet)	(141)	(16)	(6)	(4)	—	—	(159)
Commodity contracts - crude oil (millions of barrels)	4	—	—	—	—	—	(3)
Commodity contracts - NGL (millions of barrels)	—	—	—	—	—	—	(12)
Commodity contracts - power (megawatt per hour (MW/H))	64	66	(3)	(43)	(43)	(43)[1]	(43)[2]

1 As at December 31, 2018, thereafter includes an average net purchase/(sell) of power of (43) MW/H for 2024 through 2025.

2 As at December 31, 2017, thereafter includes an average net purchase/(sell) of power of (43) MW/H for 2023 through 2025.

The Effect of Derivative Instruments on the Statements of Earnings and Comprehensive Income

The following table presents the effect of cash flow hedges and net investment hedges on our consolidated earnings and consolidated comprehensive income, before the effect of income taxes:

	2018	2017	2016
(millions of Canadian dollars)			
Amount of unrealized gain/(loss) recognized in OCI			
Cash flow hedges			
Foreign exchange contracts	19	(5)	(19)
Interest rate contracts	(190)	6	(90)
Commodity contracts	2	11	14
Other contracts	(3)	1	39
Net investment hedges			
Foreign exchange contracts	31	284	22
	(141)	297	(34)
Amount of (gain)/loss reclassified from AOCI to earnings (effective portion)			
Foreign exchange contracts[1]	5	(104)	2
Interest rate contracts[2,3]	161	388	145
Commodity contracts[4]	(1)	(9)	(12)
Other contracts[5]	3	8	(29)
	168	283	106
Amount of (gain)/loss reclassified from AOCI to earnings (ineffective portion and amount excluded from effectiveness testing)			
Interest rate contracts[2, 3]	23	(4)	61
	23	(4)	61

1 Reported within Transportation and other services revenues and Other income/(expense) in the Consolidated Statements of Earnings.
2 Reported within Interest expense in the Consolidated Statements of Earnings.
3 For the year ended December 31, 2017, includes settlements of $296 million loss related to the termination of long-term interest rate swaps as not highly probable to issue long-term debt.
4 Reported within Transportation and other services revenues, Commodity sales revenues, Commodity costs and Operating and administrative expense in the Consolidated Statements of Earnings.
5 Reported within Operating and administrative expense in the Consolidated Statements of Earnings.

We estimate that a loss of $18 million from AOCI related to cash flow hedges will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the foreign exchange rates, interest rates and commodity prices in effect when derivative contracts that are currently outstanding mature. For all forecasted transactions, the maximum term over which we are hedging exposures to the variability of cash flows is 36 months as at December 31, 2018.

Fair Value Derivatives

For interest rate derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk is included in Interest expense in the Consolidated Statements of Earnings.

Year ended December 31,	2018	2017
(millions of Canadian dollars)		
Unrealized gain/(loss) on derivative	7	(10)
Unrealized gain/(loss) on hedged item	1	11

Realized gain/(loss) on derivative	(8)	2
Realized gain/(loss) on hedged item	(1)	(2)

Non-Qualifying Derivatives

The following table presents the unrealized gains and losses associated with changes in the fair value of our non-qualifying derivatives:

Year ended December 31,	2018	2017	2016
(millions of Canadian dollars)			
Foreign exchange contracts[1]	(1,390)	1,284	935
Interest rate contracts[2]	5	157	73
Commodity contracts[3]	485	(199)	(508)
Other contracts[4]	(3)	—	9
Total unrealized derivative fair value gain/(loss), net	(903)	1,242	509

1 For the respective annual periods, reported within Transportation and other services revenues (2018 - $1,108 million loss; 2017 - $800 million gain; 2016 - $497 million gain) and Other income/(expense) (2018 - $282 million loss; 2017 - $484 million gain; 2016 - $438 million gain) in the Consolidated Statements of Earnings.

2 Reported as an (increase)/decrease within Interest expense in the Consolidated Statements of Earnings.

3 For the respective annual periods, reported within Transportation and other services revenues (2018 - $66 million gain; 2017 - $104 million loss; 2016 - $52 million loss), Commodity sales (2018 - $599 million gain; 2017 - $90 million gain; 2016 - $474 million loss), Commodity costs (2018 - $193 million loss; 2017 - $223 million loss; 2016 - $38 million gain) and Operating and administrative expense (2018 - $13 million gain; 2017 - $38 million gain; 2016 - $20 million loss) in the Consolidated Statements of Earnings.

4 Reported within Operating and administrative expense in the Consolidated Statements of Earnings.

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, 2018. 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 strong investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated through maintenance and monitoring of 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 have credit concentrations and credit exposure, with respect to derivative instruments, in the following counterparty segments:

December 31,	2018	2017
(millions of Canadian dollars)		
Canadian financial institutions	28	82
United States financial institutions	107	19
European financial institutions	84	145
Asian financial institutions	6	2
Other[1]	337	137
	562	385

1 Other is comprised of commodity clearing house and physical natural gas and crude oil counterparties.

As at December 31, 2018, we provided letters of credit totaling nil in lieu of providing cash collateral to our counterparties pursuant to the terms of the relevant ISDA agreements. We held no cash collateral on derivative asset exposures as at December 31, 2018 and December 31, 2017.

Gross derivative balances have been presented without the effects of collateral posted. Derivative assets are adjusted for non-performance risk of our counterparties using their credit default swap spread rates, and are reflected at fair value. For derivative liabilities, our non-performance risk is considered in the valuation.

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 30 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value.

FAIR VALUE MEASUREMENTS

Our financial assets and liabilities measured at fair value on a recurring basis include derivative instruments. We also disclose the fair value of other financial instruments not measured at fair value. The fair value of financial instruments reflects our best estimates of market value based on generally accepted valuation techniques or models and is supported by observable market prices and rates. When such values are not available, we use discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value.

FAIR VALUE OF FINANCIAL INSTRUMENTS

We categorize our derivative instruments measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement.

Level 1

Level 1 includes derivatives measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a derivative is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis. Our Level 1 instruments consist primarily of exchange-traded derivatives used to mitigate the risk of crude oil price fluctuations.

Level 2

Level 2 includes derivative valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Derivatives in this category are valued using models or other industry standard valuation techniques derived from observable market data. Such valuation techniques

include inputs such as quoted forward prices, time value, volatility factors and broker quotes that can be observed or corroborated in the market for the entire duration of the derivative. Derivatives valued using Level 2 inputs include non-exchange traded derivatives such as over-the-counter foreign exchange forward and cross currency swap contracts, interest rate swaps, physical forward commodity contracts, as well as commodity swaps and options for which observable inputs can be obtained.

We have also categorized the fair value of our held to maturity preferred share investment and long-term debt as Level 2. The fair value of our held to maturity preferred share investment is primarily based on the yield of certain Government of Canada bonds. The fair value of our long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenor.

Level 3

Level 3 includes derivative valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the derivatives' fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available or have no binding broker quote to support Level 2 classification. We have developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on extrapolation of observable future prices and rates. Derivatives valued using Level 3 inputs primarily include long-dated derivative power contracts and NGL and natural gas contracts, basis swaps, commodity swaps, power and energy swaps, as well as options. We do not have any other financial instruments categorized in Level 3.

We use the most observable inputs available to estimate the fair value of our derivatives. When possible, we estimate the fair value of our derivatives based on quoted market prices. 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, foreign exchange, commodity and share price) 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.

We have categorized our derivative assets and liabilities measured at fair value as follows:

December 31, 2018	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	—	47	—	47
Interest rate contracts	—	22	—	22
Commodity contracts	24	45	360	429
	24	114	360	498
Long-term derivative assets				
Foreign exchange contracts	—	62	—	62
Interest rate contracts	—	5	—	5
Commodity contracts	—	30	22	52
	—	97	22	119
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	—	(615)	—	(615)
Interest rate contracts	—	(341)	—	(341)
Commodity contracts	(7)	(28)	(238)	(273)
Other contracts	—	(5)	—	(5)
	(7)	(989)	(238)	(1,234)
Long-term derivative liabilities				
Foreign exchange contracts	—	(2,212)	—	(2,212)
Interest rate contracts	—	(201)	—	(201)
Commodity contracts	—	(23)	(155)	(178)
Other contracts	—	(2)	—	(2)
	—	(2,438)	(155)	(2,593)
Total net financial asset/(liability)				
Foreign exchange contracts	—	(2,718)	—	(2,718)
Interest rate contracts	—	(515)	—	(515)
Commodity contracts	17	24	(11)	30
Other contracts	—	(7)	—	(7)
	17	(3,216)	(11)	(3,210)

December 31, 2017 (millions of Canadian dollars)	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
Financial assets				
Current derivative assets				
Foreign exchange contracts	—	143	—	143
Interest rate contracts	—	8	—	8
Commodity contracts	1	30	114	145
	1	181	114	296
Long-term derivative assets				
Foreign exchange contracts	—	145	—	145
Interest rate contracts	—	13	—	13
Commodity contracts	—	2	21	23
	—	160	21	181
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	—	(359)	—	(359)
Interest rate contracts	—	(329)	—	(329)
Commodity contracts	(13)	(87)	(339)	(439)
Other contracts	—	(3)	—	(3)
	(13)	(778)	(339)	(1,130)
Long-term derivative liabilities				
Foreign exchange contracts	—	(1,312)	—	(1,312)
Interest rate contracts	—	(40)	—	(40)
Commodity contracts	—	(3)	(183)	(186)
Other contracts	—	(1)	—	(1)
	—	(1,356)	(183)	(1,539)
Total net financial asset/(liability)				
Foreign exchange contracts	—	(1,383)	—	(1,383)
Interest rate contracts	—	(348)	—	(348)
Commodity contracts	(12)	(58)	(387)	(457)
Other contracts	—	(4)	—	(4)
	(12)	(1,793)	(387)	(2,192)

The significant unobservable inputs used in the fair value measurement of Level 3 derivative instruments were as follows:

December 31, 2018 (fair value in millions of Canadian dollars)	Fair Value	Unobservable Input	Minimum Price/Volatility	Maximum Price/Volatility	Weighted Average Price/Volatility	Unit of Measurement
Commodity contracts - financial[1]						
Natural gas	(9)	Forward gas price	2.54	6.37	3.58	$/mmbtu[3]
Crude	28	Forward crude price	27.50	123.20	59.32	$/barrel
NGL	—	Forward NGL price	—	—	—	$/gallon
Power	(91)		16.21	96.72	48.33	$/MW/H

		Forward power price				
Commodity contracts - physical[1]						
Natural gas	(119)	Forward gas price	1.09	6.95	1.51	\$/mmbtu[3]
Crude	186	Forward crude price	16.45	123.22	59.22	\$/barrel
NGL	(6)	Forward NGL price	0.13	1.40	0.59	\$/gallon
	(11)					

1 Financial and physical forward commodity contracts are valued using a market approach valuation technique.
2 One million British thermal units (mmbtu).

If adjusted, the significant unobservable inputs disclosed in the table above would have a direct impact on the fair value of our Level 3 derivative instruments. The significant unobservable inputs used in the fair value measurement of Level 3 derivative instruments include forward commodity prices and, for option contracts, price volatility. Changes in forward commodity prices could result in significantly different fair values for our Level 3 derivatives. Changes in price volatility would change the value of the option contracts. Generally, a change in the estimate of forward commodity prices is unrelated to a change in the estimate of price volatility.

Changes in net fair value of derivative assets and liabilities classified as Level 3 in the fair value hierarchy were as follows:

Year ended December 31,	2018	2017
(millions of Canadian dollars)		
Level 3 net derivative asset/(liability) at beginning of period	(387)	(295)
Total gain/(loss)		
Included in earnings[1]	206	(184)
Included in OCI	2	4
Settlements	168	88
Level 3 net derivative liability at end of period	(11)	(387)

1 Reported within Transportation and other services revenues, Commodity costs and Operating and administrative expense in the Consolidated Statements of Earnings.

Our policy is to recognize transfers as at the last day of the reporting period. There were no transfers between levels as at December 31, 2018 or 2017.

FAIR VALUE OF OTHER FINANCIAL INSTRUMENTS

Our other long-term investments in other entities with no actively quoted prices are classified as Fair Value Measurement Alternative (FVMA) investments and are recorded at cost less impairment. The carrying value of FVMA and other long-term investments totaled $102 million and $99 million as at December 31, 2018 and 2017, respectively.

We have Restricted long-term investments held in trust totaling $323 million and $267 million as at December 31, 2018 and 2017, respectively, which are recognized at fair value.

We have a held to maturity preferred share investment carried at its amortized cost of $478 million and $371 million as at December 31, 2018 and 2017, respectively. These preferred shares are entitled to a cumulative preferred dividend based on the yield of 10-year Government of Canada bonds plus a margin of 4.38%. The fair value of this preferred share investment approximates its face value of $580 million as at December 31, 2018 and 2017.

As at December 31, 2018 and 2017, our long-term debt had a carrying value of $63.9 billion and $64.0 billion, respectively, before debt issuance costs and a fair value of $64.4 billion and $67.4 billion, respectively. We also have noncurrent notes receivable carried at book value recorded in Deferred amounts and other assets in the Consolidated Statements of Financial Position. As at December 31, 2018 and 2017, the noncurrent notes receivable had a carrying value of $97 million and $89 million, and a fair value of $97 million and $89 million, respectively.

The fair value of other financial assets and liabilities other than derivative instruments, other long-term investments, restricted long-term investments and long-term debt approximate their cost due to the short period to maturity.

NET INVESTMENT HEDGES

We have designated a portion of our United States dollar denominated debt, as well as a portfolio of foreign exchange forward contracts, as a hedge of our net investment in United States dollar denominated investments and subsidiaries.

During the years ended December 31, 2018 and 2017, we recognized an unrealized foreign exchange loss of $479 million and a gain of $367 million, respectively, on the translation of United States dollar denominated debt and an unrealized gain on the change in fair value of our outstanding foreign exchange forward contracts of $30 million and $286 million, respectively, in OCI. During the years ended December 31, 2018 and 2017, we recognized a realized loss of $45 million and $198 million, respectively, in OCI associated with the settlement of foreign exchange forward contracts and also recognized a realized loss of $14 million and gain of $23 million, respectively, in OCI associated with the settlement of United States dollar denominated debt that had matured during the period. There was no ineffectiveness during the years ended December 31, 2018 and 2017.

25. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	2018	2017	2016
(millions of Canadian dollars)			
Earnings before income taxes	3,570	569	2,451
Canadian federal statutory income tax rate	15 %	15 %	15 %
Expected federal taxes at statutory rate	536	85	368
Increase/(decrease) resulting from:			
Provincial and state income taxes[1]	(24)	133	34
Foreign and other statutory rate differentials	94	(601)	(56)
Impact of United States tax reform[2]	(2)	(2,045)	—
Effects of rate-regulated accounting	(163)	(189)	(116)
Foreign allowable interest deductions	(134)	(124)	(107)
Part VI.1 tax, net of federal Part I deduction	76	68	56
Impairment of goodwill[3]	192	15	—
Intercompany sale of investment[4]	—	—	6
United States BEAT tax	43	—	—
Non-taxable portion of gain/(loss) on sale of investment to unrelated party[5]	31	—	(61)
Valuation allowance[6]	(172)	(17)	22
Intercorporate investments[7]	(149)	77	—
Noncontrolling interests	(47)	(80)	(15)
Other	(44)	(19)	11
Income tax (recovery)/expense	237	(2,697)	142
Effective income tax rate	6.6 %	(474.0)%	5.8 %

1 The change in provincial and state income taxes from 2017 to 2018 reflects the increase in earnings from the Canadian operations, the impact of the US tax reform on state income tax expense, and the impact of changes to the unitary state income tax rate in 2018.

2 The amount was due to the enactment of the TCJA by the United States on December 22, 2017, which included a reduction in the federal corporate income tax rate from 35% to 21% effective for taxation years beginning after December 31, 2017.

3 The amount relates to the federal component for the tax effect of impairment of goodwill.

4 In November 2016, certain assets were sold to entities under common control. The intercompany gains realized on these transfers were eliminated. However, because these transactions involved the sale of partnership units, tax consequences were recognized in earnings.

5 The amount represents the federal component of the non-taxable portion of the gain on the sales of the Canadian Natural Gas Gathering and Processing Businesses in 2018 and the South Prairie Region assets in 2016 to unrelated

parties.

6 The increase from 2017 to 2018 is due to the federal component of the tax effect of a valuation allowance on the deferred tax assets related to an outside basis temporary difference that, in 2018, was now more likely than not to be realized.

7 The amount relates to the federal component of changes in assertions regarding the manner of recovery of intercorporate investments such that deferred tax related to outside basis temporary differences was required to be recorded for Renewable Assets in 2018 and for EIPLP in 2017.

COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES

Year ended December 31,	2018	2017	2016
(millions of Canadian dollars)			
Earnings/(loss) before income taxes			
Canada	118	2,200	2,034
United States	2,582	(2,431)	(333)
Other	870	800	750
	3,570	569	2,451
Current income taxes			
Canada	311	129	74
United States	66	46	21
Other	8	5	4
	385	180	99
Deferred income taxes			
Canada	(598)	299	188
United States	439	(3,160)	(151)
Other	11	(16)	6
	(148)	(2,877)	43
Income tax (recovery)/expense	237	(2,697)	142

COMPONENTS OF DEFERRED INCOME TAXES

Deferred tax assets and liabilities are recognized for the future tax consequences of differences between carrying amounts of assets and liabilities and their respective tax bases. Major components of deferred income tax assets and liabilities are as follows:

December 31,	2018	2017
(millions of Canadian dollars)		
Deferred income tax liabilities		
Property, plant and equipment	(7,018)	(4,089)
Investments	(4,441)	(6,596)
Regulatory assets	(756)	(977)
Other	(192)	(50)
Total deferred income tax liabilities	(12,407)	(11,712)
Deferred income tax assets		
Financial instruments	1,103	697
Pension and OPEB plans	181	258
Loss carryforwards	1,820	1,781
Other	1,274	1,057
Total deferred income tax assets	4,378	3,793
Less valuation allowance	(51)	(286)
Total deferred income tax assets, net	4,327	3,507
Net deferred income tax liabilities	(8,080)	(8,205)
Presented as follows:		
Total deferred income tax assets	1,374	1,090
Total deferred income tax liabilities	(9,454)	(9,295)
Net deferred income tax liabilities	(8,080)	(8,205)

A valuation allowance has been established for certain loss and credit carryforwards, and outside basis temporary differences on investments that reduce deferred income tax assets to an amount that will more likely than not be realized.

As at December 31, 2018 and 2017, we recognized the benefit of unused tax loss carryforwards of $3.4 billion and $3.8 billion, respectively, in Canada which expire in 2025 and beyond.

As at December 31, 2018 and 2017, we recognized the benefit of unused tax loss carryforwards of $3.4 billion and $2.1 billion, respectively, in the United States which expire in 2023 and beyond.

As at December 31, 2018 and 2017, we recognized the benefit of unused capital loss carryforwards of nil and $143 million, respectively, in Canada.

As at December 31, 2018 and 2017, we recognized the benefit of unused capital loss carryforwards of nil and $20 million, respectively, in the United States.

We have not provided for deferred income taxes on the difference between the carrying value of substantially all of our foreign subsidiaries and their corresponding tax basis as the earnings of those subsidiaries are intended to be permanently reinvested in their operations. As such these investments are not anticipated to give rise to income taxes in the foreseeable future. The difference between the carrying values of the investments and their tax bases is largely a result of unremitted earnings and currency translation adjustments. The unremitted earnings and currency translation adjustment for which no deferred taxes have been recognized in respect of foreign subsidiaries were $5.8 billion and $2.1 billion for the period December 31, 2018 and 2017, respectively. If such earnings are remitted, in the form of dividends or otherwise, we may be subject to income taxes and foreign withholding taxes. The determination of the amount of unrecognized deferred income tax liabilities on such amounts is not practicable.

Enbridge and one or more of our subsidiaries are subject to taxation in Canada, the United States and other foreign jurisdictions. The material jurisdictions in which we are subject to potential examinations include the United States (Federal) and Canada (Federal, Alberta and Ontario). We are open to examination by Canadian tax authorities for the 2010 to 2018 tax years and by United States tax authorities for the 2013 to 2018 tax years. We are currently under examination for income tax matters in Canada for the 2013 to 2017 tax years and in the United States for the 2013 to 2014 tax years. We are not currently under examination for income tax matters in any other material jurisdiction where we are subject to income tax.

United States Tax Reform

On December 22, 2017, the United States enacted the TCJA. As disclosed in our Annual Report on Form 10-K, as filed with the Securities and Exchange Commission on February 16, 2018, we made certain estimates for the measurement and accounting of certain effects of the TCJA for the year ended and as at December 31, 2017. As we continue to gather, prepare and analyze the necessary information in reasonable detail to complete the accounting for the impact of TCJA, we continue to refine our estimates. During the first quarter of 2018 we refined our calculation of the regulatory liability associated with the TCJA which resulted in a $30 million reduction to the overall regulatory liability. An additional reduction to the regulated liability in the amount of $223 million was recorded in the fourth quarter in connection with rate cases filed that eliminated a portion of regulated liability formerly included in SEP's rate base.

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

Most changes to the TCJA are effective for taxation years beginning after December 31, 2017. While the changes are broad and complex, the most significant change was the reduction in the corporate federal income tax rate from 35% to 21%. In 2017 we were also impacted by a one-time deemed repatriation or “toll” tax on undistributed earnings and profits of United States controlled foreign affiliates, including Canadian subsidiaries.

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In 2017 we made reasonable estimates for the measurement and accounting of certain effects of the TCJA in accordance with SEC Staff Accounting Bulletin No.118 (SAB 118). Accordingly, we recorded a provisional $34 million increase to our 2017 current income tax provision related to the toll tax, payable over eight years. We recorded a provisional $2.0 billion decrease to our 2017 deferred income tax provision related to the reduction in the corporate federal income tax rate. The accounting for these provisional items decreased our accumulated deferred income tax liability by $3.1 billion and increased our regulatory liability by $1.1 billion in 2017. We have also adjusted our valuation allowance for certain deferred tax assets existing at December 31, 2016 for the reduction in the corporate federal income tax rate by $0.2 billion. We have recognized these provisional tax impacts and included these amounts in our consolidated financial statements for the year ended December 31, 2017.

UNRECOGNIZED TAX BENEFITS

Year ended December 31,	2018	2017
(millions of Canadian dollars)		
Unrecognized tax benefits at beginning of year	150	84
Gross increases for tax positions of current year	2	15
Gross increases for tax positions of prior year	—	65
Gross decreases for tax positions of prior year	(12)	—
Change in translation of foreign currency	3	(2)
Lapses of statute of limitations	(3)	(8)
Settlements	(1)	(4)
Unrecognized tax benefits at end of year	139	150

The unrecognized tax benefits as at December 31, 2018, if recognized, would impact our effective income tax rate. We do not anticipate further adjustments to the unrecognized tax benefits during the next 12 months that would have a material impact on our consolidated financial statements.

We recognize accrued interest and penalties related to unrecognized tax benefits as a component of income taxes. Income taxes for the years ended December 31, 2018 and 2017 were $5 million expense and $3 million recovery, respectively, of interest and penalties. As at December 31, 2018 and 2017, interest and penalties of $12 million and $8 million, respectively, have been accrued.

26. PENSION AND OTHER POSTRETIREMENT BENEFITS

PENSION PLANS

We maintain registered and non-registered, contributory and non-contributory pension plans which provide defined benefit and/or defined contribution pension benefits covering substantially all employees. The Canadian Plans provide Company funded defined benefit and/or defined contribution pension benefits to our Canadian employees. The United States Plans provide Company funded defined benefit pension benefits to our United States employees. We also maintain supplemental pension plans that provide pension benefits in excess of the basic plans for certain employees.

Defined Benefit Plans

Benefits payable from the defined benefit plans are based on each plan participant’s years of service and final average remuneration. These benefits are partially inflation-indexed after a plan participant’s retirement. Our contributions are made in accordance with independent actuarial valuations and are invested primarily in publicly-traded equity and fixed income securities.

Defined Contribution Plans

Contributions are generally based on each plan participant’s age, years of service and current eligible remuneration. For defined contribution plans, benefit costs equal amounts required to be contributed by us.

Benefit Obligation, Plan Assets and Funded Status

The following table details the changes in the projected benefit obligation, the fair value of plan assets and the recorded asset or liability for our defined benefit pension plans:

	Canada		United States	
December 31,	2018	2017	2018	2017
(millions of Canadian dollars)				
Change in projected benefit obligation				
Projected benefit obligation at beginning of year	4,033	2,270	1,279	508
Service cost	149	156	45	48
Interest cost	130	116	38	35
Participant contributions	25	6	—	—
Actuarial (gain)/loss	(146)	145	(103)	57
Benefits paid	(184)	(165)	(60)	(42)
Plan settlements	—	—	(65)	(59)
Transfer out	(10)	—	—	—
Acquired in Merger Transaction	—	1,505	—	811
Foreign currency exchange rate changes	—	—	105	(63)
Other	—	—	(25)	(16)
Projected benefit obligation at end of year[1]	3,997	4,033	1,214	1,279
Change in plan assets				
Fair value of plan assets at beginning of year	3,619	2,019	1,097	361
Actual return/(loss) on plan assets	(42)	308	(48)	113
Employer contributions	113	161	40	57
Participant contributions	25	6	—	—
Benefits paid	(184)	(165)	(60)	(42)
Plan settlements	—	—	(65)	(59)
Transfer out	(8)	—	—	—
Acquired in Merger Transaction	—	1,290		731
Foreign currency exchange rate changes	—	—	91	(51)
Other	—	—	(10)	(13)
Fair value of plan assets at end of year[2]	3,523	3,619	1,045	1,097
Underfunded status at end of year	(474)	(414)	(169)	(182)
Presented as follows:				
Deferred amounts and other assets	29	38	—	—
Accounts payable and other	(9)	(60)	(4)	(3)
Other long-term liabilities	(494)	(392)	(165)	(179)
	(474)	(414)	(169)	(182)

1 The accumulated benefit obligation for our Canadian pension plans was $3.7 billion as at December 31, 2018 and 2017. The accumulated benefit obligation for our United States pension plans was $1.2 billion as at December 31, 2018 and 2017.

2 Assets in the amount of $7 million (2017 - $9 million) and $39 million (2017 - $40 million), related to our Canadian and United States non-registered supplemental pension plan obligations, are held in grantor trusts that, in accordance with federal tax regulations, are not restricted from creditors. These assets are committed for the future settlement of benefit obligations included in the underfunded status as at the end of the year, however they are excluded from plan assets for accounting purposes.

Certain of our pension plans have accumulated benefit obligations in excess of the fair value of plan assets. For these plans, the projected benefit obligations, accumulated benefit obligations and the fair value of plan assets were as follows:

	Canada		United States	
December 31,	2018	2017	2018	2017
(millions of Canadian dollars)				
Projected benefit obligations	1,422	1,444	1,214	1,280
Accumulated benefit obligations	1,299	1,306	1,179	1,217
Fair value of plan assets	1,064	1,131	1,045	1,098

Amount Recognized in Accumulated Other Comprehensive Income

The amounts of pre-tax AOCI relating to our pension plans are as follows:

	Canada		United States	
December 31,	2018	2017	2018	2017
(millions of Canadian dollars)				
Net actuarial loss	435	334	133	112
Prior service credit	—	—	(3)	—
Total amount recognized in AOCI[1]	435	334	130	112

1 Includes amounts related to cumulative translation adjustment.

Net Benefit Costs Recognized

The components of net benefit cost and other amounts recognized in pre-tax OCI related to our pension plans are as follows:

	Canada			United States		
Year ended December 31,	2018	2017	2016	2018	2017	2016
(millions of Canadian dollars)						
Service cost	149	156	129	45	48	26
Interest cost	130	116	73	38	35	16
Expected return on plan assets	(245)	(201)	(127)	(88)	(57)	(21)
Amortization/settlement of net actuarial loss	25	29	32	7	10	3
Amortization/curtailment of prior service cost	—	—	—	3	—	—
Net defined benefit costs	59	100	107	~~5~~	36	24
Defined contribution benefit costs	11	11	3	19	15	—
Net benefit cost recognized in Earnings	70	111	110	24	51	24
Amount recognized in OCI:						
Amortization/settlement of net actuarial loss	(11)	(14)	(14)	(7)	(9)	(6)
Amortization/curtailment of prior service cost	—	—	—	(3)	—	—
Net actuarial loss arising during the year	112	38	28	28	—	16
Total amount recognized in OCI	101	24	14	18	(9)	10
Total amount recognized in Comprehensive income	171	135	124	42	42	34

We estimate that approximately $32 million related to the Canadian pension plans and $0 million related to the United States pension plans as at December 31, 2018 will be reclassified from AOCI into earnings in the next 12 months.

Actuarial Assumptions

The weighted average assumptions made in the measurement of the projected benefit obligations and net benefit cost of our pension plans are as follows:

	Canada			United States		
	2018	2017	2016	2018	2017	2016
Projected benefit obligations						
Discount rate	3.8 %	3.6 %	4.0 %	3.9 %	3.5 %	4.0 %
Rate of salary increase	3.2 %	3.2 %	3.7 %	2.8 %	3.1 %	3.3 %
Net benefit cost						
Discount rate	3.6 %	4.0 %	4.2 %	3.4 %	4.0 %	4.1 %
Rate of return on plan assets	6.8 %	6.5 %	6.5 %	7.4 %	7.2 %	7.2 %
Rate of salary increase	3.2 %	3.7 %	3.6 %	2.9 %	3.3 %	3.2 %

The overall expected rate of return is based on the asset allocation targets with estimates for returns on equity and debt securities based on long-term expectations.

OTHER POSTRETIREMENT BENEFITS

OPEB primarily includes supplemental health and dental, health spending accounts and life insurance coverage for qualifying retired employees on a non-contributory basis.

The following table details the changes in the accumulated postretirement benefit obligation, the fair value of plan assets and the recorded asset or liability for our defined benefit OPEB plans:

	Canada		United States	
December 31,	2018	2017	2018	2017
(millions of Canadian dollars)				
Change in accumulated postretirement benefit obligation				
Accumulated postretirement benefit obligation at beginning of year	321	179	337	133
Service cost	8	7	3	5
Interest cost	10	10	10	10
Participant contributions	—	—	6	4
Actuarial gain	(45)	(8)	(25)	(34)
Benefits paid	(11)	(10)	(29)	(19)
Plan amendments	—	(3)	(8)	1
Acquired in Merger Transaction	—	146	—	254
Foreign currency exchange rate changes	—	—	27	(17)
Other	(1)	—	(16)	—
Accumulated postretirement benefit obligation at end of year	282	321	305	337
Change in plan assets				
Fair value of plan assets at beginning of year	—	—	213	115
Actual return/(loss) on plan assets	—	—	(13)	21
Employer contributions	11	10	8	1
Participant contributions	—	—	6	4
Benefits paid	(11)	(10)	(29)	(19)
Acquired in Merger Transaction	—	—	—	102
Foreign currency exchange rate changes	—	—	16	(11)
Other	—	—	(20)	—
Fair value of plan assets at end of year	—	—	181	213
Underfunded status at end of year	(282)	(321)	(124)	(124)
Presented as follows:				
Deferred amounts and other assets	—	—	2	7
Accounts payable and other	(12)	(12)	(7)	(7)
Other long-term liabilities	(270)	(309)	(119)	(124)
	(282)	(321)	(124)	(124)

Amount Recognized in Accumulated Other Comprehensive Income

The amounts of pre-tax AOCI relating to our OPEB plans are as follows:

	Canada		United States	
December 31,	2018	2017	2018	2017
(millions of Canadian dollars)				
Net actuarial (gain)/loss	(29)	17	(15)	(15)
Prior service credit	(2)	(2)	(15)	(11)
Total amount recognized in AOCI[1]	(31)	15	(30)	(26)

1 Includes amounts related to cumulative translation adjustment.

Net Benefit Costs Recognized

The components of net benefit cost and other amounts recognized in pre-tax OCI related to our OPEB plans are as follows:

	Canada			United States		
Year ended December 31,	2018	2017	2016	2018	2017	2016
(millions of Canadian dollars)						
Service cost	8	7	4	3	5	4
Interest cost	10	10	6	10	10	5
Expected return on plan assets	—	—	—	(12)	(10)	(6)
Amortization/settlement of net actuarial gain	—	—	—	(1)	—	—
Amortization/curtailment of prior service (credit)/cost	—	1	—	(4)	—	—
Net benefit cost recognized in Earnings	18	18	10	(4)	5	3
Amount recognized in OCI:						
Amortization/settlement of net actuarial gain/(loss)	—	(1)	(1)	1	1	(1)
Amortization/curtailment of prior service credit	—	—	—	4	—	—
Net actuarial (gain)/loss arising during the year	(46)	(8)	2	(1)	(42)	12
Prior service (credit)/cost	—	(3)	—	(8)	1	(12)
Total amount recognized in OCI	(46)	(12)	1	(4)	(40)	(1)
Total amount recognized in Comprehensive income	(28)	6	11	(8)	(35)	2

We estimate that approximately nil related to the Canadian OPEB plans and $2 million related to the United States OPEB plans as at December 31, 2018 will be reclassified from AOCI into earnings in the next 12 months.

Actuarial Assumptions

The weighted average assumptions made in the measurement of the accumulated postretirement benefit obligations and net benefit cost of our OPEB plans are as follows:

	Canada			United States		
	2018	2017	2016	2018	2017	2016
Accumulated postretirement benefit obligations						
Discount rate	3.8 %	3.6 %	4.0 %	4.0 %	3.5 %	3.6 %
Net OPEB cost						
Discount rate	3.6 %	4.0 %	4.2 %	3.3 %	4.0 %	3.8 %
Rate of return on plan assets	N/A	N/A	N/A	5.7 %	6.0 %	6.0 %

The overall expected rate of return is based on the asset allocation targets with estimates for returns on equity and debt securities based on long-term expectations.

Assumed Health Care Cost Trend Rates

The assumed rates for the next year used to measure the expected cost of benefits are as follows:

	Canada		United States	
	2018	2017	2018	2017
Health care cost trend rate assumed for next year	5.6 %	5.5 %	7.4 %	7.4 %
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	4.4 %	4.4 %	4.5 %	4.5 %
Year that the rate reaches the ultimate trend rate	2034	2034	2037	2037

A 1% change in the assumed health care cost trend rate would have the following effects for the year ended and as at December 31, 2018:

	Canada		United States	
	1% Increase	1% Decrease	1% Increase	1% Decrease
(millions of Canadian dollars)				
Effect on total service and interest costs	1	(1)	1	(1)
Effect on accumulated postretirement benefit obligation	20	(16)	18	(17)

PLAN ASSETS

We manage the investment risk of our pension funds by setting a long-term asset mix policy for each plan after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plan; (iv) our operating environment and financial situation and our ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets.

The asset allocation targets and major categories of plan assets are as follows:

	Canada			United States		
	Target	December 31,		Target	December 31,	
Asset Category	Allocation	2018	2017	Allocation	2018	2017
Equity securities	40.0 - 70.0%	45.8 %	52.0 %	52.5 - 70.0%	51.7 %	47.1 %
Fixed income securities	27.5 - 60.0%	33.4 %	34.2 %	27.5 - 30.0%	32.9 %	47.7 %
Other	0.0 - 20.0%	20.7 %	13.8 %	0.0 - 20.0%	15.4 %	5.2 %

The following tables summarize the fair value of plan assets for our pension and OPEB plans recorded at each fair value hierarchy level.

Pension

	Canada				United States			
	Level 1[1]	Level 2[2]	Level 3[3]	Total	Level 1[1]	Level 2[2]	Level 3[3]	Total
(millions of Canadian dollars)								
December 31, 2018								
Cash and cash equivalents	246	—	—	246	56	—	—	56
Equity securities								
Canada	623	—	—	623	1	—	—	1
United States	(1)	—	—	(1)	50	—	—	50
Global	993	—	—	993	489	—	—	489
Fixed income securities								
Government	661	—	—	661	265	—	—	265
Corporate	457	—	60	517	54	—	25	79
Infrastructure and real estate[4]	—	—	502	502	—	—	105	105
Forward currency contracts	—	(18)	—	(18)	—	—	—	—
Total pension plan assets at fair value	2,979	(18)	562	3,523	915	—	130	1,045
December 31, 2017								
Cash and cash equivalents	169	—	—	169	2	—	—	2
Equity securities								
Canada	842	425	—	1,267	—	—	—	—
United States	427	—	—	427	343	—	—	343
Global	189	—	—	189	122	52	—	174
Fixed income securities								
Government	933	—	—	933	—	—	—	—
Corporate	301	3	—	304	522	1	—	523
Infrastructure and real estate[4]	—	—	340	340	—	—	56	56
Forward currency contracts	—	(10)	—	(10)	—	(1)	—	(1)
Total pension plan assets at fair value	2,861	418	340	3,619	989	52	56	1,097

OPEB

	Canada				United States			
	Level 1[1]	Level 2[2]	Level 3[3]	Total	Level 1[1]	Level 2[2]	Level 3[3]	Total
(millions of Canadian dollars)								
December 31, 2018								
Cash and cash equivalents	—	—	—	—	7	—	—	7
Equity securities								
United States	—	—	—	—	63	—	—	63
Global	—	—	—	—	35	—	—	35
Fixed income securities								
Government	—	—	—	—	68	—	—	68
Corporate	—	—	—	—	3	—	2	5
Infrastructure and real estate	—	—	—	—	—	—	3	3
Total OPEB plan assets at fair value	—	—	—	—	176	—	5	181
December 31, 2017								
Cash and cash equivalents	—	—	—	—	1	—	—	1
Equity securities								
United States	—	—	—	—	80	—	—	80

Global	—	—	—	—	36	—	—	36
Fixed income securities								
Government	—	—	—	—	96	—	—	96
Total OPEB plan assets at fair value	—	—	—	—	213	—	—	213

1 Level 1 assets include assets with quoted prices in active markets for identical assets.
2 Level 2 assets include assets with significant observable inputs.
3 Level 3 assets include assets with significant unobservable inputs.
4 The fair values of the infrastructure and real estate investments are established through the use of valuation models.

Changes in the net fair value of plan assets classified as Level 3 in the fair value hierarchy were as follows:

Pension

	Canada		United States	
December 31,	2018	2017	2018	2017
(millions of Canadian dollars)				
Balance at beginning of year	340	281	56	40
Unrealized and realized gains	77	26	9	5
Purchases and settlements, net	145	33	65	11
Balance at end of year	562	340	130	56

OPEB

	Canada		United States	
December 31,	2018	2017	2018	2017
(millions of Canadian dollars)				
Balance at beginning of year	—	—	—	—
Unrealized and realized gains	—	—	—	—
Purchases and settlements, net	—	—	5	—
Balance at end of year	—	—	5	—

EXPECTED BENEFIT PAYMENTS AND EMPLOYER CONTRIBUTIONS

Year ended December 31,	2019	2020	2021	2022	2023	2023-2027
(millions of Canadian dollars)						
Pension						
Canada	174	180	187	194	201	1,104
United States	124	96	97	98	95	438
OPEB						
Canada	13	12	13	13	13	39
United States	26	26	25	24	23	98

In 2019, we expect to contribute approximately $114 million and $47 million to the Canadian and United States pension plans, respectively, and $13 million and $7 million to the Canadian and United States OPEB plans, respectively.

RETIREMENT SAVINGS PLANS

In addition to the retirement plans discussed above, we also have defined contribution employee savings plans available to both Canadian and United States employees. Employees may participate in a matching contribution where we match a certain percentage of before-tax employee contributions of up to 5% of eligible pay per pay period for Canadian employees and up to 6% of eligible pay per pay period for United States employees. For the years ended December 31, 2018, 2017 and 2016, we expensed pre-tax employer matching contributions of $13 million, $14 million and nil for Canadian employees and $27 million, $31 million and $13 million for United States employees, respectively.

27. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	2018	2017	2016
(millions of Canadian dollars)			
Accounts receivable and other	857	(783)	(437)
Accounts receivable from affiliates	54	24	(7)
Inventory	164	(289)	(371)
Deferred amounts and other assets	226	(138)	(183)
Accounts payable and other	(151)	277	386
Accounts payable to affiliates	(122)	(62)	71
Interest payable	25	124	20
Other long-term liabilities	(138)	509	153
	915	(338)	(368)

28. RELATED PARTY TRANSACTIONS

Related party transactions are conducted in the normal course of business and unless otherwise noted, are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

SERVICE AGREEMENTS

Vector Pipeline L.P. (Vector), a joint venture, contracts our services to operate the pipeline. Amounts for these services, which are charged at cost in accordance with service agreements, were $7 million, $14 million and $7 million for the years ended December 31, 2018, 2017 and 2016, respectively.

TRANSPORTATION AGREEMENTS

Certain wholly-owned subsidiaries within the Liquids Pipelines, Gas Transmission and Midstream, Gas Distribution and Energy Services segments have committed and uncommitted transportation arrangements with several joint venture affiliates that are accounted for using the equity method. Total amounts charged to us for transportation services for the years ended December 31, 2018, 2017 and 2016 were $572 million, $721 million and $644 million, respectively.

AFFILIATE REVENUES AND PURCHASES

Certain wholly-owned subsidiaries within the Gas Distribution and Energy Services segments made natural gas and NGL purchases of $322 million, $142 million and $98 million from several joint venture affiliates during the years ended December 31, 2018, 2017 and 2016, respectively.

Natural gas sales of $122 million, $60 million and $49 million were made by certain wholly-owned subsidiaries within the Energy Services segment to several joint venture affiliates during the years ended December 31, 2018, 2017 and 2016, respectively.

DCP Midstream processes certain of our pipeline customers' gas to meet gas quality specifications in order to be transported on our system. DCP Midstream processes the gas and sells the NGLs that are extracted from the gas. A portion of the proceeds from those sales are retained by DCP Midstream and the balance is remitted to us. We received proceeds of $52 million (US$40 million) and $47 million (US$36 million) during the years ended December 31, 2018, and 2017, respectively, from DCP Midstream related to those sales.

In addition to the above, we recorded other revenues from DCP Midstream and its affiliates related to the transportation and storage of natural gas of $14 million (US$11 million) and $4 million (US$3 million) during the years ended December 31, 2018, and 2017, respectively.

In the ordinary course of business, we are reimbursed by joint venture partners for operating and maintenance expenses for certain projects. We received reimbursements from Spectra Energy joint

ventures of $28 million (US$22 million) and $10 million (US$8 million) during the years ended December 31, 2018, and 2017, respectively.

RECOVERIES OF COSTS

We provide certain administrative and other services to certain operating entities acquired through the Merger Transaction, and recorded recoveries of costs from these affiliates of $104 million (US$80 million) and $88 million (US$68 million) for the years ended December 31, 2018, and 2017, respectively. Cost recoveries are recorded as a reduction to Operating and administrative expense in the Consolidated Statements of Earnings.

LONG-TERM NOTES RECEIVABLE FROM AFFILIATES

As at December 31, 2018, amounts receivable from affiliates include a series of loans totaling $769 million ($275 million as at December 31, 2017), which require quarterly interest payments at annual interest rates ranging from 4% to 8%. These amounts are included in deferred amounts and other assets in the Consolidated Statements of Financial position.

29. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

At December 31, 2018, we have commitments as detailed below.

	Total	Less than 1 year	2 years	3 years	4 years	5 years	Thereafter
(millions of Canadian dollars)							
Annual debt maturities[1]	62,967	3,255	9,262	2,389	4,571	5,963	37,527
Interest obligations[2]	30,236	2,459	2,279	2,103	2,022	1,883	19,490
Purchase of services, pipe and other materials, including transportation[3,4]	10,493	3,833	1,473	1,000	754	406	3,027
Operating leases	1,079	132	134	100	98	93	522
Capital leases	23	7	—	—	2	2	12
Maintenance agreements	477	52	51	51	50	22	251
Land lease commitments	651	21	21	21	21	22	545
Total	105,926	9,759	13,220	5,664	7,518	8,391	61,374

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

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

3 Includes capital and operating commitments.

4 Consists primarily of gas transportation and storage contracts, firm capacity payments and gas purchase commitments, transportation, service and product purchase obligations, and power commitments.

Total rental expense for operating leases included in Operating and administrative expense were $91 million, $108 million and $79 million for the years ended December 31, 2018, 2017 and 2016, respectively.

ENVIRONMENTAL

We are subject to various federal, state and local laws relating to the protection of the environment. These laws and regulations can change from time to time, imposing new obligations on us.

Environmental risk is inherent to liquid hydrocarbon and natural gas pipeline operations, and Enbridge and our affiliates are, at times, subject to environmental remediation at various contaminated sites. We manage this environmental risk through appropriate environmental policies and practices to minimize any

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impact our operations may have on the environment. To the extent that we are unable to recover payment for environmental liabilities from insurance or other potentially responsible parties, we will be responsible for payment of liabilities arising from environmental incidents associated with the operating activities of our liquids and natural gas businesses.

AUX SABLE
Notice of Violation
In September 2014, Aux Sable US received a Notice and Finding of Violation (NFOV) from the United States Environmental Protection Agency (EPA) for alleged violations of the Clean Air Act related to the Leak Detection and Repair program, and related provisions of the Clean Air Act permit for Aux Sable's Channahon, Illinois facility. As part of the ongoing process of responding to the September 2014 NFOV, Aux Sable discovered what it believed to be an exceedance of currently permitted limits for Volatile Organic Material. In April 2015, a second NFOV from the EPA was received in connection with this potential exceedance. Aux Sable engaged in discussions with the EPA to evaluate the impacts and ultimate resolution of these issues, including with respect to a draft Consent Decree, and those discussions are continuing. The Consent Decree, which is effective as of December 31, 2018, did not have a material impact.

On October 14, 2016, an amended claim was filed against Aux Sable by a counterparty to an 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.

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 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.

30. GUARANTEES

In the normal course of conducting business, we enter into agreements which indemnify third parties and affiliates. Examples include indemnifying counterparties pursuant to sale agreements for assets or businesses in matters such as breaches of representations, warranties or covenants, loss or damages to property, environmental liabilities, and litigation and contingent liabilities. We may indemnify third parties for certain liabilities relating to environmental matters arising from operations prior to the purchase or transfer of certain assets and interests. Similarly, we may indemnify the purchaser of assets for certain tax liabilities incurred while we owned the assets, a misrepresentation related to taxes that result in a loss to the purchaser or other certain tax liabilities related to those assets.
We may also be a party to agreements with subsidiaries, jointly owned entities, unconsolidated entities such as equity method investees, or entities with other ownership arrangements that require us to provide financial and performance guarantees. Financial guarantees include stand-by letters of credit, debt guarantees, surety bonds and indemnifications. To varying degrees, these guarantees involve elements of performance and credit risk, which are not included on our Consolidated Statements of Financial Position. Performance guarantees require us to make payments to a third party if the guaranteed affiliate entity does not perform on its contractual obligations, such as debt agreements, purchase or sale agreements,

and construction contracts and leases. We typically enter into these arrangements to facilitate commercial transactions with third parties.
The likelihood of having to perform under these guarantees and indemnifications is largely dependent upon future operations of various subsidiaries, investees and other third parties, or the occurrence of certain future events. We cannot reasonably estimate the total maximum potential amounts that could become payable to third parties and affiliates under such agreements described above; however, historically, we have not made any significant payments under guarantee or indemnification provisions. While these agreements may specify a maximum potential exposure, or a specified duration to the guarantee or indemnification obligation, there are circumstances where the amount and duration are unlimited. The guarantees and indemnifications have not had, and are not reasonably likely to have, a material effect on our financial condition, changes in financial condition, earnings, liquidity, capital expenditures or capital resources.

31. SUBSEQUENT EVENTS

On January 1, 2019, the previously approved OEB application to amalgamate EGD and Union Gas took effect and the amalgamated company continued as EGI. Refer to Note 7 - Regulatory Matters for further discussion.

On January 15, 2019, Enbridge closed the acquisition of 100% of pipeline and tankage infrastructure assets at the Cheecham tank farm for a purchase price of $265 million. These assets were acquired from Athabasca Oil Corporation and were associated with the Leismer SAGD oil sands assets, and are included in our Liquids Pipelines segment.

Our wholly-owned subsidiaries, EEP and SEP (the Partnerships), commenced solicitations to holders of certain of the Partnerships' senior unsecured notes (the Notes) to amend (the Amendments) the respective indentures governing the Notes. The purpose of the consent solicitations is to modify the reporting covenant contained in the indentures governing the respective Notes to provide that, in the event Enbridge guarantees a series of such Notes, then in lieu of the respective Partnership's current reporting obligations, Enbridge would be subject to the reporting obligations under such indenture similar to those in the indenture governing Enbridge's U.S. dollar denominated senior notes. The Amendments will also add provisions, in the event Enbridge guarantees a series of Notes, implementing the unconditional guarantee of such series of Notes by Enbridge.

On January 18, 2019, the Partnerships received the requisite consents from the holders of the majority in principal amount of each series of outstanding Notes (collectively, the "Consenting EEP and SEP Notes"). On January 22, 2019, each Partnership entered into supplemental indentures to effect the proposed amendments described in the consent solicitation statement dated January 8, 2019 (the "Statement") with respect to each series of the Consenting EEP and SEP Notes and, together with Enbridge, entered into supplemental indentures to implement the unconditional guarantee of each series of Consenting EEP and SEP Notes by Enbridge as described in the Statement.

Subject to the terms and conditions set forth in the Statement, each Partnership made a cash payment of $1.00 for each $1,000 principal amount of a series of its Notes to each holder of record of that series of Notes who delivered (and did not revoke) a consent to the applicable Amendments. The supplemental indentures that were executed in connection with the completion of the consent solicitations will bind all holders of the Consenting EEP and SEP Notes.

32. QUARTERLY FINANCIAL DATA

(unaudited; millions of Canadian dollars, except per share amounts)	Q1	Q2	Q3	Q4	Total
2018					
Operating revenues	12,726	10,745	11,345	11,562	46,378
Operating income	878	1,571	854	1,513	4,816
Earnings	510	1,327	213	1,283	3,333
Earnings attributable to controlling interests	534	1,160	4	1,184	2,882
Earnings/(loss) attributable to common shareholders	445	1,071	(90)	1,089	2,515
Earnings/(loss) per common share					
Basic	0.26	0.63	(0.05)	0.60	1.46
Diluted	0.26	0.63	(0.05)	0.60	1.46
2017[1]					
Operating revenues	11,146	11,116	9,227	12,889	44,378
Operating income/(loss)	1,358	1,684	1,490	(2,961)	1,571
Earnings/(loss)	945	1,241	1,015	65	3,266
Earnings/(loss) attributable to controlling interests	721	1,000	847	291	2,859
Earnings/(loss) attributable to common shareholders	638	919	765	207	2,529
Earnings/(loss) per common share					
Basic	0.54	0.56	0.47	0.13	1.66
Diluted	0.54	0.56	0.47	0.12	1.65

1 The 2017 quarterly financial data reflects the effect of the Merger Transaction closed on February 27, 2017 (Note 8).

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed in reports filed with, or submitted to, securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under Canadian and United States securities law. As at December 31, 2018, an evaluation was carried out under the supervision of and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operations of our disclosure controls and procedures (as defined in Rule 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934). Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the design and operation of these disclosure controls and procedures were effective in ensuring that information required to be disclosed by us in reports that we file with or submits to the Securities and Exchange Commission (SEC) and the Canadian Securities Administrators is recorded, processed, summarized and reported within the time periods required.

INTERNAL CONTROL OVER FINANCIAL REPORTING

Management’s Annual Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in the rules of the SEC and the Canadian Securities Administrators. Our internal control over financial reporting is a process designed under the supervision and with the participation of executive and financial officers to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our financial statements for external reporting purposes in accordance with U.S. GAAP.

Our internal control over financial reporting includes policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of our assets;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with U.S. GAAP; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on the financial statements.

Our internal control over financial reporting may not prevent or detect all misstatements because of inherent limitations. Additionally, 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 deterioration in the degree of compliance with our policies and procedures.

Our management assessed the effectiveness of our internal control over financial reporting as at December 31, 2018, based on the framework established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, our management concluded that we maintained effective internal control over financial reporting as at December 31, 2018.

The effectiveness of our internal control over financial reporting as at December 31, 2018 has been audited by PricewaterhouseCoopers LLP, independent auditors appointed by our shareholders. As stated in their Report of Independent Registered Public Accounting Firm which appears in Item 8. Financial

Statements and Supplementary Data, they expressed an unqualified opinion on the effectiveness of our internal control over financial reporting as of December 31, 2018.

Changes in Internal Control Over Financial Reporting
During the three months ended December 31, 2018, there has been no material change in our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

Item 5.02. Departure of Directors or Certain Officers; Election of Directors; Appointment of Certain Officers; Compensatory Arrangements of Certain Officers

On October 30, 2018, Michael McShane announced his retirement from the Board of Directors, effective October 31, 2018. Mr. McShane has served on the Board of Directors since February 27, 2017, prior to which he was a director of Spectra Energy Corp. His decision to retire from the Board of Directors was based on the demands of his time from other professional and personal commitments, and was not the result of any disagreement relating to our operations, policies or practices.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Reference to "Executive Officers" is included in Part I. Item 1. Business of this report. Other information in response to this item, including information on our directors, is incorporated by reference from our Proxy Statement to be filed with the SEC relating to our 2019 annual meeting of shareholders.

ITEM 11. EXECUTIVE COMPENSATION

Information in response to this item is incorporated by reference from our Proxy Statement to be filed with the SEC relating to our 2019 annual meeting of shareholders.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information in response to this item is incorporated by reference from our Proxy Statement to be filed with the SEC relating to our 2019 annual meeting of shareholders.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information in response to this item is incorporated by reference from our Proxy Statement to be filed with the SEC relating to our 2019 annual meeting of shareholders.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information in response to this item is incorporated by reference from our Proxy Statement to be filed with the SEC relating to our 2019 annual meeting of shareholders.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Consolidated Financial Statements, Supplemental Financial Data and Supplemental Schedules included in Part II of this annual report are as follows:

Enbridge Inc.:

Report of Independent Registered Public Accounting Firm
Consolidated Statements of Earnings
Consolidated Statements of Comprehensive Income
Consolidated Statements of Changes in Equity
Consolidated Statements of Cash Flows
Consolidated Statements of Financial Position
Notes to the Consolidated Financial Statements

All schedules are omitted because they are not required or because the required information is included in the Consolidated Financial Statements or Notes.

(b) Exhibits:

Reference is made to the “Index of Exhibits” following Item 16. Form 10-K Summary, which is hereby incorporated into this Item.

ITEM 16. FORM 10-K SUMMARY

None.

INDEX OF EXHIBITS

Each exhibit identified below is included as a part of this annual report. Exhibits included in this filing are designated by an asterisk ("*"); all exhibits not so designated are incorporated by reference to a prior filing as indicated. Exhibits designated with a "+" constitute a management contract or compensatory plan arrangement.

Exhibit No.	Name of Exhibit
2.1	Agreement and Plan of Merger, dated as of September 5, 2016, by and among Spectra Energy Corp, Enbridge Inc. and Sand Merger Sub, Inc. (incorporated by reference to Exhibit 2.1 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
2.2	Contribution Agreement dated as of June 18, 2015 among Enbridge Inc., IPL System Inc., Enbridge Income Fund Holdings Inc., Enbridge Income Fund, Enbridge Commercial Trust and Enbridge Income Partners LP (incorporated by reference to Exhibit 2.2 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
2.3	Agreement and Plan of Merger, dated as of August 24, 2018, by and among Spectra Energy Partners, LP, Spectra Energy Partners (DE) GP, LP, Enbridge Inc., Enbridge (U.S.) Inc., Autumn Acquisition Sub, LLC, and solely for the purposes of Articles I, II and XI, Enbridge US Holdings Inc., Spectra Energy Corp, Spectra Energy Capital, LLC and Spectra Energy Transmission, LLC. (incorporated by reference to Exhibit 2.1 to Enbridge's Form 8-K filed August 24, 2018)
2.4	Agreement and Plan of Merger, dated as of September 17, 2018, by and among Enbridge Energy Partners, L.P., Enbridge Energy Company, Inc., Enbridge Energy Management, L.L.C., Enbridge Inc., Enbridge (U.S.) Inc., Winter Acquisition Sub II, LLC, and solely for the purposes of Articles I, II and XI, Enbridge US Holdings Inc. (incorporated by reference to Exhibit 2.1 to Enbridge's Form 8-K filed September 18, 2018)
2.5	Agreement and Plan of Merger, dated as of September 17, 2018, by and among Enbridge Energy Management, L.L.C., Enbridge Inc., Winter Acquisition Sub I, Inc., and solely for the purposes of Article I, Section 2.4 and Article X, Enbridge Energy Company, Inc. (incorporated by reference to Exhibit 2.2 to Enbridge's Form 8-K filed September 18, 2018)
2.6	Arrangement Agreement, dated as of September 17, 2018, by and between Enbridge Inc. and Enbridge Income Fund Holdings Inc. (incorporated by reference to Exhibit 2.3 to Enbridge's Form 8-K filed September 18, 2018)
3.1	Articles of Continuance of the Corporation, dated December 15, 1987 (incorporated by reference to Exhibit 2.1(a) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.2	Certificate of Amendment, dated August 2, 1989, to the Articles of the Corporation (incorporated by reference to Exhibit 2.1(b) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.3	Articles of Amendment of the Corporation, dated April 30, 1992 (incorporated by reference to Exhibit 2.1(c) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.4	Articles of Amendment of the Corporation, dated July 2, 1992 (incorporated by reference to Exhibit 2.1(d) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)

3.5	Articles of Amendment of the Corporation, dated August 6, 1992 (incorporated by reference to Exhibit 2.1(e) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.6	Articles of Arrangement of the Corporation dated December 18, 1992, attaching the Arrangement Agreement, dated December 15, 1992 (incorporated by reference to Exhibit 2.1(f) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.7	Certificate of Amendment of the Corporation (notarial certified copy), dated December 18, 1992 (incorporated by reference to Exhibit 2.1(g) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.8	Articles of Amendment of the Corporation, dated May 5, 1994 (incorporated by reference to Exhibit 2.1(h) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.9	Certificate of Amendment, dated October 7, 1998 (incorporated by reference to Exhibit 2.1(i) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.10	Certificate of Amendment, dated November 24, 1998 (incorporated by reference to Exhibit 2.1(j) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.11	Certificate of Amendment, dated April 29, 1999 (incorporated by reference to Exhibit 2.1(k) to Enbridge's Registration Statement on Form S-8 filed May 7, 2001)
3.12	Certificate of Amendment, dated May 5, 2005 (incorporated by reference to Exhibit 2.1(l) to Enbridge's Registration Statement on Form S-8 filed August 5, 2005)
3.13	Certificate of Amendment, dated May 11, 2011 (incorporated by reference to Exhibit 3.13 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.14	Certificate of Amendment, dated September 28, 2011 (incorporated by reference to Exhibit 3.14 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.15	Certificate of Amendment, dated November 21, 2011 (incorporated by reference to Exhibit 3.15 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.16	Certificate of Amendment, dated January 16, 2012 (incorporated by reference to Exhibit 3.16 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.17	Certificate of Amendment, dated March 27, 2012 (incorporated by reference to Exhibit 3.17 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.18	Certificate of Amendment, dated April 16, 2012 (incorporated by reference to Exhibit 3.18 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.19	Certificate of Amendment, dated May 17, 2012 (incorporated by reference to Exhibit 3.19 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.20	Certificate of Amendment, dated July 12, 2012 (incorporated by reference to Exhibit 3.20 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.21	Certificate of Amendment, dated September 11, 2012 (incorporated by reference to Exhibit 3.21 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.22	Certificate of Amendment, dated December 3, 2012 (incorporated by reference to Exhibit 3.22 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.23	Certificate of Amendment, dated March 25, 2013 (incorporated by reference to Exhibit 3.23 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.24	Certificate of Amendment, dated June 4, 2013 (incorporated by reference to Exhibit 3.24 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.25	Certificate of Amendment, dated September 25, 2013 (incorporated by reference to Exhibit 3.25 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)

3.26	Certificate of Amendment, dated December 10, 2013 (incorporated by reference to Exhibit 3.26 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.27	Certificate of Amendment, dated March 10, 2014 (incorporated by reference to Exhibit 3.27 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.28	Certificate of Amendment, dated May 20, 2014 (incorporated by reference to Exhibit 3.28 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.29	Certificate of Amendment, dated July 15, 2014 (incorporated by reference to Exhibit 3.29 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.30	Certificate of Amendment, dated September 19, 2014 (incorporated by reference to Exhibit 3.30 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
3.31	Certificate of Amendment, dated November 22, 2016 (incorporated by reference to Enbridge's Report of Foreign Issuer on Form 6-K filed December 1, 2016)
3.32	Certificate of Amendment, dated December 15, 2016 (incorporated by reference to Enbridge's Report of Foreign Issuer on Form 6-K filed December 16, 2016)
3.33	Certificate of Amendment, dated July 13, 2017 (incorporated by reference to Enbridge's Report of Foreign Issuer on Form 6-K filed July 13, 2017)
3.34	Certificate of Amendment, dated September 25, 2017 (incorporated by reference to Exhibit 3.34 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
3.35	Certificate of Amendment, dated December 7, 2017 (incorporated by reference to Exhibit 3.35 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
3.36	Certificate of Amendment, dated February 27, 2018 (incorporated by reference to Exhibit 3.1 to Enbridge's Current Report on Form 8-K filed March 1, 2018)
3.37	Certificate of Amendment, dated April 9, 2018 (incorporated by reference to Exhibit 3.1 to Enbridge's Current Report on Form 8-K filed April 12, 2018)
3.38	Certificate of Amendment, dated April 10, 2018 (incorporated by reference to Exhibit 3.1 to Enbridge's Current Report on Form 8-K filed April 12, 2018)
3.39	Amended and Restated General By-Law No. 1 of Enbridge Inc. (incorporated by reference to Enbridge's Report of Foreign Issuer on Form 6-K filed February 27, 2017)
3.40	By-Law No. 2 of Enbridge Inc. (incorporated by reference to Enbridge's Current Report on Form 6-K filed December 5, 2014)
4.1	Form of Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas to be dated February 25, 2005 (incorporated by reference to Exhibit 7.3 to Enbridge's Registration Statement on Form F-10 filed February 4, 2005)
4.2	First Supplemental Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated March 1, 2012 (incorporated by reference to Exhibit 7.3 to Enbridge's Registration Statement on Form F-10 filed May 11, 2012)
4.3	Second Supplemental Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated December 19, 2016 (incorporated by reference to Enbridge's Report of Foreign Issuer on Form 6-K filed December 20, 2016)
4.4	Third Supplemental Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated July 14, 2017 (incorporated by reference to Enbridge's Report of Foreign Issuer on Form 6-K filed July 14, 2017)
4.5	Fourth Supplemental Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated March 1, 2018 (incorporated by reference to Enbridge's Current Report on Form 8-K filed March 1, 2018)
4.6	Fifth Supplemental Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated April 12, 2018 (incorporated by reference to Enbridge's Current Report on Form 8-K filed April 12, 2018)

4.7	Shareholder Rights Plan Agreement dated as of November 9, 1995 and amended and restated as of May 1, 1996, February 24, 1999, May 3, 2002, May 5, 2005, May 7, 2008, May 11, 2011, May 7, 2014 and May 11, 2017 between Enbridge Inc. and CST Trust Company (incorporated by reference to Enbridge's Report of Foreign Issuer on Form 6-K filed May 12, 2017)
	Certain instruments defining the rights of holders of long-term debt securities of the Registrant and its subsidiaries are omitted pursuant to Item 601(b)(4)(iii) of Regulation S-K. The Registrant hereby undertakes to furnish to the SEC, upon request, copies of any such instruments.
10.1	Enbridge Pipelines Inc. Competitive Toll Settlement dated July 1, 2011 (incorporated by reference to Exhibit 10.1 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.2	Sixteenth Supplemental Indenture dated as of January 22, 2019 between Enbridge Energy Partners, L.P. and U.S. Bank National Association, as trustee (incorporated by reference as Exhibit 4.1 to Enbridge's Current Report on Form 8-K filed January 24, 2019)
10.3	Seventeenth Supplemental Indenture dated as of January 22, 2019 between Enbridge Energy Partners, L.P., Enbridge Inc. and U.S. Bank National Association, as trustee (incorporated by reference as Exhibit 4.2 to Enbridge's Current Report on Form 8-K filed January 24, 2019)
10.4	Seventh Supplemental Indenture dated as of January 22, 2019 between Spectra Energy Partners, LP, Enbridge Inc. and Wells Fargo Bank, National Association, as trustee (incorporated by reference as Exhibit 4.3 to Enbridge's Current Report on Form 8-K filed January 24, 2019)
10.5	Eighth Supplemental Indenture dated as of January 22, 2019 between Spectra Energy Partners, LP, Enbridge Inc. and Wells Fargo Bank, National Association, as trustee (incorporated by reference as Exhibit 4.4 to Enbridge's Current Report on Form 8-K filed January 24, 2019)
10.6	Subsidiary Guarantee Agreement dated as of January 22, 2019 between Spectra Energy Partners, LP and Enbridge Energy Partners, L.P. (incorporated by reference as Exhibit 4.5 to Enbridge's Current Report on Form 8-K filed January 24, 2019)
10.7 +	Form of Executive Employment Agreement (pre-2014) (incorporated by reference to Exhibit 10.2 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.8 +	Form of Executive Employment Agreement (2014-2016) (incorporated by reference to Exhibit 10.3 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.9 +	Form of Executive Employment Agreement (2017) (incorporated by reference to Exhibit 10.4 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.10+	Executive Employment Agreement between Enbridge Employee Services, Inc. and William T. Yardley, dated July 25, 2018 (incorporated by reference to Exhibit 10.1 to Enbridge's Form 8-K filed July 27, 2018)
10.11*	Form of Director Indemnity Agreement (2015)
10.12+	Enbridge Inc. Performance Stock Option Plan (2007) (Canadian) (incorporated by reference to Exhibit 10.5 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.13+	Enbridge Inc. Performance Stock Option Plan (2007), as amended and restated (2011) (incorporated by reference to Exhibit 10.6 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.14+	Enbridge Inc. Performance Stock Option Plan (2007), as amended and restated (2011) and as further amended (2012) (incorporated by reference to Exhibit 10.7 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.15+	Enbridge Inc. Performance Stock Option Plan (2007), as amended and restated (2011) and as further amended (2012 and 2014) (incorporated by reference to Exhibit 10.8 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)

10.16+	Enbridge Inc. Performance Stock Unit Plan (2007, revised effective November 2014) (incorporated by reference to Exhibit 10.9 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.17+	Enbridge Inc. Performance Stock Unit Plan (2007), as revised (incorporated by reference to Exhibit 10.10 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.18+	Enbridge Inc. Restricted Stock Unit Plan (2006), as revised (incorporated by reference to Exhibit 10.11 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.19+	Enbridge Inc. Incentive Stock Option Plan (2007) (incorporated by reference to Exhibit 10.12 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.20+	Enbridge Inc. Incentive Stock Option Plan (2007), as amended and restated (2011) (incorporated by reference to Exhibit 10.13 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.21+	Enbridge Inc. Incentive Stock Option Plan (2007), as amended and restated (2011 and 2014) (incorporated by reference to Exhibit 10.14 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.22+	Enbridge Inc. Incentive Stock Option Plan (2017), as revised (incorporated by reference to Exhibit 10.15 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.23+	Enbridge Inc. Directors' Compensation Plan dated February 14, 2018, effective January 1, 2018 (incorporated by reference as Exhibit 10.3 to Enbridge's Quarterly Report on Form 10-Q filed May 10, 2018)
10.24+	Enbridge Inc. Short Term Incentive Plan (2007), as revised (incorporated by reference to Exhibit 10.17 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.25+	The Enbridge Supplemental Pension Plan, As Amended and Restated Effective January 1, 2018 (incorporated by reference as Exhibit 10.1 to Enbridge's Quarterly Report on Form 10-Q filed May 10, 2018)
10.26+	Amendment No. 1 and Amendment No. 2 to The Enbridge Supplemental Pension Plan, As Amended and Restated Effective January 1, 2005 (incorporated by reference to Exhibit 10.19 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.27+	Enbridge Supplemental Pension Plan for United States Employees (As Amended and Restated Effective January 1, 2005) (incorporated by reference to Exhibit 10.20 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.28+	Amendment 1 and Amendment 2 to the Enbridge Supplemental Pension Plan for United States Employees (As Amended and Restated Effective January 1, 2005) (incorporated by reference to Exhibit 10.21 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.29+	Third Amendment to The Enbridge Supplemental Pension Plan for United States Employees (As Amended and Restated Effective January 1, 2005) (incorporated by reference as Exhibit 10.2 to Enbridge's Quarterly Report on Form 10-Q filed May 10, 2018)
10.30+	Spectra Energy Corp Directors' Savings Plan, as amended and restated (incorporated by reference to Exhibit 10.22 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.31+	Spectra Energy Corp Executive Savings Plan, as amended and restated (incorporated by reference to Exhibit 10.23 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.32+	Spectra Energy Executive Cash Balance Plan, as amended and restated (incorporated by reference to Exhibit 10.24 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.33+	Omnibus Amendment, dated June 20, 2014, to Spectra Energy Corp Executive Savings Plan, Spectra Energy Corp Executive Cash Balance Plan and Spectra Energy Corp 2007 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.25 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)

10.34	+	Form of Spectra Energy Corp Change in Control Agreement (As Amended and Restated) (incorporated by reference to Exhibit 10.26 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.35	+	Form of Spectra Energy Corp Phantom Stock Award Agreement (2015) pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.27 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.36	+	Form of Spectra Energy Corp Stock Option Agreement (Nonqualified Stock Options) (2016) pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.28 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.37	+	Form of Spectra Energy Corp Performance Share Award Agreement (2016) pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.29 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.38	+	Form of Spectra Energy Corp Phantom Stock Award Agreement (2016) pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (Cash-settled) (incorporated by reference to Exhibit 10.30 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.39	+	Form of Spectra Energy Corp Phantom Stock Award Agreement (2016) pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (Stock-settled) (incorporated by reference to Exhibit 10.31 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.40	+	Spectra Energy Corp 2007 Long-Term Incentive Plan (as amended and restated) (incorporated by reference to Exhibit 10.32 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.41	+	Spectra Energy Corp Executive Short-Term Incentive Plan (as amended and restated) (incorporated by reference to Exhibit 10.33 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.42	+	Form of Spectra Energy Corp Phantom Stock Award Agreement (2017) pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (Cash-settled) (incorporated by reference to Exhibit 10.34 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.43	+	Form of Spectra Energy Corp Phantom Stock Award Agreement (2017) pursuant to the Spectra Energy Corp 2007 Long-Term Incentive Plan (Stock-settled) (incorporated by reference to Exhibit 10.35 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.44	+	Second Amendment to the Spectra Energy Corp Executive Savings Plan (As Amended and Restated Effective May 1, 2012) (incorporated by reference to Exhibit 10.36 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.45	+	Second Amendment to the Spectra Energy Corp Executive Cash Balance Plan (As Amended and Restated Effective May 1, 2012) (incorporated by reference to Exhibit 10.37 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
21.1	*	Subsidiaries of the Registrant
23.1	*	Consent of PricewaterhouseCoopers LLP
24.1		Powers of Attorney (included on the signature page of the Annual Report)
31.1	*	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	*	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	*	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	*	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS	*	XBRL Instance Document.
101.SCH	*	XBRL Taxonomy Extension Schema.
101.CAL	*	XBRL Taxonomy Extension Calculation Linkbase.

101.DEF	*	XBRL Taxonomy Extension Definition Linkbase.
101.LAB	*	XBRL Taxonomy Extension Label Linkbase.
101.PRE	*	XBRL Taxonomy Extension Presentation Linkbase.

SIGNATURES

POWER OF ATTORNEY

Each person whose signature appears below appoints Robert R. Rooney, John K. Whelen and Tyler W. Robinson, and each of them, any of whom may act without the joinder of the other, as their true and lawful attorneys-in-fact and agents, with full power of substitution, for him or her and in his or her name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report of Enbridge on Form 10-K, and to file the same, with all exhibits thereto, and all other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite and necessary to be done, as fully to all intents and purposes as he or she might or would do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents or any of them or their or his or her substitute and substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ENBRIDGE INC.
(Registrant)

Date:	February 15, 2019	By:	/s/ Al Monaco
			Al Monaco
			President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on February 15, 2019 by the following persons on behalf of the registrant and in the capacities indicated.

/s/ Al Monaco
Al Monaco
President, Chief Executive Officer and Director
(Principal Executive Officer)

/s/ John K. Whelen
John K. Whelen
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ Allen C. Capps
Allen C. Capps
Senior Vice President and Chief Accounting Officer
(Principal Accounting Officer)

/s/ Gregory L. Ebel
Gregory L. Ebel
Chairman of the Board of Directors

/s/ Pamela L. Carter
Pamela L. Carter
Director

/s/ Clarence P. Cazalot, Jr.
Clarence P. Cazalot, Jr.
Director

/s/ Susan M. Cunningham
Susan M. Cunningham
Director

/s/ Marcel R. Coutu
Marcel R. Coutu
Director

/s/ J. Herb England
J. Herb England
Director

/s/ Charles W. Fischer
Charles W. Fischer
Director

/s/ V. Maureen Kempston Darkes
V. Maureen Kempston Darkes
Director

/s/ Teresa S. Madden
Teresa S. Madden
Director

/s/ Michael E.J. Phelps
Michael E.J. Phelps
Director

/s/ Dan C. Tutcher
Dan C. Tutcher
Director

/s/ Cathy L. Williams
Cathy L. Williams
Director