ENBRIDGE
Life Takes Energy®

2019 Annual Report

Flanagan Terminal

Contents

Enbridge Today

Enbridge is North America's largest energy infrastructure company with an extensive delivery network of crude oil, natural gas and renewable energy. Our purpose is to fuel quality of life by delivering energy, safely and reliably. Our 13,000-person team brings enthusiasm and ingenuity to work every day in support of this mission.

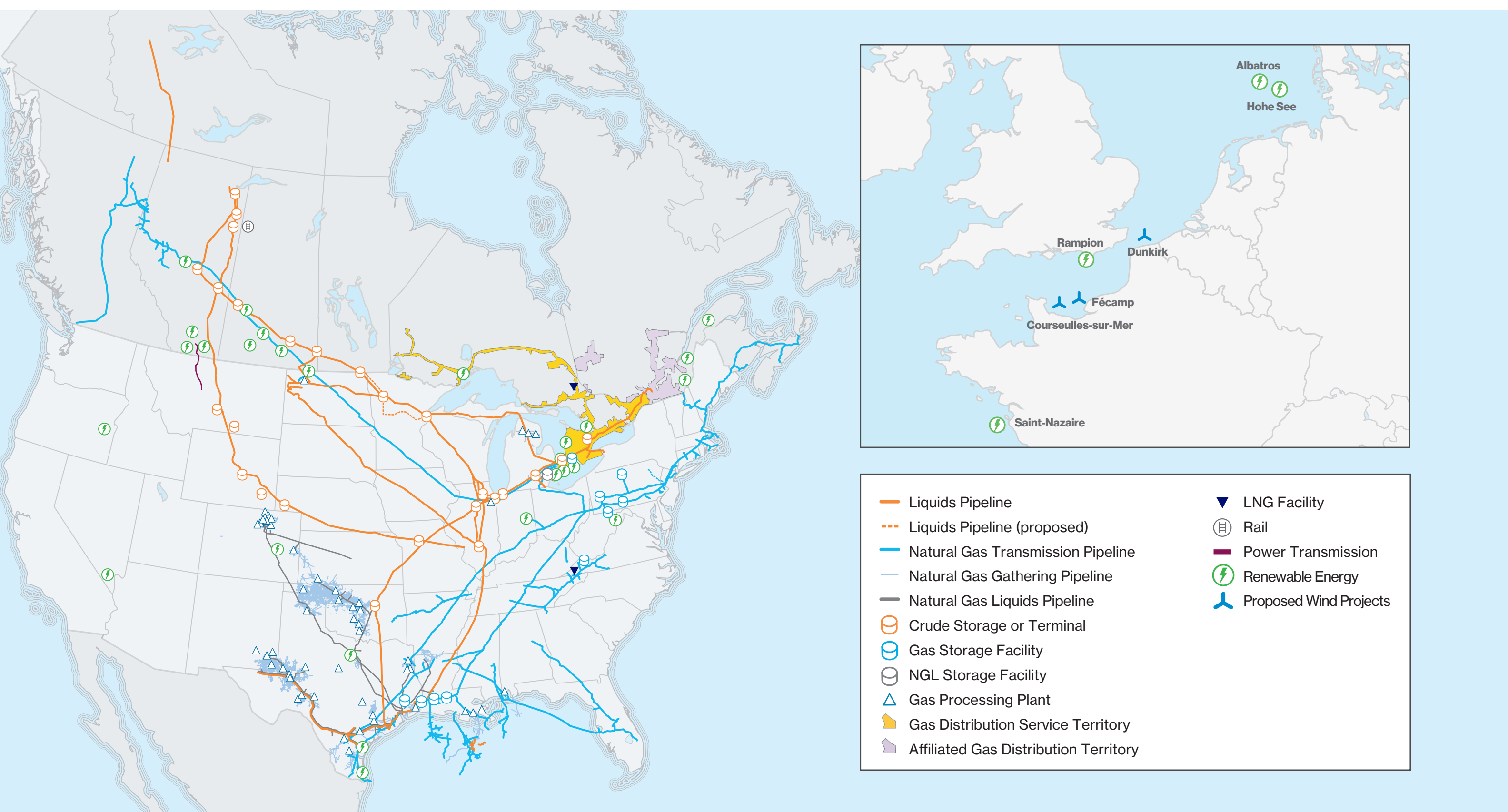
We connect energy supply to the best markets in North America through our three core businesses, and our growing renewable power generation business — to provide energy that's critical to everyday life and drives our economy.

Liquids Pipelines moves approximately 25% of North American crude oil demand, serving 12 million barrels per day (bpd) of refining capacity and connecting producers to the best markets in the U.S. Midwest, the Gulf Coast and Eastern Canada.

Gas Distribution and Storage (Enbridge Gas) is the largest natural gas utility in North America by throughput and serves approximately 12 million people with our 3.8 million meter connections in Ontario and Quebec.

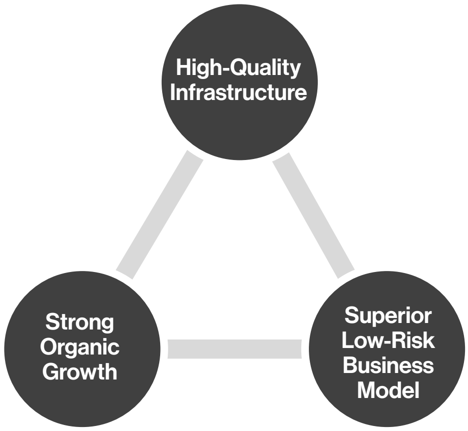
Gas Transmission and Midstream transports nearly 20% of the natural gas consumed in the U.S., connecting to key residential, industrial and commercial markets totaling approximately 170 million people as well as power generation facilities across the continent.

Renewable Power Generation has interests in more than 30 renewable power facilities, including a growing presence in offshore wind in Europe. Our operating facilities have the capacity to generate about 1,750 MW (net ownership) of zero-emission energy in North America and Europe, which is enough energy to power about 700,000 homes.

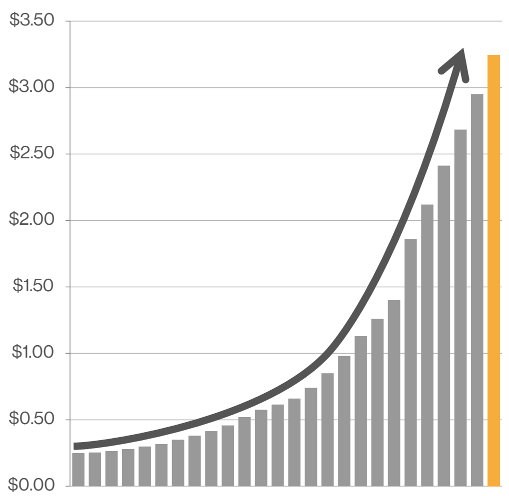


Our value proposition is straightforward and consistent: we invest in high-quality, long-lived assets that fit within our low-risk business model and generate stable, predictable cash flows and strong organic growth. We call this our Pipeline-Utility business model and it's illustrated by our value proposition triangle.

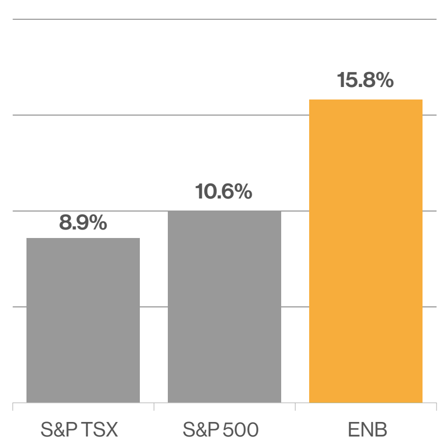
Our business model has proven to be successful and has created long-term value for shareholders. We've delivered 25 years of consecutive dividend growth and we've outperformed the S&P 500 by more than 15% over the same period.



Dividend Growth
(1995 – 2020)



Total Shareholder Return
(1995 – 2019)



Our approach to the business is guided by our values of safety, integrity and respect.
These values help us to establish trust with our people, customers and the hundreds of communities we serve across North America.

We engage regularly with various stakeholder and Indigenous groups who live and work near our operations, and our aim is to build long-term relationships by addressing concerns, respecting culture and designing projects that create mutual benefits. We believe strongly in supporting the communities where we live and operate – by giving back and contributing to their strength and vitality.

Our priority is to protect our people, communities and the environment, and we believe that all incidents can be prevented. Safety is not just a value; it's the very foundation of our business.

Letter to Shareholders

We're very pleased to report that 2019 was another strong year for Enbridge and our investors. We delivered solid operating and financial results, advanced our strategic priorities and focused on further improving the safety and reliability of our assets.

Completion of our three-year plan

2019 marked the final year of the three-year plan we established following the acquisition of Spectra Energy in 2017. By bringing Spectra into the fold, we accelerated our gas strategy and expanded our U.S. presence, and today, it's even clearer it was the right thing to do. Not only has it diversified our asset mix, opportunity set and geography, which has made us more resilient; it has also repositioned Enbridge for the future and the changing energy landscape.

Over the past three years, we completed Spectra integration and exceeded the synergies we targeted from the deal, and we greatly simplified our corporate structure. We've sold $8 billion of assets that were not part of our future, markedly strengthened our balance sheet and financial flexibility, and placed $28 billion of new projects into service. Given the strength of our business and growth outlook, we increased the dividend by 10% annually over the last three years. This contributed to a total shareholder return of 30% in 2019 and a great outcome for shareholders.

2019 look back

We made excellent progress on our strategic priorities last year, particularly with our focus on optimizing our asset base, enhancing returns and extending our growth outlook while preserving our financial strength and our low-risk business model.

- We delivered record financial results and distributable cash flow (DCF) per share of $4.57, at the top end of our guidance range. Year-end Debt:EBITDA was 4.5x, which is the very strong end of our 4.5–5.0x target. We increased our 2020 annual dividend by approximately 10% to $3.24 per share, which marks 25 years of consecutive dividend increases for our shareholders.
- We strengthened our core business by enabling 100,000 barrels per day of throughput optimizations to our Mainline system, completing our first rate case in 28 years on our Texas Eastern system and capturing synergies from the amalgamation of our Ontario natural gas utilities.
- We placed $9 billion of new projects into service, including the Canadian segment of the Line 3 Replacement Project (L3RP), the Gray Oak pipeline in the U.S. Gulf Coast and the Hohe See offshore wind project in Germany.

Gregory L. Ebel
Chair,
Board of Directors

Al Monaco
President & Chief
Executive Officer

- We've progressed a slate of $11 billion of secured growth projects that are diversified, low risk and capital efficient. These include the U.S. segment of L3RP, modernization projects in Gas Transmission and Midstream, customer-growth and expansions in our utility, and one offshore wind project in France.
- We advanced our energy export strategy by announcing new projects in the U.S. Gulf Coast that extend our integrated value chain and leverage our existing footprint, including the acquisition of the Rio Bravo Pipeline development project and an option to purchase interest in an offshore VLCC-capable oil export terminal.
- We continued to enhance our environment, social and governance (ESG) performance and disclosure, including: enabling $450 million of economic opportunities for Indigenous groups along our Line 3 Canada right-of-way; issuing our first climate report that outlines our climate-related risks, strategies and approach to energy transition; and advancing our diversity strategy to increase the number of women on the board to 42% and in senior management roles nearing 30%.

30% total shareholder return
3 years of 10% dividend increases
25 consecutive years of dividend increases

Challenges

While we had good results in many areas of safety and reliability in 2019, we experienced incidents in our Gas Transmission and Midstream business, one of which caused a fatality. All of our hearts at Enbridge go out to the family. No incident is acceptable to us and we've taken steps in response to these events to deepen our resolve to further enhance the safety and integrity of our systems.

Although we were disappointed by the regulatory delay to our Line 3 Replacement Project in Minnesota, we have strong support from the communities and Tribal Nations along the route. Ultimately, the segment must be replaced to assure safety, reliability and environmental protection. In February 2020, the Minnesota Public Utilities Commission re-certified the Environmental Impact Statement and Certificate of Need and Route Permit, which allow us to progress the remaining permits. We continue to work closely with State and Federal agencies to secure all necessary permits required to commence construction.

Enbridge's resilience for the future

We've come out of 2019 in a strong position with great assets that provide resiliency to the changing energy landscape. Our best-in-class liquids, natural gas transmission and natural gas utility businesses provide reach and diverse options to grow, and we're connected to the best markets in North America, including export links. The energy we deliver is essential to the North American economy, and millions of people rely on it every day in every aspect of their lives. Importantly, our assets will continue to serve our customers and their communities long into the future.

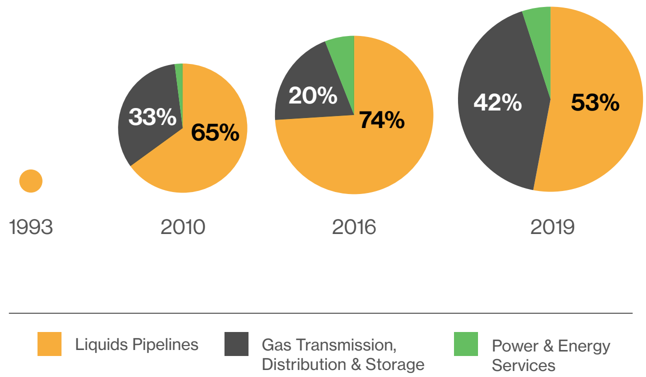
We have the financial strength and flexibility to execute on our strategic plan, and take advantage of emerging opportunities in an evolving and transitioning energy market – and we have the very best people to make it happen.

Long ago, we began integrating ESG principles into our strategy and decision-making, and today ESG is core to our long-term value and resilience.

It's clear from the actions we've taken that Enbridge is already playing an active role in the energy transition.

By responding to energy fundamentals, we've transformed our business, from largely liquids-pipeline focused to an increasingly diversified business mix with natural gas and renewables.

Repositioning Our Business
(Asset mix*)



*Size of pie represents earnings before interest, income tax and depreciation and amortization (EBITDA).

> We're proud of our role to deliver energy that millions of people rely on every day in every aspect of their lives.

We've made significant investments into our renewables business over the past two decades and built a solid operating and development capability in this growing part of our business. In addition to our three operating offshore windfarms in Europe, we're advancing four new development projects in offshore France, which will help grow this business into a new Enbridge platform.

We've set and met our own emissions targets, lowering direct energy emissions by 21% between 2005 and 2011. And our energy conservation programs, which have been in place since 1995, have helped our utility customers save energy and resulted in emissions reductions equivalent to taking 10 million cars off the road.

We'll continue to do our part to reduce emissions and conserve energy, while at the same time meeting society's growing need for sustainable energy.

Even though we've led our sector in many aspects of energy efficiency and conservation, we're setting the next phase of emissions reductions targets.

We're investing in low-carbon innovation and greening the gas grid, including: renewable natural gas that captures methane in landfills; our power-to-gas-facility – the first in North America – that allows us to inject hydrogen into the gas grid to reduce carbon content; and compressed natural gas.

We're also now beginning to invest in self-powering our pipeline assets with our own renewable power plants.

For more information on our ESG performance and disclosure, please review our 2019 Climate Report and our 2018 Sustainability Report.

Resilient Energy Infrastructure: Addressing Climate-Related Risks and Opportunities Report
enbridge.com/Sustainability-Reports/Resilient-Energy-Infrastructure

Building Connections: 2018 Sustainability Report
enbridge.com/sustainability-reports/sustainability-report-2018

Looking ahead

At Enbridge, we've always focused on improving returns from existing assets and allocating cash flow generated from those assets to the opportunities that sustain long-term growth.

Opportunity set

Post completion of our secured capital program, we'll have $5 billion to $6 billion of available capital and financial capacity – within our equity self-funding model – to re-invest in the business, and we expect annual DCF per share growth to be 5 to 7%. We'll continue to be disciplined about where we invest, prioritizing capital-efficient opportunities that are in our expansive footprint.

Within each core business, we're seeing opportunities to increase revenue, reduce costs and further improve our operations. We'll continue to optimize and expand our core franchises, with a focus on energy-export infrastructure with our integrated Liquids and Gas Pipeline platforms and investment in our Gas Distribution franchise to grow its customer base. We'll also grow our Renewable Power division by developing new offshore wind projects that fit our low-risk business model.

Embracing technology

Another area of opportunity we're leveraging in a big way is technology. We're using technology to improve business performance and find solutions to drive higher levels of safety, reliability and productivity. Last year, we established a Technology + Innovation Lab, with locations in Calgary and Houston, to bring together business and operations people with technology experts to tackle problems using machine learning, Ai and predictive analytics. We've adopted agile ways of working to deliver progress quickly – and we're beginning to see results. For example, in Liquids we built a "simulation engine" to optimize how crude flows through our pipeline system, and in Gas Transmission and Midstream we're using digital platforms to better assess the integrity of our gas system and predict where to prioritize maintenance.

People

We believe it's vitally important to continue to strengthen our organizational capabilities by developing our people and helping them advance their careers. In 2019, we expanded our executive leadership team as part of a broader succession-planning and development effort.

We're also focused on building a diverse team and inclusive culture where everyone feels valued. This is important for two reasons; first, fairness, equity and merit are core to our values, and second, we believe that diversity of thought leads to improving our business. We set diversity targets in 2018 and we're beginning to see progress. Today, 42% of our Board is comprised of women and 28% of senior leadership roles are held by women.

Leading ESG performance and approach

ESG is not new to Enbridge – environmental and social considerations have long been integrated into how we think about our business. We have strong Board oversight in this area and our Corporate Social Responsibility and Safety & Reliability Board committees have been in place for more than 15 years. We report annually on the ESG factors of greatest relevance to our stakeholders: climate and energy transition, safety and asset integrity, and community and Indigenous engagement. Our disclosure and performance have earned us strong ESG ratings from investors. We're proud of our standing and we're focused on maintaining industry leadership.

Final thoughts

We'd like to thank all members of the team for their continuing dedication to Enbridge.

We'd also like to thank our Board of Directors for their guidance and strong governance. Our Board possesses a wide range of skills, experience and knowledge to steer our company forward into the future.

We were saddened by the passing last year of Michael Phelps who was a valued director and friend. He will be missed by us all.

In February 2020, we welcomed Gregory J. Goff as a director. He brings extensive experience in energy and will be a strong addition to our Board. And this year, we say farewell to one of our longest-serving directors, Cathy Williams. Cathy has made valuable contributions during her tenure, particularly through her leadership on our Human Resources and Governance committees.

Today, Enbridge's diversified asset base provides reach and scale that makes us resilient and gives us many options to grow. We provide critical energy to the best markets and to millions of people. Our business model, our commitment to people, safety and the environment, and our track record of evolving our business and adapting to changing markets will allow us to prosper and deliver shareholder value for decades to come.

Gregory L. Ebel **Al Monaco**

March 3, 2020

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

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2019

or

☐ **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

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

Canada	**98-0377957**
(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	Trading Symbol(s)	Name of each exchange on which registered
Common Shares	ENB	New York Stock Exchange
6.375% Fixed-to-Floating Rate Subordinated Notes Series 2018-B due 2078	ENBA	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.Yes ☒ No ☐

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 ☐ No ☒

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 ☒ No ☐

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 ☒ No ☐

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	☒	Accelerated Filer	☐
Non-Accelerated Filer	☐	Smaller reporting company	☐
Emerging growth company	☐		

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. ☐

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

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, 2019, was approximately US$73.1 billion.

As at February 7, 2020, the registrant had 2,024,814,011 common shares outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:
Not applicable.

EXPLANATORY NOTE

Enbridge Inc., a corporation existing under the *Canada Business Corporations Act*, qualifies as a foreign private issuer in the United States for purposes of the Securities Exchange Act of 1934, as amended (the Exchange Act). Although, as a foreign private issuer, Enbridge Inc. is no longer required to do so, Enbridge Inc. currently continues to file annual reports on Form 10-K, quarterly reports on Form 10-Q, and current reports on Form 8-K with the Securities and Exchange Commission (SEC) instead of filing the reporting forms available to foreign private issuers.

Enbridge Inc. intends to prepare and file a management proxy circular and related material under Canadian requirements. As Enbridge Inc.'s management proxy circular is not filed pursuant to Regulation 14A, Enbridge Inc. may not incorporate by reference information required by Part III of this Form 10-K from its management proxy circular. Accordingly, in reliance upon and as permitted by Instruction G(3) to Form 10-K, Enbridge Inc. will be filing an amendment to this Form 10-K containing the Part III information no later than 120 days after the end of the fiscal year covered by this Form 10-K.

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
CER	The Canadian Regulator Act created the new Canada Energy Regulator and repealed the National Energy Board Act, on August 28, 2019
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
EEM	Enbridge Energy Management, L.L.C.
EEP	Enbridge Energy Partners, L.P.
EGD	Enbridge Gas Distribution Inc.
Enbridge	Enbridge Inc.
ENF	Enbridge Income Fund Holdings Inc.
FEIS	Final Environmental Impact Statement
FERC	Federal Energy Regulatory Commission
Flanagan South	Flanagan South Pipeline
GHG	Greenhouse gas
ISO	Incentive Stock Options
LIBOR	London Interbank Offered Rate
LMCI	Land Matters Consultation Initiative
LNG	Liquefied natural gas
MATL	Montana-Alberta Tie-Line
MD&A	Management's Discussion and Analysis
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
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
RSU	Restricted Stock Units
Sabal Trail	Sabal Trail Transmission, LLC
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
TSX	Toronto Stock Exchange
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”, “plan”, “project”, “target” and similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information or statements included or incorporated by reference in this document include, but are not limited to, statements with respect to the following: our corporate vision and strategy, including strategic priorities and enablers; expected earnings before interest, income taxes and depreciation and amortization (EBITDA); expected earnings/(loss); expected future cash flows; expected distributable cash flow; expected debt-to-EBITDA ratio; financial strength and flexibility; expectations on sources of liquidity and sufficiency of financial resources; expected strategic priorities and performance of the Liquids Pipelines, Gas Transmission and Midstream, Gas Distribution and Storage, Renewable Power Generation and Energy Services businesses; expected costs related to announced projects and projects under construction; expected in-service dates for announced projects and projects under construction; expected capital expenditures; expected equity funding requirements for our commercially secured growth program; expected future growth and expansion opportunities; expectations about our joint venture partners’ ability to complete and finance projects under construction; expected closing of acquisitions and dispositions and the timing thereof; expected benefits of transactions, including the realization of efficiencies and synergies; expected future actions of regulators and related court proceedings and other litigation; expectations regarding commodity prices; supply and demand forecasts; anticipated utilization of our existing assets; anticipated competition; United States Line 3 Replacement Program (U.S. L3R Program); Line 5 related matters; Mainline System contracting; Texas Eastern rate case; estimated future dividends; our dividend payout policy; dividend growth and dividend payout expectation; and expectations on impact of our hedging program.

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

Our forward-looking statements are subject to risks and uncertainties pertaining to the successful execution of our strategic priorities, operating performance, regulatory parameters, changes in regulations applicable to our business, acquisitions, dispositions and other transactions, our dividend policy, project approval and support, renewals of rights-of-way, weather, economic and competitive conditions, public opinion, changes in tax laws and tax rates, changes in trade agreements, exchange rates, interest rates, commodity prices, political decisions and supply of and demand for commodities, including but not limited to those risks and uncertainties discussed in this 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

We are a leading North American energy infrastructure company. We safely and reliably deliver the energy people need and want to fuel quality of life. Our core businesses include Liquids Pipelines, which transports approximately 25 percent of the crude oil produced in North America; Gas Transmission and Midstream, which transports approximately 20 percent of the natural gas consumed in the United States; Gas Distribution and Storage, which serves approximately 3.8 million retail customers in Ontario and Quebec; and Renewable Power Generation, which generates approximately 1,750 megawatts (MW) of net renewable power in North America and Europe. Our common shares trade on the Toronto Stock Exchange (TSX) and 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 reliable energy. Our unparalleled infrastructure franchises transport, distribute and generate energy, and our primary purpose is to fuel quality of life by delivering the energy North Americans need and want, in the safest and most responsible way possible.

Our investor value proposition is founded on our ability to deliver predictable cash flows and a growing stream of dividends year-over-year through investment in and efficient operation of energy infrastructure assets that are strategically positioned between key supply basins and strong demand-pull markets. Our assets are underpinned by long-term contracts, regulated cost-of-service tolling frameworks and other low-risk commercial arrangements. 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

An in-depth understanding of supply and demand fundamentals has helped us become one of North America's largest energy infrastructure companies. Throughout our more than 70-year history, we have demonstrated the ability to respond to change and spot opportunity in energy transitions.

In recent years, we have become more resilient by diversifying our assets to reflect an evolving global energy mix. The 2017 acquisition of Spectra Energy Corp (Spectra Energy) is a notable example in that it substantially diversified our asset base across commodity types, energy basins and regulatory jurisdictions and created a significant new platform for sustainable growth. With a more diverse set of assets across our energy system, we have a unique vantage point from which to capitalize on current and future global energy trends.

On closing of the Spectra Energy transaction in early 2017, we embarked on an aggressive multi-year plan to position our newly combined company for long-term success. Key objectives included the realization of anticipated synergies through the quick and efficient integration of Spectra Energy's operations, strengthening of our balance sheet and business risk profile through the sale of non-core assets, the streamlining of our corporate structure through the buy-in of our four, publicly traded sponsored vehicles, ongoing execution of an industry-leading organic growth program and delivery of strong operating and financial performance.

With most of the key elements of that plan now substantially completed our focus has shifted to the optimization of our core asset base, enhancing our competitive positioning and securing new growth opportunities, all while continuing to execute on our secured capital program and the delivery of strong operating and financial performance.

During 2019 we made significant progress on a number of key objectives. For example:

- Completed the sale of our federally regulated Canadian midstream assets, bringing total proceeds from non-core asset sales over the last 3 years to approximately $8 billion;
- Brought into service approximately $9 billion of new growth projects including the Canadian component of the Line 3 Replacement Program on our Mainline System as well as the Atlantic Bridge (phase 1), Stratton Ridge and the Generation Pipeline Projects on our United States gas transmission system;
- Achieved a consolidated Debt-to-EBITDA ratio of 4.5x (on a trailing twelve month basis), the low end of our current target range;
- Optimized our liquids Mainline System operations to allow an incremental 100 thousand barrels per day (kbpd) of throughput;
- Successfully negotiated the Texas Eastern rate case, securing favorable regulatory treatment for a system-wide modernization program on our largest natural gas transmission pipeline;
- Further simplified our corporate structure with the amalgamation of our Ontario gas utilities;
- Achieved record financial results at the high end of our 2019 guidance range; and
- Increased our common share dividend by 9.8 percent.

These achievements are discussed in further detail in Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.*

Looking ahead, our near-term strategic priorities remain similar to years past. We remain focused on growing our three core business lines - Liquids Pipelines, Gas Transmission and Midstream, and Gas Distribution and Storage within a regulated pipeline and utility business model, while enhancing our competitive position by optimizing operations, maintaining a strong financial position and pursuing efficiencies through continuous process improvement and the application of technology solutions. As North American production of crude oil and natural gas is projected to exceed demand, we will continue to orient the development of our liquids and natural gas pipeline infrastructure toward export-driven opportunities that will further enhance the growth and resilience of our systems. Our renewable power generation business, anchored by investments in contracted offshore wind power, compliments our low risk business model and supports our increasing focus on energy transition. We will continue to invest in renewable power generation where we can achieve attractive risk adjusted returns.

Our key strategic priorities are summarized below:

Commitment to Safety and Operational Reliability

Safety and operational reliability remain the foundation of our strategy. 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.

Optimize Core Businesses
A key priority is to drive growth through an ongoing focus on optimization, productivity and efficiency across all of our businesses. Examples include throughput enhancements on our liquids system from the application of drag-reducing agents and improvements in scheduling logistics at our terminals, revenue optimization through negotiated toll settlements or rate cases, ongoing synergy capture following our recent utility merger and, more generally, creating sustainable cost savings across the organization through process improvement and/or system enhancements.

Execute and Extend Growth
Successful project execution is integral to our financial performance and to the strategic positioning of our business over the long-term. Our ongoing objective is to deliver our slate of secured projects (currently $11 billion) 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*.

In seeking to extend growth, we expect to have sufficient self-funding capacity, post completion of our secured capital program, to invest $5 to $6 billion per year in new growth capital without issuing any additional common equity and maintaining key credit metrics within planning parameters and targets established with credit rating agencies.

Through 2040, we see strong utilization of our existing network and opportunities for future growth within each of our businesses. For example:

- Our liquids pipelines infrastructure will remain a vital connection between key supply basins and demand-pull markets, while the growing North American export market represents an opportunity to further expand midstream offerings and services.
- Our natural gas pipelines business plays an essential role in driving the North American economy, servicing markets totaling more than 170 million people. We expect natural gas to play an increasing role in power generation supporting the retirement of coal, while the growing Liquefied Natural Gas (LNG) export sector will drive opportunities to expand our existing network.
- Our gas distribution utility, serving the fifth largest population center in North America, is forecast to continue to provide customers with a significant cost advantage versus other fuels. In addition, technology is now being advanced and deployed to produce pipeline quality natural gas with a lower carbon footprint such as renewable natural gas.
- We also have several offshore wind projects in the advanced development phase. Growth in offshore wind is accelerating due to public policy support and technology advancement in the renewable energy sector. New renewable assets with long-term contracts will contribute to our low-risk growth.
- In all of our business segments, the replacement, renewal and modernization of our existing infrastructure is a further capital deployment opportunity.

Maintain a Strong Financial Position
The maintenance of our financial strength is critical to our strategy. 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” equity 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*.

Disciplined Capital Allocation
As we seek growth, we assess the latest fundamental trends, monitor the business landscape and proactively conduct business development activities with the goal of identifying an industry-leading opportunity set for capital deployment. Opportunities are screened, analyzed and assessed using a disciplined investment framework with the objective of ensuring effective deployment of capital to achieve attractive risk-adjusted returns.

All projects are evaluated based on their potential to advance our strategy, sustain growth and create additional financial flexibility. Our primary emphasis is on projects that optimize and extend our existing footprint and position us for sustained long-term growth. Execution risk remains high for large scale, long-duration development projects and therefore, our focus will be on projects where we can carefully manage at-risk capital during the permitting and construction phases.

In evaluating typical investment opportunities we also consider other potential capital allocation choices that may add value. Other potential choices for capital deployment will depend on our current outlook and the size of our existing capital project backlog, and could include dividend increases, further debt reduction, a large scale acquisition or share re-purchases.

Adapt to Energy Transition Over Time
As the global population grows and standards of living continue to improve around the world, more energy will be needed. At the same time, our society increasingly recognizes the impacts of energy consumption on the world's climate. Accordingly, energy systems are being reshaped as industry participants, regulators and consumers seek to balance competing objectives. As a diversified energy infrastructure company, we are well positioned to play a key role in the transition to a lower-carbon economy while working to reduce our own emissions intensity at the same time.

We believe that diversification and innovation will play a significant role in the transition to a lower carbon future. To date, we have made large investments in natural gas infrastructure and continue to see significant opportunity in renewable energy, particularly offshore wind. Furthermore, we have tested our existing assets for various energy transition scenarios and concluded that they are highly resilient and can be relied upon for stable cash flow generation well into the future.

STRATEGIC ENABLERS
Our success in executing on our strategic priorities is very much enabled by our commitment to environment, social and governance (ESG) issues, the quality and capabilities of our people and the extent to which we embrace technology and encourage innovation as a competitive advantage.

ESG
Our everyday decision-making is informed by ESG issues, delivering the energy people need and want in a way that is environmentally, socially and economically responsible is critical to the long-term sustainability of our business. We're focused on reducing the intensity of our own greenhouse gas (GHG) emissions from operations, helping customers reduce their energy use and GHG impact and investing in lower carbon solutions such as natural gas and renewable energy.

We're also focused on building and maintaining constructive relationships with local communities and other groups directly impacted by our activities over the life-cycle of our assets. Recognizing the distinct rights of Indigenous communities, we have dedicated accountabilities and resources focused on consultation and inclusion. 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.

People
Our employees are essential to our long-term success and enhancing the capability of our people to maximize their potential is a key area of focus. We 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.

Technology
Given the competitive climate of today's energy sector, we recognize the vital role technology can play in helping us achieve our strategic objectives. Our two Technology and Innovation labs, located in Calgary and Houston, embody our commitment to technology-driven business solutions. Leveraging the benefits of technology to contribute to safety, reliability and the profitability of assets has become entrenched in our everyday operations.

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***.

BUSINESS SEGMENTS

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

During 2019, we renamed the Gas Distribution segment to Gas Distribution and Storage, and the Green Power and Transmission segment to Renewable Power Generation. The presentation of the prior years' tables have been revised in order to align with the current presentation.

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 2.9 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 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 other shippers on the Canadian Mainline. It was approved by the Canada Energy Regulator (CER), formerly the National Energy Board 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, 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. The IJT 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 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, Clearbrook, Minnesota and other points to principal delivery points on the Lakehead System. 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 of each year.

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

For further information, refer to Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Recent Developments - Mainline System Contracting.*

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. 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 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), Spearhead Pipeline and Gray Oak Pipeline, as well as the Mid-Continent System comprised of the Cushing Terminal.

Seaway Pipeline
We have 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 950,000 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
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 a 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 approximately 193,000 bpd.

Gray Oak Pipeline
The Gray Oak pipeline is a 1,368-kilometer (850-mile) crude oil system, which runs from the Permian Basin in West Texas to the United States gulf coast. The Gray Oak pipeline has an expected average annual capacity of 900,000 bpd and transports light crude oil. We have an effective 22.8% interest in the pipeline. Initial in-service for the pipeline commenced in November 2019 with full in-service expected in the second quarter of 2020.

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 are 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, as well as blending fees.

OTHER
Other includes Southern Lights Pipeline, Express-Platte System, Bakken System and Feeder Pipelines and Other.

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 consists of 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, Minnesota for service on the Lakehead system or a variety of interconnecting pipeline and rail export facilities. The interstate portion of the system has both Unites States 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 CER on a complaint basis. Tolls on the interstate pipeline system are based on long-term take-or-pay agreements with anchor shippers.

We have 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. Current capacity is 570,000 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 in 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. In addition, we are currently pursuing the offering of contracted service on the Mainline System which would further contribute to mitigating competition risk.

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.

The International Energy Agency 2019 World Energy Outlook indicated that upstream investment in 2019 demonstrated a continued upward trend. International prices weakened in 2019 compared to the previous year with United States tensions with China and continued supply growth outside of the Organization of Petroleum Exporting Countries (OPEC). World oil demand rose marginally over the year however, supply grew at a faster pace. The United States continued to increase its productive capacity, supported by its crude oil exports growing to over 3 million bpd in September 2019.

In western Canada, lack of export pipeline capacity resulted in the rapid buildup of inventories and discounts to the price of western Canadian crude. Western Canadian Select discounts peaked at over US $50 per barrel against West Texas Intermediate (WTI) in October 2018. This, in turn, resulted in the Alberta Government approving a plan to lease 4,400 rail cars to add approximately 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 was 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 decline 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 approximately 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. Rail movements dropped by more than 200,000 bpd between December 2018 and February 2019 as differentials were narrow enough that it was not economic to ship crude by rail in the first quarter of 2019. The differentials widened to above $10 per barrel in subsequent quarters to support the return of crude by rail. Throughout the year, the curtailment levels declined to a year end restriction of 75,000 bpd with an expectation that Alberta production volumes will continue to increase in 2020.

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 2.845 million bpd in December 2019, slightly higher than our previous record in July 2019. 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 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 in North America, Brazil and 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. 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, safe 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 AND 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, 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 Transmission (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 have a 92% interest in 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*). We have a 78% interest in 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 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 have a 50% interest in 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 to a Duke Energy Florida 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 have a 50% interest in Sabal Trail.

NEXUS 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, with capacity of approximately 1.5 bcf/d. Through its interconnect with Vector, NEXUS provides a connection to Dawn Hub, 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 have a 50% interest in NEXUS.

Valley Crossing 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, Mexico's state-owned utility.

SESH is an approximately 467-kilometer (290-mile) natural gas transmission system with associated compressor stations, owned and 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 have a 50% interest in 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 have a 60% interest in 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

On July 4, 2018, we entered into agreements to sell our British Columbia Field Services business to Brookfield Infrastructure Partners L.P. and its institutional partners. Separate agreements were entered into for those facilities governed by provincial regulations and those governed by federal regulations. On October 1, 2018, we closed the sale of the provincially regulated facilities and on December 31, 2019, we closed the sale of the federally regulated facilities. For further information, refer to Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Recent Developments - Asset Monetization* and *Item 8. Financial Statements and Supplementary Data - Note 8. Acquisitions and Dispositions.*

On May 28, 2019, we completed the sale of our federally regulated natural gas gathering and processing assets in the Grizzly Valley area of British Columbia to Sukunka Natural Resources Inc., a subsidiary of Canadian Natural Resources Limited.

Canadian Gas Transmission still includes British Columbia Pipeline, M&N Canada, Alliance Pipeline and certain other midstream gas pipelines, gathering, processing and storage assets.

British Columbia Pipeline has approximately 2,900-kilometers (1,800-miles) of transmission pipeline in British Columbia and Alberta, as well as associated mainline compressor stations and provides fee-for-service based natural gas transmission services.

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 have a 78% interest in M&N Canada.

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 have a 50% interest in Alliance Pipeline.

The majority of transportation services provided by Canadian Gas Transmission 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 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.

US MIDSTREAM

US Midstream 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 57% of DCP Midstream, LP, including limited partner and general partner interests. DCP Midstream, LP is a 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.

In 2010, natural gas production in each of the Appalachian and Permian basins were less than 5.0 bcf/d each. Today, these regions produce more than 50.0 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 US 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 2.5 bcf/d through 2040, 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 end users with a contract renewal rate of over 99 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 4.0 bcf/d through 2040. 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 is expected to continue 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 19.0 bcf/d through 2040. 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 Liquefied Petroleum Gas (LPG) exports see strong growth. The United States exported approximately 4.0 bcf/d of natural gas from the gulf coast region at the end of 2019 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 million British Thermal Units (MMBtu) relative to Henry Hub in the gulf coast over the last few years. 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 10.0 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 through the early 2020s, 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.

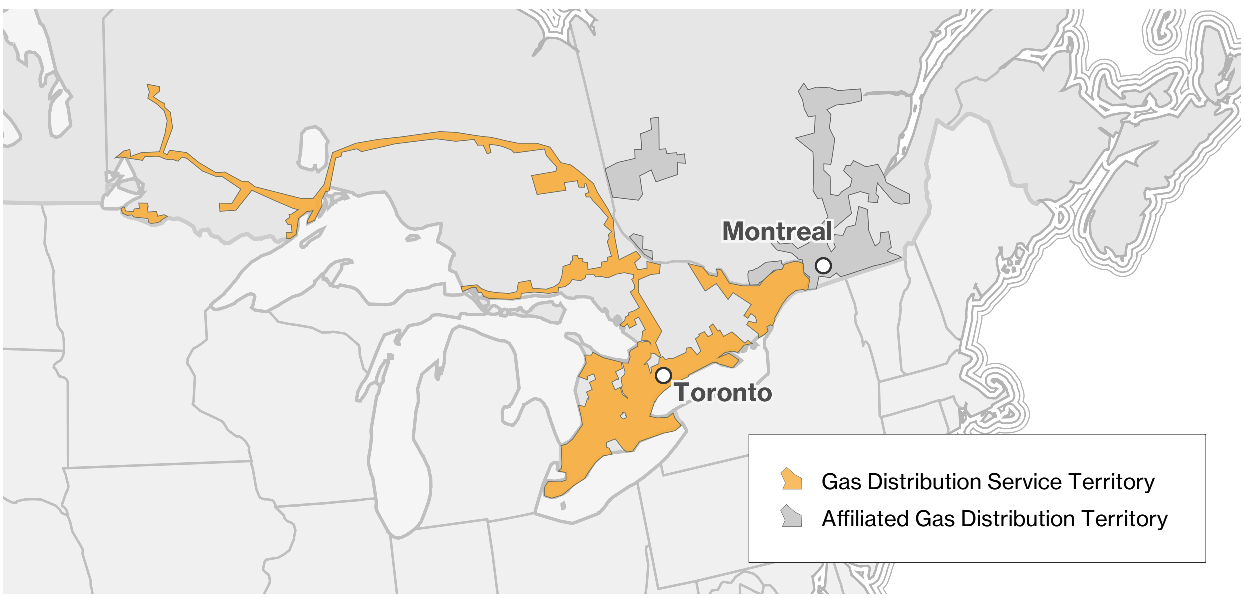
Global energy demand is expected to increase approximately 25 percent by 2040, according to the International Energy Agency, driven primarily by economic growth in non-OECD countries. Natural gas will play an important role in meeting this energy demand as gas consumption is anticipated to grow by approximately 40 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 AND STORAGE

Gas Distribution and Storage consists of our natural gas utility operations, the core of which is Enbridge Gas Inc. (Enbridge Gas), which serves residential, commercial and industrial customers throughout Ontario. This business segment also includes natural gas distribution activities in Québec and an investment in Noverco Inc. (Noverco).

Enbridge Gas Distribution Inc. (EGD) and Union Gas Limited (Union Gas) were amalgamated on January 1, 2019. The amalgamated company has continued as Enbridge Gas. The amalgamation creates 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 the ongoing amalgamation will drive efficiencies and synergies, leverage greater supply-chain strength, create new opportunities for growth and form a stronger platform to deliver strong, provide predictable returns to shareholders and superior value and service to customers.

On October 1, 2019, we closed the sale of Enbridge Gas New Brunswick Inc. (EGNB) to Liberty Utilities (Canada) LP and on November 1, 2019, we closed the sale of St. Lawrence Gas Company, Inc. to Liberty Utilities Co., both wholly-owned subsidiaries of Algonquin Power & Utilities Corp. For further information, refer to Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Recent Developments - Asset Monetization* and *Item 8. Financial Statements and Supplementary Data - Note 8. Acquisitions and Dispositions.*



ENBRIDGE GAS

Enbridge Gas is a rate-regulated natural gas distribution utility with storage and transmission services and has been in operation for approximately 170 years. Enbridge Gas serves approximately 3.8 million residential, commercial and industrial customers across Ontario.

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

Distribution
Enbridge 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 usually on an annual contract basis under firm or interruptible service contracts. Under a firm contract, Enbridge Gas is obligated to deliver natural gas to the customer up to a maximum daily volume. The service provided under an interruptible contract is similar to that of a firm contract, except that it allows for service interruption at Enbridge Gas' option to meet seasonal or peak demands. The Ontario Energy Board (OEB) approves rates for both contract and general services. The distribution system consists of approximately 151,000-kilometers (93,800-miles) of pipelines that carry natural gas from the point of local supply to customers.

Customers have a choice with respect to natural gas supply. Customers may purchase and deliver their own natural gas into Enbridge Gas' distribution system or alternatively they may choose a system supply option, whereby customers purchase natural gas from Enbridge Gas' supply portfolio. To acquire the necessary volume of natural gas to serve its customers, Enbridge Gas maintains a diversified natural gas supply portfolio, acquiring supplies on a delivered basis in Ontario, as well as acquiring supply from multiple supply basins across North America.

Transportation
Enbridge Gas contracts for firm transportation service, primarily with TransCanada Pipelines Limited (TransCanada), Vector Pipeline Limited Partnership and NEXUS Gas Transmission Pipeline, 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 Enbridge Gas flexibility in obtaining its own natural gas supply and accommodating the requests of its direct purchase customers for assignment of TransCanada capacity. Enbridge Gas forecasts the natural gas supply needs of its customers, including the associated transportation and storage requirements.

In addition to contracting for transportation service, Enbridge Gas offers firm and interruptible transportation services on its own Dawn-Parkway pipeline system. Enbridge Gas' transmission system consists of approximately 5,500-kilometers (3,418-miles) of high-pressure pipeline, five mainline compressor stations and has an effective peak daily demand capacity of 7.6 bcf/d. Enbridge Gas' transmission system also links an extensive network of underground storage pools at the Tecumseh Gas Storage facility and Dawn Hub (collectively, Dawn) to major Canadian and United States markets, and forms an important link in moving natural gas from western Canada and United States supply basins to central Canadian and northeastern United States markets.

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. Enbridge Gas delivered 1,860 Bcf of gas through its distribution and transmission system in 2019. A substantial amount of Enbridge Gas' transportation revenue is generated by fixed annual demand charges, with the average length of a long-term contract being approximately 13 years and the longest remaining contract term being 21 years.

Storage
Enbridge Gas' 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 Enbridge Gas 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 Enbridge Gas 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 Enbridge Gas' franchise areas.

Enbridge Gas' storage facility at Dawn is located in southwestern Ontario, and has a total working capacity of approximately 272 bcf in 34 underground facilities located in depleted gas fields. Dawn is the largest integrated underground storage facility in Canada and one of the largest in North America. Approximately 181 bcf, at their respective current heat values, of the total working capacity is available to Enbridge Gas for utility operations. Enbridge Gas also has storage contracts with third parties for 17 bcf of storage capacity.

Dawn offers customers an important link in the movement of natural gas from western Canadian and United States supply basins to markets in central Canada and the northeast United States. 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 2019, Dawn provided services such as storage, balancing, gas loans, transport, exchange and peaking services to over 200 counterparties.

A substantial amount of Enbridge Gas' storage revenue is generated by fixed annual demand charges, with the average length of a long-term contract being approximately four years and the longest remaining contract term being 17 years.

NOVERCO

Noverco is a holding company that wholly-owns Énergir, 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 Québec and the State of Vermont. Energir serves approximately 525,000 residential and industrial customers and is regulated by the Québec 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.

GAZIFÈRE

We wholly own Gazifère, a natural gas distribution company that serves approximately 43,000 customers in western Québec, a market not served by Energir. Gazifère is regulated by the Québec Régie de l'énergie.

COMPETITON

Enbridge Gas' distribution system is regulated by the OEB and is subject to regulation in a number of areas, including rates. Enbridge Gas is not generally subject to third-party competition within its distribution franchise areas.

Enbridge Gas competes with other forms of energy available to its 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 alternate energy options, with specific interest coming from communities that are not currently serviced by natural gas. Enbridge Gas continues 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. We expect demand for natural gas in the greater Toronto metropolitan area to continue to grow due to favorable population growth supplemented by the expansion of other communities served by our system.

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.

RENEWABLE POWER GENERATION

Renewable Power Generation consists primarily of investments in wind and solar assets, as well as geothermal, waste heat recovery, and transmission assets. In North America, assets are primarily located in the provinces of Alberta, Saskatchewan, Ontario, and Québec and in the states of Colorado, Texas, Indiana and West Virginia. In Europe, Enbridge holds equity interests in operating offshore wind facilities in the coastal waters of the United Kingdom and Germany, as well as in several projects under active development in France. Further, we are pursuing new European development opportunities through Maple Power Ltd., a joint venture in which we hold a 50% interest.

Combined Renewable Power Generation investments represent approximately 1,991 MW of net generation capacity. Of this amount, approximately:

- 1,392 MW is generated by North American wind facilities;
- 255 MW is generated by European offshore wind facilities;
- 240 MW is generated by the Saint-Nazaire Offshore Wind project, currently under construction; and
- 78 MW is generated by North American solar facilities.

The vast majority of the power produced from these wind facilities is sold under long-term power purchase agreements.

Renewable Power Generation includes the Montana-Alberta Tie-Line (MATL), a 300 MW transmission line which runs from Great Falls, Montana to Lethbridge, Alberta. In the fourth quarter of 2019, we committed to a plan to sell the MATL transmission assets. The purchase and sale agreement was signed in January 2020. Subject to certain regulatory approvals and customary closing conditions, the transaction is expected to close in the first quarter of 2020.

JOINT VENTURES / EQUITY INVESTMENTS

Effective August 1, 2018, the investments in the Canadian renewable assets and two of the United States renewable assets are held within a joint venture in which we maintain a 51% interest and continue to manage, operate, and provide administrative support.

We also own interests in European offshore wind facilities through the following joint ventures:

- a 24.9% interest in Rampion Offshore, located in the United Kingdom, which went into service April 2018;
- a 25% interest in Hohe See Offshore and its subsequent expansion, located in Germany, which went into service October 2019 and January 2020, respectively; and
- a 50% interest in the Saint-Nazaire Offshore Wind project, located in France, that is currently under construction.

COMPETITION

Our Renewable Power Generation assets operate in the North American and European power markets, which are subject to competition and supply and demand fundamentals for power in the jurisdictions in which they operate. The majority of revenue is generated pursuant to long-term power purchase agreements or has been substantially hedged. As such, the financial performance 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 sector includes large utilities, small independent power producers and private equity investors, which are expected to aggressively compete for new project development opportunities and for the right to supply customers when contracts expire.

To grow in an environment of heightened competition, we strategically seek opportunities to collaborate with well-established renewable power developers and financial partners and to target regions with commercial constructs consistent with our low risk business model. In addition, we bring to bear the expertise of completing and delivering large scale infrastructure projects.

SUPPLY AND DEMAND

The renewable power generation network in North America is expected to undergo significant growth over the next 20 years due to the replacement of older sources of electricity generation. 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 is expected to accelerate the retirement of aging coal-fired generation plants, resulting in a requirement for significant new generation capacity and extending project lives and/or power purchase agreements of preferred technologies. 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 (the latter of which make up the bulk of our assets), are expected to be the preferred sources to replace coal-fired generation due to their lower carbon intensities. In addition, changes in the administration in the jurisdictions within which we operate, or in societal views, could result in a significant policy shift or pressure to accelerate low carbon transition.

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, regardless of available incentives. Related growth opportunities could include repowering projects to increase output from and extend project-life of our existing facilities.

In Europe, the renewable energy outlook is positive, especially for offshore wind in countries with long coastlines and densely populated areas. According to the European Wind Energy Association, by 2030, wind energy capacity in Europe is expected to be 320 Gigawatts (GW), including 66 GW of offshore capacity as compared to 18.5 GW at the end of 2018. There is also wide public support for carbon reduction targets and broader adoption of renewable generation across all governmental levels. We, through our European joint ventures, continue to invest in offshore wind projects in the United Kingdom, France, and Germany to meet the growing demand.

ENERGY SERVICES

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

Energy Services is primarily 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, railcar, 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 and determine the pressures at which our pipelines can operate.

PHMSA has designed 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 CER 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 CER 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 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. In 2019, the Government of Canada implemented a federal system of carbon pricing. The pricing applies 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 Mainline System and other liquids pipelines are subject to the actions of various regulators, including the CER 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 U.S. L3R Program, could result in cost escalations and construction delays, which also negatively impact our operations.

GAS TRANSMISSION AND 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. 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. We reached an agreement with Texas Eastern shippers and filed a Stipulation and Agreement with the FERC on October 28, 2019. We expect a decision from the FERC in the second quarter of 2020, upon which we will begin recognizing updated rates within our results of operations.

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. DCP Midstream's interstate NGL transportation pipelines are subject to FERC 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 CER, the Transportation Safety Board and the Ontario Technical Standards and Safety Authority.

Our Canadian natural gas transmission operations are subject to regulation by the CER 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. We are in the process of negotiating a rate settlement agreement with our British Columbia Pipeline shippers. Since the expiration of our previous Settlement Agreement at the end of 2019, we have been charging interim rates as approved by the CER.

GAS DISTRIBUTION AND STORAGE

Operational Regulation

Our gas distribution and storage utility operations are regulated by the OEB and the Québec Régie de l'énergie, 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 amounts 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 2019 following the OEB's Decision and Order to approve Enbridge Gas' application for 2019 rates. The Decision and Order approved an effective date for base rates of April 1, 2019, and the inclusion of incremental capital module amounts to allow for the recovery of incremental capital investments.

Enbridge Gas' distribution rates, beginning in 2019, are set under a five-year incentive regulation (IR) framework using a price cap mechanism. The price cap mechanism establishes new rates each year through an annual base rate escalation at inflation less a 0.3% productivity factor, annual updates for certain costs to be passed through to customers, and where applicable, the recovery of material discrete incremental capital investments beyond those that can be funded through base rates. The IR framework includes the continuation and establishment of certain deferral and variance accounts, as well as an earnings sharing mechanism that requires Enbridge Gas to share equally with customers, any earnings in excess of 150 basis points over the annual OEB approved return on equity (ROE).

Environmental Regulation

Our workers, operations and facilities are subject to municipal, provincial and federal legislation which regulate the protection of the environment and the health and safety of workers. Environmental legislation primarily includes regulation of discharges to air, land and water; management and disposal of hazardous waste; the assessment and management of contaminated sites; and the reporting and reduction of GHG emissions.

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, adverse impacts to the environment in which we operate within, property damage or regulatory violations including order and fines. We could also incur future liability for soil and groundwater contamination associated with past and present site activities.

In addition to gas distribution, we also operate storage facilities and small oil and brine productions 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 environmental approvals and permits from regulators to operate. As a result, these assets and facilities are subject to periodic inspections and/or audits. Annual reports, such as the Annual Written Summary Report are submitted to the Ontario Ministry of Environment, Conservation and Parks (MECP) and other regulators 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.

As with previous years, in 2019, we reported GHG emissions to Environment and Climate Change Canada (ECCC), 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 Ontario regulations.

Enbridge Gas utilizes 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. Enbridge Gas continues to work with industry associations to refine quantification methodologies and emissions factors, as well as best management practices to minimize emissions.

In October 2018, the federal government confirmed that Ontario is subject to the federal government's carbon pricing program, otherwise known as the Federal Carbon Pricing Backstop Program. This program consists of two components: an output-based pricing system (OBPS) and carbon charge levied on fossil fuels, including natural gas.

The OBPS component began on January 1, 2019. Under OBPS, a registered facility will have a facility-specific annual emission limit which is based on the relevant output-based standard for its level of production. Enbridge Gas has registered with ECCC as an emitter in the OBPS program and will have an annual compliance obligation associated with its natural gas pipeline transmission system. Annually, Enbridge Gas is required to report its emissions covered under the OBPS, have the emissions report verified by an accredited third-party verifier and remit payment for any emissions that exceed the facility-specific emission limit.

The federal carbon charge took effect on April 1, 2019 at a rate of 3.91 cents/cubic meter (m^3) of natural gas, and is applicable to the majority of customers. Enbridge Gas has registered as a natural gas distributor with the Canadian Revenue Agency and remits the federal carbon charge on a monthly basis. The charge increases annually on April 1 by 1.96 cents/m^3 up to 9.79 cents/m^3 in 2022.

EMPLOYEES

We had approximately 11,300 employees as at December 31, 2019, including approximately 7,800 employees in Canada and approximately 3,500 employees in the United States. Approximately 1,700 of our employees are subject to collective bargaining agreements governing their employment with us. All of the collective bargaining agreements governing our employees have expired or will expire during the year ended December 31, 2020. 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.

EXECUTIVE OFFICERS

The following table sets forth information regarding our executive officers:

Name	Age	Position
Al Monaco	60	President & Chief Executive Officer
Colin K. Gruending	50	Executive Vice President & Chief Financial Officer
Robert R. Rooney	63	Executive Vice President & Chief Legal Officer
John K. Whelen	60	Executive Vice President & Chief Development Officer
William T. Yardley	55	Executive Vice President & President, Gas Transmission and Midstream
Cynthia L. Hansen	55	Executive Vice President & President, Gas Distribution and Storage
Byron C. Neiles	54	Executive Vice President, Corporate Services
D. Guy Jarvis	56	Executive Vice President, Liquids Pipelines
Vern D. Yu	53	Executive Vice President & President, Liquids Pipelines
Laura B. Sayavedra	52	Senior Vice President, Projects, Safety and Reliability, and ERP

Al Monaco was appointed President and Chief Executive Officer on October 1, 2012. Mr. Monaco 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 and 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 Pipeline, Vector and Aux Sable, as well as our International business development and investment activities and Renewable Power Generation.

Colin K. Gruending was appointed Executive Vice President and Chief Financial Officer of Enbridge on June 1, 2019. Previously, our Senior Vice President, Corporate Development and Investment Review, Mr. Gruending performed a number of progressively challenging executive roles such as Vice President Corporate Development and Planning and Vice President, Treasury and Tax while concurrently serving as Chief Financial Officer for Enbridge Income Fund and Enbridge Income Fund Holdings Inc. Prior to that, Mr. Gruending served as Corporate Controller and also led enterprise Investor Relations and Pension Investments.

Robert R. Rooney was appointed Executive Vice President and Chief Legal Officer on February 1, 2017. Mr. Rooney leads our legal and aviation teams across the organization.

John K. Whelen was appointed Executive Vice President and Chief Development Officer on June 1, 2019. Previously, our Executive Vice President and Chief Financial Officer, Mr. Whelen held responsibility for our financial reporting function, as well as our tax, treasury and risk management functions. Prior to that, Mr. Whelen served as Senior Vice President and Controller, Senior Vice President Corporate Development and Vice President and Treasurer. Mr. Whelen has been part of the Enbridge team since 1992.

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, 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.

Cynthia L. Hansen was appointed Executive Vice President and President, Gas Distribution and Storage, on June 1, 2019. Ms. Hansen is responsible for the overall leadership and operations of Enbridge Gas, following the amalgamation of EGD and Union Gas, as well as Gazifère. Previously, our Executive Vice President, Utilities and Power Operations, Ms. Hansen is also the Executive Sponsor for Asset and Work Management Transformation across Enbridge, working with other business unit leaders.

Byron C. Neiles was appointed Executive Vice President, Corporate Services on May 2, 2016. Mr. Neiles has oversight of our Technology & Information Services, Human Resources, Real Estate, Supply Chain Management, and Public Affairs, Communications & Sustainability. 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.

D. Guy Jarvis was appointed Executive Vice President, Liquids Pipelines on June 1, 2019. Mr. Jarvis had previously been President of our Liquids Pipelines group, 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 EGNB and Gazifère. On November 7, 2019, Mr. Jarvis notified us of his intention to retire effective February 28, 2020.

Vern D. Yu was appointed Executive Vice President and President, Liquids Pipelines on January 1, 2020. Previously, Mr. Yu served as President and Chief Operating Officer for Liquids Pipelines and prior to that served as Executive Vice President and Chief Development Officer. He had previously served as Senior Vice President, Corporate Planning and Chief Development Officer. Prior to joining Corporate Development, Mr. Yu served as Senior Vice President of Business and Market Development for Enbridge's Liquids Pipelines division and previously has held a series of roles with increasing responsibility in our corporate and financial areas.

Laura B. Sayavedra was appointed Senior Vice President, Projects, Safety and Reliability and Enterprise Resource Planning (ERP) on June 1, 2019. Ms. Sayavedra is accountable for providing the overall strategic vision, leadership, integration and executive oversight of Enbridge's enterprise-wide Projects, Safety and Reliability, and ERP functions spanning operations in Canada and the United States, including multiple interests, jurisdictions and sensitivities. Previously, Ms. Sayavedra served as Vice President of Finance Transformation and took on a leadership role for the multi-year ERP program in late 2017.

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 Securities and Exchange Commission (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 INC.
Additional information about Enbridge Gas can be found in its annual information form, financial statements and management's discussion and analysis (MD&A) for the year ended December 31, 2019, 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 Enbridge Gas and are publicly available on SEDAR at www.sedar.com. These documents are not, unless otherwise specifically stated, incorporated by reference into this Annual Report on Form 10-K.

ENBRIDGE PIPELINES INC.
Additional information about Enbridge Pipelines Inc. (EPI) can be found in its annual information form, financial statements and MD&A for the year ended December 31, 2019, 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, 2019, 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

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, including those related to climate change, 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 British Columbia (BC) Pipeline T-South system, in January 2019 at the Texas Eastern pipeline, and in August 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 litigation and 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.

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, curtailment of commodity supply, operational incident or other reasons could have a significant impact on our operations and negatively impact financial results, relationships with stakeholders and our reputation. 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 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 or loss of life 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 or loss of life to our workers or contractors could result in reputational damage to us, material repair costs or increased costs of operating and insuring our assets.

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. We monitor our control effectiveness in an increasing threat landscape and continuously take action to improve our security posture. We have implemented a security operations center, which operates at all times 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. 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 reputation, business, operations or financial results.

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, 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 and Storage 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 Renewable Power Generation 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 Renewable Power Generation 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 Renewable Power Generation facilities could lead to decreased earnings and cash flows for us. Additionally, inefficiencies or interruptions of Renewable Power Generation facilities due to operational disturbances or outages resulting from weather conditions or other factors, could also impact earnings.

Power produced from Renewable Power Generation 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 Renewable Power Generation assets is dependent on each counterparty performing its contractual obligations under the power purchase agreements or pricing arrangement applicable to it.

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

U.S. 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.

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.

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.

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

Our ability to successfully execute our projects is subject to various regulatory, development, operational, litigation 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 and operations by third parties, including 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 projects.

Climate related risks are integrated into multiple of our larger risk categories that encompass operational, financial and stakeholder consequences. This is done because of the interconnected economic, social and environmental nature of climate impacts requires a comprehensive review within the context of other risks that impact us.

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, Spruce Ridge Project and the T-South Reliability and Expansion Project. 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.*

Erosion of stakeholder trust or confidence or changes in our reputation with stakeholders, interest groups, political leadership, the media or other entities could influence actions or decisions about our company and industry and have negative impacts on our business, operations or financial results.

Our operations, projects and growth opportunities require us to have strong relationships with key stakeholders including local communities, Indigenous communities, and other groups directly impacted by our activities, as well as governments and government agencies. Inadequately managing expectations and issues important to stakeholders, including those related to environment and climate change, could affect stakeholder trust and confidence and our reputation.

There could be negative impacts on our business, operations or financial results due to erosion of stakeholder trust or confidence or changes in our reputation with stakeholders, interest groups (including non-governmental organizations), political leadership, the media or other entities. Public and stakeholder opinion may be influenced by certain media and others' negative portrayal of the industry in which we operate as well as their opposition to our projects and ongoing operations. Potential impacts of an erosion of stakeholder trust or confidence or negative public opinion may include:

- loss of business;
- loss of ability to secure growth opportunities;
- delays in project execution;
- legal action, such as the legal challenges to the operation of Line 5 in Michigan and Wisconsin;
- increased regulatory oversight;
- negative impact on our ability to obtain and maintain necessary approvals and permits from governments and regulatory agencies on a timely basis and on acceptable terms;
- impediments on our ability to acquire or renew rights-of-way or land rights on a timely basis and on acceptable terms
- changing investor sentiment regarding investment in the oil and gas industry or our company;
- negative impact on access to and cost of capital; and
- loss of ability to hire and retain top talent.

We are also exposed to the risk of higher costs, delays, project cancellations, new restrictions or the cessation of operations of existing pipelines due to increasing pressure on governments and regulators. Recent judicial decisions have increased the ability of 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 and gas extraction and shipment of oil and gas products.

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.

Many of our operations are regulated and failure to secure regulatory approval for our proposed projects, or loss of required approvals for our existing operations, could have a negative impact on our business, financial condition or results of operations.

The nature and degree of regulation and legislation affecting energy companies in Canada and the United States have changed significantly in past years.

In Canada, the passing of the CER Act and the Impact Assessment Act under Bill C-69, which came into force on August 28, 2019, is expected to extend timelines associated with regulatory approvals for new projects which fall under Canadian federal jurisdiction and meet the criteria for an environmental impact assessment. Changes to the British Columbia regulatory framework have also been made, affecting provincially-regulated projects in a similar manner as those that are federally-regulated. Within the United States, pipelines companies continue to face opposition from anti-oil activists, Indigenous communities, citizens, environmental groups and politicians concerned with either the safety of pipelines or keeping oil in the ground. In the United States, several federal agencies are proposing changes to regulations pursuant to Executive Orders requiring them to streamline permitting, which would include changes to Section 401 of the Clean Water Act and the National Environmental Policy Act. These regulations are anticipated to be finalized this year but will be challenged in court and could be modified or withdrawn with a new administration. Additionally there are numerous cases pending in federal court challenging various aspects of other laws or regulations that could adversely impact permitting.

We may not be able to obtain or maintain all required regulatory approvals for our operating assets or development projects. If there is a delay in obtaining any required regulatory approvals, if we fail to obtain or comply with them, or if 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.

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, including those related to climate change and GHG emissions, 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 operations are subject to operational regulation and other requirements, including compliance with easements and other land tenure documents, and failure to comply with applicable regulations and other requirements could have a negative impact on our business, financial condition or results of operations.

Operational risks relate to compliance with applicable operational rules and regulations mandated by governments, applicable regulatory authorities, or other requirements that may be found in easements or other agreements that provide a legal basis for our operations, breaches of which could result in fines, penalties, awards of damages, operating restrictions (including shutdown of lines) and an overall increase in operating and compliance costs. Scrutiny over the integrity of our assets and operations has the potential to increase operating costs or limit future projects. Potential regulatory changes and legal challenges could have an impact on our future earnings from existing operations 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. While 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, and by developing response plans to regulatory changes or enforcement actions, such mitigation efforts may be ineffective or insufficient. 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 or other government officials 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 commercial arrangements 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. 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. However, 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.

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 2020 and 2021, including integration initiatives arising out of the merger with Spectra Energy 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.

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 and storage services are with customers who have an investment-grade rating (or the equivalent based on our evaluation) or are secured by collateral. However, we cannot predict to what extent our business would be impacted by deteriorating conditions in the economy, including possible declines in our customers' creditworthiness. As a result of future capital projects for which natural gas and oil producers may be the primary customer, our credit exposure with below investment-grade customers may increase. It is possible that customer payment defaults, if significant, could adversely affect our earnings and cash flows.

We could be subject to changes in our tax rates, the adoption of new United States, Canadian or international tax legislation or exposure to additional tax liabilities.

We are subject to taxes in the United States, Canada and numerous foreign jurisdictions. Due to economic and political conditions, tax rates in various jurisdictions may be subject to significant change. Our effective tax rates could be affected by changes in the mix of earnings in countries with differing statutory tax rates, changes in the valuation of deferred tax assets and liabilities, or changes in tax laws or their interpretation, including in the United States, Canada and other foreign jurisdictions in which we operate.

We are also subject to the examination of our tax returns and other tax matters by the United States Internal Revenue Service, the Canada Revenue Agency and other tax authorities and governmental bodies. We regularly assess the likelihood of an adverse outcome resulting from these examinations to determine the adequacy of our provision for taxes. There can be no assurance as to the outcome of these examinations. If our effective tax rates were to increase, particularly in the United States or Canada, or if the ultimate determination of our taxes owed is for an amount in excess of amounts previously accrued, our financial condition and operating results could be materially adversely affected.

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 directly and indirectly affected by commodity prices and Government policy.

The efforts implemented in 2019 by the Alberta Government to manage supply and inventories in Western Canada is expected to continue at diminishing levels to the end of 2020 as incremental take away capacity is introduced to the market. This intervention has negligible impact on mainline throughput, as enough inventory exists to meet refinery customer needs and service our favorable markets. 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 of 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.

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 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 to mitigate the financial impacts arising from these hazards. This program includes insurance coverage in types and amounts and with terms and conditions that are generally consistent with coverage customary for our industry, however insurance does not cover all events in all circumstances.

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. Additionally, even with insurance, if any natural disaster or other hazardous event leads to a catastrophic interruption in operations, we may not be able to restore operations without significant interruption.

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). The USMCA/CUSMA has been ratified by the United States and Mexico, and will not come into effect until after Canada ratifies the agreement. 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.

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 7, 2020, there were approximately 2,024,814,011 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):

	2019	2018
Q1	**0.738**	0.671
Q2	**0.738**	0.671
Q3	**0.738**	0.671
Q4	**0.738**	0.671

Consistent with our objective of delivering annual cash dividend increases, we announced a quarterly dividend of $0.81 per common share payable on March 1, 2020, which represents a 9.8 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

The information required by this Item will be contained in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2019.

Recent Sales of Unregistered Equity Securities

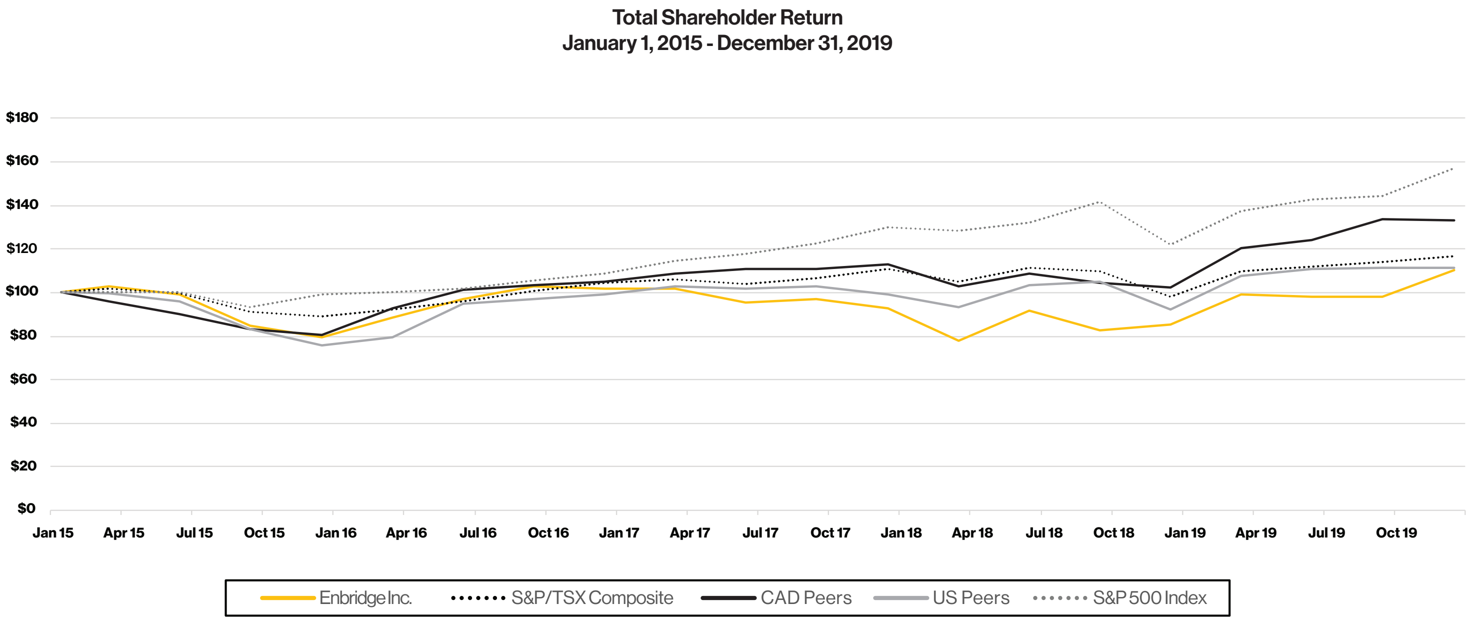
None.

Issuer Purchases of Equity Securities

None.

Total Shareholder Return

The following graph reflects the comparative changes in the value from January 1, 2015 through December 31, 2019 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, 2015	December 31, 2015	2016	2017	2018	2019
Enbridge Inc.	100.00	79.66	101.94	92.93	85.40	110.45
S&P/TSX Composite	100.00	88.91	104.48	110.78	97.88	116.61
S&P 500 Index	100.00	99.27	108.74	129.86	121.76	156.92
United States Peers[1]	100.00	75.58	99.08	99.42	92.47	111.43
Canadian Peers	100.00	80.50	105.22	113.05	102.32	133.14

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 is not necessarily indicative of results of future operations and 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* to fully understand factors that may affect the comparability of the information presented below.

	Years Ended December 31,				
	2019	2018	2017	2016	2015
(millions of Canadian dollars, except per share amounts)					
Consolidated Statements of Earnings					
Operating revenues	**$ 50,069**	$ 46,378	$ 44,378	$ 34,560	$ 33,794
Operating income	**8,260**	4,816	1,571	2,581	1,862
Earnings/(loss) from continuing operations	**5,827**	3,333	3,266	2,309	(159)
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**(122)**	(451)	(407)	(240)	410
Earnings attributable to controlling interests	**5,705**	2,882	2,859	2,069	251
Earnings/(loss) attributable to common shareholders	**5,322**	2,515	2,529	1,776	(37)
Common Stock Data					
Earnings/(loss) per common share					
Basic	**2.64**	1.46	1.66	1.95	(0.04)
Diluted	**2.63**	1.46	1.65	1.93	(0.04)
Dividends paid per common share	**2.95**	2.68	2.41	2.12	1.86

	December 31,				
	2019	2018	2017	2016	2015
(millions of Canadian dollars)					
Consolidated Statements of Financial Position					
Total assets[1]	**$ 163,269**	$ 166,905	$ 162,093	$ 85,209	$ 84,154
Long-term debt including capital leases, less current portion	**59,661**	60,327	60,865	36,494	39,391

1 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.

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

RECENT DEVELOPMENTS

CANADIAN LINE 3 REPLACEMENT PROGRAM PLACED INTO SERVICE

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

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

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

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

MAINLINE SYSTEM CONTRACTING

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

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

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

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

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

ASSET MONETIZATION

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

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

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

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

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

ENBRIDGE GAS INC. 2019 RATE APPLICATION

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

ENBRIDGE GAS INC. 2020 RATE APPLICATION

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

TEXAS EASTERN PIPELINE RUPTURE

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

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

TEXAS EASTERN RATE CASE

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

RESULTS OF OPERATIONS

	Year ended December 31,		
	2019	2018	2017
(millions of Canadian dollars, except per share amounts)			
Segment earnings/(loss) before interest, income taxes and depreciation and amortization			
Liquids Pipelines	**7,681**	5,331	6,395
Gas Transmission and Midstream	**3,371**	2,334	(1,269)
Gas Distribution and Storage	**1,747**	1,711	1,390
Renewable Power Generation	**111**	369	372
Energy Services	**250**	482	(263)
Eliminations and Other	**429**	(708)	(337)
Depreciation and amortization	**(3,391)**	(3,246)	(3,163)
Interest expense	**(2,663)**	(2,703)	(2,556)
Income tax expense	**(1,708)**	(237)	2,697
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	**(122)**	(451)	(407)
Preference share dividends	**(383)**	(367)	(330)
Earnings attributable to common shareholders	**5,322**	2,515	2,529
Earnings per common share	**2.64**	1.46	1.66
Diluted earnings per common share	**2.63**	1.46	1.65

EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS

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

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

- a non-cash, unrealized derivative fair value gain of $1,806 million ($1,276 million after-tax attributable to us) in 2019, compared with a loss of $660 million ($397 million after-tax attributable to us) in 2018, reflecting net fair value gains and losses arising from changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange and commodity prices risks;
- a non-cash, write-down of crude oil and natural gas inventories to the lower of cost or market in our Energy Services business segment of $188 million ($144 million after-tax attributable to us) in 2019, compared with $327 million ($239 million after-tax attributable to us) in 2018;
- the absence in 2019 of a goodwill impairment charge of $1,019 million after-tax attributable to us in 2018 resulting from the classification of our Canadian natural gas gathering and processing businesses as held for sale;
- the absence in 2019 of a loss of $913 million ($701 million after-tax attributable to us) in 2018 on Midcoast Operating, L.P. and its subsidiaries (MOLP) resulting from a revision to the fair value of the assets held for sale based on the sale price;
- the absence in 2019 of a loss of $154 million ($95 million after-tax attributable to us) in 2018 related to the Line 10 crude oil pipeline, which is a component of our Mainline System, resulting from its classification as an asset held for sale and the subsequent measurement at the lower of carrying value or fair value less costs to sell; and
- employee severance, transition and transformation costs of $140 million ($127 million after-tax attributable to us) in 2019, compared with $203 million ($181 million after-tax attributable to us) in 2018.

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

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

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

After taking into consideration the factors above, the remaining $773 million increase in Earnings Attributable to Common Shareholders is primarily explained by the following significant business factors:

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

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

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

REVENUES

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

Transportation and other services revenues of $16,555 million, $14,358 million and $13,877 million for the years ended December 31, 2019, 2018 and 2017, respectively, were earned from our crude oil and natural gas pipeline transportation businesses and also include power generation revenues from our portfolio of renewable and power generation assets. For our transportation assets operating under market-based arrangements, revenues are driven by volumes transported and the corresponding tolls for transportation services. For assets operating under take-or-pay contracts, revenues reflect the terms of the underlying contract for services or capacity. For rate-regulated assets, revenues are charged in accordance with tolls established by the regulator, and in most cost-of-service based arrangements are reflective of our cost to provide the service plus a regulator-approved rate of return. Higher transportation and other services revenues reflected increased throughput on our core liquids pipeline assets combined with the incremental revenues associated with assets placed into service over the past three years.

Gas distribution sales revenues of $4,205 million, $4,360 million and $4,215 million for the years ended December 31, 2019, 2018 and 2017, respectively, were recognized in a manner consistent with the underlying rate-setting mechanism mandated by the regulator. Revenues generated by the gas distribution businesses are primarily driven by volumes delivered, which vary with weather and customer composition and utilization, as well as regulator-approved rates. The cost of natural gas is passed through to customers through rates and does not ultimately impact earnings due to its flow-through nature.

Commodity sales of $29,309 million, $27,660 million and $26,286 million for the years ended December 31, 2019, 2018 and 2017, respectively, were generated primarily through our Energy Services operations. Energy Services includes the contemporaneous purchase and sale of crude oil, natural gas, power and Natural Gas Liquids (NGLs) to generate a margin, which is typically a small fraction of gross revenue. While sales revenue generated from these operations are impacted by commodity prices, net margins and earnings are relatively insensitive to commodity prices and reflect activity levels which are driven by differences in commodity prices between locations, grades and points in time, rather than on absolute prices. Any residual commodity margin risk is closely monitored and managed. Revenues from these operations depend on activity levels, which vary from year-to-year depending on market conditions and commodity prices.

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

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

BUSINESS SEGMENTS

LIQUIDS PIPELINES

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

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

EBITDA was positively impacted by $1,926 million due to certain unusual, infrequent or other non-operating factors, primarily explained by the following:
- a non-cash, unrealized gain of $976 million in 2019 compared with a loss of $1,077 million in 2018 reflecting net fair value gains and losses arising from changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange and commodity price risks; and
- the absence in 2019 of a loss of $154 million in 2018 related to Line 10, which is a component of our Mainline System, resulting from its classification as an asset held for sale and the subsequent measurement at the lower of carrying value or fair value less costs to sell.

The positive factors above were partially offset by the following unusual, infrequent or other non-operating factors:
- a loss of $310 million in 2019 resulting from the review of our comprehensive long-term economic hedging program and a payment to certain hedge counterparties to pre-settle and reset the hedge rate on a portion of our hedging program; and
- a loss of $21 million in 2019 related to the write-off of project development costs resulting from the withdrawal of our permit application for the Texas COLT Offshore Loading Project.

After taking into consideration the factors above, the remaining $424 million increase is primarily explained by the following significant business factors:
- higher Flanagan South and Seaway Pipeline throughput year-over-year driven by the redirection of throughput to the Gulf Coast resulting from refinery outages in the United States Midwest in the first half of 2019 and strong Gulf Coast demand resulting from favorable price differentials;
- higher Bakken Pipeline System throughput year-over-year driven by strong production in the region;
- higher Mainline System ex-Gretna throughput of 2,705 kbpd in 2019 compared with 2,631 kbpd in 2018 driven by an increase in supply and continuous capacity optimization;
- a higher average IJT Benchmark Toll of $4.18 in 2019 compared with $4.11 in 2018; and
- the net favorable effect of translating United States dollar EBITDA at a higher Average Exchange Rate of $1.33 in 2019 compared with $1.30 in 2018.

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

GAS TRANSMISSION AND MIDSTREAM

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

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

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

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

- the absence in 2019 of a goodwill impairment charge of $1,019 million in 2018 resulting from the classification of our Canadian natural gas gathering and processing businesses as held for sale; and
- the absence in 2019 of a loss of $913 million in 2018 resulting from the further revision to the fair value of our MOLP assets held for sale based on the sale price.

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

- a loss of $268 million in 2019 resulting from the sale of the federally regulated portion of our Canadian natural gas gathering and processing businesses;
- a loss of $105 million in 2019 resulting from the write-off of project costs related to the Access Northeast pipeline project;
- a loss of $86 million in 2019 related to the sale of assets, asset write-downs and goodwill impairment losses at our equity investee, DCP Midstream; and
- the absence in 2019 of a recovery of $223 million in 2018 related to rate cases filed that eliminated a portion of the regulated liability formerly included in our US Gas Transmission business rate base.

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

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

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

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

GAS DISTRIBUTION AND STORAGE

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

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

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

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

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

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

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

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

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

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

RENEWABLE POWER GENERATION

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

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

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

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

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

- the absence in 2019 of a loss of $20 million in 2018 resulting from the sale of 49% of our interest in the Hohe See Offshore wind facility and its expansion;
- the absence in 2019 of an asset impairment charge of $22 million in 2018 from our equity investment in NRGreen Power Limited Partnership related to the Chickadee Creek waste heat recovery facility in Alberta; and
- the absence in 2019 of a loss of $25 million in 2018 representing our share of losses incurred by our equity investee, Rampion Offshore Wind Limited, primarily due to the repair and restoration of damaged power transmission cables.

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

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

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

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

ENERGY SERVICES

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

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

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

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

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

ELIMINATIONS AND OTHER

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

Eliminations and Other includes operating and administrative costs and the impact of foreign exchange hedge settlements which are not allocated to business segments. Eliminations and Other also includes the impact of new business development activities and corporate investments.

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

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

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

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

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

1 These amounts are estimates and are subject to upward or downward adjustment based on various factors. Where appropriate, the amounts reflect our share of joint venture projects.
2 Expenditures to date reflect total cumulative expenditures incurred from inception of the project up to December 31, 2019.
3 Update to in-service date pending receipt of all permits required to commence construction.
4 Includes the Lakehead System Mainline Expansion - Line 61. Estimated in-service date will be adjusted to coincide with the in-service date of the U.S. L3R Program.
5 Includes Connecticut and New York portions of the project that were placed into service in 2017 and in the fourth quarter of 2019, respectively.
6 Includes the US$0.2 billion Stratton Ridge Project placed into service in the second quarter of 2019 and the US$0.1 billion Generation Pipeline Acquisition closed in the third quarter of 2019.
7 Our equity contribution is $0.3 billion, with the remainder of the project financed through non-recourse project level debt.

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

LIQUIDS PIPELINES

The following commercially secured growth projects were acquired or placed into service in 2019:

- **AOC Lateral Acquisition** - in January 2019, we acquired 75-kilometers (47-miles) of existing lateral pipelines and tankage infrastructure supporting Athabasca Oil Corporation's (AOC's) Leismer oil sands asset.

- **Gray Oak Pipeline Project -** a crude oil pipeline project connecting the Permian Basin and Eagle Ford to destinations in the Corpus Christi and Sweeny/Freeport markets. The pipeline is a joint development with Phillips 66 and could have an ultimate capacity of approximately 900,000 bpd, subject to additional shipper commitments. Initial in-service for the pipeline commenced in November 2019 with full in-service expected in the second quarter of 2020.

- **Canadian Line 3 Replacement Program -** replacement of the existing Line 3 crude oil pipeline between Hardisty, Alberta and Gretna, Manitoba. This will support the safety and operational reliability of the overall system, enhancing flexibility and allowing us to optimize throughput from western Canada into Superior, Wisconsin.

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

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

Liquids Pipelines

1 AOC Lateral Acquisition

2 Gray Oak Pipeline Project

3 Canadian Line 3 Replacement Program

4 United States Line 3 Replacement Program

Assets in Operation
Projects Placed into Service in 2019
Growth Projects

GAS TRANSMISSION AND MIDSTREAM

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

- **Atlantic Bridge -** expansion of the Algonquin natural gas transmission systems to transport 133 million cubic feet per day (mmcf/d) of natural gas to the New England Region. The expansion primarily consists of various meter station additions, the replacement of a natural gas pipeline in Connecticut and New York, compression additions in Connecticut and a new compressor station in Massachusetts. The meter stations were placed into service in 2017 and 2018. The Connecticut portion of the project was placed into service in the fourth quarter of 2017. The New York portion of the project achieved partial in-service in November 2018 and reached full in-service in October 2019, upon which we began earning incremental revenues. Due to ongoing permitting delays in Massachusetts, the revised expected in service date for the Massachusetts portion of the project is the second half of 2020.

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

- **Spruce Ridge Project** - a natural gas pipeline expansion of Westcoast Energy Inc.'s BC Pipeline in northern BC. The project will provide additional capacity of up to 402 mmcf/d. Due to commercial delays, the revised expected in-service date is the second half of 2021.

- **T-South Reliability & Expansion Program** - a natural gas pipeline expansion of Westcoast Energy Inc.'s BC Pipeline in southern BC that will provide improved compressor reliability and additional capacity of approximately 190 mmcf/d into the Huntington/Sumas market at the United States/ Canada border. The projects were approved by the CER in September 2019.

Gas Transmission

6 Atlantic Bridge

7 Spruce Ridge Project

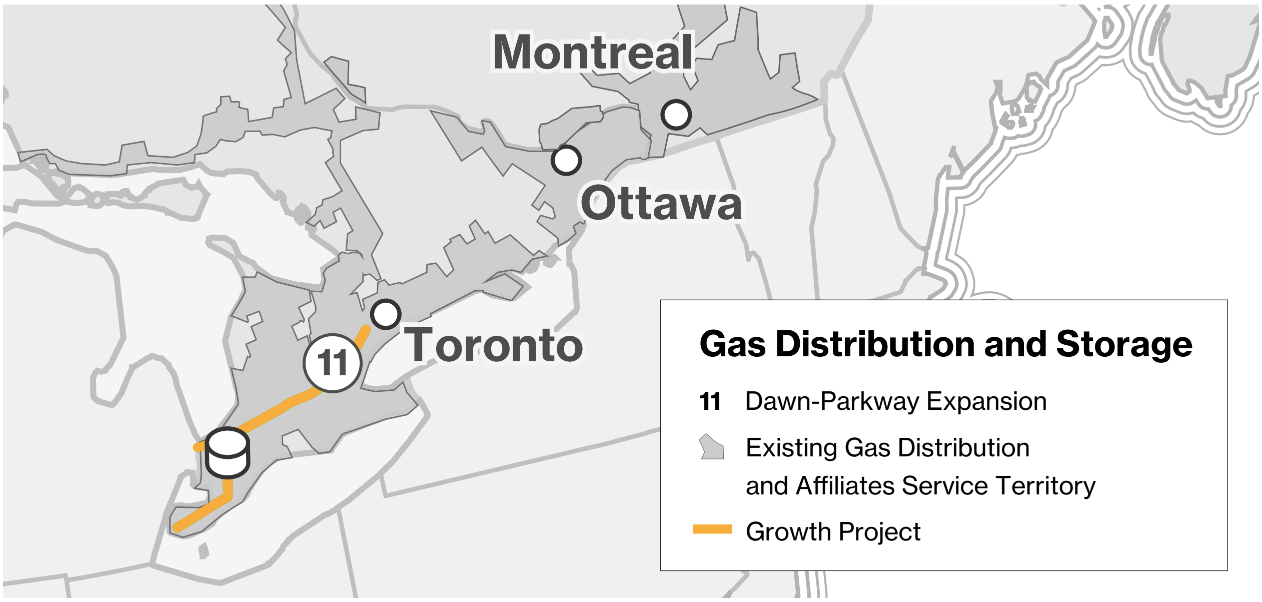
8 T-South Reliability & Expansion Program

- Assets in Operation
- Growth Projects
- Gas Plants in Operation

GAS DISTRIBUTION AND STORAGE

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

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



RENEWABLE POWER GENERATION

The following commercially secured growth project was placed into service in 2019:

- **Hohe See Offshore Wind Project and Expansion** - a wind project located in the North Sea, off the coast of Germany that will generate approximately 497-MW, with an additional 112-MW from the expansion. The Hohe See Project and Expansion is backed by a government legislated 20-year revenue support mechanism. The project generated first power in July 2019, and full operating capacity was reached in October 2019. The project expansion came into service in January 2020.

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

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

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

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

Renewable Power Generation

12 Hohe See Offshore Wind Project and Expansion

13 East-West Tie Line Project

14 Saint-Nazaire Offshore Wind Project

GROWTH PROJECTS - REGULATORY MATTERS

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

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

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

OTHER ANNOUNCED PROJECTS UNDER DEVELOPMENT

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

LIQUIDS PIPELINES

- **Sea Port Oil Terminal Project -** the Sea Port Oil Terminal (SPOT) project consists of onshore and offshore facilities, including a fixed platform located approximately 30 miles off the coast of Brazoria County, Texas. SPOT is designed to load very large crude carriers at rates of approximately 85,000 barrels per hour, or up to approximately 2 million bpd. Along with Enterprise Products Partners, L.P., we announced our intent to jointly develop and market SPOT, and we will work to finalize an equity participation agreement. The agreement will allow us to purchase an ownership interest in SPOT, subject to SPOT receiving a deep-water port license.

- **Jones Creek Crude Oil Storage Terminal -** the Jones Creek terminal is expected to have an ultimate capability of up to 15 million barrels of storage, access to crude oil from all major North American production basins and will be fully integrated with the Seaway Pipeline system to allow for access to Houston-area refineries, existing export facilities, the SPOT project and other facilities in the future.

GAS TRANSMISSION AND MIDSTREAM

- **Rio Bravo Pipeline -** the Rio Bravo Pipeline is designed to transport up to 4.5 bcf/d of natural gas from the Agua Dulce supply area to NextDecade's Rio Grande LNG export facility in the Port of Brownsville, Texas. We have executed an agreement with NextDecade to acquire the Rio Bravo Pipeline development project. In addition, we have negotiated a precedent agreement with NextDecade, to be executed at closing, under which we will provide firm transportation capacity on the Rio Bravo Pipeline to NextDecade's Rio Grande LNG export facility for a term of at least twenty years. Construction of the pipeline will be subject to the Rio Grande LNG export facility reaching a final investment decision.

- **Annova LNG -** we have executed a precedent agreement to supply the Annova LNG facilities in the Port of Brownsville, Texas for a term of at least twenty years, by expanding our existing Valley Crossing system. The expansion will be subject to the Annova LNG facilities reaching a final investment decision.

- **Texas Eastern Venice Extension Project -** a reversal and expansion of Texas Eastern's Line 40 from its existing New Roads compressor station to a new delivery point with the proposed Gator Express pipeline just south of Texas Eastern's Larose compressor station. The project is expected to deliver 1.26 bcf of feed gas to Venture Global's proposed Plaquemines LNG export facility located in Plaquemine Parish, Louisiana. The project is expected to be placed into service in 2022.

RENEWABLE POWER GENERATION

- **Éolien Maritime France SAS** - a 50% interest in EMF, a French offshore wind development company, which is co-owned by EDF Energies Nouvelles, a subsidiary of Électricité de France S.A. EMF holds licenses for three large-scale offshore wind facilities off the coast of France that is expected to generate approximately 1,428 MW. One wind facility, the Saint-Nazaire Offshore Wind Project, achieved a positive final investment decision during the third quarter of 2019. The development of the remaining two wind facilities is subject to final investment decisions and regulatory approvals, the timing of which are not yet certain.

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

LIQUIDITY AND CAPITAL RESOURCES

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

Our financing plan is regularly updated to reflect evolving capital requirements and financial market conditions and identifies a variety of potential sources of debt and equity funding alternatives. Our current financing plan does not include any issuances of additional common equity and was the leading principle behind the suspension of our Dividend Reinvestment and Share Purchase Plan in November 2018.

CAPITAL MARKET ACCESS

We ensure ready access to capital markets, subject to market conditions, through maintenance of shelf prospectuses that allow for issuance of long-term debt, equity and other forms of long-term capital when market conditions are attractive. In accordance with our funding plan we completed the following issuances in 2019:

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

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

Credit Facilities, Ratings and Liquidity

To ensure ongoing liquidity and to mitigate the risk of capital market disruption, we maintain ready access to funds through committed bank credit facilities and actively manage our bank funding sources to optimize pricing and other terms. The following table provides details of our committed credit facilities at December 31, 2019:

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

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

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

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

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

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

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

Our credit facility agreements and term debt indentures include standard events of default and covenant provisions, whereby accelerated repayment and/or termination of the agreements may result if we were to default on payment or violate certain covenants. As at December 31, 2019, we were in compliance with all debt covenants and expect to continue to comply with such covenants.

Strong growth in internal cash flow, proceeds from non-core asset dispositions, ready access to liquidity from diversified sources and a stable business model have enabled us to manage our credit profile. We actively monitor and manage key financial metrics with the objective of sustaining investment grade credit ratings from the major credit rating agencies and ongoing access to bank funding and term debt capital on attractive terms. Key measures of financial strength that are closely managed include the ability to service debt obligations from operating cash flow and the ratio of debt to EBITDA.

During 2019, our credit ratings were affirmed as follows:

- On July 23, 2019, DBRS Limited affirmed our issuer rating and medium-term notes and unsecured debentures rating of BBB (high), fixed-to-floating subordinated notes rating of BBB (low), preference share rating of Pfd-3 (high) and commercial paper rating of R-2 (high), all with stable outlooks.
- On April 15, 2019, Fitch Rating services affirmed long-term issuer default rating and senior unsecured debt rating of BBB+, preference share rating of BBB-, junior subordinated note rating of BBB-, and short-term and commercial paper rating of F2 with a stable rating outlook.
- On January 25, 2019, Moody's Investor Services, Inc. upgraded our issuer and senior unsecured ratings from Baa3 to Baa2 with outlook revised to positive, upgraded our subordinated rating from Ba2 to Ba1, preference share rating from Ba2 to Ba1 and the commercial paper rating for Enbridge (U.S.) Inc. from P-3 to P-2.
- On December 30, 2019, Standard & Poor's Rating Services (S&P) affirmed our corporate credit rating and senior unsecured debt rating of BBB+, preference share rating of P-2 (low) and commercial paper rating of A-1 (low), and reaffirmed a stable outlook. S&P also affirmed our global overall short-term rating of A-2.

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

There are no material restrictions on our cash. Total restricted cash of $28 million, as reported on the Consolidated Statements of Financial Position, primarily includes cash collateral and amounts received in respect of specific shipper commitments. Cash and cash equivalents held by certain subsidiaries may not be readily accessible for alternative use by us.

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

To address this negative working capital position, we maintain significant liquidity in the form of committed credit facilities and other sources as previously discussed, which enable the funding of liabilities as they become due.

SOURCES AND USES OF CASH

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

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

Operating Activities
2019

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

2018

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

Investing Activities
We continue with the execution of our growth capital program which is further described in Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Growth Projects - Commercially Secured Projects*. The timing of project approval, construction and in-service dates impacts the timing of cash requirements.

A summary of additions to property, plant and equipment for the years ended December 31, 2019, 2018 and 2017 is set out below:

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

2019

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

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

2018

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

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

Financing Activities

2019

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

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

2018

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

- Decreased long-term debt issuances and common shares issued in 2018 when compared with 2017, partially offset by lower repayments of maturing long-term debt.
- Higher common share dividend payments in 2018 due to the increase in the common share dividend rate and an increase in the number of common shares outstanding as a result of common shares issued in connection with the Merger Transaction and the issuance of approximately 33 million common shares in December 2017 in a private placement offering.
- Proceeds received from the sale of a portion of our interest in our Canadian and United States renewable assets to the CPPIB in the third quarter of 2018.
- Decreased contributions from noncontrolling interests and redeemable noncontrolling interests in 2018 primarily due to a secondary public offering in 2017 attributable to our holdings in Enbridge Income Fund Holdings Inc. (ENF).

Preference Share Issuances

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

	Gross Proceeds	Dividend Rate	Dividend[1]	Per Share Base Redemption Value[2]	Redemption and Conversion Option Date[2,3]	Right to Convert Into[3,4]
(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%	$1.17224	$25	June 1, 2023	Series G
Series H[6]	$350 million	4.38%	$1.09400	$25	September 1, 2023	Series I
Series J	US$200 million	4.89%	US$1.22160	US$25	June 1, 2022	Series K
Series L	US$400 million	4.96%	US$1.23972	US$25	September 1, 2022	Series M
Series N[6]	$450 million	5.09%	$1.27152	$25	December 1, 2023	Series O
Series P	$400 million	4.38%	$1.09476	$25	March 1, 2024	Series Q
Series R	$400 million	4.07%	$1.01825	$25	June 1, 2024	Series S
Series 1[6]	US$400 million	5.95%	US$1.48728	US$25	June 1, 2023	Series 2
Series 3	$600 million	3.74%	$0.93425	$25	September 1, 2024	Series 4
Series 5	US$200 million	5.38%	US$1.34383	US$25	March 1, 2024	Series 6
Series 7	$250 million	4.45%	$1.11224	$25	March 1, 2024	Series 8
Series 9	$275 million	4.10%	$1.02424	$25	December 1, 2024	Series 10
Series 11	$500 million	4.40%	$1.10000	$25	March 1, 2020	Series 12
Series 13	$350 million	4.40%	$1.10000	$25	June 1, 2020	Series 14
Series 15	$275 million	4.40%	$1.10000	$25	September 1, 2020	Series 16
Series 17	$750 million	5.15%	$1.28750	$25	March 1, 2022	Series 18
Series 19	$500 million	4.90%	$1.22500	$25	March 1, 2023	Series 20

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

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

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

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

5 *The floating quarterly dividend amount for the Series C Preference Shares was decreased to $0.25395 from $0.25459 on March 1, 2019, was increased to $0.25647 from $0.25395 on June 1, 2019, was decreased to $0.25243 from $0.25647 on September 1, 2019 and was increased to $0.25305 from $0.25243 on December 1, 2019, due to reset on a quarterly basis following the issuance thereof.*

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

Common Share Issuances

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

Dividends

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

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

Common Shares[1]	$0.81000
Preference Shares, Series A	$0.34375
Preference Shares, Series B	$0.21340
Preference Shares, Series C[2]	$0.25305
Preference Shares, Series D	$0.27875
Preference Shares, Series F	$0.29306
Preference Shares, Series H	$0.27350
Preference Shares, Series J	US$0.30540
Preference Shares, Series L	US$0.30993
Preference Shares, Series N	$0.31788
Preference Shares, Series P[3]	$0.27369
Preference Shares, Series R[4]	$0.25456
Preference Shares, Series 1	US$0.37182
Preference Shares, Series 3[5]	$0.23356
Preference Shares, Series 5[6]	US$0.33596
Preference Shares, Series 7[7]	$0.27806
Preference Shares, Series 9[8]	$0.25606
Preference Shares, Series 11	$0.27500
Preference Shares, Series 13	$0.27500
Preference Shares, Series 15	$0.27500
Preference Shares, Series 17	$0.32188
Preference Shares, Series 19	$0.30625

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

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

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

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

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

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

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

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

OFF-BALANCE SHEET ARRANGEMENTS

We enter into guarantee arrangements in the normal course of business to facilitate commercial transactions with third parties. These arrangements include financial guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. See Part II. *Item 8. Financial Statements and Supplementary Data - Note 31. Guarantees* for further discussion of guarantee arrangements.

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

We do not have material off-balance sheet financing entities or structures, except for normal operating lease arrangements, guarantee arrangements and financings entered into by our equity investments. For additional information on these commitments, see Part II. *Item 8. Financial Statements and Supplementary Data - Note 30. Commitments and Contingencies* and *Note 31. Guarantees*.

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

CONTRACTUAL OBLIGATIONS

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

As at December 31, 2019	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
(millions of Canadian dollars)					
Annual debt maturities[1]	63,585	4,394	10,910	10,297	37,984
Interest obligations[2]	29,498	2,416	4,512	3,991	18,579
Land leases	1,190	30	70	71	1,019
Pension obligations[3]	135	135	—	—	—
Long-term contracts[4]	9,883	2,947	2,832	1,179	2,925
Other long-term liabilities[5]	—	—	—	—	—
Total contractual obligations	104,291	9,922	18,324	15,538	60,507

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

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

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

4 *Included within long-term contracts, in the table above, are contracts that we have signed for the purchase of services, pipe and other materials totaling $2,237 million which are expected to be paid over the next five years. Also consists of the following purchase obligations: gas transportation and storage contracts, firm capacity payments and gas purchase commitments, transportation, service and product purchase obligations, and power commitments.*

5 *We are unable to estimate deferred income taxes (Part II. Item 8. Financial Statements and Supplementary Data - Note 25. Income Taxes) since cash payments for income taxes are determined primarily by taxable income for each discrete fiscal year. We are also unable to estimate asset retirement obligations (ARO) (Part II. Item 8. Financial Statements and Supplementary Data - Note 19. Asset Retirement Obligations), environmental liabilities (Part II. Item 8. Financial Statements and Supplementary Data - Note 30. Commitments and Contingencies) and hedges payable (Part II. Item 8. Financial Statements and Supplementary Data - Note 24. Risk Management and Financial Instruments) due to the uncertainty as to the amount and, or, timing of when cash payments will be required.*

LEGAL AND OTHER UPDATES

LIQUIDS PIPELINES

Eddystone Rail Legal Matter

In February 2017, our subsidiary Eddystone Rail Company, LLC (Eddystone Rail) filed an action against several defendants in the United States District Court for the Eastern District of Pennsylvania, seeking damages in excess of US$140 million. On September 7, 2018, the United States District Court for the Eastern District of Pennsylvania granted Eddystone Rail's motion to amend its complaint to add several affiliates of the corporate defendants as additional defendants (the Amended Complaint). Eddystone Rail's chances of success on its Amended Complaint cannot be predicted at this time. Defendants have filed Answers and Counterclaims which, together with subsequent amendments, seek damages from Eddystone Rail in excess of US$32 million. The defendants' chances of success on their counterclaims cannot be predicted at this time. The non-corporate defendants filed a Motion to Dismiss on October 25, 2019, based on alleged lack of standing. The motion has been fully briefed to the Court and decision is pending. The individual defendants' chances of success on this motion cannot be predicted at this time.

Dakota Access Pipeline

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

Line 5 Dual Pipelines

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

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

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

Line 5 Easement

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

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

GAS TRANSMMISSION

DCP Midstream, LP Definitive Agreement and Equity Restructuring

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

OTHER LITIGATION

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

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

CRITICAL ACCOUNTING ESTIMATES

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

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

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

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

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

We perform our annual review for impairment at the reporting unit level, which is identified by assessing whether the components of our operating segments constitute businesses for which discrete information is available, whether segment management regularly reviews the operating results of those components and whether the economic and regulatory characteristics are similar.

We have the option to first assess qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment test. When performing a qualitative assessment, we determine the drivers of fair value for each reporting unit and evaluate whether those drivers have been positively or negatively affected by relevant events and circumstances since the last fair value assessment. Our evaluation includes, but is not limited to, assessment of macroeconomic trends, regulatory environments, capital accessibility, operating income trends, and industry conditions. Based on our assessment of the qualitative factors, if we determine it is more likely than not that the fair value of the reporting unit is less than it's carrying amount, a quantitative goodwill impairment test is performed.

The quantitative goodwill impairment test involves determining the fair value of our reporting units and comparing those values to the carrying value of each corresponding reporting unit. If the carrying value of a reporting unit, including allocated goodwill, exceeds its fair value, goodwill impairment is measured at the amount by which the reporting unit's carrying value exceeds its fair value. This amount should not exceed the carrying amount of goodwill. Fair value of our reporting units is estimated using a combination of discounted cash flow model and earnings multiples techniques. The determination of fair value using the discounted cash flow model technique requires the use of estimates and assumptions related to discount rates, projected operating income, terminal value growth rates, capital expenditures and working capital levels. The cash flow projections included significant judgments and assumptions relating to revenue growth rates and expected future capital expenditure. The determination of fair value using the earnings multiples technique requires assumptions to be made in relation to maintainable earnings and earnings multipliers for reporting units.

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

The allocation of goodwill to held for sale and disposed businesses is based on the fair value of businesses relative to their corresponding reporting unit. During the years ended December 31, 2019, and 2018, we impaired nil and $1,019 million, respectively, of goodwill allocated to assets held for sale.

Asset Impairment

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

Assets held for sale

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

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

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

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

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

As at December 31, 2019 and 2018, our significant regulatory assets totaled $4,800 million and $4,695 million, respectively, and significant regulatory liabilities totaled $2,786 million and $2,363 million, respectively.

Depreciation
Depreciation of property, plant and equipment, our largest asset with a net book value at December 31, 2019 and 2018, of $93,723 million and $94,540 million, respectively, is charged in accordance with two primary methods. For distinct assets, depreciation is generally provided on a straight-line basis over the estimated useful lives of the assets commencing when the asset is placed in service. For largely homogeneous groups of assets with comparable useful lives, the pool method of accounting is followed whereby similar assets are grouped and depreciated as a pool. When group assets are retired or otherwise disposed of, gains and losses are not reflected in earnings but are booked as an adjustment to accumulated depreciation.

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

Pension and Other Postretirement Benefits
We use certain assumptions relating to the calculation of defined benefit pension and other postretirement liabilities and net periodic benefit costs. These assumptions comprise management's best estimates of expected return on plan assets, future salary levels, other cost escalations, retirement ages of employees and other actuarial factors including discount rates and mortality. We determine discount rates by reference to rates of high-quality long-term corporate bonds with maturities that approximate the timing of future payments anticipated to be made under each of the respective plans. The expected return on plan assets is determined using market-related values and assumptions on the asset mix consistent with the investment policy relating to the assets and their projected returns. The assumptions are reviewed annually by our independent actuaries. Actual results that differ from results based on assumptions are amortized over future periods and therefore could materially affect the expense recognized and the recorded obligation in future periods.

The following sensitivity analysis identifies the impact on the December 31, 2019 Consolidated Financial Statements of a 0.5% change in key pension and OPEB assumptions:

	Canada		United States	
	Obligation	Expense	Obligation	Expense
(millions of Canadian dollars)				
Pension				
Decrease in discount rate	368	34	69	6
Decrease in expected return on assets	—	18	—	5
Decrease in rate of salary increase	(66)	(15)	(7)	(1)
OPEB				
Decrease in discount rate	23	1	15	—
Decrease in expected return on assets	—	—	—	1

Contingent Liabilities
Provisions for claims filed against us are determined on a case-by-case basis. Case estimates are reviewed on a regular basis and are updated as new information is received. The process of evaluating claims involves the use of estimates and a high degree of management judgment. Claims outstanding, the final determination of which could have a material impact on our financial results and certain subsidiaries and investments are detailed in Part II. *Item 8. Financial Statements and Supplementary Data - Note 30. Commitments and Contingencies*. In addition, any unasserted claims that later may become evident could have a material impact on our financial results and certain subsidiaries and investments.

Asset Retirement Obligations
ARO associated with the retirement of long-lived assets are measured at fair value and recognized as Accounts payable and other or Other long-term liabilities in the period in which they can be reasonably determined. The fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. Discount rates used to estimate the present value of the expected future cash flows range from 1.8% to 9.0% for the years ended December 31, 2019 and 2018. ARO is added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. Our estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements. Currently, for the majority of our assets, there is insufficient data or information to reasonably determine the timing of settlement for estimating the fair value of the ARO. In these cases, the ARO cost is considered indeterminate for accounting purposes, as there is no data or information that can be derived from past practice, industry practice or the estimated economic life of the asset.

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

CHANGES IN ACCOUNTING POLICIES

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

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 is 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. We 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. 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 2.9%.

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 at December 31, 2019, 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%.

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. Our market risk metric is Cash Flow at Risk (CFaR).

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, 2019. 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, 2019 and 2018 CFaR was $113 million and $140 million or 1.2% and 1.6%, respectively, 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 ready access to either the Canadian or United States public capital markets, subject to market conditions. 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, 2019. 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, 2019 and 2018, 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, 2019, 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, 2019, 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, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019 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, 2019, 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 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.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Goodwill Impairment Review

As described in Notes 2 and 16 to the consolidated financial statements, the Company's goodwill balance was $33,153 million at December 31, 2019. Management performs an annual goodwill impairment review at the reporting unit level as of April 1 of each year, or more frequently if events or circumstances indicate that the carrying value of goodwill may be impaired. Management has the option to first assess qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment test. In making the qualitative assessment, management considers macroeconomic trends, changes to regulatory environments, capital accessibility, operating income trends, and changes to industry conditions. The quantitative goodwill impairment test involves determining the fair value of the Company's reporting units and comparing those values to the carrying value of each reporting unit, including goodwill. Fair value 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, revenue growth rates, terminal value growth rates, expected future capital expenditures and working capital levels. 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. In the current year, the quantitative goodwill impairment test was only performed for the Gas Midstream reporting unit.

The principal considerations for our determination that performing procedures relating to the goodwill impairment review is a critical audit matter are that there was significant judgment required by management when (i) developing the significant assumptions related to operating income trends used in the qualitative assessment for all reporting units outside of the Gas Midstream reporting unit, and (ii) developing such significant assumptions as discount rates, projected operating income, expected future capital expenditures and earnings multipliers used to estimate the fair value of the Gas Midstream reporting unit. This in turn led to a high degree of auditor judgment, effort and subjectivity in performing procedures to evaluate (a) management's significant assumptions used in the qualitative assessment and

(b) the cash flow projections and significant assumptions used by management in their quantitative assessment of the Gas Midstream reporting unit. In addition, the audit effort involved the use of professionals with specialized skill and knowledge to assist in performing the procedures and evaluating the audit evidence obtained over the quantitative assessment.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management’s goodwill impairment review, including controls over (i) the development of assumptions related to operating income trends used in the qualitative assessment and (ii) the determination of the fair value estimate of the Gas Midstream reporting unit. These procedures also included, among others, evaluating the reasonableness of significant assumptions used by management in the qualitative assessment of the Company’s reporting units, specifically those related to operating income trends, and testing management’s process for developing the fair value estimate of the Gas Midstream reporting unit. Testing management’s process for developing the fair value estimate of the Gas Midstream reporting unit included evaluating the appropriateness of the discounted cash flow and the earnings multiples models; testing the completeness, accuracy, and relevance of underlying data used in the models; and evaluating the reasonableness of significant assumptions used by management in developing the fair value measurement including discount rates, projected operating income, expected future capital expenditures and earnings multipliers. When assessing the reasonableness of projected operating income and its trends, and expected future capital expenditures, we evaluated whether these significant assumptions were reasonable considering the current and past performance of the Company’s reporting units, external industry data, and evidence obtained in other areas of the audit. We utilized professionals with specialized skill and knowledge to assist in evaluating the appropriateness of management’s discounted cash flow and earnings multiples models and evaluating the reasonableness of assumptions used in the models, specifically discount rates and earnings multiples.

/s/PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Alberta, Canada
February 14, 2020

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

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	**2019**	2018	2017
(millions of Canadian dollars, except per share amounts)			
Operating revenues			
Commodity sales	**29,309**	27,660	26,286
Gas distribution sales	**4,205**	4,360	4,215
Transportation and other services	**16,555**	14,358	13,877
Total operating revenues *(Note 4)*	**50,069**	46,378	44,378
Operating expenses			
Commodity costs	**28,802**	26,818	26,065
Gas distribution costs	**2,202**	2,583	2,572
Operating and administrative	**6,991**	6,792	6,442
Depreciation and amortization	**3,391**	3,246	3,163
Impairment of long-lived assets *(Note 8 and Note 11)*	**423**	1,104	4,463
Impairment of goodwill *(Note 8 and Note 16)*	**—**	1,019	102
Total operating expenses	**41,809**	41,562	42,807
Operating income	**8,260**	4,816	1,571
Income from equity investments *(Note 13)*	**1,503**	1,509	1,102
Other income/(expense)			
Net foreign currency gain/(loss)	**477**	(522)	237
Gain/(loss) on dispositions	**(300)**	(46)	16
Other	**258**	516	199
Interest expense *(Note 18)*	**(2,663)**	(2,703)	(2,556)
Earnings before income taxes	**7,535**	3,570	569
Income tax recovery/(expense) *(Note 25)*	**(1,708)**	(237)	2,697
Earnings	**5,827**	3,333	3,266
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	**(122)**	(451)	(407)
Earnings attributable to controlling interests	**5,705**	2,882	2,859
Preference share dividends	**(383)**	(367)	(330)
Earnings attributable to common shareholders	**5,322**	2,515	2,529
Earnings per common share attributable to common shareholders *(Note 6)*	**2.64**	1.46	1.66
Diluted earnings per common share attributable to common shareholders *(Note 6)*	**2.63**	1.46	1.65

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

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2019**	2018	2017
(millions of Canadian dollars)			
Earnings	**5,827**	3,333	3,266
Other comprehensive income/(loss), net of tax			
Change in unrealized loss on cash flow hedges	**(437)**	(153)	(21)
Change in unrealized gain/(loss) on net investment hedges	**281**	(458)	490
Other comprehensive income/(loss) from equity investees	**40**	38	(27)
Reclassification to earnings of loss on cash flow hedges	**127**	152	313
Reclassification to earnings of pension and other postretirement benefits amounts	**13**	12	19
Actuarial gain/(loss) on pension plans and other postretirement benefits	**(96)**	(52)	8
Foreign currency translation adjustments	**(3,035)**	4,599	(3,060)
Other comprehensive income/(loss), net of tax	**(3,107)**	4,138	(2,278)
Comprehensive income	**2,720**	7,471	988
Comprehensive income attributable to noncontrolling interests and redeemable noncontrolling interests	**(7)**	(801)	(160)
Comprehensive income attributable to controlling interests	**2,713**	6,670	828
Preference share dividends	**(383)**	(367)	(330)
Comprehensive income attributable to common shareholders	**2,330**	6,303	498

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

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

Year ended December 31,	**2019**	2018	2017
(millions of Canadian dollars, except per share amounts)			
Preference shares *(Note 21)*			
Balance at beginning of year	**7,747**	7,747	7,255
Preference shares issued	**—**	—	492
Balance at end of year	**7,747**	7,747	7,747
Common shares *(Note 21)*			
Balance at beginning of year	**64,677**	50,737	10,492
Common shares issued	**—**	—	1,500
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
Shares issued on exercise of stock options	**69**	32	90
Balance at end of year	**64,746**	64,677	50,737
Additional paid-in capital			
Balance at beginning of year	**—**	3,194	3,399
Stock-based compensation	**34**	49	82
Sponsored Vehicles buy-in (*Note 20)*	**—**	(4,323)	—
Repurchase of noncontrolling interest	**65**	—	—
Options exercised	**(61)**	(24)	(95)
Dilution gain on Spectra Energy Partners, LP restructuring *(Note 20)*	**—**	1,136	—
Change in reciprocal interest	**117**	47	—
Other	**32**	(158)	(192)
Sale of noncontrolling interest in subsidiaries *(Note 20)*	**—**	79	—
Balance at end of year	**187**	—	3,194
Retained earnings/(deficit)			
Balance at beginning of year	**(5,538)**	(2,468)	(716)
Earnings attributable to controlling interests	**5,705**	2,882	2,859
Preference share dividends	**(383)**	(367)	(330)
Common share dividends declared	**(6,125)**	(5,019)	(4,702)
Dividends paid to reciprocal shareholder	**18**	33	30
Modified retrospective adoption of *ASC 606 Revenue from Contracts with Customers*	**—**	(86)	—
Redemption value adjustment to redeemable noncontrolling interests *(Note 20)*	**—**	(456)	292
Other	**9**	(57)	99
Balance at end of year	**(6,314)**	(5,538)	(2,468)
Accumulated other comprehensive income/(loss) *(Note 23)*			
Balance at beginning of year	**2,672**	(973)	1,058
Impact of Sponsored Vehicles buy-in	**—**	(142)	—
Other comprehensive income/(loss) attributable to common shareholders, net of tax	**(2,992)**	3,787	(2,031)
Other	**48**	—	—
Balance at end of year	**(272)**	2,672	(973)
Reciprocal shareholding *(Note 13)*			
Balance at beginning of year	**(88)**	(102)	(102)
Change in reciprocal interest	**37**	14	—
Balance at end of year	**(51)**	(88)	(102)
Total Enbridge Inc. shareholders' equity	**66,043**	69,470	58,135
Noncontrolling interests *(Note 20)*			
Balance at beginning of year	**3,965**	7,597	577
Earnings attributable to noncontrolling interests	**122**	334	232
Other comprehensive income/(loss) attributable to noncontrolling interests, net of tax			
Change in unrealized gain/(loss) on cash flow hedges	**(7)**	31	15
Foreign currency translation adjustments	**(108)**	294	(431)
Reclassification to earnings of loss on cash flow hedges	**—**	4	139
	(115)	329	(277)
Comprehensive income/(loss) attributable to noncontrolling interests	**7**	663	(45)
Noncontrolling interests resulting from Merger Transaction *(Note 8)*	**—**	—	8,955
Enbridge Energy Company, Inc. common control transaction	**—**	—	(343)
Distributions	**(254)**	(857)	(839)
Contributions	**12**	24	832
Deconsolidation of Sabal Trail Transmission, LLC	**—**	—	(2,318)
Spectra Energy Partners, LP restructuring *(Note 20)*	**—**	(1,486)	—
Sale of noncontrolling interests in subsidiaries	**—**	1,183	—
Change in noncontrolling interests on Sponsored Vehicles buy-in (*Note 20*)	**—**	(2,867)	—
Preferred shares redemption *(Note 20)*	**(300)**	(210)	—
Repurchase of noncontrolling interest	**(65)**	—	—
Dilution gain and other	**(1)**	(82)	778
Balance at end of year	**3,364**	3,965	7,597
Total equity	**69,407**	73,435	65,732
Dividends paid per common share	**2.95**	2.68	2.41

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

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	**2019**	2018	2017
(millions of Canadian dollars)			
Operating activities			
Earnings	**5,827**	3,333	3,266
Adjustments to reconcile earnings to net cash provided by operating activities:			
Depreciation and amortization	**3,391**	3,246	3,163
Deferred income tax (recovery)/expense *(Note 25)*	**1,156**	(148)	(2,877)
Changes in unrealized (gain)/loss on derivative instruments, net *(Note 24)*	**(1,751)**	903	(1,242)
Earnings from equity investments	**(1,503)**	(1,509)	(1,102)
Distributions from equity investments	**1,804**	1,539	1,264
Impairment of long-lived assets	**423**	1,104	4,463
Impairment of goodwill	**—**	1,019	102
(Gain)/loss on dispositions	**254**	8	(120)
Other	**56**	92	79
Changes in operating assets and liabilities *(Note 28)*	**(259)**	915	(338)
Net cash provided by operating activities	**9,398**	10,502	6,658
Investing activities			
Capital expenditures	**(5,492)**	(6,806)	(8,287)
Long-term investments and restricted long-term investments	**(1,159)**	(1,312)	(3,586)
Distributions from equity investments in excess of cumulative earnings	**417**	1,277	125
Additions to intangible assets	**(200)**	(540)	(789)
Cash acquired in Merger Transaction *(Note 8)*	**—**	—	682
Proceeds from dispositions	**2,110**	4,452	628
Other	**(20)**	(12)	212
Affiliate loans, net	**(314)**	(76)	(22)
Net cash used in investing activities	**(4,658)**	(3,017)	(11,037)
Financing activities			
Net change in short-term borrowings *(Note 18)*	**(127)**	(420)	721
Net change in commercial paper and credit facility draws	**825**	(2,256)	(1,249)
Debenture and term note issues, net of issue costs	**6,176**	3,537	9,483
Debenture and term note repayments	**(4,668)**	(4,445)	(5,054)
Sale of noncontrolling interest in subsidiary	**—**	1,289	—
Purchase of interest in consolidated subsidiary	**—**	—	(227)
Contributions from noncontrolling interests	**12**	24	832
Distributions to noncontrolling interests	**(254)**	(857)	(919)
Contributions from redeemable noncontrolling interests	**—**	70	1,178
Distributions to redeemable noncontrolling interests	**—**	(325)	(247)
Sponsored Vehicle buy-in cash payment	**—**	(64)	—
Preference shares issued	**—**	—	489
Redemption of preferred shares	**(300)**	(210)	—
Common shares issued	**18**	21	1,549
Preference share dividends	**(383)**	(364)	(330)
Common share dividends	**(5,973)**	(3,480)	(2,750)
Other	**(71)**	(23)	—
Net cash (used in)/provided by financing activities	**(4,745)**	(7,503)	3,476
Effect of translation of foreign denominated cash and cash equivalents and restricted cash	**44**	68	(72)
Net increase/(decrease) in cash and cash equivalents and restricted cash	**39**	50	(975)
Cash and cash equivalents and restricted cash at beginning of year	**637**	587	1,562
Cash and cash equivalents and restricted cash at end of year	**676**	637	587
Supplementary cash flow information			
Cash paid for income taxes	**571**	277	172
Cash paid for interest, net of amount capitalized	**2,738**	2,508	2,668
Property, plant and equipment non-cash accruals	**730**	847	889

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

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	**2019**	2018
(millions of Canadian dollars; number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents *(Note 2)*	**648**	518
Restricted cash	**28**	119
Accounts receivable and other *(Note 9)*	**6,781**	6,517
Accounts receivable from affiliates	**69**	79
Inventory *(Note 10)*	**1,299**	1,339
	8,825	8,572
Property, plant and equipment, net *(Note 11)*	**93,723**	94,540
Long-term investments *(Note 13)*	**16,528**	16,707
Restricted long-term investments *(Note 14)*	**434**	323
Deferred amounts and other assets	**7,433**	8,558
Intangible assets, net *(Note 15)*	**2,173**	2,372
Goodwill *(Note 16)*	**33,153**	34,459
Deferred income taxes *(Note 25)*	**1,000**	1,374
Total assets	**163,269**	166,905
Liabilities and equity		
Current liabilities		
Short-term borrowings *(Note 18)*	**898**	1,024
Accounts payable and other *(Note 17)*	**10,063**	9,863
Accounts payable to affiliates	**21**	40
Interest payable	**624**	669
Current portion of long-term debt *(Note 18)*	**4,404**	3,259
	16,010	14,855
Long-term debt *(Note 18)*	**59,661**	60,327
Other long-term liabilities	**8,324**	8,834
Deferred income taxes *(Note 25)*	**9,867**	9,454
	93,862	93,470
Commitments and contingencies *(Note 30)*		
Equity		
Share capital *(Note 21)*		
Preference shares	**7,747**	7,747
Common shares *(2,025 and 2,022 outstanding at December 31, 2019 and December 31, 2018, respectively)*	**64,746**	64,677
Additional paid-in capital	**187**	—
Deficit	**(6,314)**	(5,538)
Accumulated other comprehensive income/(loss) *(Note 23)*	**(272)**	2,672
Reciprocal shareholding	**(51)**	(88)
Total Enbridge Inc. shareholders' equity	**66,043**	69,470
Noncontrolling interests *(Note 20)*	**3,364**	3,965
	69,407	73,435
Total liabilities and equity	**163,269**	166,905

Variable Interest Entities (VIEs) (*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 and Storage; Renewable Power Generation; 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 pipelines and related terminals in Canada and the United States that transport various grades of crude oil and other liquid hydrocarbons, including the Mainline 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, including US Gas Transmission, Canadian Gas Transmission, US Midstream and Other.

GAS DISTRIBUTION AND STORAGE

Gas Distribution and Storage consists of our natural gas utility operations, the core of which is Enbridge Gas, which serves residential, commercial and industrial customers, located throughout Ontario. Gas Distribution and Storage also includes natural gas distribution activities in Quebec and an investment in Noverco, which holds a majority interest in a subsidiary entity engaged in distribution and energy transportation primarily in Quebec.

RENEWABLE POWER GENERATION

Renewable Power Generation consists primarily of investments in wind and solar power generating assets, as well as geothermal, waste heat recovery, and transmission assets. In North America, assets are primarily located in the provinces of Alberta, Saskatchewan, Ontario, and Quebec and in the states of Colorado, Texas, Indiana and West Virginia. We also have offshore wind assets in operation and under development located in United Kingdom, Germany, and France.

ENERGY SERVICES

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

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. Eliminations and Other also includes new business development activities and corporate investments.

SPONSORED VEHICLES BUY-IN
In the fourth quarter of 2018, Enbridge completed the buy-ins of our sponsored vehicles: SEP, EEP, Enbridge Energy Management, L.L.C. (EEM) and 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 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, 2019 and 2018, 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 U.S. Generally accepted accounting principles in the United States of America (U.S. GAAP) . Amounts are stated in Canadian dollars unless otherwise noted. As a 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 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 30)*; and estimates of losses related to environmental remediation obligations *(Note 30)*. Actual results could differ from these estimates.

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include our accounts and accounts of our subsidiaries and 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.

REGULATION

Certain parts of our businesses are subject to regulation by various authorities including, but not limited to, the CER, the FERC, the Alberta Energy Regulator, the 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 CER's 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. The corresponding impact on earnings is included in Interest expense for the interest component and Other income for the equity component. In the absence of rate regulation, we would capitalize interest using a capitalization rate based on our cost of borrowing, whereas the capitalized equity component, the corresponding earnings during the construction phase and the subsequent depreciation relating to the equity component 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)*.

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, 2019, 2018 and 2017, cash received net of revenue recognized for contracts under make-up rights and similar deferred revenue arrangements was $169 million, $208 million, and $196 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 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 change in the fair value of a cash flow hedging instrument is recorded in OCI and is reclassified to earnings when the hedged item impacts 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 in earnings concurrently with the related transaction. If an anticipated hedged 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 may 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 risk of the 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 risk of the asset or liability 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), a component of OCI. 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 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. 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 the investment during such period.

RESTRICTED LONG-TERM INVESTMENTS
Long-term investments that are restricted as to withdrawal or usage, for the purposes of the CER'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.

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 the 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 Enbridge Gas, and crude oil and natural gas held primarily by energy services businesses in the Energy Services segment. Natural gas in storage in Enbridge 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; derivative financial instruments; and actuarial gains and losses arising from defined benefit pension plans.

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 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 have the option to first assess qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment test. When performing a qualitative assessment, we determine the drivers of fair value for each reporting unit and evaluate whether those drivers have been positively or negatively affected by relevant events and circumstances since the last fair value assessment. Our evaluation includes, but is not limited to, assessment of macroeconomic trends, regulatory environments, capital accessibility, operating income trends, and industry conditions. Based on our assessment of the qualitative factors, if we determine it is more likely than not that the fair value of the reporting unit is less than it's carrying amount, a quantitative goodwill impairment test is performed.

The quantitative goodwill impairment test involves determining the fair value of our reporting units and comparing those values to the carrying value of each reporting unit. If the carrying value of a reporting unit, including allocated goodwill, exceeds its fair value, goodwill impairment is measured at the amount by which the reporting unit’s carrying value exceeds its fair value. This amount should not exceed the carrying amount of goodwill. Fair value of our reporting units is estimated using a combination of discounted cash flow model and earnings multiples techniques. The determination of fair value using the discounted cash flow model technique requires the use of estimates and assumptions related to discount rates, projected operating income, terminal value growth rates, capital expenditures and working capital levels. The cash flow projections included significant judgments and assumptions relating to revenue growth rates and expected future capital expenditure. The determination of fair value using the earnings multiples technique requires assumptions to be made in relation to maintainable earnings and earnings multipliers for reporting units.

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.

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

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

ASSET RETIREMENT OBLIGATIONS

ARO associated with the retirement of long-lived assets are measured at fair value and recognized as Accounts payable and other or Other long-term liabilities in the period in which they can be reasonably determined. The fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. 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.

PENSION AND OTHER POSTRETIREMENT BENEFITS

We sponsor defined benefit and defined contribution pension plans, and defined benefit OPEB plans, which provide group health care, life insurance benefits and other postretirement benefits.

Defined benefit pension obligation and net periodic benefit cost are estimated using the projected unit credit 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. The OPEB benefit obligation and net periodic benefit cost are estimated using the projected unit credit method, where benefits are attributed to years of service, taking into consideration projection of benefit costs.

We use mortality tables issued by the Society of Actuaries in the United States (revised in 2019) and the Canadian Institute of Actuaries (revised in 2014) to measure the 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.

Funded pension and OPEB plan assets are measured at fair value. The expected return on funded pension and OPEB plan assets is determined using market related values and assumptions on the invested asset mix consistent with the investment policies relating to the plan assets. The market related values reflect estimated return on investments consistent with long-term historical averages for similar assets.

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

The excess of the fair value of a plan's assets over the fair value of a plan's benefit obligation is recognized as Deferred amounts and other assets in our Consolidated Statements of Financial Position. The excess of the fair value of a plan's benefit obligation over the fair value of a plan's assets is recognized as Accounts payable and other and Other long-term liabilities in our Consolidated Statements of Financial Position.

Net periodic benefit cost is charged to Earnings and includes:

- Cost of benefits provided in exchange for employee services rendered during the year (current service cost);
- Interest cost of plan obligations;
- Expected return on plan assets (funded pension and OPEB plans);
- Amortization of prior service costs 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.

Cumulative unrecognized net actuarial gains and losses and prior service costs arising from defined benefit pension plans for our non-utility operations and from defined benefit OPEB plans are presented as a component of AOCI in our Consolidated Statements of Changes in Equity. Any unrecognized actuarial gains and losses and prior service costs and credits related to those plans that arise during the period are recognized as a component of OCI, net of tax. Cumulative unrecognized net actuarial gains and losses and prior service costs arising from defined benefit pension plans for our utility operations, which have been permitted or are expected to be permitted by the Regulators, to be recovered through future rates, are presented as a component of Deferred amounts and other assets in our Consolidated Statements of Financial Position.

Our utility operations also record regulatory adjustments to reflect the difference between certain net periodic benefit costs for accounting purposes and net periodic benefit costs for ratemaking purposes. Offsetting regulatory assets or liabilities are recorded to the extent net periodic benefit costs are expected to be collected from or refunded to customers, respectively, in future rates. In the absence of rate regulation, regulatory assets or liabilities would not be recorded and net periodic benefit costs would be charged to Earnings and OCI on an accrual basis.

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

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.

Performance Stock Units (PSU) and Restricted Stock Units (RSU) are cash settled awards for which the related liability is remeasured each reporting period. PSUs vest at the completion of a three-year term and 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. The value of the PSUs are also dependent on our performance relative to performance targets set out under the plan.

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 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, 2019.

ADOPTION OF NEW ACCOUNTING STANDARDS
Cloud Computing Arrangements
Effective January 1, 2019, we adopted Accounting Standards Update (ASU) 2018-15 on a prospective basis. The new standard was issued to provide guidance on the accounting for implementation costs incurred in a cloud computing arrangement that is a service contract. This ASU 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. The amendments in the update also require that the 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, in addition to specifying that the capitalized costs must be presented on the same balance sheet line as the prepayment of fees related to the hosting arrangement. This ASU requires similar consistency in classifications from a cash flow statement perspective. The adoption of this ASU did not have a material impact on our consolidated financial statements.

Improvements to Accounting for Hedging Activities
Effective January 1, 2019, we adopted ASU 2017-12 on a modified retrospective basis. The new standard was issued 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. As a result of the new standard, hedge ineffectiveness will no longer be measured or recorded, and hedging instruments' fair value changes will be recorded in the same income statement line as the hedged item. The adoption of this accounting update did not have a material impact on our consolidated financial statements.

Amending the Amortization Period for Certain Callable Debt Securities Purchased at a Premium
Effective January 1, 2019, we adopted ASU 2017-08 on a modified retrospective basis. The new standard was issued with the intent of shortening the amortization period to the earliest call date for certain callable debt securities held at a premium. The adoption of this accounting update did not have a material impact on our consolidated financial statements.

Recognition of Leases
Effective January 1, 2019 we adopted ASU 2016-02 Leases (Topic 842) using the modified retrospective approach.

We recognize an arrangement as a lease when a customer has the right to obtain substantially all of the economic benefits from the use of an asset, as well as the right to direct the use of the asset. We recognize right-of-use (ROU) assets and the related lease liabilities on the statement of financial position for operating lease arrangements with a term of 12 months or longer. We do not separate non-lease components from the associated lease components of our lessee contracts and account for both components as a single lease component. We combine lease and non-lease components within a contract for operating lessor leases when certain conditions are met. ROU assets are assessed for impairment using the same approach as is applied for other long-lived assets, as described under the Impairment section of the Significant Accounting Policies Note 2 in the annual consolidated financial statements.

Lease liabilities and ROU assets require the use of judgment and estimates, which are applied in determining the term of a lease, appropriate discount rates, whether an arrangement contains a lease, whether there are any indicators of impairment for ROU assets and whether any ROU assets should be grouped with other long-lived assets for impairment testing.

In adopting Topic 842, we elected the package of practical expedients permitted under the transition guidance. The election to apply the package of practical expedients allows an entity to not apply the new lease standard to the prior year comparative periods in the year of adoption. The application of the package of practical expedients also permits entities not to reassess whether any expired or existing contracts contain leases in accordance with the new guidance, lease classifications, and whether initial direct costs capitalized under current guidance continue to meet the definition of initial direct costs under the new guidance. We also elected the practical expedient related to land easements, allowing us to carry forward our accounting treatment for land easements on existing agreements that had commenced prior to January 1, 2019.

On January 1, 2019, ROU assets and corresponding lease liabilities of $771 million were recorded in connection with the adoption of Topic 842. When added to the $85 million of pre-existing liabilities relating to operating leases for which we no longer utilize the leased assets, total lease liabilities at January 1, 2019 were $856 million. All lease liabilities were measured using a weighted average discount rate of 4.32%. The adoption of this standard had no impact to the Consolidated Statements of Earnings, Comprehensive Income, Changes in Equity or Cash Flows during the period.

Improvements to Related Party Guidance for Variable Interest Entities
Effective September 30, 2019, we adopted ASU 2018-17 on a retrospective basis. The new standard was issued with the objective 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 decision maker fees constitute a variable interest. The adoption of this ASU did not have a material impact on our consolidated financial statements.

FUTURE ACCOUNTING POLICY CHANGES

Accounting for Income Taxes

ASU 2019-12 was issued in December 2019 with the intent of simplifying the accounting for income taxes. The accounting update removes certain exceptions to the general principles in ASC 740 as well as provides simplification by clarifying and amending existing guidance. ASU 2019-12 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.

Clarifying Interaction between Collaborative Arrangements and Revenue from Contracts with Customers

ASU 2018-18 was issued in November 2018 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. The adoption of ASU 2018-18 is not expected 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. The adoption of ASU 2018-14 is not expected to have a material impact 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. The adoption of ASU 2018-13 is not expected 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 delay 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 Instruments - Credit Losses. Both accounting updates are effective January 1, 2020.

We have performed a detailed evaluation as of December 31, 2019 and do not anticipate the adoption of ASU 2016-13 to have a material impact on our consolidated financial statements.

4. REVENUE

REVENUE FROM CONTRACTS WITH CUSTOMERS
Major Products and Services

Year ended December 31, 2019	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Transportation revenue	**9,082**	**4,477**	**743**	**—**	**—**	**—**	**14,302**
Storage and other revenue	**109**	**268**	**201**	**—**	**—**	**—**	**578**
Gas gathering and processing revenue	**—**	**423**	**—**	**—**	**—**	**—**	**423**
Gas distribution revenue	**—**	**—**	**4,210**	**—**	**—**	**—**	**4,210**
Electricity and transmission revenue	**—**	**—**	**—**	**180**	**—**	**—**	**180**
Commodity sales	**—**	**4**	**—**	**—**	**—**	**—**	**4**
Total revenue from contracts with customers	**9,191**	**5,172**	**5,154**	**180**	**—**	**—**	**19,697**
Commodity sales	**—**	**—**	**—**	**—**	**29,305**	**—**	**29,305**
Other revenue[1,2]	**659**	**30**	**9**	**387**	**(2)**	**(16)**	**1,067**
Intersegment revenue	**369**	**5**	**16**	**—**	**71**	**(461)**	**—**
Total revenue	**10,219**	**5,207**	**5,179**	**567**	**29,374**	**(477)**	**50,069**

Year ended December 31, 2018	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	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	—	—	—	206	—	—	206
Commodity sales	—	1,590	—	—	—	—	1,590
Total revenue from contracts with customers	8,589	6,555	5,447	206	—	—	20,797
Commodity sales	—	—	—	—	26,070	—	26,070
Other revenue[1,2]	(894)	6	9	361	4	25	(489)
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.
2 Includes revenues from lease contracts. Refer to Note 27 Leases.

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

	Contract Receivables	Contract Assets	Contract Liabilities
(millions of Canadian dollars)			
Balance as at December 31, 2018	1,929	191	1,297
Balance as at December 31, 2019	**2,099**	**216**	**1,424**

Contract receivables represent the amount of receivables derived from contracts with customers.

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, 2019 included in contract liabilities at the beginning of the period is $185 million. Increases in contract liabilities from cash received, net of amounts recognized as revenue during the year ended December 31, 2019 were $358 million. 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
Gas Transmission and Midstream	• Transportation, storage, gathering, compression and treating of natural gas • Transportation of NGLs • Sale of crude oil, natural gas and NGLs
Gas Distribution and Storage	• Supply and delivery of natural gas • Transportation of natural gas • Storage of natural gas
Renewable Power Generation	• 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, 2019 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 and Storage 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 $65.8 billion, of which $7.1 billion is expected to be recognized during the year ended December 31, 2020.

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 of 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, 2019	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Energy Services	Consolidated
(millions of Canadian dollars)						
Revenue from products transferred at a point in time	**—**	**4**	**65**	**—**	**—**	**69**
Revenue from products and services transferred over time[1]	**9,191**	**5,168**	**5,089**	**180**	**—**	**19,628**
Total revenue from contracts with customers	**9,191**	**5,172**	**5,154**	**180**	**—**	**19,697**

1 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.

Year ended December 31, 2018	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	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	206	—	19,139
Total revenue from contracts with customers	8,589	6,555	5,447	206	—	20,797

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

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 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, 2019, 2018 and 2017 is as follows:

Year ended December 31, 2019	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues	**10,219**	**5,207**	**5,179**	**567**	**29,374**	**(477)**	**50,069**
Commodity and gas distribution costs	**(29)**	**—**	**(2,354)**	**(2)**	**(29,091)**	**472**	**(31,004)**
Operating and administrative	**(3,298)**	**(2,232)**	**(1,149)**	**(189)**	**(44)**	**(79)**	**(6,991)**
Impairment of long-lived assets	**(21)**	**(105)**	**—**	**(297)**	**—**	**—**	**(423)**
Income/(loss) from equity investments	**780**	**682**	**4**	**31**	**8**	**(2)**	**1,503**
Other income/(expense)	**30**	**(181)**	**67**	**1**	**3**	**515**	**435**
Earnings before interest, income tax expense, and depreciation and amortization	**7,681**	**3,371**	**1,747**	**111**	**250**	**429**	**13,589**
Depreciation and amortization							**(3,391)**
Interest expense							**(2,663)**
Income tax expense							**(1,708)**
Earnings							**5,827**
Capital expenditures[1]	**2,548**	**1,753**	**1,100**	**23**	**2**	**124**	**5,550**
Total property, plant and equipment, net	**48,783**	**25,268**	**15,622**	**3,658**	**24**	**368**	**93,723**

Year ended December 31, 2018	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	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 property, plant and equipment, net	49,214	25,601	15,148	4,335	22	220	94,540

Year ended December 31, 2017	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues	8,913	7,067	4,992	534	23,282	(410)	44,378
Commodity and gas distribution costs	(18)	(2,834)	(2,689)	—	(23,508)	412	(28,637)
Operating and administrative	(2,949)	(1,756)	(960)	(163)	(47)	(567)	(6,442)
Impairment of long-lived assets	—	(4,463)	—	—	—	—	(4,463)
Impairment of goodwill	—	(102)	—	—	—	—	(102)
Income/(loss) from equity investments	416	653	23	6	8	(4)	1,102
Other income/(expense)	33	166	24	(5)	2	232	452
Earnings/(loss) before interest, income tax expense, and depreciation and amortization	6,395	(1,269)	1,390	372	(263)	(337)	6,288
Depreciation and amortization							(3,163)
Interest expense							(2,556)
Income tax recovery							2,697
Earnings							3,266
Capital expenditures[1]	2,799	4,016	1,177	321	1	108	8,422

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 years ended December 31, 2019 and 2018, respectively. Our largest non-affiliated customer accounted for approximately 11.8% of our third-party revenues for the year ended December 31, 2017. Revenue from this one customer is primarily reported in the Energy Services segment.

GEOGRAPHIC INFORMATION
Revenues[1]

Year ended December 31,	**2019**	2018	2017
(millions of Canadian dollars)			
Canada	**19,954**	19,023	18,076
United States	**30,115**	27,355	26,302
	50,069	46,378	44,378

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

Property, Plant and Equipment[1]

December 31,	**2019**	2018
(millions of Canadian dollars)		
Canada	**45,993**	44,716
United States	**47,730**	49,824
	93,723	94,540

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 approximately 6 million as at December 31, 2019, 12 million as at December 31, 2018, and 13 million as at December 31, 2017, 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,	**2019**	2018	2017
(number of shares in millions)			
Weighted average shares outstanding	**2,017**	1,724	1,525
Effect of dilutive options	**3**	3	7
Diluted weighted average shares outstanding	**2,020**	1,727	1,532

For the years ended December 31, 2019, 2018 and 2017, 17.8 million, 26.8 million and 14.3 million, respectively, of anti-dilutive stock options with a weighted average exercise price of $53.56, $50.38 and $56.71, 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 regulated ratemaking processes 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 various regulators, including the CER, OEB and FERC. We also collect and set aside funds to cover future pipeline abandonment costs for all CER regulated pipelines as a result of the CER's regulatory requirements under LMCI *(Note 14)* and to cover future removal and site restoration reserves as approved by the OEB and other agencies. Amounts expected to be paid for these future costs are recognized as long-term regulatory liabilities. Our significant regulated businesses and the 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 CER. Tolls (excluding Lines 8 and 9) are currently governed by the 10-year CTS, which establishes a CLT for all volumes shipped on the Canadian Mainline and an IJT for all volumes shipped from western Canadian receipt points to delivery points on Enbridge’s Lakehead System, as well as delivery points on the Canadian Mainline downstream of the Lakehead System. The CTS was negotiated with shippers in accordance with CER guidelines, was approved by the CER in June 2011, and took effect July 1, 2011. Under the CTS, a regulatory asset is recognized to offset deferred income taxes as a CER 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 CER. 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 and provide for the recovery of allowable operating and debt financing costs, plus a pre-determined after-tax rate of return on equity of 10%.

Gas Transmission and Midstream

BC Pipeline and BC Field Services
Until December 31, 2019, our Gas Transmission and Midstream business in British Columbia was comprised of BC Pipeline and BC Field Services. BC Pipeline and BC Field Services provide fee-for-service based natural gas transmission and raw gas gathering and processing services, respectively.

BC Pipeline is regulated by the CER under full cost-of-service regulation. Under the current CER-authorized rate structure for our 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 existing temporary differences are related to property, plant and equipment costs, this recovery is expected to occur over the life of the BC Pipeline assets.

On December 31, 2019, we closed the sale of our BC Field Services business to Brookfield Infrastructure Partners L.P. and its institutional partners (Brookfield) *(Note 8)*. The BC Field Services business was regulated by the CER under the Framework for Light-Handed Regulation. Regulatory assets of $349 million, related to the regulatory offset to deferred income tax liabilities associated with the BC Field Services business, were derecognized as a result of this sale.

Spectra Energy Partners, LP
Most of SEP's gas transmission and storage services are regulated by the FERC and may also be subject to the jurisdiction of various other federal, state and local agencies. Rates for the FERC jurisdictional services are governed by the applicable FERC-approved natural gas tariffs while rates for the intrastate and/or gathering services are governed by the appropriate state gas commissions.

Gas Distribution and Storage

Enbridge Gas Inc.
Enbridge Gas' distribution rates, beginning in 2019, are set under a five-year IR framework using a price cap mechanism. The price cap mechanism establishes new rates each year through an annual base rate escalation at inflation less a 0.3% productivity factor, annual updates for certain costs to be passed through to customers, and where applicable, the recovery of material discrete incremental capital investments beyond those that can be funded through base rates. The IR framework includes the continuation and establishment of certain deferral and variance accounts, as well as an earnings sharing mechanism that requires Enbridge Gas to share equally with customers, any earnings in excess of 150 basis points over the annual OEB approved return on equity.

FINANCIAL STATEMENT EFFECTS

Accounting for rate-regulated activities has resulted in the recognition of the following significant regulatory assets and liabilities on the Consolidated Statements of Financial Position:

December 31,	Recovery/Refund Period Ends	2019	2018
(millions of Canadian dollars)			
Regulatory assets/(liabilities), net			
Liquids Pipelines			
Deferred income taxes[1]	Various	**1,767**	1,673
Tolling deferrals	Various	**(25)**	(28)
Recoverable income taxes	Through 2040	**24**	27
Pipeline future abandonment costs[2]	Various	**(293)**	(201)
Other deferrals	Various	**32**	—
Gas Transmission and Midstream			
Deferred income taxes[1]	Various	**511**	826
Regulatory liability related to income taxes[3]	Various	**(866)**	(912)
Long-term debt[4]	Various	**108**	124
Pipeline future abandonment costs[2]	Various	**(159)**	(111)
Other	Various	**215**	205
Gas Distribution and Storage			
Deferred income taxes[1]	Various	**1,273**	1,132
Purchased gas variance	2020	**(19)**	197
Pension plans and OPEB	Various	**275**	118
Future removal and site restoration reserves[5]	Various	**(1,424)**	(1,107)
Federal carbon program	2020	**145**	—
Long-term debt[4]	Various	**362**	387
Constant dollar net salvage adjustment	2018	**—**	6
Other	Various	**88**	(4)

1 *The deferred income taxes balance represents the regulatory offset to deferred income tax liabilities to the extent that it is expected to be included in regulator-approved future rates and recovered from future customers. The recovery period depends on the timing of the reversal of the temporary differences. In the absence of rate-regulated accounting, this regulatory balance and the related earnings impact would not be recorded.*

2 *The pipeline future abandonment costs liability results from amounts collected and set aside in accordance with the CER's LMCI to cover future abandonment costs for CER regulated Canadian pipelines. Funds collected are included in Restricted long-term investments (Note 14).Concurrently, we reflect the future abandonment cost as a regulatory liability. The settlement of this balance will occur as pipeline abandonment costs are incurred.*

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

4 *The debt balance represents our regulatory offset to the fair value adjustment to debt that resulted from the merger with Spectra Energy. The offset is viewed as a proxy for the regulatory asset that would be recorded in the event such debt was extinguished at an amount higher than the carrying value.*

5 *Future removal and site restoration reserves result from amounts collected from customers by us, 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 we have 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-regulated 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.

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 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 Merger Transaction brought together two highly complementary platforms to create North America's largest energy infrastructure company and meaningfully enhanced customer optionality, positioning us for long-term growth opportunities, and strengthening our balance sheet.

The Merger Transaction was 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 were recorded at their estimated fair values at the date of acquisition.

The purchase price allocation was 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 previous Gas Transmission and Midstream segment, which was 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, 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, 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 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 year ended December 31, 2017 of $180 million were 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 year ended December 31, 2017, including the results of operations for Spectra Energy as if the Merger Transaction had been completed on January 1, 2017 are as follows:

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

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

ASSETS HELD FOR SALE

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. Subject to certain regulatory approvals and customary closing conditions, the transaction is expected to close in 2020.

A loss of $154 million was included within Impairment of long-lived assets on the Consolidated Statements of Earnings for the year ended December 31, 2018 in relation to measuring Line 10 assets at the lower of their carrying value or fair value less costs to sell.

Montana-Alberta Tie Line

In the fourth quarter of 2019, we committed to a plan to sell the Montana-Alberta Tie Line transmission assets, a 345 kilometer transmission line from Great Falls, Montana to Lethbridge, Alberta. Its related assets are included in our Renewable Power Generation segment. The purchase and sale agreement was signed in January 2020. Subject to certain regulatory approvals and customary closing conditions, the transaction is expected to close in the first quarter of 2020.

Upon the reclassification and subsequent remeasurement of MATL assets as held for sale, a loss of $297 million was included within Impairment of long-lived assets on the Consolidated Statements of Earnings.

Summary of Assets Held for Sale

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

	December 31, 2019	December 31, 2018[2]
(millions of Canadian dollars)		
Accounts receivable and other (current assets held for sale)	**28**	117
Deferred amounts and other assets (long-term assets held for sale)[1]	**269**	2,383
Accounts payable and other (current liabilities held for sale)	**—**	(63)
Other long-term liabilities (long-term liabilities held for sale)	**—**	(96)
Net assets held for sale	**297**	2,341

1 Included within Deferred amounts and other assets at December 31, 2019 and 2018 respectively is property, plant and equipment of $181 million and $2.1 billion.

2 Figures are inclusive of net assets held for sale at December 31, 2018 and subsequently disposed of during the year ended December 31, 2019.

DISPOSITIONS

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). St. Lawrence Gas assets were included in the Gas Distribution and Storage segment. On November 1, 2019 we closed the sale of St. Lawrence Gas for cash proceeds of approximately $72 million (US$55 million). After closing adjustments, a loss on disposal of $10 million was included in Other income/(expense) in the Consolidated Statements of Earnings.

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). EGNB assets were a part of our Gas Distribution and Storage segment. On October 1, 2019 we closed the sale of EGNB to Liberty Utilities (Canada) LP, a wholly-owned subsidiary of Algonquin Power and Utilities Corp. for cash proceeds of approximately $331 million. After closing adjustments, a loss on disposal of $3 million was included in Other income/(expense) in the Consolidated Statements of Earnings.

As EGNB 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, allocated goodwill of $133 million was included in assets subsequently disposed.

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).

As the Canadian Natural Gas Gathering and Processing Businesses assets represented a portion of a reporting unit, we allocated a portion of the goodwill of the reporting unit of 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 was greater than the sale price consideration less the cost to sell and 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.

On October 1, 2018, we closed the sale of the provincially regulated facilities 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 for the year ended December 31, 2018.

On December 31, 2019, we closed the sale of the federally regulated facilities for proceeds of approximately $1.7 billion. After closing adjustments, a loss on disposal of $268 million before tax was included in Other income/(expense) in the Consolidated Statements of Earnings for the year ended December 31, 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, allocated goodwill of $55 million was included in assets subsequently disposed.

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 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 year ended December 31, 2018 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 Renewable Power Generation 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 year ended December 31, 2018 for the sale of 49% interest in the Canadian and United States renewable assets, respectively.

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)*.

Midcoast Operating, L.P.
On August 1, 2018, we closed the sale of 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 the reclassification and subsequent re-measurement of MOLP assets as held for sale, an asset impairment loss of $4.4 billion and a related goodwill impairment of $102 million, were included in the Consolidated Statement of Earnings for the year ended December 31, 2017.

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 included within Impairment of long-lived assets on the Consolidated Statements of Earnings for the year ended December 31, 2018.

In the second quarter of 2018, our equity method investment in the Texas Express NGL pipeline system, 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.

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, 2019 and December 31, 2018 respectively, $299 million (US$230 million) and $375 million (US$274 million) were included in liabilities on the Consolidated Statements of Financial Position.

Sandpiper Project
During the years ended December 31, 2018 and 2017, we sold unused pipe related to the 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 for the year ended December 31, 2017. This interest was a part of our Liquids Pipelines segment.

Ozark Pipeline
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 for the year ended December 31, 2017. These assets were a part of our Liquids Pipelines segment.

9. ACCOUNTS RECEIVABLE AND OTHER

December 31,	**2019**	2018
(millions of Canadian dollars)		
Trade receivables and unbilled revenues[1]	**5,164**	4,711
Short-term portion of derivative assets	**327**	498
Other	**1,290**	1,308
	6,781	6,517

1 Net of allowance for doubtful accounts of $50 million and $64 million as at December 31, 2019 and 2018, respectively.

10. INVENTORY

December 31,	**2019**	2018
(millions of Canadian dollars)		
Natural gas	**696**	776
Crude oil	**542**	482
Other commodities	**61**	81
	1,299	1,339

Adjustments of $188 million, $327 million and $58 million were included in Commodity costs on the Consolidated Statements of Earnings for the years ended December 31, 2019, 2018 and 2017, respectively, to reduce inventory to market value.

11. PROPERTY, PLANT AND EQUIPMENT

December 31,	Weighted Average Depreciation Rate	**2019**	2018[1]
(millions of Canadian dollars)			
Pipelines	2.5%	**56,330**	51,647
Facilities and equipment	2.7%	**29,287**	27,149
Land and right-of-way[2]	2.0%	**2,947**	2,614
Gas mains, services and other	2.7%	**12,194**	12,088
Storage	2.3%	**2,748**	2,730
Wind turbines, solar panels and other	4.1%	**4,914**	5,015
Other	6.4%	**1,486**	1,463
Under construction	—%	**4,057**	9,698
Total property, plant and equipment[3]		**113,963**	112,404
Total accumulated depreciation		**(20,240)**	(17,864)
Property, plant and equipment, net		**93,723**	94,540

1 Asset categories were revised and collapsed in the current year. 2018 comparative figures have been reclassified to conform to current year's asset classifications.
2 The measurement of weighted average depreciation rate excludes non-depreciable assets.
3 Certain assets were reclassified as held for sale as at December 31, 2019 and December 31, 2018 (Note 8).

Depreciation expense for the years ended December 31, 2019, 2018 and 2017 was $3.0 billion, $2.9 billion and $2.9 billion, respectively.

IMPAIRMENT

Access Northeast Project

In 2019, we announced that we terminated the agreements with Eversource and National Grid related to the Access Northeast project. As a result, we recognized an impairment loss of $105 million for the year ended December 31, 2019, which is included in Impairment of long-lived assets in the Consolidated Statements of Earnings. Access Northeast is 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.

12. VARIABLE INTEREST ENTITIES

CONSOLIDATED VARIABLE INTEREST ENTITIES

Enbridge Canadian Renewable LP (ECRLP)

ECRLP, an entity which we have a 51% ownership in, is a VIE as its limited partners lack 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.

Renewable Power Generation

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 power to direct the activities that most significantly impact the economic performance of the wind facilities, and our obligation to absorb losses and the right to receive benefits that are significant.

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.

Enbridge Income Partners LP (EIPLP)

EIPLP, formed in 2002, was 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, an interest in the Alliance Pipeline, which transports natural gas, and its renewable and alternative power generation facilities. EIPLP was wound up in 2019 and thus is no longer a VIE.

Enbridge Income Fund (the Fund)

The Fund is an unincorporated open-ended trust established by a trust indenture under the laws of the Province of Alberta. In 2019, an amendment to the Fund's governing documents was executed which resulted in the Fund no longer being considered a VIE.

Enbridge Commercial Trust (ECT)

In 2019, an amendment to ECT's governing documents was executed which resulted in ECT no longer being considered a VIE.

Other Limited Partnerships
By virtue of limited partners' lack of substantive kick-out rights and participating rights, substantially all limited partnerships wholly-owned by us and/or our subsidiaries are considered VIEs, including EEP and SEP. 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,	**2019**[1]	2018
(millions of Canadian dollars)		
Assets		
Cash and cash equivalents	**208**	506
Restricted cash	**1**	61
Accounts receivable and other	**76**	2,006
Accounts receivable from affiliates	**—**	38
Inventory	**4**	244
	289	2,855
Property, plant and equipment, net	**3,392**	72,349
Long-term investments	**15**	6,481
Restricted long-term investments	**69**	244
Deferred amounts and other assets	**4**	3,156
Intangible assets, net	**124**	705
Goodwill	**—**	29
Deferred income taxes	**—**	131
	3,893	85,950
Liabilities		
Short-term borrowings	**—**	275
Accounts payable and other	**56**	2,925
Accounts payable to affiliates	**—**	4
Interest payable	**—**	303
Environmental liabilities	**—**	22
Current portion of long-term debt	**—**	1,034
	56	4,563
Long-term debt	**—**	29,577
Other long-term liabilities	**130**	5,074
Deferred income taxes	**5**	6,911
	191	46,125
Net assets before noncontrolling interests	**3,702**	39,825

1 Excludes assets and liabilities of EEP and SEP following the subsidiary guarantees agreement entered on January 22, 2019 (Note 32).

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 that 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, 2019 and 2018 are presented below:

December 31, 2019	Carrying Amount of Investment in VIE	Enbridge's Maximum Exposure to Loss
(millions of Canadian dollars)		
Aux Sable Liquid Products L.P.[1]	**267**	**331**
Eolien Maritime France SAS[2]	**67**	**725**
Enbridge Renewable Infrastructure Investments S.a.r.l.[3]	**141**	**2,720**
Gray Oak Holdings LLC[4]	**463**	**935**
PennEast Pipeline Company, LLC[5]	**106**	**368**
Rampion Offshore Wind Limited[6]	**600**	**620**
Vector Pipeline L.P.[7]	**195**	**392**
Other[8]	**57**	**57**
	1,896	**6,148**

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]	127	3,037
Illinois Extension Pipeline Company, L.L.C.[8]	724	724
NEXUS Gas Transmission, LLC[9]	1,757	2,668
PennEast Pipeline Company, LLC[5]	97	385
Rampion Offshore Wind Limited[6]	638	648
Vector Pipeline L.P.[7]	198	301
Other[8]	27	27
	3,947	8,949

1 *At December 31, 2019 and 2018, the maximum exposure to loss includes a guarantee issued by us for our respective share of the VIE's borrowing on a bank credit facility.*
2 *At December 31, 2019 and 2018, the maximum exposure to loss includes the portion of our parental guarantee that has been committed in project construction contracts for which we would be liable in the event of default by the VIE and an outstanding affiliate loan receivable for $166 million and $202 million held by us as at December 31, 2019 and 2018, respectively.*
3 *At December 31, 2019 and 2018, the maximum exposure to loss includes the portion of our parental guarantee that has been committed in project construction contracts for which we would be liable in the event of default by the VIE and an outstanding affiliate loan receivable for $766 million and $461 million held by us as at December 31, 2019 and 2018, respectively.*
4 *At December 31, 2019, the maximum exposure to loss includes our portion of project construction costs.*
5 *At December 31, 2019 and 2018, the maximum exposure to loss includes the remaining expected contributions to the joint venture.*
6 *At December 31, 2019 and 2018, the maximum exposure to loss includes the portion of our parental guarantee that has been committed in project construction contracts for which we would be liable in the event of default by the VIE.*
7 *At December 31, 2019 and 2018, the maximum exposure to loss includes the carrying value of an outstanding affiliate loan receivable for $92 million and $102 million held by us as at December 31, 2019 and 2018, respectively, in addition to us providing a credit facility for $105 million as at December 31, 2019.*
8 *At December 31, 2019 and 2018, the maximum exposure to loss is limited to our equity investment as these companies are in operation and self-sustaining.*
9 *As 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.*

We do not have an obligation to and did not provide any additional financial support to the VIEs during the years ended December 31, 2019 and 2018.

Gray Oak Holdings LLC
In December 2018, Enbridge acquired an effective 22.8% interest in the Gray Oak crude oil pipeline through acquisition of a 35% membership interest in Gray Oak Holdings LLC (Gray Oak Holdings), which operates the Gray Oak crude oil pipeline from Texas to the Gulf coast of the United States.

Gray Oak Holdings is a VIE as it does not have sufficient equity at risk to finance its activities and requires subordinated financial support from Enbridge and other partners. We have determined that we do not have the power to direct the activities of Gray Oak Holdings that most significantly impact its economic performance. Specifically, the power to direct the activities of the VIE is shared amongst the partners. Each partner has representatives that make up an executive committee that makes the significant decisions for the VIE and none of the partners may make significant decisions unilaterally. Therefore, the VIE is accounted for as an unconsolidated VIE.

NEXUS Gas Transmission, LLC
NEXUS is a joint venture that engages in transmission of natural gas received from Appalachian shale gas supplies to markets in the United States midwest, as well as Ontario, Canada was previously classified as a VIE.

The NEXUS pipeline construction was completed and the pipeline was placed into service in October 2018. After NEXUS received the last significant equity contribution, it became capable of financing its own operations without any additional subordinated financial support. As a result, it was concluded that NEXUS was no longer a VIE due to sufficient equity at risk to finance its activities.

Illinois Extension Pipeline Company, L.L.C.
Illinois Extension Pipeline Company, L.L.C. owns the Southern Access Extension Pipeline. It was previously classified as a VIE.

After Illinois Extension Pipeline Company, L.L.C. received the last significant equity contribution, it became capable of financing its own operations without any additional subordinated financial support. As a result, it was concluded that Illinois Extension Pipeline Company, L.L.C. was no longer a VIE due to sufficient equity at risk to finance its activities.

13. LONG-TERM INVESTMENTS

December 31,	Ownership Interest	**2019**	2018
(millions of Canadian dollars)			
EQUITY INVESTMENTS			
Liquids Pipelines			
MarEn Bakken Company L.L.C.[1]	75.0%	**1,892**	2,039
Gray Oak Holdings L.L.C.[2]	35.0%	**463**	—
Seaway Crude Pipeline System	50.0%	**2,907**	3,113
Illinois Extension Pipeline Company, L.L.C.[3]	65.0%	**662**	724
Other	30.0% - 43.8%	**73**	97
Gas Transmission and Midstream			
Alliance Pipeline	50.0%	**310**	368
Aux Sable	42.7% - 50.0%	**267**	311
DCP Midstream, LLC	50.0%	**2,193**	2,368
Gulfstream Natural Gas System, L.L.C.	50.0%	**1,213**	1,289
NEXUS Gas Transmission, LLC	50.0%	**1,778**	1,757
Offshore - various joint ventures	22.0% - 74.3%	**362**	400
PennEast Pipeline Company LLC	20.0%	**106**	97
Sabal Trail Transmission, LLC	50.0%	**1,533**	1,586
Southeast Supply Header L.L.C.	50.0%	**484**	519
Steckman Ridge LP	49.5%	**222**	237
Vector Pipeline L.P.	60.0%	**195**	198
Other	33.3% - 50.0%	**5**	6
Gas Distribution and Storage			
Noverco Common Shares	38.9%	**95**	—
Other	50.0%	**14**	15
Renewable Power Generation			
Eolien Maritime France SAS	50.0%	**67**	68
Enbridge Renewable Infrastructure Investments S.a.r.l.[4]	51.0%	**141**	127
Rampion Offshore Wind Project	24.9%	**600**	638
Other	21.0% - 50.0%	**127**	72
Eliminations and Other			
Other	42.7% - 50%	**16**	10
OTHER LONG-TERM INVESTMENTS			
Gas Distribution and Storage			
Noverco Preferred Shares		**580**	478
Renewable Power Generation			
Emerging Technologies and Other		**78**	80
Eliminations and Other			
Other		**145**	110
		16,528	16,707

1 Owns 49% interest in Bakken Pipeline Investments L.L.C., which owns 75% of the Bakken Pipeline System resulting in a 27.6% effective interest in the Bakken Pipeline System.
2 In December 2018 we acquired an effective 22.8% interest in the Gray Oak crude oil pipeline through acquisition of a 35% membership interest in Gray Oak Holdings, L.L.C. (Note 12).
3 Owns the Southern Access Extension Project.
4 In 2018 we sold a 49% interest in the Hohe See Offshore wind facilities to CPPIB, reducing our effective 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, 2019, this comprised of $2.1 billion in Goodwill and $681 million in amortizable assets. As at December 31, 2018, this comprised of $2.2 billion in Goodwill and $706 million in amortizable assets.

For the years ended December 31, 2019, 2018 and 2017, distributions received from equity investments were $2.2 billion, $2.8 billion and $1.4 billion, respectively.

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

	Year Ended December 31,								
	2019			2018			2017		
	Seaway	**Other**	**Total**	Seaway	Other	Total	Seaway	Other	Total
(millions of Canadian dollars)									
Operating revenues	**1,252**	**14,435**	**15,687**	966	18,251	19,217	959	15,254	16,213
Operating expenses	**428**	**12,725**	**13,153**	212	15,422	15,634	286	12,911	13,197
Earnings	**818**	**2,198**	**3,016**	646	2,308	2,954	672	2,056	2,728
Earnings attributable to Enbridge	**409**	**950**	**1,359**	323	1,059	1,382	336	926	1,262

	December 31, 2019			December 31, 2018		
	Seaway	**Other**	**Total**	Seaway	Other	Total
(millions of Canadian dollars)						
Current assets	**107**	**2,374**	**2,481**	113	3,176	3,289
Non-current assets	**3,404**	**45,538**	**48,942**	3,585	45,531	49,116
Current liabilities	**136**	**3,911**	**4,047**	123	5,413	5,536
Non-current liabilities	**45**	**18,081**	**18,126**	16	15,859	15,875
Noncontrolling interests	**—**	**2,779**	**2,779**	—	3,479	3,479

Noverco Inc.

As at December 31, 2019 and 2018, 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, 2019 and 2018, Noverco owned an approximate 0.5% and 1.4% reciprocal shareholding in our common shares, respectively. Noverco sold 11.6 million common shares in January 2019 and 4.4 million common shares in December 2018. 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, 2019 and 2018, we had an indirect pro-rata interest of 0.2% and 0.5%, respectively, in our own shares. Both the equity investment in Noverco and shareholders' equity have been reduced by the reciprocal shareholding of $51 million and $88 million as at December 31, 2019 and 2018. 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 CER regulated pipelines as a result of the CER's regulatory requirements under LMCI. The funds collected are held in trusts in accordance with the CER 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, 2019 and 2018, we had restricted long-term investments held in trust and classified as available for sale or held to maturity of $434 million and $323 million, respectively. Within Other long-term liabilities we had estimated future abandonment costs related to LMCI of $454 million and $328 million as at December 31, 2019 and 2018, 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, 2019[1]	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Customer relationships	5.4%	**861**	**(231)**	**630**
Power purchase agreements	4.5%	**64**	**(16)**	**48**
Project agreement[2]	4.0%	**156**	**(16)**	**140**
Software	11.2%	**1,988**	**(1,014)**	**974**
Other intangible assets[3]	2.9%	**463**	**(82)**	**381**
		3,532	**(1,359)**	**2,173**

December 31, 2018[1]	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Customer relationships	5.7%	889	(187)	702
Power purchase agreements	5.4%	82	(15)	67
Project agreement[2]	4.0%	164	(10)	154
Software	10.0%	1,902	(875)	1,027
Other intangible assets[3]	2.0%	485	(63)	422
		3,522	(1,150)	2,372

1 Certain assets were reclassified as held for sale as at December 31, 2019 and December 31, 2018 (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, 2019, 2018 and 2017, our amortization expense related to intangible assets totaled $296 million, $281 million and $280 million, respectively. The following table presents our expected amortization expense associated with existing intangible assets for the years indicated as follows:

	2020	2021	2022	2023	2024
Forecast of amortization expense *(millions of Canadian dollars)*	292	263	238	216	195

16. GOODWILL

	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Gross Cost							
Balance at January 1, 2018	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
Foreign exchange and other	**(373)**	**(933)**	**—**	**—**	**—**	**—**	**(1,306)**
Balance at December 31, 2019	**7,951**	**21,405**	**5,363**	**—**	**2**	**13**	**34,734**
Accumulated Impairment							
Balance at January 1, 2018	—	(542)	(7)	—	—	(13)	(562)
Impairment	—	(1,019)	—	—	—	—	(1,019)
Balance at December 31, 2018	—	(1,561)	(7)	—	—	(13)	(1,581)
Balance at December 31, 2019	**—**	**(1,561)**	**(7)**	**—**	**—**	**(13)**	**(1,581)**
Carrying Value							
Balance at December 31, 2018	8,324	20,777	5,356	—	2	—	34,459
Balance at December 31, 2019	**7,951**	**19,844**	**5,356**	**—**	**2**	**—**	**33,153**

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 of 2018. The provincially regulated assets were subsequently sold in the fourth quarter of 2018 (*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 values of these assets were estimated using the discounted cash flow method, which was negatively impacted by a 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*).

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

17. ACCOUNTS PAYABLE AND OTHER

December 31,	**2019**	2018
(millions of Canadian dollars)		
Trade payables and operating accrued liabilities	**4,536**	4,604
Construction payables and contractor holdbacks	**804**	804
Current derivative liabilities	**920**	1,234
Dividends payable	**1,678**	1,539
Taxes payable	**890**	801
Current deferred credits	**652**	850
Other	**583**	31
	10,063	9,863

18. DEBT

On January 22, 2019, Enbridge entered into supplemental indentures with its wholly-owned subsidiaries, SEP and EEP (together, the Partnerships), pursuant to which Enbridge fully and unconditionally guaranteed, on a senior unsecured basis, the payment obligations of the Partnerships with respect to the outstanding series of notes issued under the respective indentures of the Partnerships. Concurrently, the Partnerships entered into a subsidiary guarantee agreement pursuant to which they fully and unconditionally guaranteed, on a senior unsecured basis, the outstanding series of senior notes of Enbridge. See *Note 32 - Condensed Consolidating Financial Information* for further discussion.

December 31,	Weighted Average Interest Rate[22]	Maturity	**2019**	2018
(millions of Canadian dollars)				
Enbridge Inc.				
United States dollar senior notes[1]	3.8%	2022-2049	**8,689**	6,419
Medium-term notes	4.2%	2020-2064	**7,623**	7,323
Fixed-to-floating rate subordinated term notes[2,3]	5.9%	2077-2078	**6,550**	6,771
Floating rate notes[4]		2020	**1,556**	2,389
Commercial paper and credit facility draws[5]	1.9%	2021-2024	**5,210**	1,999
Other[6]			**5**	4
Enbridge (U.S.) Inc.				
Commercial paper and credit facility draws[7]	2.1%	2021-2024	**1,734**	1,065
Enbridge Energy Partners, L.P.				
Senior notes[8]	6.0%	2021-2045	**3,955**	6,214
Junior subordinated notes[9]			**—**	546
Commercial paper and credit facility draws[10]			**—**	1,044
Enbridge Gas Distribution Inc.[11]				
Medium-term notes			**—**	3,695
Debentures			**—**	85
Commercial paper and credit facility draws			**—**	750
Enbridge Gas Inc.[11]				
Medium-term notes	4.2%	2020-2050	**7,685**	—
Debentures	9.1%	2024-2025	**210**	—
Commercial paper and credit facility draws	2.0%	2021	**898**	—
Enbridge Pipelines (Southern Lights) L.L.C.				
Senior notes[12]	4.0%	2040	**1,129**	1,257
Enbridge Pipelines Inc.				
Medium-term notes[13]	4.2%	2020-2049	**5,125**	4,225
Debentures	8.2%	2024	**200**	200
Commercial paper and credit facility draws[14]	2.0%	2021	**2,030**	2,200
Enbridge Southern Lights LP				
Senior notes	4.0%	2040	**272**	289
Spectra Energy Capital, LLC				
Senior notes[15]	7.1%	2032-2038	**224**	236
Spectra Energy Partners, LP				
Senior secured notes[16]	6.1%	2020	**143**	150
Senior notes[17]	4.2%	2020-2048	**8,481**	8,249
Floating rate notes[18]		2020	**519**	546
Commercial paper and credit facility draws[19]			**—**	2,065
Union Gas Limited[11]				
Medium-term notes			**—**	3,290
Debentures			**—**	125
Commercial paper and credit facility draws			**—**	275
Westcoast Energy Inc.				
Senior secured notes			**—**	33
Medium-term notes	4.5%	2020-2041	**1,875**	2,175
Debentures	8.6%	2020-2026	**375**	375
Fair value adjustment - Merger Transaction			**844**	964
Other[20]			**(369)**	(348)
Total debt			**64,963**	64,610
Current maturities			**(4,404)**	(3,259)
Short-term borrowings[21]			**(898)**	(1,024)
Long-term debt			**59,661**	60,327

1 *2019 - US$6,700 million; 2018 - US$4,700 million.*

2 *2019 - $2,400 million and US$3,200 million; 2018 - $2,400 million and US$3,200 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 Canadian Dollar Offered Rate (CDOR) or the London Interbank Offered Rate (LIBOR) plus a margin.*

3 *The notes would be converted automatically into Conversion Preference Shares in the event of bankruptcy and related events.*

4 *2019 - US$1,200 million; 2018 - $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.*

5 *2019 - $5,210 million; 2018 - $1,906 million and US$69 million.*

6 *Primarily capital lease obligations.*

7 *2019 - US$1,337 million; 2018 - US$780 million.*

8 *2019 - US$3,050 million; 2018 - US$4,550 million.*

9 2018 - US$400 million.
10 2018 - US$764 million.
11 Reflects the amalgamation of EGD and Union Gas into Enbridge Gas Inc.
12 2019 - US$871 million; 2018 - US$920 million.
13 Included in medium-term notes is $100 million with a maturity date of 2112.
14 2019 - $1,570 million and US$355 million; 2018 - $1,905 million and US$216 million.
15 2019 - US$173 million; 2018 - US$173 million.
16 2019 - US$110 million; 2018 - US$110 million.
17 2019 - US$6,540 million; 2018 - US$6,040 million.
18 2019 - US$400 million; 2018 - US$400 million. Carries an interest rate equal to the three-month LIBOR plus a margin of 70 basis points.
19 2018 - US$1,512 million.
20 Primarily unamortized discounts and debt issuance costs.
21 Weighted average interest rates on outstanding commercial paper were 2.0% as at December 31, 2019 (2018 - 2.3%).
22 Calculated based on term notes and commercial paper and credit facility draws balances outstanding as at December 31, 2019.

SECURED DEBT
Senior secured notes, totaling $143 million as at December 31, 2019, include project financings for the Express-Platte System. 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 as at December 31, 2019:

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

1 Includes facility draws and commercial paper issuances that are back-stopped by the credit facility.
2 Maturity date is inclusive of the one year term out option.

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

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

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

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

Our credit facilities carry a weighted average standby fee of 0.1% 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 scheduled to mature from 2021 to 2024.

As at December 31, 2019 and 2018, commercial paper and credit facility draws, net of short-term borrowings and non-revolving credit facilities that mature within one year, of $8,974 million and $7,967 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

During the years ended December 31, 2019 and 2018, we completed the following long-term debt issuances, excluding the debt exchange discussed below:

Company	Issue Date		Principal Amount
(millions of Canadian dollars unless otherwise stated)			
Enbridge Inc.			
	October 2019	2.99% medium-term notes due October 2029	$1,000
	November 2019	2.50% senior notes due July 2025	US$500
	November 2019	3.13% senior notes due November 2029	US$1,000
	November 2019	4.00% senior notes due November 2049	US$500
	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
Enbridge Gas Inc.			
	August 2019	2.37% medium-term notes due August 2029	$400
	August 2019	3.01% medium-term notes due August 2049	$300
Enbridge Pipelines Inc.			
	February 2019	3.52% medium-term notes due February 2029	$600
	February 2019	4.33% medium-term notes due February 2049	$600
Spectra Energy Partners, LP			
	August 2019	3.24% senior notes due August 2029[4]	US$500
	January 2018	3.50% senior notes due January 2028[5]	US$400
	January 2018	4.15% senior notes due January 2048[5]	US$400

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 CDOR 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 *Issued through Algonquin Gas Transmission, LLC, an operating subsidiary of SEP.*

5 *Issued through Texas Eastern, a wholly-owned operating subsidiary of SEP.*

LONG-TERM DEBT REPAYMENTS

During the years ended December 31, 2019 and 2018, we completed the following long-term debt repayments, excluding the debt exchange discussed below:

Company	Retirement/Repayment Date		Principal Amount	Cash Consideration[1]
(millions of Canadian dollars unless otherwise stated)				
Enbridge Inc.				
Repayment				
	February 2019	4.10% medium-term notes	$300	
	May 2019	Floating rate notes	$750	
	September 2019	4.77% medium-term notes	$400	
Enbridge Energy Partners, L.P.				
Redemption				
	February 2019	8.05% fixed/floating rate junior subordinated notes due 2067	US$400	
	December 2019	5.20% senior notes due 2020	US$500	US$504
	December 2019	4.38% senior notes due 2020	US$500	US$509
Repayment				
	March 2019	9.88% senior notes	US$500	
	April 2018	6.50% senior notes	US$400	
	October 2018	7.00% senior notes	US$100	
Enbridge Income Fund				
Repayment				
	December 2018	4.00% medium-term notes	$125	
Enbridge Pipelines (Southern Lights) L.L.C.				
Repayment				
	June and December 2019	3.98% senior notes due 2040	US$49	
	June and December 2018	3.98% senior notes due 2040	US$43	
Enbridge Pipelines Inc.				
Repayment				
	November 2019	4.49% medium-term notes	$200	
	November 2019	4.49% medium-term notes	$100	
	November 2018	6.62% medium-term notes	$170	
	November 2018	6.62% medium-term notes	$130	
Enbridge Southern Lights LP				
Repayment				
	July and December 2019	4.01% senior notes due 2040	$17	
	January, July and December 2018	4.01% senior notes due 2040	$27	
Midcoast Energy Partners, L.P.				
Redemption				
	July 2018[2]	3.56% senior notes due 2019	US$75	US$76
	July 2018[2]	4.04% senior notes due 2021	US$175	US$182
	July 2018[2]	4.42% senior notes due 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
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
Repayment				
	April 2018	6.20% senior notes	US$272	
	July 2018	6.75% senior notes	US$118	
Spectra Energy Partners, LP				
Repayment				
	September 2018	2.95% senior notes	US$500	

Union Gas Limited		
Repayment		
April 2018	5.35% medium-term notes	$200
August 2018	8.75% debentures	$125
October 2018	8.65% senior debentures	$75
Westcoast Energy Inc.		
Repayment		
January 2019	5.60% medium-term notes	$250
January 2019	5.60% medium-term notes	$50
May and November 2019	6.90% senior secured notes	$26
May and November 2019	4.34% senior secured notes	$5
December 2019	1.00% senior secured notes	$2
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% debentures	$150

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.

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, having financial terms that are the same as the financial terms of the Fund Notes.

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, 2019, we were in compliance with all debt covenants.

INTEREST EXPENSE

Year ended December 31,	**2019**	2018	2017
(millions of Canadian dollars)			
Debentures and term notes	**2,783**	3,011	3,011
Commercial paper and credit facility draws	**273**	171	206
Amortization of fair value adjustment - Spectra Energy acquisition	**(67)**	(131)	(270)
Capitalized	**(326)**	(348)	(391)
	2,663	2,703	2,556

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,	**2019**	2018
(millions of Canadian dollars)		
Obligations at beginning of year	**989**	793
Liabilities acquired	**—**	—
Liabilities disposed	**(59)**	(13)
Liabilities incurred	**15**	145
Liabilities settled	**(12)**	(21)
Change in estimate and other	**(417)**	29
Foreign currency translation adjustment	**(18)**	22
Accretion expense	**22**	34
Obligations at end of year	**520**	989
Presented as follows:		
Accounts payable and other	**7**	6
Other long-term liabilities	**513**	983
	520	989

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,	**2019**	2018
(millions of Canadian dollars)		
Algonquin Gas Transmission, L.L.C	**394**	518
Maritimes & Northeast Pipeline, L.L.C	**579**	613
Renewable energy assets[1]	**1,864**	1,961
Westcoast Energy Inc.[2]	**527**	841
Other	**—**	32
	3,364	3,965

1 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, 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, 2019 and 2018.

2 Represents the 16.6 million cumulative redeemable preferred shares as at December 31, 2019 and 2018, nil and 12 million cumulative first preferred shares as at December 31, 2019 and 2018, respectively, held by third parties in Westcoast Energy Inc., in addition to the 22.2% interest in Maritimes & Northeast Pipeline Limited Partnership held by third parties as at December 31, 2019 and 2018.

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 received 0.335 of our common shares for each class A common unit of EEP, and EEM public shareholders received 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 and 2019, CPPIB's distributions and allocation of earnings were not proportionate to its ownership.

SEP Incentive Distribution Rights
On January 22, 2018, Enbridge and SEP announced the execution of a definitive agreement, resulting in us converting all of our ownership of incentive distribution rights (IDRs) and general partner economic interests in SEP into 172.5 million newly issued SEP common units. As part of the transaction, all of the IDRs were eliminated. As a result of this restructuring, in 2018 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).

EEP Sponsored Vehicle Strategy
On April 28, 2017, we completed a strategic review of EEP and took actions including acquisition of all EEP's interest in the Midcoast assets and privatization of Midcoast Energy Partners, L.P. 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.

Westcoast Preferred Shares Redemption
On March 20, 2019, Westcoast Energy Inc. exercised its right to redeem all of its outstanding 5.5% Cumulative Redeemable First Preferred Shares, Series 7 (Series 7 Shares) and all of its outstanding 5.6% Cumulative Redeemable First Preferred Shares, Series 8 (Series 8 Shares) at a price of $25.00 per Series 7 Share and $25.00 per Series 8 Share, respectively, for a total payment of $300 million. In addition, payment of $4 million was made for all accrued and unpaid dividends. As a result, we recorded a $300 million decrease in Noncontrolling interests.

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

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, 2018, the balance of Redeemable noncontrolling interests was nil.

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,	2019 Number of Shares	2019 Amount	2018 Number of Shares	2018 Amount	2017 Number of Shares	2017 Amount
(millions of Canadian dollars; number of shares in millions)						
Balance at beginning of year	**2,022**	**64,677**	1,695	50,737	943	10,492
Common shares issued	**—**	**—**	—	—	33	1,500
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
Shares issued on exercise of stock options	**3**	**69**	2	32	3	90
Balance at end of year	**2,025**	**64,746**	2,022	64,677	1,695	50,737

PREFERENCE SHARES

December 31,	2019 Number of Shares	2019 Amount	2018 Number of Shares	2018 Amount	2017 Number of Shares	2017 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	18	457
Preference Shares, Series C	**2**	**43**	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	20	500
Issuance costs		**(155)**		(155)		(155)
Balance at end of year		**7,747**		7,747		7,747

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	4.46%	$1.11500	$25	March 1, 2023	Series E
Preference Shares, Series F	4.69%	$1.17224	$25	June 1, 2023	Series G
Preference Shares, Series H	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	5.09%	$1.27152	$25	December 1, 2023	Series O
Preference Shares, Series P[6]	4.38%	$1.09476	$25	March 1, 2024	Series Q
Preference Shares, Series R[6]	4.07%	$1.01825	$25	June 1, 2024	Series S
Preference Shares, Series 1	5.95%	US$1.48728	US$25	June 1, 2023	Series 2
Preference Shares, Series 3[6]	3.74%	$0.93425	$25	September 1, 2024	Series 4
Preference Shares, Series 5[6]	5.38%	US$1.34383	US$25	March 1, 2024	Series 6
Preference Shares, Series 7[6]	4.45%	$1.11224	$25	March 1, 2024	Series 8
Preference Shares, Series 9[6]	4.10%	$1.02424	$25	December 1, 2024	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 decreased to $0.25395 from $0.25459 on March 1, 2019, was increased to $0.25647 from $0.25395 on June 1, 2019, was decreased to $0.25243 from $0.25647 on September 1, 2019 and was increased to $0.25305 from $0.25243 on December 1, 2019, due to reset on a quarterly basis following the issuance thereof.

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

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 - Liquidity and Capital Resources - Dividends* 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 PSU Plan and the RSU Plan. In 2019, Enbridge adopted a new Long Term Incentive Plan with an effective date of February 13, 2019. The 2019 plan replaced several of Enbridge's prior incentive award plans and no additional awards were made or will be made under the prior plans as of the effective date. A reserve of 50 million was approved and established for the 2019 ISO Plan. Awards of PSUs and RUSs are 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. Spectra Energy's cash-settled phantom awards were included in the fair value of the net assets acquired *(Note 8)*.

Total stock-based compensation expense recorded for the years ended December 31, 2019, 2018 and 2017 was $117 million, $106 million and $165 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, 2019	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	**34,387**	**43.47**		
Options granted	**6,777**	**48.32**		
Options exercised[1]	**(4,519)**	**34.19**		
Options cancelled or expired	**(1,598)**	**50.62**		
Options outstanding at end of year	**35,047**	**47.73**	**6.2**	**157**
Options vested at end of year[2]	**20,581**	**47.67**	**4.7**	**92**

1 The total intrinsic value of ISOs exercised during the years ended December 31, 2019, 2018 and 2017 was $58 million, $42 million and $62 million, respectively, and cash received on exercise was $1 million, $15 million and $17 million, respectively.

2 The total fair value of ISOs vested during the years ended December 31, 2019, 2018 and 2017 was $32 million, $36 million and $44 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,	**2019**	2018	2017
Fair value per option *(Canadian dollars)*[1]	**4.37**	3.86	6.00
Valuation assumptions			
Expected option term *(years)*[2]	**5**	5	5
Expected volatility[3]	**19.9%**	21.9%	20.4%
Expected dividend yield[4]	**6.1%**	6.4%	4.4%
Risk-free interest rate[5]	**2.0%**	2.2%	1.2%

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, 2019, 2018 and 2017 were $4.04, $3.75 and $5.66, respectively, for Canadian employees and US$4.09, US$3.30 and US$5.72, 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, 2019, 2018 and 2017 for ISOs was $32 million, $28 million and $40 million, respectively. As at December 31, 2019, unrecognized compensation expense related to non-vested stock-based compensation arrangements granted under the ISO Plan was $18 million. The expense is expected to be fully recognized over a weighted average period of approximately two years.

PERFORMANCE STOCK UNITS

Under PSU awards for certain key employees, cash awards are paid following a three-year performance cycle. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by the Company's weighted average share price for 20 days prior to the maturity of the grant and by a performance multiplier. The performance multiplier ranges from zero, if our performance fails to meet threshold performance levels, to a maximum of two if we perform within the highest range of its performance targets. The performance multiplier is derived through a calculation of our Risk Adjusted Total Shareholder Return (in 2017) and Total Shareholder Return (commencing in 2018) percentile rank, in each case relative to a specified peer group of companies and our distributable cash flow, adjusted for unusual, non-operating or non-recurring items, relative to targets established at the time of grant. To calculate the 2019 expense, a multiplier of one was used for each of the 2017, 2018 and 2019 PSU grants.

December 31, 2019	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	**1,069**		
Units granted	**1,093**		
Units cancelled	**(65)**		
Units matured[1]	**(25)**		
Dividend reinvestment	**117**		
Units outstanding at end of year	**2,189**	**1.5**	**111**

1 The total amount paid during the years ended December 31, 2019, 2018 and 2017 for PSUs was $19 million, $18 million and $28 million, respectively.

Compensation expense recorded for the years ended December 31, 2019, 2018 and 2017 for PSUs was $40 million, $15 million and $5 million, respectively. As at December 31, 2019, unrecognized compensation expense related to non-vested PSUs was $55 million. The expense is expected to be fully recognized over a weighted average period of approximately two years.

RESTRICTED STOCK UNITS

Under RSU awards, 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, 2019	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	**1,213**		
Units granted	**1,087**		
Units cancelled	**(96)**		
Units matured[1]	**(706)**		
Dividend reinvestment	**126**		
Units outstanding at end of year	**1,624**	**1.6**	**82**

1 The total amount paid during the years ended December 31, 2019, 2018 and 2017 for RSUs was $34 million, $41 million and $39 million, respectively.

Compensation expense recorded for the years ended December 31, 2019, 2018 and 2017 for RSUs was $41 million, $32 million and $46 million, respectively. As at December 31, 2019, unrecognized compensation expense related to non-vested RSUs was $47 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, 2019, 2018 and 2017 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, 2019	**(770)**	**(598)**	**4,323**	**34**	**(317)**	**2,672**
Other comprehensive income/(loss) retained in AOCI	**(599)**	**320**	**(2,927)**	**34**	**(124)**	**(3,296)**
Other comprehensive (income)/loss reclassified to earnings						
Interest rate contracts[1]	**157**	**—**	**—**	**—**	**—**	**157**
Commodity contracts[2]	**(1)**	**—**	**—**	**—**	**—**	**(1)**
Foreign exchange contracts[3]	**5**	**—**	**—**	**—**	**—**	**5**
Other contracts[4]	**(3)**	**—**	**—**	**—**	**—**	**(3)**
Amortization of pension and OPEB actuarial loss and prior service costs[5]	**—**	**—**	**—**	**—**	**17**	**17**
	(441)	**320**	**(2,927)**	**34**	**(107)**	**(3,121)**
Tax impact						
Income tax on amounts retained in AOCI	**169**	**(39)**	**—**	**6**	**28**	**164**
Income tax on amounts reclassified to earnings	**(31)**	**—**	**—**	**—**	**(4)**	**(35)**
	138	**(39)**	**—**	**6**	**24**	**129**
Other	**—**	**—**	**—**	**(7)**	**55**	**48**
Balance at December 31, 2019	**(1,073)**	**(317)**	**1,396**	**67**	**(345)**	**(272)**

	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

	Cash Flow Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Adjustment	Total
(millions of Canadian dollars)						
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)

1 Reported within Interest expense in the Consolidated Statements of Earnings.

2 Reported within Transportation and other services revenue, Commodity sales revenues, Commodity costs and Operating and administrative expense in the Consolidated Statements of Earnings.

3 Reported within Transportation and other services revenues and Net foreign currency gain/(loss) 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 Other income/(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 is 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. We 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. 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 2.9%.

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 at December 31, 2019, 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%.

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 reduce 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.

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, 2019	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment	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	**—**	**—**	**161**	**161**	**(78)**	**83**
Commodity contracts	**—**	**—**	**163**	**163**	**(47)**	**116**
Other contracts	**1**	**—**	**3**	**4**	**—**	**4**
	1	**—**	**327**	**328** [1]	**(125)**	**203**
Deferred amounts and other assets						
Foreign exchange contracts	**10**	**—**	**71**	**81**	**(42)**	**39**
Commodity contracts	**—**	**—**	**17**	**17**	**(2)**	**15**
Other contracts	**2**	**—**	**1**	**3**	**—**	**3**
	12	**—**	**89**	**101**	**(44)**	**57**
Accounts payable and other						
Foreign exchange contracts	**(5)**	**(13)**	**(392)**	**(410)**	**78**	**(332)**
Interest rate contracts	**(353)**	**—**	**—**	**(353)**	**—**	**(353)**
Commodity contracts	**—**	**—**	**(173)**	**(173)**	**47**	**(126)**
	(358)	**(13)**	**(565)**	**(936)** [2]	**125**	**(811)**
Other long-term liabilities						
Foreign exchange contracts	**—**	**—**	**(934)**	**(934)**	**42**	**(892)**
Interest rate contracts	**(181)**	**—**	**—**	**(181)**	**—**	**(181)**
Commodity contracts	**(5)**	**—**	**(60)**	**(65)**	**2**	**(63)**
	(186)	**—**	**(994)**	**(1,180)**	**44**	**(1,136)**
Total net derivative asset/(liability)						
Foreign exchange contracts	**5**	**(13)**	**(1,094)**	**(1,102)**	**—**	**(1,102)**
Interest rate contracts	**(534)**	**—**	**—**	**(534)**	**—**	**(534)**
Commodity contracts	**(5)**	**—**	**(53)**	**(58)**	**—**	**(58)**
Other contracts	**3**	**—**	**4**	**7**	**—**	**7**
	(531)	**(13)**	**(1,143)**	**(1,687)**	**—**	**(1,687)**

1 Reported within Accounts receivable and other (2019 - $327 million; 2018 - $498 million) and Accounts receivable from affiliates (2019 - $1 million; 2018 - nil) on the Consolidated Statements of Financial Position.

2 Reported within Accounts payable and other (2019 - $920 million; 2018 - $1,234 million) and Accounts payable to affiliates (2019 - $16 million; 2018 - nil) on the Consolidated Statements of Financial Position.

December 31, 2018	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment 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)						
Foreign exchange contracts	17	(15)	(2,720)	(2,718)	—	(2,718)
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)

The following table summarizes the maturity and notional principal or quantity outstanding related to our derivative instruments.

As at December 31,	2019 2020	2021	2022	2023	2024	Thereafter	Total	2018 Total
Foreign exchange contracts - United States dollar forwards - purchase *(millions of United States dollars)*	**1,121**	**—**	**—**	**—**	**—**	**—**	**1,121**	926
Foreign exchange contracts - United States dollar forwards - sell *(millions of United States dollars)*	**5,631**	**4,946**	**5,182**	**1,804**	**1,856**	**—**	**19,419**	19,075
Foreign exchange contracts - GBP forwards - sell *(millions of GBP)*	**94**	**27**	**28**	**29**	**30**	**90**	**298**	318
Foreign exchange contracts - Euro forwards - purchase *(millions of Euro)*	**—**	**—**	**—**	**—**	**—**	**—**	**—**	226
Foreign exchange contracts - Euro forwards - sell *(millions of Euro)*	**23**	**94**	**94**	**92**	**91**	**515**	**909**	909
Foreign exchange contracts - Japanese yen forwards - purchase *(millions of yen)*	**—**	**—**	**72,500**	**—**	**—**	**—**	**72,500**	52,662
Interest rate contracts - short-term pay fixed rate *(millions of Canadian dollars)*	**6,090**	**4,090**	**400**	**48**	**35**	**121**	**10,784**	19,664
Interest rate contracts - long-term pay fixed rate *(millions of Canadian dollars)*	**3,533**	**1,569**	**—**	**—**	**—**	**—**	**5,102**	8,558
Equity contracts *(millions of Canadian dollars)*	**20**	**34**	**—**	**—**	**—**	**—**	**54**	55
Commodity contracts - natural gas *(billions of cubic feet)*	**(33)**	**14**	**15**	**3**	**—**	**—**	**(1)**	(167)
Commodity contracts - crude oil *(millions of barrels)*	**28**	**—**	**—**	**—**	**—**	**—**	**28**	4
Commodity contracts - NGL *(millions of barrels)*	**2**	**—**	**—**	**—**	**—**	**—**	**2**	—
Commodity contracts - power *(megawatt per hour (MW/H)*	**80**	**(3)**	**(43)**	**(43)**	**(43)**	**(43)** [1]	**(16)** [2]	(7) [2]

1 As at December 31, 2019, thereafter includes an average net purchase/(sell) of power of (43) MW/H for 2025.
2 Total is an average net purchase/(sell) of power.

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:

	2019	2018	2017
(millions of Canadian dollars)			
Amount of unrealized gain/(loss) recognized in OCI			
Cash flow hedges			
Foreign exchange contracts	**(19)**	19	(5)
Interest rate contracts	**(559)**	(190)	6
Commodity contracts	**(25)**	2	11
Other contracts	**10**	(3)	1
Net investment hedges			
Foreign exchange contracts	**2**	31	284
	(591)	(141)	297
Amount of (gain)/loss reclassified from AOCI to earnings			
Foreign exchange contracts[1]	**5**	5	(104)
Interest rate contracts[2,3]	**157**	184	384
Commodity contracts[4]	**(1)**	(1)	(9)
Other contracts[5]	**(3)**	3	8
	158	191	279

1 Reported within Transportation and other services revenues and Net foreign currency gain/(loss) in the Consolidated Statements of Earnings.

2 Reported within Interest expense in the Consolidated Statements of Earnings. Effective January 1, 2019, hedge ineffectiveness will no longer be measured or recorded. See Note 2.

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 revenue, Commodity sales revenues, Commodity costs and Operating and administrative expense in the Consolidated Statements of Earnings.

5 Reported within Operating and administrative expenses in the Consolidated Statements of Earnings.

We estimate that a loss of $80 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 24 months as at December 31, 2019.

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,	**2019**	2018
(millions of Canadian dollars)		
Unrealized gain on derivative	**—**	7
Unrealized gain on hedged item	**—**	1
Realized loss on derivative	**—**	(8)
Realized loss on hedged item	**—**	(1)

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,	**2019**	2018	2017
(millions of Canadian dollars)			
Foreign exchange contracts[1]	**1,626**	(1,390)	1,284
Interest rate contracts[2]	**178**	5	157
Commodity contracts[3]	**(62)**	485	(199)
Other contracts[4]	**9**	(3)	—
Total unrealized derivative fair value gain/(loss), net	**1,751**	(903)	1,242

1 *For the respective annual periods, reported within Transportation and other services revenue (2019 - $930 million gain; 2018 - $1,108 million loss; 2017 - $800 million gain) and Net foreign currency gain/(loss) (2019 - $696 million gain; 2018 - $282 million loss; 2017 - $484 million gain) in the Consolidated Statements of Earnings.*

2 *Reported as a decrease within Interest expense in the Consolidated Statements of Earnings.*

3 *For the respective annual periods, reported within Transportation and other services revenue (2019 - $26 million loss; 2018 - $66 million gain; 2017 - $104 million loss), Commodity sales (2019 - $544 million loss; 2018 - $599 million gain; 2017 - $90 million gain), Commodity costs (2019 - $459 million gain; 2018 - $193 million loss; 2017 - $223 million loss) and Operating and administrative expense (2019 - $49 million gain; 2018 - $13 million gain; 2017 - $38 million gain) 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 ready access to either the Canadian or United States public capital markets, subject to market conditions. 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, 2019. 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,	**2019**	2018
(millions of Canadian dollars)		
Canadian financial institutions	**146**	28
United States financial institutions	**40**	107
European financial institutions	**3**	84
Asian financial institutions	**92**	6
Other[1]	**113**	337
	394	562

1 Other is comprised of commodity clearing house and physical natural gas and crude oil counterparties.

As at December 31, 2019, we provided letters of credit totaling nil in lieu of providing cash collateral to our counterparties pursuant to the terms of the relevant International Swaps and Derivatives Association agreements. We held no cash collateral on derivative asset exposures as at December 31, 2019 and December 31, 2018.

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 Enbridge 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, 2019	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	**—**	**161**	**—**	**161**
Commodity contracts	**—**	**33**	**130**	**163**
Other contracts	**—**	**4**	**—**	**4**
	—	**198**	**130**	**328**
Long-term derivative assets				
Foreign exchange contracts	**—**	**81**	**—**	**81**
Commodity contracts	**—**	**12**	**5**	**17**
Other contracts	**—**	**3**	**—**	**3**
	—	**96**	**5**	**101**
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	**—**	**(410)**	**—**	**(410)**
Interest rate contracts	**—**	**(353)**	**—**	**(353)**
Commodity contracts	**(5)**	**(23)**	**(145)**	**(173)**
Other contracts	**—**	**—**	**—**	**—**
	(5)	**(786)**	**(145)**	**(936)**
Long-term derivative liabilities				
Foreign exchange contracts	**—**	**(934)**	**—**	**(934)**
Interest rate contracts	**—**	**(181)**	**—**	**(181)**
Commodity contracts	**—**	**(6)**	**(59)**	**(65)**
Other contracts	**—**	**—**	**—**	**—**
	—	**(1,121)**	**(59)**	**(1,180)**
Total net financial asset/(liability)				
Foreign exchange contracts	**—**	**(1,102)**	**—**	**(1,102)**
Interest rate contracts	**—**	**(534)**	**—**	**(534)**
Commodity contracts	**(5)**	**16**	**(69)**	**(58)**
Other contracts	**—**	**7**	**—**	**7**
	(5)	**(1,613)**	**(69)**	**(1,687)**

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)

The significant unobservable inputs used in the fair value measurement of Level 3 derivative instruments were as follows:

December 31, 2019	Fair Value	Unobservable Input	Minimum Price/Volatility	Maximum Price/Volatility	Weighted Average Price/Volatility	Unit of Measurement
(fair value in millions of Canadian dollars)						
Commodity contracts - financial[1]						
Natural gas	**—**	**Forward gas price**	**1.95**	**4.88**	**3.04**	**$/mmbtu[2]**
Crude	**4**	**Forward crude price**	**44.24**	**82.29**	**52.76**	**$/barrel**
NGL	**3**	**Forward NGL price**	**0.54**	**0.86**	**0.82**	**$/gallon**
Power	**(61)**	**Forward power price**	**27.84**	**71.79**	**57.46**	**$/MW/H**
Commodity contracts - physical[1]						
Natural gas	**28**	**Forward gas price**	**1.00**	**8.37**	**2.53**	**$/mmbtu[2]**
Crude	**(45)**	**Forward crude price**	**40.20**	**90.75**	**70.27**	**$/barrel**
NGL	**2**	**Forward NGL price**	**0.18**	**2.01**	**0.79**	**$/gallon**
	(69)					

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,	**2019**	2018
(millions of Canadian dollars)		
Level 3 net derivative liability at beginning of period	**(11)**	(387)
Total gain/(loss)		
Included in earnings[1]	**27**	206
Included in OCI	**(25)**	2
Settlements	**(60)**	168
Level 3 net derivative liability at end of period	**(69)**	(11)

1 Reported within Transportation and other services revenue, Commodity costs and Operating and administrative expenses 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, 2019 or 2018.

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 $99 million and $102 million as at December 31, 2019 and 2018, respectively.

We have Restricted long-term investments held in trust totaling $434 million and $323 million as at December 31, 2019 and 2018, respectively, which are recognized at fair value.

We have a held to maturity preferred share investment carried at its amortized cost of $580 million and $478 million as at December 31, 2019 and 2018, 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, 2019 and 2018.

As at December 31, 2019 and 2018, our long-term debt had a carrying value of $64.4 billion and $63.9 billion, respectively, before debt issuance costs and a fair value of $70.5 billion and $64.4 billion, respectively. We also have non-current notes receivable carried at book value and recorded in Deferred amounts and other assets in the Consolidated Statements of Financial Position. As at December 31, 2019 and 2018, the non-current notes receivable had a carrying value of $1,026 million and $767 million, respectively, which also approximates their fair value.

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, 2019 and 2018, we recognized an unrealized foreign exchange gain of $317 million and a loss of $479 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 $2 million and $30 million, respectively, in OCI. During the years ended December 31, 2019 and 2018, we recognized a realized loss of nil and $45 million, respectively, in OCI associated with the settlement of foreign exchange forward contracts and also recognized a realized loss of nil and loss of $14 million, respectively, in OCI associated with the settlement of United States dollar denominated debt that had matured during the period.

25. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	**2019**	2018	2017
(millions of Canadian dollars)			
Earnings before income taxes	**7,535**	3,570	569
Canadian federal statutory income tax rate	**15%**	15%	15 %
Expected federal taxes at statutory rate	**1,130**	536	85
Increase/(decrease) resulting from:			
Provincial and state income taxes[1]	**415**	(24)	133
Foreign and other statutory rate differentials	**129**	94	(601)
Impact of United States tax reform[2]	**—**	(2)	(2,045)
Effects of rate-regulated accounting[3]	**(63)**	(163)	(189)
Foreign allowable interest deductions[4]	**(29)**	(134)	(124)
Part VI.1 tax, net of federal Part I deduction[5]	**78**	76	68
Impairment of goodwill	**—**	192	15
United States BEAT tax	**67**	43	—
Non-taxable portion of gain/(loss) on sale of investment to unrelated party[6]	**—**	31	—
Valuation allowance[7]	**26**	(172)	(17)
Intercorporate investments[8]	**(14)**	(149)	77
Noncontrolling interests	**(13)**	(47)	(80)
Other	**(18)**	(44)	(19)
Income tax (recovery)/expense	**1,708**	237	(2,697)
Effective income tax rate	**22.7%**	6.6%	(474.0)%

1 The change in provincial and state income taxes from 2018 to 2019 reflects the increase in earnings from operations and the impact of state tax rate changes in both the United States and Canada.

2 The amount was related to the enactment of the Tax Cuts and Jobs Act (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 in 2019 included the federal component of the tax effect of the write-off of regulatory assets (Note 7).

4 The decrease in foreign allowable interest deductions in 2019 was due to changes in the related loan portfolio and tax legislative changes in Canada, the United States, and Europe.

5 Part VI.1 tax is a tax levied on preferred share dividends paid in Canada.

6 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.

7 The increase in 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 more likely than not to be realized.

8 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 MATL (Note 8), Renewable Assets in 2018 and for EIPLP in 2017.

COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES

Year ended December 31,	**2019**	2018	2017
(millions of Canadian dollars)			
Earnings/(loss) before income taxes			
Canada	**3,560**	118	2,200
United States	**3,115**	2,582	(2,431)
Other	**860**	870	800
	7,535	3,570	569
Current income taxes			
Canada	**347**	311	129
United States	**107**	66	46
Other	**98**	8	5
	552	385	180
Deferred income taxes			
Canada	**490**	(598)	299
United States	**672**	439	(3,160)
Other	**(6)**	11	(16)
	1,156	(148)	(2,877)
Income tax (recovery)/expense	**1,708**	237	(2,697)

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,	**2019**	2018
(millions of Canadian dollars)		
Deferred income tax liabilities		
Property, plant and equipment	**(7,290)**	(7,018)
Investments	**(4,620)**	(4,441)
Regulatory assets	**(1,052)**	(756)
Other	**(40)**	(192)
Total deferred income tax liabilities	**(13,002)**	(12,407)
Deferred income tax assets		
Financial instruments	**679**	1,103
Pension and OPEB plans	**206**	181
Loss carryforwards	**1,693**	1,820
Other	**1,641**	1,274
Total deferred income tax assets	**4,219**	4,378
Less valuation allowance	**(84)**	(51)
Total deferred income tax assets, net	**4,135**	4,327
Net deferred income tax liabilities	**(8,867)**	(8,080)
Presented as follows:		
Total deferred income tax assets	**1,000**	1,374
Total deferred income tax liabilities	**(9,867)**	(9,454)
Net deferred income tax liabilities	**(8,867)**	(8,080)

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, 2019 and 2018, we recognized the benefit of unused tax loss carryforwards of $3.2 billion and $3.4 billion, respectively, in Canada which expire in 2026 and beyond.

As at December 31, 2019 and 2018, we recognized the benefit of unused tax loss carryforwards of $3.6 billion and $3.4 billion, respectively, in the United States which expire in 2023 and beyond.

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 $5.3 billion and $5.8 billion for the period December 31, 2019 and 2018, 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 certain 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 2019 tax years and by United States tax authorities for the 2015 to 2019 tax years. We are currently under examination for income tax matters in Canada for the 2013 to 2017 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 a result of the TCJA we recorded $67 million and $43 million in tax expense for the years ended December 31, 2019 and 2018, respectively in connection with the Base erosion and Anti-abuse tax (BEAT). We recorded no provisions 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.

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 of 2018 in connection with rate cases filed that eliminated a portion of regulated liability formerly included in SEP's rate base.

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 $34 million increase to our 2017 current income tax provision related to the toll tax, payable over eight years. We recorded a $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 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 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,	**2019**	2018
(millions of Canadian dollars)		
Unrecognized tax benefits at beginning of year	**139**	150
Gross increases for tax positions of current year	**1**	2
Gross decreases for tax positions of prior year	**(1)**	(12)
Change in translation of foreign currency	**(4)**	3
Lapses of statute of limitations	**(6)**	(3)
Settlements	**—**	(1)
Unrecognized tax benefits at end of year	**129**	139

The unrecognized tax benefits as at December 31, 2019, 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, 2019 and 2018 were $3 million expense and $5 million expense, respectively, of interest and penalties. As at December 31, 2019 and 2018, interest and penalties of $15 million and $12 million, respectively, have been accrued.

26. PENSION AND OTHER POSTRETIREMENT BENEFITS

PENSION PLANS

We sponsor Canadian and United States contributory and non-contributory registered defined benefit and defined contribution pension plans, which provide benefits covering substantially all employees. The Canadian Plans provide defined benefit and defined contribution pension benefits to our Canadian employees. The United States Plans provide defined benefit pension benefits to our United States employees. We also sponsor supplemental non-contributory defined benefit pension plans, which provide non-registered benefits for certain employees in Canada and the United States.

Defined Benefit Pension Plan Benefits

Benefits payable from the defined benefit pension plans are based on each plan participant’s years of service and final average remuneration. Some benefits are partially inflation-indexed after a plan participant’s retirement. Our contributions are made in accordance with independent actuarial valuations. Participant contributions to contributory defined benefit pension plans are based upon each plan participant’s current eligible remuneration.

Defined Contribution Pension Plan Benefits

Our contributions are based on each plan participant’s current eligible remuneration. Our contributions for some defined contribution pension plans are also based on age and years of service. Our defined contribution pension benefit costs are equal to the amount of contributions required to be made by us.

Benefit Obligations, 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 assets or liabilities for our defined benefit pension plans:

	Canada		United States	
December 31,	**2019**	2018	**2019**	2018
(millions of Canadian dollars)				
Change in projected benefit obligation				
Projected benefit obligation at beginning of year	**3,997**	4,033	**1,214**	1,279
Service cost	**149**	149	**45**	45
Interest cost	**139**	130	**41**	38
Participant contributions	**32**	25	**—**	—
Actuarial (gain)/loss	**423**	(146)	**106**	(103)
Benefits paid	**(187)**	(184)	**(101)**	(60)
Plan settlements[1]	**(99)**	—	**(1)**	(65)
Transfers out	**(8)**	(10)	**(6)**	—
Foreign currency exchange rate changes	**—**	—	**(63)**	105
Other	**—**	—	**(5)**	(25)
Projected benefit obligation at end of year[2]	**4,446**	3,997	**1,230**	1,214
Change in plan assets				
Fair value of plan assets at beginning of year	**3,523**	3,619	**1,045**	1,097
Actual return/(loss) on plan assets	**448**	(42)	**176**	(48)
Employer contributions	**114**	113	**46**	40
Participant contributions	**32**	25	**—**	—
Benefits paid	**(187)**	(184)	**(101)**	(60)
Plan settlements[1]	**(99)**	—	**(1)**	(65)
Transfers out	**(4)**	(8)	**—**	—
Foreign currency exchange rate changes	**—**	—	**(56)**	91
Other	**—**	—	**(5)**	(10)
Fair value of plan assets at end of year[3]	**3,827**	3,523	**1,104**	1,045
Underfunded status at end of year	**(619)**	(474)	**(126)**	(169)
Presented as follows:				
Deferred amounts and other assets	**35**	29	**—**	—
Accounts payable and other	**(9)**	(9)	**(4)**	(4)
Other long-term liabilities	**(645)**	(494)	**(122)**	(165)
	(619)	(474)	**(126)**	(169)

1 Plan settlements for the Canadian Plans are related to the disposition of our federally regulated BC Field Services business.

2 The accumulated benefit obligation for our Canadian pension plans was $4.0 billion and $3.7 billion as at December 31, 2019 and 2018, respectively. The accumulated benefit obligation for our United States pension plans was $1.2 billion as at December 31, 2019 and 2018.

3 Assets in the amount of $10 million (2018 - $7 million) and $51 million (2018 - $39 million), related to our Canadian and United States non-registered supplemental pension plan obligations, are held in Grantor Trusts and Rabbi 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 an accumulated benefit obligation in excess of the fair value of plan assets. For these plans, the projected benefit obligation, accumulated benefit obligation and fair value of plan assets were as follows:

	Canada		United States	
December 31,	**2019**	2018	**2019**	2018
(millions of Canadian dollars)				
Projected benefit obligation	**1,481**	1,422	**103**	1,214
Accumulated benefit obligation	**1,361**	1,299	**98**	1,179
Fair value of plan assets	**1,087**	1,064	**—**	1,045

Amount Recognized in Accumulated Other Comprehensive Income
The amount of pre-tax AOCI relating to our pension plans are as follows:

	Canada		United States	
December 31,	**2019**	2018	**2019**	2018
(millions of Canadian dollars)				
Net actuarial loss	**445**	435	**134**	133
Prior service credit	**—**	—	**(2)**	(3)
Total amount recognized in AOCI[1]	**445**	435	**132**	130

1 Excludes amounts related to cumulative translation adjustment.

Net Periodic Benefit Cost and Other Amounts Recognized in Comprehensive Income
The components of net periodic benefit cost and other amounts recognized in pre-tax Comprehensive income related to our pension plans are as follows:

	Canada			United States		
Year ended December 31,	**2019**	2018	2017	**2019**	2018	2017
(millions of Canadian dollars)						
Service cost	**149**	149	156	**45**	45	48
Interest cost	**139**	130	116	**41**	38	35
Expected return on plan assets	**(245)**	(245)	(201)	**(78)**	(88)	(57)
Amortization/settlement of net actuarial loss	**41**	25	29	**2**	7	10
Amortization/curtailment of prior service (credit)/ cost	**—**	—	—	**(1)**	3	—
Net periodic benefit cost	**84**	59	100	**9**	5	36
Defined contribution benefit cost	**8**	11	11	**—**	—	—
Net pension cost recognized in Earnings	**92**	70	111	**9**	5	36
Amount recognized in OCI:						
Effect of plan combination	**—**	—	—	**(6)**	—	—
Amortization/settlement of net actuarial loss	**(26)**	(11)	(14)	**(2)**	(7)	(9)
Amortization/curtailment of prior service credit/ (cost)	**—**	—	—	**1**	(3)	—
Net actuarial loss arising during the year	**115**	112	38	**8**	28	—
Total amount recognized in OCI	**89**	101	24	**1**	18	(9)
Total amount recognized in Comprehensive income	**181**	171	135	**10**	23	27

We estimate that approximately $21 million related to the Canadian pension plans and nil related to the United States pension plans as at December 31, 2019 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 obligation and net periodic benefit cost of our pension plans are as follows:

	Canada			United States		
	2019	2018	2017	**2019**	2018	2017
Projected benefit obligation						
Discount rate	**3.0%**	3.8%	3.6%	**3.0%**	3.9%	3.5%
Rate of salary increase	**3.2%**	3.2%	3.2%	**2.9%**	2.8%	3.1%
Net periodic benefit cost						
Discount rate	**3.8%**	3.6%	4.0%	**3.9%**	3.4%	4.0%
Expected rate of return on plan assets	**7.0%**	6.8%	6.5%	**8.0%**	7.4%	7.2%
Rate of salary increase	**3.2%**	3.2%	3.7%	**2.9%**	2.9%	3.3%

OTHER POSTRETIREMENT BENEFIT PLANS

We sponsor funded and unfunded defined benefit OPEB Plans, which provide non-contributory supplemental health, dental, life and health spending account benefit coverage for certain qualifying retired employees.

Benefit Obligations, Plan Assets and Funded Status

The following table details the changes in the accumulated postretirement benefit obligation, the fair value of plan assets and the recorded assets or liabilities for our defined benefit OPEB plans:

	Canada		United States	
December 31,	**2019**	2018	**2019**	2018
(millions of Canadian dollars)				
Change in accumulated postretirement benefit obligation				
Accumulated postretirement benefit obligation at beginning of year	**282**	321	**305**	337
Service cost	**5**	8	**2**	3
Interest cost	**10**	10	**10**	10
Participant contributions	**—**	—	**5**	6
Actuarial (gain)/loss	**15**	(45)	**7**	(25)
Benefits paid	**(6)**	(11)	**(28)**	(29)
Plan amendments	**—**	—	**—**	(8)
Foreign currency exchange rate changes	**—**	—	**(15)**	27
Other	**(13)**	(1)	**2**	(16)
Accumulated postretirement benefit obligation at end of year	**293**	282	**288**	305
Change in plan assets				
Fair value of plan assets at beginning of year	**—**	—	**181**	213
Actual return/(loss) on plan assets	**—**	—	**27**	(13)
Employer contributions	**6**	11	**10**	8
Participant contributions	**—**	—	**5**	6
Benefits paid	**(6)**	(11)	**(28)**	(29)
Foreign currency exchange rate changes	**—**	—	**(9)**	16
Other	**—**	—	**2**	(20)
Fair value of plan assets at end of year	**—**	—	**188**	181
Underfunded status at end of year	**(293)**	(282)	**(100)**	(124)
Presented as follows:				
Deferred amounts and other assets	**—**	—	**—**	2
Accounts payable and other	**(12)**	(12)	**(8)**	(7)
Other long-term liabilities	**(281)**	(270)	**(92)**	(119)
	(293)	(282)	**(100)**	(124)

Amount Recognized in Accumulated Other Comprehensive Income

The amount of pre-tax AOCI relating to our OPEB plans are as follows:

	Canada		United States	
December 31,	**2019**	2018	**2019**	2018
(millions of Canadian dollars)				
Net actuarial gain	**(7)**	(29)	**(23)**	(15)
Prior service credit	**(1)**	(2)	**(13)**	(15)
Total amount recognized in AOCI[1]	**(8)**	(31)	**(36)**	(30)

1 Excludes amounts related to cumulative translation adjustment.

Net Periodic Benefit Cost and Other Amounts Recognized in Comprehensive Income

The components of net periodic benefit cost and other amounts recognized in pre-tax Comprehensive income related to our OPEB plans are as follows:

	Canada			United States		
Year ended December 31,	**2019**	2018	2017	**2019**	2018	2017
(millions of Canadian dollars)						
Service cost	**5**	8	7	**2**	3	5
Interest cost	**10**	10	10	**10**	10	10
Expected return on plan assets	**—**	—	—	**(12)**	(12)	(10)
Amortization/settlement of net actuarial gain	**(7)**	—	—	**—**	(1)	—
Amortization/curtailment of prior service (credit)/ cost	**(1)**	—	1	**(2)**	(4)	—
Net periodic benefit cost recognized in Earnings	**7**	18	18	**(2)**	(4)	5
Amount recognized in OCI:						
Amortization/settlement of net actuarial gain/ (loss)	**7**	—	(1)	**—**	1	1
Amortization/curtailment of prior service credit	**1**	—	—	**2**	4	—
Net actuarial (gain)/loss arising during the year	**15**	(46)	(8)	**(8)**	(1)	(42)
Prior service (credit)/cost	**—**	—	(3)	**—**	(8)	1
Total amount recognized in OCI	**23**	(46)	(12)	**(6)**	(4)	(40)
Total amount recognized in Comprehensive income	**30**	(28)	6	**(8)**	(8)	(35)

We estimate that approximately $1 million related to the Canadian OPEB plans and $3 million related to the United States OPEB plans as at December 31, 2019 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 obligation and net periodic benefit cost of our OPEB plans are as follows:

	Canada			United States		
	2019	2018	2017	**2019**	2018	2017
Accumulated postretirement benefit obligation						
Discount rate	**3.1%**	3.8%	3.6%	**2.8%**	4.0%	3.5%
Net periodic benefit cost						
Discount rate	**3.8%**	3.6%	4.0%	**4.0%**	3.3%	4.0%
Rate of return on plan assets	**N/A**	N/A	N/A	**6.7%**	5.7%	6.0%

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	
	2019	2018	**2019**	2018
Health care cost trend rate assumed for next year	**4.0%**	5.6%	**7.2%**	7.4%
Rate to which the cost trend is assumed to decline (ultimate trend rate)	**4.0%**	4.4%	**4.5%**	4.5%
Year that the rate reaches the ultimate trend rate	**N/A**	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, 2019:

	Canada		United States	
	1% Increase	1% Decrease	1% Increase	1% Decrease
(millions of Canadian dollars)				
Total service and interest costs	**1**	**(1)**	**1**	**(1)**
Accumulated postretirement benefit obligation	**21**	**(17)**	**19**	**(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 overall expected rate of return on plan assets is based on the asset allocation targets with estimates for returns based on long-term expectations.

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**	**2019**	2018	**Allocation**	**2019**	2018
Equity securities	**43.4%**	**46.4%**	45.8%	**45.0%**	**55.2%**	52.7%
Fixed income securities	**30.3%**	**31.0%**	38.8%	**20.0%**	**19.8%**	34.9%
Alternatives[1]	**26.3%**	**22.6%**	15.4%	**35.0%**	**25.0%**	12.4%

1 Alternatives include investments in private debt, private equity, infrastructure and real estate funds.

Pension Plans

The following table summarizes the fair value of plan assets for our pension plans recorded at each fair value hierarchy level:

	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, 2019								
Cash and cash equivalents	**184**	**—**	**—**	**184**	**14**	**—**	**—**	**14**
Equity securities								
Canada	**165**	**183**	**—**	**348**	**—**	**—**	**—**	**—**
United States	**—**	**—**	**—**	**—**	**—**	**93**	**—**	**93**
Global	**—**	**1,429**	**—**	**1,429**	**—**	**516**	**—**	**516**
Fixed income securities								
Government	**196**	**418**	**—**	**614**	**—**	**164**	**—**	**164**
Corporate	**—**	**388**	**—**	**388**	**—**	**41**	**—**	**41**
Alternatives[4]	**—**	**—**	**852**	**852**	**—**	**—**	**276**	**276**
Forward currency contracts	**—**	**12**	**—**	**12**	**—**	**—**	**—**	**—**
Total pension plan assets at fair value	**545**	**2,430**	**852**	**3,827**	**14**	**814**	**276**	**1,104**
December 31, 2018								
Cash and cash equivalents	240	—	—	240	56	—	—	56
Equity securities								
Canada	138	481	—	619	—	—	—	—
United States	—	—	—	—	—	110	—	110
Global	—	992	—	992	—	440	—	440
Fixed income securities								
Government	218	453	—	671	—	265	—	265
Corporate	—	457	—	457	—	44	—	44
Alternatives[4]	—	—	562	562	—	—	130	130
Forward currency contracts	—	(18)	—	(18)	—	—	—	—
Total pension plan assets at fair value	596	2,365	562	3,523	56	859	130	1,045

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 Alternatives include investments in private debt, private equity, infrastructure and real estate funds.

Changes in the net fair value of pension plan assets classified as Level 3 in the fair value hierarchy were as follows:

	Canada		United States	
December 31,	**2019**	2018	**2019**	2018
(millions of Canadian dollars)				
Balance at beginning of year	**562**	340	**130**	56
Unrealized and realized gains	**10**	77	**13**	9
Purchases and settlements, net	**280**	145	**133**	65
Balance at end of year	**852**	562	**276**	130

OPEB Plans

The following table summarizes the fair value of plan assets for our OPEB plans recorded at each fair value hierarchy level:

	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, 2019								
Cash and cash equivalents	**—**	**—**	**—**	**—**	**2**	**—**	**—**	**2**
Equity securities								
United States	**—**	**—**	**—**	**—**	**—**	**75**	**—**	**75**
Global	**—**	**—**	**—**	**—**	**—**	**38**	**—**	**38**
Fixed income securities								
Government	**—**	**—**	**—**	**—**	**40**	**15**	**—**	**55**
Alternatives[4]	**—**	**—**	**—**	**—**	**—**	**—**	**18**	**18**
Total OPEB plan assets at fair value	**—**	**—**	**—**	**—**	**42**	**128**	**18**	**188**
December 31, 2018								
Cash and cash equivalents	—	—	—	—	7	—	—	7
Equity securities								
United States	—	—	—	—	—	68	—	68
Global	—	—	—	—	—	30	—	30
Fixed income securities								
Government	—	—	—	—	43	28	—	71
Corporate	—	—	—	—	—	—	—	—
Alternatives[4]	—	—	—	—	—	—	5	5
Total OPEB plan assets at fair value	—	—	—	—	50	126	5	181

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 Alternatives includes investments in private debt, private equity, infrastructure and real estate.

Changes in the net fair value of OPEB plan assets classified as Level 3 in the fair value hierarchy were as follows:

	Canada		United States	
December 31,	**2019**	2018	**2019**	2018
(millions of Canadian dollars)				
Balance at beginning of year	**—**	—	**5**	—
Unrealized and realized gains	**—**	—	**1**	—
Purchases and settlements, net	**—**	—	**12**	5
Balance at end of year	**—**	—	**18**	5

EXPECTED BENEFIT PAYMENTS

Year ending December 31,	2020	2021	2022	2023	2024	2025-2029
(millions of Canadian dollars)						
Pension						
Canada	180	186	192	198	204	1,105
United States	87	90	91	89	91	402
OPEB						
Canada	12	12	12	13	13	69
United States	23	22	21	20	19	82

EXPECTED EMPLOYER CONTRIBUTIONS

In 2020, we expect to contribute approximately $104 million and $31 million to the Canadian and United States pension plans, respectively, and $12 million and $8 million to the Canadian and United States OPEB plans, respectively.

RETIREMENT SAVINGS PLANS
In addition to the pension and OPEB 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 2.5% and 6.0% of eligible pay per pay period for Canadian and United States employees, respectively. For the years ended December 31, 2019, 2018 and 2017, pre-tax employer matching contribution costs were $4 million, $13 million and $14 million for Canadian employees and $27 million, $27 million and $31 million for United States employees, respectively.

27. LEASES

LESSEE
We incur operating lease expenses related primarily to real estate, pipelines, storage and equipment. Our operating leases have remaining lease terms of 3 months to 28 years.

For the year ended December 31, 2019, we incurred operating lease expenses of $113 million. Operating lease expenses are reported under Operating and administrative expenses on the Consolidated Statements of Earnings.

For the year ended December 31, 2019, operating lease payments to settle lease liabilities were $123 million. Operating lease payments are reported under operating activities in the Consolidated Statements of Cash Flows.

Supplemental Statements of Financial Position Information

	December 31, 2019	January 1, 2019
(millions of Canadian dollars, except lease term and discount rate)		
Operating leases		
Operating lease right-of-use assets, net[1]	**713**	771
Operating lease liabilities - current[2]	**94**	86
Operating lease liabilities - long-term[3]	**689**	770
Total operating lease liabilities	**783**	856
Weighted average remaining lease term		
Operating leases	**13 years**	14 years
Weighted average discount rate		
Operating leases	**4.3%**	4.3%

1 *Right-of-use assets are reported under Deferred amounts and other assets in the Consolidated Statements of Financial Position.*
2 *Current lease liabilities are reported under Accounts payable and other in the Consolidated Statements of Financial Position.*
3 *Long-term lease liabilities are reported under Other long-term liabilities in the Consolidated Statements of Financial Position.*

As at December 31, 2019, our operating lease liabilities are expected to mature as follows:

	Operating leases
(millions of Canadian dollars)	
2020	128
2021	99
2022	94
2023	84
2024	79
Thereafter	588
Total undiscounted lease payments	1,072
Less imputed interest	(289)
Total operating lease liabilities	783

LESSOR

We receive revenues from operating leases primarily related to natural gas and crude oil storage and processing facilities, rail cars, and wind power generation assets. Our operating leases have remaining lease terms of 2 months to 24 years.

Year ended December 31,	**2019**
(millions of Canadian dollars)	
Operating lease income	**265**
Variable lease income	**360**
Total lease income[1]	**625**

1 *Lease income is recorded under Transportation and other services in the Consolidated Statements of Earnings.*

As at December 31, 2019, the following table sets out future lease payments to be received under operating lease contracts where we are the lessor:

	Operating leases
(millions of Canadian dollars)	
2020	236
2021	199
2022	188
2023	180
2024	178
Thereafter	2,276
Future lease payments	3,257

28. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	**2019**	2018	2017
(millions of Canadian dollars)			
Accounts receivable and other	**(659)**	857	(783)
Accounts receivable from affiliates	**6**	54	24
Inventory	**(24)**	164	(289)
Deferred amounts and other assets	**133**	226	(138)
Accounts payable and other	**175**	(151)	277
Accounts payable to affiliates	**(24)**	(122)	(62)
Interest payable	**(41)**	25	124
Other long-term liabilities	**175**	(138)	509
	(259)	915	(338)

29. 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, 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, $7 million and $14 million for the years ended December 31, 2019, 2018 and 2017, respectively.

TRANSPORTATION AGREEMENTS

Certain wholly-owned subsidiaries within the Liquids Pipelines, Gas Transmission and Midstream, Gas Distribution and Storage 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, 2019, 2018 and 2017 were $812 million, $572 million and $721 million, respectively.

AFFILIATE REVENUES AND PURCHASES

Certain wholly-owned subsidiaries within the Energy Services segments made natural gas and NGL purchases of $392 million, $322 million and $142 million from several joint venture affiliates during the years ended December 31, 2019, 2018 and 2017, respectively.

In addition to this, Enbridge recorded transportation and natural gas sales of $145 million, $122 million and $60 million within the Energy Services and Gas Distribution and Storage segments to equity investment affiliates during the years ended December 31, 2019, 2018 and 2017, 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 $34 million (US$26 million), $52 million (US$40 million) and $47 million (US$36 million) during the years ended December 31, 2019, 2018 and 2017, respectively, from DCP Midstream related to those sales.

In addition to the above, we recorded other revenues from several joint venture affiliates related to the transportation and storage of natural gas of $69 million (US$52 million), $14 million (US$11 million) and $4 million (US$3 million) during the years ended December 31, 2019, 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 these joint ventures of $48 million (US$36 million), $28 million (US$22 million) and $10 million (US$8 million) during the years ended December 31, 2019, 2018 and 2017, respectively.

LONG-TERM NOTES RECEIVABLE FROM AFFILIATES

As at December 31, 2019, amounts receivable from affiliates include a series of loans totaling $1,023 million ($769 million as at December 31, 2018), which require quarterly interest payments at annual interest rates ranging from 3% to 8%. These amounts are included in deferred amounts and other assets in the Consolidated Statements of Financial position.

30. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

At December 31, 2019, 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]	63,585	4,394	6,856	4,054	2,585	7,712	37,984
Interest obligations[2]	29,498	2,416	2,296	2,216	2,076	1,915	18,579
Purchase of services, pipe and other materials, including transportation[3,4]	9,448	2,891	1,507	1,217	564	570	2,699
Maintenance agreements	435	56	55	53	25	20	226
Land lease commitments	1,190	30	35	35	35	36	1,019
Total	104,156	9,787	10,749	7,575	5,285	10,253	60,507

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

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

3 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.

ENVIRONMENTAL

We are subject to various Canadian and US 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 obligations at various sites where we operate. We manage this environmental risk through appropriate environmental policies, programs and practices to minimize any 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 costs arising from environmental incidents associated with the operating activities of our liquids and natural gas businesses.

AUX SABLE

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.

On November 27, 2019, the counterparty filed an amended amended claim providing further particulars of its claim against Aux Sable, increasing its damages claimed, and adding defendants Aux Sable Liquid Products Inc. and Aux Sable Extraction LLC (general partners of the previously existing defendants). Aux Sable filed an amended Statement of Defence responding to the amended amended claim on January 31, 2020.

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 and our subsidiaries are subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits. 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.

31. GUARANTEES

In the normal course of conducting business, we enter into agreements which indemnify third parties and affiliates. 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.

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.

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. As at December 31, 2019 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. Please refer to *Note 12 - Variable Interest Entities* for further discussion regarding specific guarantees related to unconsolidated VIEs.

32. CONDENSED CONSOLIDATING FINANCIAL INFORMATION

On January 22, 2019, Enbridge entered into supplemental indentures with its wholly-owned subsidiaries, the Partnerships, pursuant to which Enbridge fully and unconditionally guaranteed, on a senior unsecured basis, the payment obligations of the Partnerships with respect to the outstanding series of notes issued under the respective indentures of the Partnerships. Concurrently, the Partnerships entered into a subsidiary guarantee agreement pursuant to which they fully and unconditionally guaranteed, on a senior unsecured basis, the outstanding series of senior notes of Enbridge. As a result of the guarantees, holders of any of the outstanding guaranteed notes of the Partnerships are in the same position with respect to the net assets, income and cash flows of Enbridge as holders of Enbridge's outstanding guaranteed notes, and vice versa. Other than the Partnerships, Enbridge subsidiaries (including the subsidiaries of the Partnerships, collectively, the Subsidiary Non-Guarantors), are not parties to the subsidiary guarantee agreement and have not otherwise guaranteed any of Enbridge's outstanding series of senior notes.

Consenting SEP notes and EEP notes under Guarantee

SEP Notes[1]	EEP Notes[2]
Floating Rate Senior Notes due 2020	4.200% Notes due 2021
4.600% Senior Notes due 2021	5.875% Notes due 2025
4.750% Senior Notes due 2024	5.950% Notes due 2033
3.500% Senior Notes due 2025	6.300% Notes due 2034
3.375% Senior Notes due 2026	7.500% Notes due 2038
5.950% Senior Notes due 2043	5.500% Notes due 2040
4.500% Senior Notes due 2045	7.375% Notes due 2045

1 *As at December 31, 2019, the aggregate outstanding principal amount of SEP notes was approximately US$3.9 billion.*
2 *As at December 31, 2019, the aggregate outstanding principal amount of EEP notes was approximately US$3.0 billion.*

Enbridge Notes under Guarantees

USD Denominated[1]	CAD Denominated[2]
Senior Floating Rate Notes due 2020	4.530% Senior Notes due 2020
Senior Floating Rate Notes due 2020	4.850% Senior Notes due 2020
2.900% Senior Notes due 2022	4.260% Senior Notes due 2021
4.000% Senior Notes due 2023	3.160% Senior Notes due 2021
3.500% Senior Notes due 2024	4.850% Senior Notes due 2022
2.500% Senior Notes due 2025	3.190% Senior Notes due 2022
4.250% Senior Notes due 2026	3.940% Senior Notes due 2023
3.700% Senior Notes due 2027	3.940% Senior Notes due 2023
3.125% Senior Notes due 2029	3.950% Senior Notes due 2024
4.500% Senior Notes due 2044	3.200% Senior Notes due 2027
5.500% Senior Notes due 2046	6.100% Senior Notes due 2028
4.000% Senior Notes due 2049	2.990% Senior Notes due 2029
	7.220% Senior Notes due 2030
	7.200% Senior Notes due 2032
	5.570% Senior Notes due 2035
	5.750% Senior Notes due 2039
	5.120% Senior Notes due 2040
	4.240% Senior Notes due 2042
	4.570% Senior Notes due 2044
	4.870% Senior Notes due 2044
	4.560% Senior Notes due 2064

1 *As at December 31, 2019, the aggregate outstanding principal amount of the Enbridge United States dollar denominated notes was approximately US$7.9 billion.*

2 *As at December 31, 2019, the aggregate outstanding principal amount of the Enbridge Canadian dollar denominated notes was approximately $7.6 billion.*

In accordance with Rule 3-10 of the United States Securities and Exchange Commission's Regulation S-X, which provides an exemption from the reporting requirements of the Securities Exchange Act of 1934 for subsidiary issuers of guaranteed securities and subsidiary guarantors, in lieu of filing separate financial statements for each of the Partnerships, we have included the accompanying condensed consolidating financial information with separate columns representing the following:

1. Enbridge Inc., the Parent Issuer and Guarantor;
2. SEP, a Subsidiary Issuer and Guarantor;
3. EEP, a Subsidiary Issuer and Guarantor;
4. Subsidiary Non-Guarantors, as defined herein;
5. Consolidating and elimination entries required to consolidate the Parent Issuer and Guarantor and its subsidiaries, including the Subsidiary Issuers and Guarantors, and
6. Enbridge Inc. and subsidiaries on a consolidated basis.

For the purposes of the condensed consolidating financial information only, investments in subsidiaries are accounted for under the equity method. In addition, the Condensed Consolidating Statements of Cash Flows present the intercompany loan and distribution activity, as well as cash collection and payments made on behalf of our subsidiaries, as cash activities. These intercompany investments and related activities eliminate on consolidation and are presented separately only for the purpose of the accompanying Condensed Consolidating Statements.

Condensed Consolidating Statements of Earnings and Comprehensive Income for the year ended December 31, 2019

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - SEP	Subsidiary Issuer and Guarantor - EEP	Subsidiary Non-Guarantors	Consolidating and elimination adjustments	Consolidated - Enbridge
(millions of Canadian dollars)						
Operating revenues						
Commodity sales	—	—	—	29,309	—	**29,309**
Gas distribution sales	—	—	—	4,205	—	**4,205**
Transportation and other services	—	—	—	16,555	—	**16,555**
Total operating revenues	—	—	—	50,069	—	**50,069**
Operating Expenses						
Commodity costs	—	—	—	28,802	—	**28,802**
Gas distribution costs	—	—	—	2,202	—	**2,202**
Operating and administrative	128	5	(16)	6,874	—	**6,991**
Depreciation and amortization	67	—	—	3,324	—	**3,391**
Impairment of long-lived assets	—	—	—	423	—	**423**
Impairment of goodwill	—	—	—	—	—	**—**
Total operating expenses	195	5	(16)	41,625	—	**41,809**
Operating income/(loss)	(195)	(5)	16	8,444	—	**8,260**
Income from equity investments	70	133	—	1,366	(66)	**1,503**
Equity earnings from consolidated subsidiaries	3,881	1,189	1,043	1,696	(7,809)	**—**
Other	—	—	—	—	—	**—**
Net foreign currency gain/(loss)	1,671	—	—	(106)	(1,088)	**477**
Gain/(loss) on dispositions	(7)	—	—	(293)	—	**(300)**
Other, including other income from affiliates	1,944	2	189	573	(2,450)	**258**
Interest expense	(1,268)	(330)	(591)	(2,966)	2,492	**(2,663)**
Earnings before income taxes	6,096	989	657	8,714	(8,921)	**7,535**
Income tax (expense)/recovery	(391)	44	6	(1,985)	618	**(1,708)**
Earnings	5,705	1,033	663	6,729	(8,303)	**5,827**
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	—	—	—	—	(122)	**(122)**
Earnings attributable to controlling interests	5,705	1,033	663	6,729	(8,425)	**5,705**
Preference share dividends	(383)	—	—	—	—	**(383)**
Earnings attributable to common shareholders	5,322	1,033	663	6,729	(8,425)	**5,322**
Earnings	5,705	1,033	663	6,729	(8,303)	**5,827**
Total other comprehensive income/(loss)	(2,992)	(67)	51	(929)	830	**(3,107)**
Comprehensive income	2,713	966	714	5,800	(7,473)	**2,720**
Comprehensive income attributable to noncontrolling interests	—	—	—	—	(7)	**(7)**
Comprehensive income attributable to controlling interests	2,713	966	714	5,800	(7,480)	**2,713**

Condensed Consolidating Statements of Earnings and Comprehensive Income for the year ended December 31, 2018

(millions of Canadian dollars)	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - SEP	Subsidiary Issuer and Guarantor - EEP	Subsidiary Non-Guarantors	Consolidating and elimination adjustments	Consolidated - Enbridge
Operating revenues						
Commodity sales	—	—	—	27,660	—	27,660
Gas distribution sales	—	—	—	4,360	—	4,360
Transportation and other services	—	—	—	14,358	—	14,358
Total operating revenues	—	—	—	46,378	—	46,378
Operating Expenses						
Commodity costs	—	—	—	26,818	—	26,818
Gas distribution costs	—	—	—	2,583	—	2,583
Operating and administrative	180	14	54	6,622	(78)	6,792
Depreciation and amortization	59	—	—	3,187	—	3,246
Impairment of long-lived assets	—	—	—	1,104	—	1,104
Impairment of goodwill	—	—	—	1,019	—	1,019
Total operating expenses	239	14	54	41,333	(78)	41,562
Operating income/(loss)	(239)	(14)	(54)	5,045	78	4,816
Income from equity investments	302	142	—	1,360	(295)	1,509
Equity earnings/(loss) from consolidated subsidiaries	3,119	(1,634)	921	(1,581)	(825)	—
Other						
Net foreign currency gain/(loss)	(829)	8	—	80	219	(522)
Gain/(loss) on dispositions	360	—	—	(406)	—	(46)
Other, including other income/(expense) from affiliates	945	72	153	254	(908)	516
Interest expense	(1,080)	(302)	(557)	(1,689)	925	(2,703)
Earnings/(loss) before income taxes	2,578	(1,728)	463	3,063	(806)	3,570
Income tax recovery/(expense)	304	(319)	3	(4,373)	4,148	(237)
Earnings/(loss)	2,882	(2,047)	466	(1,310)	3,342	3,333
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	—	—	—	—	(451)	(451)
Earnings/(loss) attributable to controlling interests	2,882	(2,047)	466	(1,310)	2,891	2,882
Preference share dividends	(367)	—	—	—	—	(367)
Earnings/(loss) attributable to common shareholders	2,515	(2,047)	466	(1,310)	2,891	2,515
Earnings/(loss)	2,882	(2,047)	466	(1,310)	3,342	3,333
Total other comprehensive income/(loss)	3,788	(9)	28	556	(225)	4,138
Comprehensive income/(loss)	6,670	(2,056)	494	(754)	3,117	7,471
Comprehensive income attributable to noncontrolling interests	—	—	—	—	(801)	(801)
Comprehensive income/(loss) attributable to controlling interests	6,670	(2,056)	494	(754)	2,316	6,670

Condensed Consolidating Statements of Earnings and Comprehensive Income for the year ended December 31, 2017

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - SEP	Subsidiary Issuer and Guarantor - EEP	Subsidiary Non-Guarantors	Consolidating and elimination adjustments	Consolidated - Enbridge
(millions of Canadian dollars)						
Operating revenues						
Commodity sales	—	—	—	26,286	—	26,286
Gas distribution sales	—	—	—	4,215	—	4,215
Transportation and other services	—	—	—	13,877	—	13,877
Total operating revenues	—	—	—	44,378	—	44,378
Operating expenses						
Commodity costs	—	—	—	26,065	—	26,065
Gas distribution costs	—	—	—	2,572	—	2,572
Operating and administrative	169	146	16	6,111	—	6,442
Depreciation and amortization	56	—	—	3,107	—	3,163
Impairment of long lived assets	—	—	—	4,463	—	4,463
Impairment of goodwill	—	—	—	102	—	102
Total operating expenses	225	146	16	42,420	—	42,807
Operating income/(loss)	(225)	(146)	(16)	1,958	—	1,571
Income from equity investments	471	118	—	981	(468)	1,102
Equity earnings from consolidated subsidiaries	2,130	752	926	881	(4,689)	—
Other						
Net foreign currency gain/(loss)	500	—	—	(22)	(241)	237
Gain/(loss) on dispositions	(11)	—	—	27	—	16
Other, including other income/(expense) from affiliates	871	11	139	74	(896)	199
Interest expense	(816)	(221)	(691)	(1,753)	925	(2,556)
Earnings before income taxes	2,920	514	358	2,146	(5,369)	569
Income tax (expense)/recovery	(61)	—	9	2,706	43	2,697
Earnings	2,859	514	367	4,852	(5,326)	3,266
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	—	—	—	—	(407)	(407)
Earnings attributable to controlling interests	2,859	514	367	4,852	(5,733)	2,859
Preference share dividends	(330)	—	—	—	—	(330)
Earnings attributable to common shareholders	2,529	514	367	4,852	(5,733)	2,529
Earnings	2,859	514	367	4,852	(5,326)	3,266
Total other comprehensive income/(loss)	(2,031)	12	204	(412)	(51)	(2,278)
Comprehensive income	828	526	571	4,440	(5,377)	988
Comprehensive income attributable to noncontrolling interests	—	—	—	—	(160)	(160)
Comprehensive income attributable to controlling interests	828	526	571	4,440	(5,537)	828

Condensed Consolidating Statements of Financial Position as at December 31, 2019

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - SEP	Subsidiary Issuer and Guarantor - EEP	Subsidiary Non-Guarantors	Consolidating and elimination adjustments	Consolidated - Enbridge
(millions of Canadian dollars)						
Assets						
Current assets						
Cash and cash equivalents	—	33	4	611	—	**648**
Restricted cash	9	—	—	19	—	**28**
Accounts receivable and other	429	8	4	6,340	—	**6,781**
Accounts receivable from affiliates	746	—	12	(164)	(525)	**69**
Short-term loans receivable from affiliates	1,691	—	3,961	4,417	(10,069)	**—**
Inventory	—	—	—	1,299	—	**1,299**
	2,875	41	3,981	12,522	(10,594)	**8,825**
Property, plant and equipment, net	248	—	—	93,475	—	**93,723**
Long-term loans receivable from affiliates	47,285	73	2,387	35,672	(85,417)	**—**
Investments in subsidiaries	80,456	18,956	5,180	14,782	(119,374)	**—**
Long-term investments	1,701	932	—	14,467	(572)	**16,528**
Restricted long-term investments	—	—	—	434	—	**434**
Deferred amounts and other assets	998	1	1	7,282	(849)	**7,433**
Intangible assets, net	247	—	—	1,926	—	**2,173**
Goodwill	—	—	—	33,153	—	**33,153**
Deferred income taxes	486	—	—	514	—	**1,000**
Total assets	134,296	20,003	11,549	214,227	(216,806)	**163,269**
Liabilities and equity						
Current liabilities						
Short-term borrowings	—	—	—	898	—	**898**
Accounts payable and other	2,765	28	1	7,745	(476)	**10,063**
Accounts payable to affiliates	736	367	83	(640)	(525)	**21**
Interest payable	279	52	51	242	—	**624**
Short-term loans payable to affiliates	367	2,058	1,991	5,653	(10,069)	**—**
Current portion of long-term debt	2,160	518	—	1,726	—	**4,404**
	6,307	3,023	2,126	15,624	(11,070)	**16,010**
Long-term debt	27,290	4,435	3,789	24,147	—	**59,661**
Other long-term liabilities	1,295	2	12	7,864	(849)	**8,324**
Long-term loans payable to affiliates	33,686	—	3,112	48,619	(85,417)	**—**
Deferred income taxes	—	271	—	13,887	(4,291)	**9,867**
	68,578	7,731	9,039	110,141	(101,627)	**93,862**
Equity						
Controlling interests[1]	65,718	12,272	2,510	104,086	(118,543)	**66,043**
Noncontrolling interests	—	—	—	—	3,364	**3,364**
	65,718	12,272	2,510	104,086	(115,179)	**69,407**
Total liabilities and equity	134,296	20,003	11,549	214,227	(216,806)	**163,269**

1 *Equity attributable to controlling interests for parent issuer and guarantor excludes reciprocal shareholding balance included within consolidating and elimination adjustments.*

Condensed Consolidating Statements of Financial Position as at December 31, 2018

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - SEP	Subsidiary Issuer and Guarantor - EEP	Subsidiary Non-Guarantors	Consolidating and elimination adjustments	Consolidated - Enbridge
(millions of Canadian dollars)						
Assets						
Current assets						
Cash and cash equivalents	—	16	—	502	—	518
Restricted cash	9	—	—	110	—	119
Accounts receivable and other	283	15	8	6,211	—	6,517
Accounts receivable from affiliates	726	—	13	(142)	(518)	79
Short-term loans receivable from affiliates	3,943	—	3,689	653	(8,285)	—
Inventory	—	—	—	1,339	—	1,339
	4,961	31	3,710	8,673	(8,803)	8,572
Property, plant and equipment, net	140	—	—	94,400	—	94,540
Long-term loans receivable from affiliates	10,318	73	2,539	1,344	(14,274)	—
Investments in subsidiaries	78,474	19,777	6,363	15,567	(120,181)	—
Long-term investments	4,561	987	—	14,841	(3,682)	16,707
Restricted long-term investments	—	—	—	323	—	323
Deferred amounts and other assets	1,700	9	17	8,558	(1,726)	8,558
Intangible assets, net	234	—	—	2,138	—	2,372
Goodwill	—	—	—	34,459	—	34,459
Deferred income taxes	817	—	—	229	328	1,374
Total assets	101,205	20,877	12,629	180,532	(148,338)	166,905
Liabilities and equity						
Current liabilities						
Short-term borrowings	—	—	—	1,024	—	1,024
Accounts payable and other	2,742	7	34	7,059	(6)	9,836
Accounts payable to affiliates	946	233	56	(677)	(518)	40
Interest payable	283	56	105	225	—	669
Short-term loans payable to affiliates	426	682	—	7,177	(8,285)	—
Environmental liabilities, current	—	—	—	27	—	27
Current portion of long-term debt	1,853	—	683	723	—	3,259
	6,250	978	878	15,558	(8,809)	14,855
Long-term debt	22,893	7,276	6,943	23,215	—	60,327
Other long-term liabilities	2,428	2	30	8,100	(1,726)	8,834
Long-term loans payable to affiliates	76	—	1,502	12,696	(14,274)	—
Deferred income taxes	—	331	—	13,523	(4,400)	9,454
	31,647	8,587	9,353	73,092	(29,209)	93,470
Equity						
Controlling interests[1]	69,558	12,290	3,276	107,440	(123,094)	69,470
Noncontrolling interests	—	—	—	—	3,965	3,965
	69,558	12,290	3,276	107,440	(119,129)	73,435
Total liabilities and equity	101,205	20,877	12,629	180,532	(148,338)	166,905

1 Equity attributable to controlling interests for parent issuer and guarantor excludes reciprocal shareholding balance included within consolidating and elimination adjustments.

Condensed Consolidating Statements of Cash Flows for the year ended December 31, 2019

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - SEP	Subsidiary Issuer and Guarantor - EEP	Subsidiary Non-Guarantors	Consolidating and elimination adjustments	Consolidated - Enbridge
(millions of Canadian dollars)						
Net cash provided by operating activities	2,246	1,676	(365)	9,675	(3,834)	**9,398**
Investing activities						
Capital expenditures	(75)	—	—	(5,417)	—	**(5,492)**
Long-term investments and restricted long-term investments	(26)	(11)	—	(1,122)	—	**(1,159)**
Distributions from equity investments in excess of cumulative earnings	—	24	1,196	393	(1,196)	**417**
Additions to intangible assets	(68)	—	—	(132)	—	**(200)**
Affiliate loans, net	—	—	—	(314)	—	**(314)**
Proceeds from disposition	—	—	—	2,110	—	**2,110**
Contributions to subsidiaries	(4,759)	—	(12)	—	4,771	**—**
Return of share capital from subsidiary companies	5,281	—	—	—	(5,281)	**—**
Advances to affiliates	(50,897)	—	(2,778)	(60,787)	114,462	**—**
Repayment of advances to affiliates	15,808	—	2,357	22,136	(40,301)	**—**
Other	—	—	—	(20)	—	**(20)**
Net cash (used in)/provided by investing activities	(34,736)	13	763	(43,153)	72,455	**(4,658)**
Financing activities						
Net change in short-term borrowings	—	—	—	(127)	—	**(127)**
Net change in commercial paper and credit facility draws	3,158	(2,011)	(1,017)	695	—	**825**
Debenture and term note issues, net of issue costs	3,621	—	—	2,555	—	**6,176**
Debenture and term note repayments	(1,450)	—	(2,514)	(704)	—	**(4,668)**
Contributions from noncontrolling interests	—	—	—	—	12	**12**
Distributions to noncontrolling interests	—	—	—	—	(254)	**(254)**
Contributions from redeemable noncontrolling interests	—	—	—	—	—	**—**
Distributions to redeemable noncontrolling interests	—	—	—	—	—	**—**
Contributions from parents	—	—	—	4,771	(4,771)	**—**
Distributions to parents	—	(1,014)	(651)	(8,888)	10,553	**—**
Redemption of preferred shares	—	—	—	(300)	—	**(300)**
Common shares issued	18	—	—	—	—	**18**
Preference share dividends	(383)	—	—	—	—	**(383)**
Common share dividends	(5,973)	—	—	—	—	**(5,973)**
Advances from affiliates	46,860	5,678	8,249	53,675	(114,462)	**—**
Repayment of advances from affiliates	(13,361)	(4,321)	(4,454)	(18,165)	40,301	**—**
Other	—	(4)	(7)	(60)	—	**(71)**
Net cash provided by/(used in) financing activities	32,490	(1,672)	(394)	33,452	(68,621)	**(4,745)**
Effect of translation of foreign denominated cash and cash equivalents and restricted cash	—	—	—	44	—	**44**
Net increase/(decrease) in cash and cash equivalents and restricted cash	—	17	4	18	—	**39**
Cash and cash equivalents and restricted cash at beginning of year	9	16	—	612	—	**637**
Cash and cash equivalents and restricted cash at end of year	9	33	4	630	—	**676**

Condensed Consolidating Statements of Cash Flows for the year ended December 31, 2018

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - SEP	Subsidiary Issuer and Guarantor - EEP	Subsidiary Non-Guarantors	Consolidating and elimination adjustments	Consolidated - Enbridge
(millions of Canadian dollars)						
Net cash provided by/(used in) operating activities	1,696	1,751	(239)	11,683	(4,389)	10,502
Investing activities						
Capital expenditures	(28)	—	—	(6,778)	—	(6,806)
Long-term investments and restricted long-term investments	(81)	(12)	—	(1,297)	78	(1,312)
Distributions from equity investments in excess of cumulative earnings	287	45	982	1,232	(1,269)	1,277
Additions to intangible assets	(43)	—	—	(497)	—	(540)
Proceeds from dispositions	1,790	—	—	2,662	—	4,452
Contributions to subsidiaries	(8,131)	(79)	(13)	(1,655)	9,878	—
Return of share capital from subsidiaries	3,753	—	—	—	(3,753)	—
Advances to affiliates	(6,863)	—	(1,703)	(5,685)	14,251	—
Repayment of advances to affiliates	9,427	518	1,504	4,124	(15,573)	—
Affiliate loans, net				(76)		(76)
Other	—	—	—	(12)	—	(12)
Net cash provided by/(used in) investing activities	111	472	770	(7,982)	3,612	(3,017)
Financing activities						
Net change in short-term borrowings	—	—	—	(420)	—	(420)
Net change in commercial paper and credit facility draws	(734)	(962)	(1,009)	449	—	(2,256)
Debenture and term note issues, net of issue costs	2,554	—	—	983	—	3,537
Debenture and term note repayments	—	(648)	(509)	(3,288)	—	(4,445)
Sale of noncontrolling interests in subsidiaries	—	—	—	—	1,289	1,289
Contributions from noncontrolling interests	—	—	—	—	24	24
Distributions to noncontrolling interests	—	—	—	—	(857)	(857)
Contributions from redeemable noncontrolling interests	—	—	—	—	70	70
Distributions to redeemable noncontrolling interests	—	—	—	—	(325)	(325)
Contributions from parents	—	—	1,007	8,223	(9,230)	—
Distributions to parents	—	(1,902)	(666)	(6,564)	9,132	—
Sponsored Vehicle buy-in cash payment	(64)	—	—	—	—	(64)
Redemption of preferred shares	—	—	—	(210)	—	(210)
Common shares issued	21	648	—	—	(648)	21
Preference share dividends	(364)	—	—	—	—	(364)
Common share dividends	(3,480)	—	—	—	—	(3,480)
Advances from affiliates	710	1,474	3,501	8,566	(14,251)	—
Repayment of advances from affiliates	(443)	(826)	(2,855)	(11,449)	15,573	—
Other	—	(5)	—	(18)	—	(23)
Net cash (used in)/provided by financing activities	(1,800)	(2,221)	(531)	(3,728)	777	(7,503)
Effect of translation of foreign denominated cash and cash equivalents and restricted cash	—	—	—	68	—	68
Net increase in cash and cash equivalents and restricted cash	7	2	—	41	—	50
Cash and cash equivalents and restricted cash at beginning of year	2	14	—	571	—	587
Cash and cash equivalents and restricted cash at end of year	9	16	—	612	—	637

Condensed Consolidating Statements of Cash Flows for the year ended December 31, 2017

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - SEP	Subsidiary Issuer and Guarantor - EEP	Subsidiary Non-Guarantors	Consolidating and elimination adjustments	Consolidated - Enbridge
(millions of Canadian dollars)						
Net cash (used in)/provided by operating activities	620	355	(695)	9,654	(3,276)	6,658
Investing activities						
Capital expenditures	(21)	—	—	(8,266)	—	(8,287)
Long-term investments and restricted long-term investments	(202)	(51)	—	(3,535)	202	(3,586)
Distributions from equity investments in excess of cumulative earnings	36	22	921	103	(957)	125
Additions to intangible assets	(47)	—	—	(742)	—	(789)
Cash acquired in Merger Transaction	—	—	—	682	—	682
Proceeds from dispositions	—	—	1,742	1,103	(2,217)	628
Contributions to subsidiaries	(4,866)	—	(2,056)	—	6,922	—
Return of share capital from subsidiaries	2,192	—	1,532	—	(3,724)	—
Advances to affiliates	(7,145)	(519)	(1,410)	(3,020)	12,094	—
Repayment of advances to affiliates	4,506	—	2,129	2,887	(9,522)	—
Affiliate loans, net	—	—	—	(22)	—	(22)
Other	—	—	—	212	—	212
Net cash (used in)/provided by investing activities	(5,547)	(548)	2,858	(10,598)	2,798	(11,037)
Financing activities						
Net change in short-term borrowings	—	—	—	721	—	721
Net change in commercial paper and credit facility draws	(1,845)	1,965	(316)	(1,053)	—	(1,249)
Debenture and term note issues, net of issue costs	8,177	519	—	787	—	9,483
Debenture and term note repayments	(1,711)	(533)	—	(2,810)	—	(5,054)
Purchase of interest in consolidated subsidiary	—	—	(475)	(1,969)	2,217	(227)
Contributions from noncontrolling interests	—	—	—	—	832	832
Distributions to noncontrolling interests	—	—	—	—	(919)	(919)
Contributions from redeemable noncontrolling interests	563	—	—	—	615	1,178
Distributions to redeemable noncontrolling interests	—	—	—	—	(247)	(247)
Contributions from parents	—	—	—	6,922	(6,922)	—
Distributions to parents	—	(1,987)	(789)	(6,093)	8,869	—
Preference shares issued	489	—	—	—	—	489
Redemption of preferred shares	—	—	(1,613)	1,613	—	—
Common shares issued	1,549	227	1,646	—	(1,873)	1,549
Preference share dividends	(330)	—	(478)	—	478	(330)
Common share dividends[1]	(2,336)	—	—	(414)	—	(2,750)
Advances from affiliates	407	—	2,613	9,074	(12,094)	—
Repayment of advances from affiliates	(40)	—	(2,847)	(6,635)	9,522	—
Net cash provided by/(used in) financing activities	4,923	191	(2,259)	143	478	3,476
Effect of translation of foreign denominated cash and cash equivalents and restricted cash	—	—	(2)	(70)	—	(72)
Net decrease in cash and cash equivalents and restricted cash	(4)	(2)	(98)	(871)	—	(975)
Cash and cash equivalents and restricted cash at beginning of year	6	16	98	1,442	—	1,562
Cash and cash equivalents and restricted cash at end of year	2	14	—	571	—	587

1 Common share dividends for the year ended December 31, 2017 includes amounts distributed by Spectra Energy Corp. related to dividends accrued prior to the Merger Transaction.

33. QUARTERLY FINANCIAL DATA (UNAUDITED)

(unaudited; millions of Canadian dollars, except per share amounts)	Q1	Q2	Q3	Q4	Total
2019					
Operating revenues	**12,856**	**13,263**	**11,598**	**12,352**	**50,069**
Operating income	**2,619**	**2,285**	**1,588**	**1,768**	**8,260**
Earnings	**2,023**	**1,830**	**1,060**	**914**	**5,827**
Earnings attributable to controlling interests	**1,986**	**1,832**	**1,045**	**842**	**5,705**
Earnings attributable to common shareholders	**1,891**	**1,736**	**949**	**746**	**5,322**
Earnings per common share					
Basic	**0.94**	**0.86**	**0.47**	**0.37**	**2.64**
Diluted	**0.94**	**0.86**	**0.47**	**0.36**	**2.63**
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

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, 2019, 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 submit to the 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, 2019, 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, 2019.

The effectiveness of our internal control over financial reporting as at December 31, 2019 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, 2019.

Changes in Internal Control Over Financial Reporting
During the three months ended December 31, 2019, there has been no material change in our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Directors of Registrant
The information required by this Item will be contained in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2019. This information will also be contained in the management proxy information that we prepare in accordance with Canadian corporate and securities law requirements.

Executive Officers of Registrant
The information regarding executive officers is included in Part I. *Item 1. Business - Executive Officers.*

Code of Ethics for Chief Executive Officer and Senior Financial Officers
The information required by this Item will be contained in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2019. This information will also be contained in the management proxy information that we prepare in accordance with Canadian corporate and securities law requirements.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item will be contained in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2019. This information will also be contained in the management proxy information that we prepare in accordance with Canadian corporate and securities law requirements.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this Item will be contained in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2019. This information will also be contained in the management proxy information that we prepare in accordance with Canadian corporate and securities law requirements.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this Item will be contained in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2019. This information will also be contained in the management proxy information that we prepare in accordance with Canadian corporate and securities law requirements.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this Item will be contained in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2019. This information will also be contained in the management proxy information that we prepare in accordance with Canadian corporate and securities law requirements.

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	*	General By-Law No. 1 of Enbridge Inc.
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 7.1 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		Sixth Supplemental Indenture between Enbridge Inc., Spectra Energy Partners, LP (as guarantor), Enbridge Energy Partners, L.P. (as guarantor) and Deutsche Bank Trust Company Americas, dated May 13, 2019 (incorporated by reference to Enbridge's Registration Statement on Form S-3 filed May 17, 2019)
4.8		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)
4.9	*	Description of Securities Registered Under Section 12 of the Securities Exchange Act, as amended

		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) (incorporated by reference to Exhibit 10.11 to Enbridge's Annual Report on Form 10-K filed February 15, 2019)
10.12	+	Enbridge Inc. 2019 Long Term Incentive Plan (incorporated by reference to Appendix A to Enbridge's Proxy Statement on Schedule 14A for Enbridge's Annual Meeting of Shareholders (File No. 001-15254) filed March 27, 2019)
10.13	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Stock Option Grant Notice and Stock Option Award Agreement (incorporated by reference to Exhibit 10.4 to Enbridge's Form 10-Q filed May 10, 2019)
10.14	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Performance Stock Unit Grant Notice and Performance Stock Unit Award Agreement (incorporated by reference to Exhibit 10.5 to Enbridge's Form 10-Q filed May 10, 2019)
10.15	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Stock Unit Award Agreement (incorporated by reference to Exhibit 10.6 to Enbridge's Form 10-Q filed May 10, 2019)
10.16	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Restricted Stock Unit - Energy Marketers Grant Notice and Restricted Stock Unit Award Agreement (incorporated by reference to Exhibit 10.7 to Enbridge's Form 10-Q filed May 10, 2019)

10.17	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Stock Unit Award Agreement - Retention Award Version (incorporated by reference to Exhibit 10.8 to Enbridge's Form 10-Q filed August 2, 2019)
10.18	+	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)
10.19	+	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)
10.20	+	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)
10.21	+	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)
10.22	+	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)
10.23	+	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)
10.24	+	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)
10.25	+	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)
10.26	+	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)
10.27	+	Enbridge Inc. Incentive Stock Option Plan (2007), as revised (incorporated by reference to Exhibit 10.15 to Enbridge's Annual Report on Form 10-K filed February 16, 2018)
10.28	+	Enbridge Inc. Directors' Compensation Plan dated February 14, 2018 Amended Effective February 12, 2019 (incorporated by reference to Exhibit 10.2 to Enbridge's Form 10-Q filed May 10, 2019)
10.29	+	Enbridge Inc. Directors' Compensation Plan dated February 14, 2018, effective January 1, 2018 (incorporated by reference as Exhibit 10.3 to Enbridge's Form 10-Q filed May 10, 2018)
10.30	+	Enbridge Inc. Short Term Incentive Plan (As Amended and Restated Effective January 1, 2019) (incorporated by reference to Exhibit 10.1 to Enbridge's Form 10-Q filed May 10, 2019)
10.31	+	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)
10.32	+	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)
10.33	+	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)
10.34	+	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)

10.35	+	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)
10.36	+	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)
10.37	+	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)
10.38	+	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)
10.39	+	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)
10.40	+	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)
10.41	+	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)
10.42	+	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)
10.43	+	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)
10.44	+	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)
10.45	+	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)
10.46	+	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)
10.47	+	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, Colin K. Gruending and Karen K. L. Uehara, 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 14, 2020	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 14, 2020 by the following persons on behalf of the registrant and in the capacities indicated.

/s/ Al Monaco	/s/ Colin K. Gruending
Al Monaco *President, Chief Executive Officer and Director* *(Principal Executive Officer)*	Colin K. Gruending *Executive Vice President and Chief Financial Officer* *(Principal Financial Officer)*
/s/ Mark A. Maki	/s/ Gregory L. Ebel
Mark A. Maki *Senior Vice President and Chief Accounting Officer* *(Principal Accounting Officer)*	Gregory L. Ebel *Chairman of the Board of Directors*
/s/ Pamela L. Carter	/s/ Marcel R. Coutu
Pamela L. Carter *Director*	Marcel R. Coutu *Director*
/s/ Susan M. Cunningham	/s/ J. Herb England
Susan M. Cunningham *Director*	J. Herb England Director
/s/ Charles W. Fischer	/s/ Gregory J. Goff
Charles W. Fischer Director	Gregory J. Goff Director
/s/ V. Maureen Kempston Darkes	/s/ Teresa S. Madden
V. Maureen Kempston Darkes Director	Teresa S. Madden Director
/s/ Dan C. Tutcher	/s/ Cathy L. Williams
Dan C. Tutcher Director	Cathy L. Williams Director

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Investor Information

Investor Inquiries

If you have inquiries regarding the following:

- The latest news releases or investor presentations
- Any investment-related inquiries

Please contact Enbridge Investor Relations
Toll-free: 1-800-481-2804
investor.relations@enbridge.com

Enbridge Inc.
200, 425 – 1 Street S.W.
Calgary, Alberta, Canada T2P 3L8

Telephone: 1-403-231-3900
Facsimile: 1-403-231-3920
enbridge.com

Registrar and Transfer Agent

For information relating to shareholdings, shareholder investment plan, dividends, direct dividend deposit and lost certificates, please contact:

Computershare Trust Company of Canada
100 University Avenue, 8th Floor
Toronto, Ontario M5J 2Y1

Toll-free North America: 1-866-276-9479
Outside North America: 1-514-982-8696
computershare.com/enbridge

Auditors

PricewaterhouseCoopers LLP

2020 Enbridge Inc. Common Share Dividends

	Q1	Q2	Q3	Q4
Dividend	$0.81	$ – [2]	$ – [2]	$ – [2]
Payment date	Mar 01	Jun 01	Sep 01	Dec 01
Record date[1]	Feb 14	May 15	Aug 14	Nov 13

[1] Dividend record dates for Common Shares are generally February 15, May 15, August 15 and November 15 in each year unless the 15th falls on a Saturday or Sunday.

[2] Amount will be announced as declared by the Board of Directors.

On November 2, 2018, Enbridge Inc. announced that it has suspended its dividend reinvestment and share purchase plan (DRIP) until further notice.

Common and Preference Shares

The Common Shares of Enbridge Inc. trade in Canada on the Toronto Stock Exchange and in the United States on the New York Stock Exchange under the trading symbol "ENB." The Preference Shares of Enbridge Inc. trade in Canada on the Toronto Stock Exchange under the trading symbols:

Series A – ENB.PR.A
Series B – ENB.PR.B
Series C – ENB.PR.C
Series D – ENB.PR.D
Series F – ENB.PR.F
Series H – ENB.PR.H
Series J – ENB.PR.U
Series L – ENB.PF.U
Series N – ENB.PR.N
Series P – ENB.PR.P
Series R – ENB.PR.T

Series 1 – ENB.PR.V
Series 3 – ENB.PR.Y
Series 5 – ENB.PF.V
Series 7 – ENB.PR.J
Series 9 – ENB.PF.A
Series 11 – ENB.PF.C
Series 13 – ENB.PF.E
Series 15 – ENB.PF.G
Series 17 – ENB.PF.I
Series 19 – ENB.PF.K

Forward-Looking Information

This Annual Report includes references to forward-looking information. By its nature this information involves certain assumptions and expectations about future outcomes, so we remind you it is subject to risks and uncertainties that affect our business. The more significant factors and risks that might affect our future outcomes are listed and discussed in the "Forward-Looking Information" and Risk Factors sections of our Form 10-K and Management's Discussion & Analysis, included in this Annual Report and available on both sedar.com and sec.gov.

Enbridge is committed to reducing its impact on the environment in every way, including the production of this publication. This report was printed entirely on FSC® Certified paper containing post-consumer waste fiber.

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