Bridge to a cleaner

energy future

2021 Annual Report

ENBRIDGE®

Life Takes Energy®

Letter to Shareholders

Dear Shareholder,

Last year, global economies and the energy business continued to be challenged by the COVID-19 pandemic. However, a robust economic recovery drove energy demand and commodity prices higher, and underscored the importance of reliable, affordable energy in our lives.

Our people safely navigated COVID restrictions and supported each other and our communities. We continued to focus and deliver on our purpose – to provide the energy that people rely on every day to fuel their quality of life. We delivered record safety, operating and financial performance, and executed on key strategic priorities. At the same time, we took steps to modernize our systems, diversify our assets, and advance our net-zero emissions and diversity and inclusion targets.

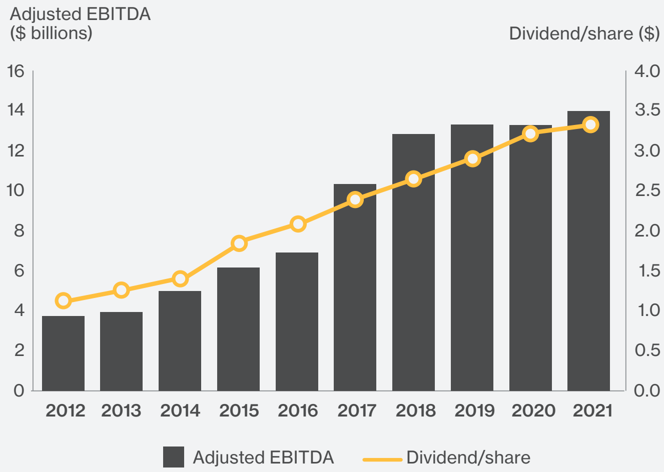
We're proud of our people and what we achieved last year – helping to further cement Enbridge's position as North America's leading energy delivery company.

In 2021, Enbridge set employee and contractor safety and system reliability records because of our strong safety culture and investments in system integrity and preventative maintenance.

Delivering on results and strategic priorities

2021 was a catalyst year for the Company. We built on our momentum to grow our conventional business, reduce emissions intensity from our existing assets and expand our low-carbon investments. We reached the top end of our external guidance range for distributable cash flow (DCF)[1] per share, increased our dividend for the 26th consecutive year – and extended that track record with another 3% dividend increase for 2022.

In 2021, Enbridge generated strong total shareholder returns of 30%. Over the last 10 years, we have grown earnings before interest taxes depreciation and amortization (adjusted EBITDA[1]) at an average annual rate of 14% by executing a $65 billion organic capital program, delivering on revenue and productivity improvements, as well as selective acquisitions that have advanced our strategies and driven further organic growth. That includes the 2017 acquisition of Spectra, which transformed the business by adding a leading natural gas utility and pipeline footprint – complementing Enbridge's irreplaceable crude oil assets and growing renewables business. Last year, Enbridge added North America's leading crude oil export platform through the acquisition of the Ingleside Energy Center, which positions the Company to play a pivotal role in global energy exports. Our disciplined investment of capital, while protecting our sector-leading financial strength, has enabled us to grow the dividend on average by 13% per year over the last 10 years, supporting robust shareholder returns.



[1] Adjusted EBITDA and DCF per share are non-GAAP measures.

In 2021, we placed $10 billion of secured capital into service – including completion of the state-of-the-art Line 3 Replacement Project, the largest capital project in Enbridge's history – and sanctioned $2 billion of new projects. These investments will contribute to cash flow growth and provide additional financial capacity in the years to come.

Engagement with Indigenous groups along the Line 3 right-of-way led to a better route, as well as tailored environmental measures to protect the land and minimize impacts. This engagement also resulted in $900 million in Indigenous business opportunities, including Indigenous workers comprising 7% of the U.S. Line 3 workforce. This valuable experience is being shared across our organization to further strengthen our lifecycle approach to Indigenous and stakeholder engagement.

> Indigenous-owned MB Customs worked on the Line 3 Replacement Program in Minnesota.

We also advanced our export strategy with the acquisition of the Ingleside Energy Center, through which we established a leading light-oil export position and platform for future organic growth. We aligned that investment with our target to reach net-zero emissions by 2050 by committing to develop an on-site solar farm that will drive net-zero Scope 1 and 2 emissions, while also contributing to Scope 3 reductions. This is a great example of how Enbridge is differentiating its approach to energy infrastructure.

> In February 2022, Enbridge and First Nation Capital Investment Partnership (FNCIP) announced plans to work together to advance a new carbon transportation and storage solution west of Edmonton called the Open Access Wabamun Carbon Hub. The proposed Wabamun Hub will tie into planned carbon capture projects, with the combined potential to abate nearly 4 million tonnes of CO_2 emissions annually.

Good progress is being made on our $10 billion commercially secured growth program, including construction of four offshore wind projects in Europe, connecting new customers to our natural gas distribution system, and modernizing our long-haul pipeline systems. We also established industry partnerships to advance our early-mover position in renewable natural gas, hydrogen, and carbon capture and storage.

Over the last several years we've worked with our customers to develop a new contract offering for our Canadian Mainline. Last year, our proposal was declined by the Canada Energy Regulator (CER), despite having support from more than 75% of our shippers. We'll continue to collaborate with our customers on two alternative options to assure a solid, long-term commercial arrangement is in place.

> The Enbridge team continued to make a positive impact in our communities – including a US$4 million contribution to the United Way – and thousands of hours of volunteering with close to 3,000 local community and Indigenous organizations. Our people stepped up to support recovery efforts following wildfires and flooding in B.C., and the same care was shown after Hurricane Ida in Louisiana.

Bridging to a cleaner energy future

Forecasts show that the demand for energy will continue to increase as populations grow and developing nations raise their standards of living. Natural gas and oil make up more than half of that energy demand today and we expect demand to remain strong for decades to come, even as renewables grow. This energy is critical for transportation, heating, cooking, manufacturing, electronics, pharmaceuticals – and more. North America has an abundant supply of oil and gas with leading environmental performance – supply that can be exported to where it's needed.

It's clear that society is moving toward a lower-carbon economy. We believe that we need to transition our energy systems prudently to ensure adequate supply of conventional energy while lowering emissions and increasing investment in low-carbon energies.

We have a solid inventory of both conventional and low-carbon opportunities, totaling about $6 billion of annual investment. On the conventional side, we'll expand and modernize gas systems, which will displace coal and support renewables growth. We'll continue to build out our LNG and export positions and invest in our gas utility. We'll also pursue capital-efficient Liquids Pipelines optimizations.

These businesses also come with embedded low-carbon opportunities. Our existing assets will support the energy transition by blending and transporting renewable natural gas and hydrogen, transporting and storing carbon, and moving more natural gas. Our Renewables business also gives us high visibility to growth, with 14 projects in construction, including solar self-power in North America and offshore wind in France.

Getting the pace of the transition right will be critical. We're taking a disciplined approach to ensure that new opportunities provide an attractive return, and we'll build on proven technologies and partner with those who can bolster our capability. This is exactly the model we used for wind and solar 20 years ago, and today Enbridge has a leading renewables platform.

Energy is needed in every aspect of daily life, and our assets provide an essential source of safe, reliable and affordable energy. Our systems have longevity because they serve the best markets and can't be replaced. We're modernizing our assets to improve efficiency and reduce emissions.

Sustaining our growth

In 2022, we're positioned to grow adjusted EBITDA and DCF per share by about 8%. We expect to exit 2022 near the bottom of our 4.5x to 5.0x debt to EBITDA range, driven by annualized contributions from Line 3 and the Ingleside terminal. We remain focused on managing costs and maximizing our financial strength and flexibility.

Our visible cash flow growth outlook and healthy balance sheet will enable the return of capital as part of our shareholder value proposition.

Over the next three years, we expect to generate $5 to $6 billion of annual investment capacity. Of that amount, $3 to $4 billion will be prioritized to low-capital intensity and utility-like investments, and the remaining $2 billion will be deployed to the next best alternatives, such as organic growth, profitable energy transition investments, share repurchases or debt reduction. The $1.5 billion share-buyback program we recently introduced creates an additional avenue to return value to shareholders.

By executing on our secured capital program, enhancing returns on our existing businesses, and deploying excess financial capacity, we estimate 5 – 7% DCF per share compound annual growth through 2024 versus 2021 results.

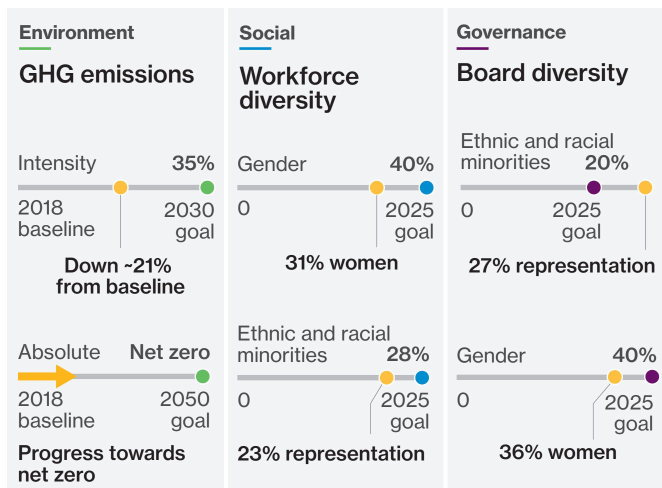
Enbridge was an early investor in low-carbon energies and is well positioned to be a North American leader. In 2021, we established a dedicated New Energy Technologies team. Through 2025, we see opportunity to invest a further $1.5 billion to advance low-carbon opportunities, in addition to the $2.5 billion in offshore wind projects already in execution.

Being a differentiated service provider

Core to our strategy is our industry-leading approach to our environmental, social and governance (ESG) performance. Our performance in these areas has and will continue to differentiate Enbridge – setting us apart as the service provider of choice for our customers, an employer of choice, a trusted partner to communities, Indigenous groups and policy makers, and a best-in-class investment.

In 2020, we introduced ESG goals, including continuing to drive industry-leading safety performance, reducing emissions to net zero, and improving diversity and inclusion. We've set ambitious goals for our ESG efforts, made them public and linked discretionary pay for all employees to progress in these areas. At our inaugural ESG Forum in September 2021, we shared detailed plans for how we're going about achieving these goals and how we've integrated them into each of our businesses.

2021 ESG performance update



Last year, we issued $3 billion in sustainability-linked financings that are tied to achievement of our ESG goals. We also further advanced our capital-allocation framework to ensure that all new investments account for carbon prices and are aligned with our emissions-reduction goals.

We're on track to reduce our emissions intensity 35% by 2030 and reach our net-zero emissions target by 2050. Additionally, we expanded emissions reporting to include new Scope 3 metrics designed to measure the emissions intensity of energy delivered and the emissions avoided through our more than two decades of investment in renewables, low-carbon fuels, and demand-side management programs. Since 2018, we have reduced our emissions intensity and absolute emissions by approximately 21% and 14%, respectively.

Through demand-side management in our Gas Distribution and Storage business unit, we've reduced emissions by nearly 55 million tCO_2e since 1995.

We're committed to industry leadership in sustainability and continuous improvement in this area. That's why we've implemented additional measures, including working with our supply chain to lower Scope 3 emissions, developing partnerships to advance low-carbon innovation within our businesses, and working proactively with organizations developing science-based guidelines for emissions targets in the midstream sector. This year's annual sustainability report will include a scenario analysis that considers the resiliency of our strategy on a net-zero pathway.

We remain steadfast in our belief that an energized work force is driven by diversity, equity and inclusion. This continues to be a priority and has been embedded in our hiring decisions and training, including mandatory training on racial justice, unconscious bias and Indigenous cultural awareness.

Prior to the pandemic, we enhanced our Workplace Mental Health initiatives to provide more resources and education on well-being – programs that proved to be critically important over the last two years. We're now advancing our efforts by raising awareness of the small actions we can take to reduce stigma, create personal well-being, and make people feel valued and appreciated.

We're deliberate about creating the right environment for our people. We conduct regular surveys and focus groups to listen to their input and ensure that we continue to evolve and meet the needs of today. Last year, we expanded our FlexWork program to give Enbridge employees more choice to balance accountabilities at work and at home.

Our highly engaged Board reflects a balance of diverse perspectives, backgrounds and experiences. Our independent Board Chair and separate Chair and CEO positions represent corporate governance best practices. Four of our directors are women, three of whom chair Board committees. Three of 11 directors self-identify as members of an ethnic or visible minority and, subject to shareholder approval of our 2022 director nominees, we expect to increase our diversity further.

Evolving our leadership and Board

There were several changes to senior leadership last year as part of development and succession planning, and we're fortunate to have strong leaders to step into new roles. This included the retirement of Bill Yardley, Executive Vice President and President, Gas Transmission and Midstream, who spent 22 years with Enbridge. Bill leaves a strong legacy and will be remembered for his passion for the business and his deep care and respect for the people around him.

In 2021, the Board welcomed three new directors: Mayank (Mike) Ashar, Gaurdie Banister and Jane Rowe; three highly qualified individuals who bring significant energy industry experience and strong skills and business judgment to the Board. We're also bringing forward two new Board candidates, Jason Few and Steven Williams, who will stand for election at our annual general meeting in May. Information about our Board directors and new candidates can be found in our Management Information Circular.

We said goodbye to Gregory Goff, Maureen Kempston-Darkes and Marcel Coutu as directors. We'd like to thank them for their valuable contributions to the Company. We'd also like to acknowledge Herb England who will be retiring at this year's meeting. As one of our longest-serving Board members, Herb has played a significant role in shaping Enbridge's strategy, and his leadership and dedication will be missed.

Our thanks

Each year our performance comes down to our people, who fulfill Enbridge's purpose while living our values of Safety, Integrity, Respect and Inclusion. We thank them for their commitment to our business.

As we look to next year, the strong demand for our systems and execution on our capital program continue to drive stable and growing cash flows. We believe that our embedded conventional and low-carbon organic growth opportunities, along with our disciplined approach to investment and increasing dividends, provide a compelling growth outlook and continued strong value proposition for our shareholders and our other important stakeholders.

Sincerely,

Greg Ebel and Al Monaco

Gregory L. Ebel
Chair, Board of Directors

Al Monaco
President & Chief Executive Officer

Calgary, Alberta
March 2, 2022

Our Board

Gregory L. Ebel

Mayank (Mike) M. Ashar

Gaurdie E. Banister Jr.

Pamela L. Carter

Susan M. Cunningham

J. Herb England

Teresa S. Madden

Al Monaco

Stephen S. Poloz

S. Jane Rowe

Dan C. Tutcher

About us

At Enbridge, our purpose is to fuel quality of life by delivering energy safely, reliably and sustainably. Whether it's oil, natural gas or renewable power, the energy we deliver helps to heat homes, feed families, fuel vehicles, power industry and benefit society in thousands of ways. The passion and innovation of our 11,000-person team has helped Enbridge become North America's leading energy delivery company.

Throughout our history, we've looked beyond the horizon to invest in modern infrastructure, resilient communities and reliable energy. We're building a bridge to a more sustainable future by meeting energy needs today and growing our low-carbon businesses for tomorrow.

While conventional energy will continue to be needed for decades to come, Enbridge is taking a balanced approach to the energy transition.

Our networks stretch across North America and we're modernizing our systems, expanding our footprint, and working toward our goal to be net zero by 2050. We're taking steps big and small to reduce emissions and accelerate the energy transition, including pursuing the potential for investment of $4 billion through 2025 in renewable power and low-carbon energy solutions such as hydrogen, renewable natural gas (RNG), and carbon capture and storage (CCS).

As we grow and evolve, we'll continue to be guided by a strong set of core values – Safety, Integrity, Respect and Inclusion – that reflect what is truly important to Enbridge.

Our core businesses

Enbridge plays a significant role in the energy value chain by connecting people to the energy they need and want.

- Gas Transmission and Midstream (GTM) transports approximately 20% of the natural gas consumed in the U.S., supplying natural gas to approximately 170 million people, as well as power generation facilities across the continent.
- Gas Distribution and Storage (GDS) has more than 3.9 million metered connections in over 300 municipalities across Ontario and Quebec and supplies energy to 75% of Ontario residents.
- Liquids Pipelines (LP) transports approximately 30% of the crude oil produced in North America to 25 refiners, connecting producers to the best markets in the U.S. Midwest, the U.S. Gulf Coast and Eastern Canada.
- Renewable Power Generation has ownership interests in more than 48 renewable energy facilities (in operation and under construction) with 2,178 megawatts (MW) of net generation capacity – enough to meet the electricity needs of nearly one million homes.
- Enbridge's recently formed New Energy Technologies team collaborates with each business unit to advance low-carbon energy infrastructure opportunities across the Company and build on Enbridge's early investments in RNG, hydrogen and CCS.

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, 2021

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 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 has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. Yes ☒ No ☐
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, 2021, was approximately US$77.7 billion.
As at February 4, 2022, the registrant had 2,026,274,277 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 of America (US) for purposes of the Securities Exchange Act of 1934, as amended (the Exchange Act). Although, as a foreign private issuer, Enbridge Inc. is not required to do so, Enbridge Inc. currently files 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

AFUDC	Allowance for funds used during construction
AOCI	Accumulated other comprehensive income/(loss)
ARO	Asset retirement obligations
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
BC	British Columbia
bcf/d	Billion cubic feet per day
bpd	Barrels per day
CCS	Carbon capture and storage
CER	Canada Energy Regulator, created by the Canadian Energy Regulator Act which also repealed the National Energy Board Act, on August 28, 2019
CPP Investments	Canada Pension Plan Investment Board
CTS	Competitive Toll Settlement
DAPL	Dakota Access Pipeline
Dawn	An extensive network of underground storage pools at the Tecumseh Gas Storage facility and Dawn Hub
DCP Midstream	DCP Midstream, LLC
EBITDA	Earnings before interest, income taxes and depreciation and amortization
EEP	Enbridge Energy Partners, L.P.
EIEC	Enbridge Ingleside Energy Center
EIS	Environmental Impact Statement
EMF	Éolien Maritime France SAS
Enbridge	Enbridge Inc.
Enbridge Gas	Enbridge Gas Inc.
ESG	Environment, Social and Governance
FERC	Federal Energy Regulatory Commission
Flanagan South	Flanagan South Pipeline
GHG	Greenhouse gas
H2	Hydrogen gas
IJT	International Joint Tariff
ISO	Incentive Stock Options
kbpd	Thousand barrels per day
LMCI	Land Matters Consultation Initiative
LNG	Liquefied natural gas
MATL	Montana-Alberta Tie-Line
MD&A	Management’s Discussion and Analysis
Moda	Moda Midstream Operating, LLC

MW	Megawatts
NCIB	Normal course issuer bid
NGLs	Natural gas liquids
Noverco	Noverco Inc.
NYSE	New York Stock Exchange
OBPS	Output-based pricing system
OCI	Other comprehensive income/(loss)
OEB	Ontario Energy Board
OPEB	Other postretirement benefit obligations
PHMSA	Pipeline and Hazardous Materials Safety Administration
PSU	Performance Stock Units
RNG	Renewable natural gas
ROU	Right-of-use
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
SPOT	Sea Port Oil Terminal
Texas Eastern	Texas Eastern Transmission, L.P.
TSX	Toronto Stock Exchange
US	United States of America
US GAAP	Generally accepted accounting principles in the United States of America
US L3R Program	United States portion of the Line 3 Replacement Program
VIE	Variable interest entities
Westcoast	Westcoast Energy Inc.

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 “$” are to Canadian dollars and all references to “US$” are to US 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; the COVID-19 pandemic and the duration and impact thereof; energy intensity and emissions reduction targets and related Environment, Social and Governance (ESG) matters; diversity and inclusion goals; expected supply of, demand for, and prices of crude oil, natural gas, natural gas liquids (NGLs), liquified natural gas and renewable energy; energy transition; anticipated utilization of our existing assets; expected earnings before interest, income taxes and depreciation and amortization (EBITDA); expected earnings/(loss); expected future cash flows and distributable cash flow; dividend growth and payout policy; 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 and for maintenance; expected in-service dates for announced projects and projects under construction and for maintenance; expected capital expenditures, investment capacity and capital allocation priorities; 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, synergies and cost savings; expected future actions of regulators and courts; toll and rate cases discussions and filings, including Mainline System contracting; anticipated competition; United States Line 3 Replacement Program (US L3R Program), including anticipated in-service dates and capital costs; and Line 5 dual pipelines and related litigation and other matters.

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 COVID-19 pandemic and the duration and impact thereof; the expected supply of and demand for crude oil, natural gas, NGL and renewable energy; prices of crude oil, natural gas, NGLs and renewable energy; anticipated utilization of assets; 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; litigation; estimated future dividends and impact of our dividend policy on our future cash flows; our credit ratings; capital project funding; hedging program; expected EBITDA; expected earnings/(loss); expected future cash flows; and expected distributable cash flow. Assumptions regarding the expected supply of and demand for crude oil, natural gas, NGLs 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, interest rates and the COVID-19 pandemic 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 regarding 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, customer, government, court and regulatory approvals on construction and in-service schedules and cost recovery regimes; and the COVID-19 pandemic and the duration and impact thereof.

Our forward-looking statements are subject to risks and uncertainties pertaining to the successful execution of our strategic priorities, operating performance, legislative and regulatory parameters; litigation, including with respect to the Dakota Access Pipeline (DAPL) and the Line 5 dual pipelines; acquisitions, dispositions and other transactions and the realization of anticipated benefits therefrom; 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; exchange rates; interest rates; commodity prices; political decisions; the supply of, demand for and prices of commodities; and the COVID-19 pandemic, 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 US 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 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.

NON-GAAP AND OTHER FINANCIAL MEASURES

Part II. Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations *(MD&A) in this Annual Report on Form 10-K makes reference to non-GAAP and other financial measures, including EBITDA. EBITDA is defined as earnings before interest, income taxes, depreciation and amortization. Management uses EBITDA to assess performance of Enbridge and to set targets. Management believes the presentation of EBITDA gives useful information to investors as it provides increased transparency and insight into the performance of Enbridge.*

The non-GAAP and other financial measures described above are not measures that have a standardized meaning prescribed by generally accepted accounting principles in the United States of America (US GAAP) and are not US GAAP measures. Therefore, these measures may not be comparable with similar measures presented by other issuers. A reconciliation of historical non-GAAP and other financial measures to the most directly comparable GAAP measures is set out in this MD&A and is available on our website. Additional information on non-GAAP and other financial measures may be found on our website, www.sedar.com or www.sec.gov.

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 30% of the crude oil produced in North America; Gas Transmission and Midstream, which transports approximately 20% of the natural gas consumed in the US; Gas Distribution and Storage, which serves approximately 75% of Ontario residents via approximately 3.8 million meter connections; and Renewable Power Generation, which generates approximately 1,766 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 primary purpose as a company is to fuel quality of life by providing the energy people need and want, in a safe, clean and socially responsible way. Our vision to be the leading energy infrastructure company in North America supports this purpose. In pursuing this vision, we play a critical role in enabling the economic and social well-being of people in the areas we serve who depend on access to affordable and reliable energy of all types. Our infrastructure franchises transport, distribute, and generate energy including liquids, natural gas, renewable power, and low-carbon fuels like Renewable Natural Gas (RNG). We recognize that the energy system is changing, and we aim to bridge to that cleaner energy future by investing in low-carbon platforms while ensuring the continuity and stability that the world requires through the transition.

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, power purchase agreements, and other low-risk commercial arrangements.

We strive to be a leader in ESG; worker and public safety; emissions reduction; stakeholder relations; customer service; community investment; and employee engagement and satisfaction.

STRATEGY

An in-depth understanding of energy supply and demand fundamentals coupled with disciplined capital allocation principles has helped us become an industry leader supported by a diverse set of assets across the energy system. Our assets have reliably generated low-risk, resilient cash flows through many commodity and economic cycles, including the COVID-19 pandemic and the ensuing volatile economic recovery.

To ensure we continue to be an industry leader and value creator going forward, we maintain a robust strategic planning approach. We regularly conduct scenario and resiliency analysis on both our assets and on our business strategy. We test various value enhancement and maximization options, and we engage regularly with our Board of Directors (Board) to ensure alignment and maintain active oversight. This Board participation includes updates and discussions throughout the year and a dedicated session to Strategy Planning annually. This comprehensive approach will continue to guide investment decisions moving forward.

Predictable growth is a hallmark of our investor value proposition. We see a 5-7% compound annual growth rate in distributable cash flow per share through 2024, relative to 2021, underpinned by opportunities to advance returns in our base business and grow organically through disciplined capital allocation. Our diversified footprint allows for selective investment in both our core businesses and in emerging low carbon energy platforms such as carbon capture and storage (CCS), hydrogen gas (H2), and RNG.

In 2021, we progressed several of our strategic priorities. For example:

- Our Liquids Pipelines team delivered record mainline throughput, placed $5.6 billion of capital into service (Line 3 Replacement, Southern Access), added 90 kbpd of system expansions into Petroleum Administration for Defense Districts (PADD) III, and acquired the Ingleside Energy Center in Corpus Christi and related assets which extends our reach into global light-oil export markets.

- Our Gas Transmission and Midstream business successfully placed $3.1 billion of capital into service, completed favorable rate settlements, which added $150 million of incremental EBITDA, and continued to advance more than $2 billion of expansion opportunities.

- Our Gas Distribution and Storage utility provided uninterrupted services during the ongoing pandemic, added over 40 thousand new customers, completed 190 modernization projects, placed two RNG projects into service, and completed an H2 blending pilot.

- In Europe, Renewable Power Generation advanced construction of the 480 MW Saint Nazaire project, the 500 MW Fécamp project, and the 448 MW Calvados project, and sanctioned the Provence Grand Large floating offshore wind facility.

- We advanced our self-power strategy and commissioned two projects, Alberta Solar One on our Liquids Pipeline system and Heidlersberg on our Gas Transmission system. Ten additional self-power facilities (~100MW) were approved for future development.

- We established our New Energy Technologies team to advance our low-carbon strategy. Through several strategic partnerships, we are working to develop solutions in RNG, H2 and CCS and to accelerate global and industry-specific low-carbon objectives.

- We continued to make meaningful progress towards our ESG goals that include a 35% reduction in greenhouse gas (GHG) emissions intensity from our operations by 2030 (net zero GHG emissions by 2050) and increased representation of diverse groups within our workforce and the Board of Directors by 2025.

- We sold $1.2 billion of assets at attractive valuations, further strengthening our financial flexibility. In addition, we continued to reduce our operating costs ($1.2 billion since 2017), increasing our profitability and competitiveness.

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. As always, proactively advancing the safety of communities and assets, protecting the environment, and maintaining reliability will always be our top priorities. We are focused on enhancing the value of our existing assets in Liquids Pipelines, Gas Transmission and Midstream, Gas Distribution and Storage, and Renewable Power Generation.

We will continue to enhance base business returns, capitalize on our advantaged liquids and natural gas pipeline infrastructure, emphasizing export-driven opportunities and in-franchise organic growth, and developing low-carbon opportunities across our business.

Our key strategic priorities are summarized below:

Ensure Safe Reliable Operations
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.

Enhance Returns from our Base Businesses
A key priority is to drive growth through an ongoing focus on optimization, productivity, and efficiency across all our businesses. Examples include: the application of drag-reducing agents and pump station horsepower additions to optimize throughput on our liquids system, the execution of toll settlements and rate case filings to optimize revenue within our gas transmission franchises, the expansion of low-carbon gas offerings to modernize and integrate value chains at our gas utility, and more generally, and the creation of sustainable cost savings across the organization through process improvement and/or system enhancements.

Execute the Capital Program and Grow Core Business
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 $9 billion through 2024) 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 of about $5 to $6 billion per year to invest in new organic growth capital without issuing any additional common equity and maintaining key credit metrics. We will remain disciplined and deploy capital towards the best uses, prioritizing balance sheet strength, investment in low capital intensity growth and regulated utility or utility-like projects. We will carefully assess our remaining investable capacity, deploying capital to the most value-enhancing opportunities available to us, including further organic growth, asset acquisitions, and share buybacks, or further deleveraging our balance sheet.

Looking ahead, 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 such as the refinery hubs in the US Midwest, Eastern Canada, and the US Gulf Coast. The emergence of CCS offers the potential to provide new growth opportunities over the long term.

- Our natural gas pipelines business will seek extension and expansion opportunities driven by new load demand from gas-fired power generation, industrial growth, and coastal liquefied natural gas (LNG) plants. Looking forward, blending RNG and H2 production projects into our system will enhance asset longevity and enable us to offer a differentiated low-carbon service to customers.

- Our gas distribution utility will continue to grow through customer additions, productivity enhancements, modernization investments and facilities that blend H2 and RNG into gas supply, and expansion of our demand-side management and distributed energy programs.

- Our mature capabilities in the offshore and onshore wind sector position us well to compete for new projects across the development cycle in Europe and North America, while our multi-year program to self-power existing pipeline compressor stations represents highly visible and scalable growth.

Maintain Financial Strength and Flexibility
The maintenance of our financial strength is critical to our strategy. Our financing strategies are designed to retain 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. Our current secured capital program, which extends to 2024, 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 secure new growth within our “self-funded” equity model. In addition, we continue to look at opportunities to monetize non-core assets at attractive valuations. 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
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, while maintaining our low-risk “utility-like” business model.

All investment opportunities are evaluated based on their potential to advance our strategy, mitigate risk, support our ESG goals, and create additional financial flexibility. Our primary emphasis in the near term is on low capital-intensive opportunities to enhance returns in existing businesses (organic expansions and optimizations), modernization of our systems and utility rate-based investments. 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 alternatives. Other alternatives for capital deployment depend on our current outlook and include further dividend increases, further debt reduction, and/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 greenhouse gas emissions on the world’s climate. Accordingly, energy systems are being reshaped as industry participants, regulators and consumers seek to lower emissions. As a diversified energy infrastructure company, we are well positioned to play a key role in the transition to a low-emissions economy by leading the development of the future energy systems and partnering with customers on their low-carbon strategies, while at the same time working to reduce our own emissions. Furthermore, we have tested our 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.

We believe that diversification and innovation will play a significant role in the transition to a low-carbon future. To date, we have made large investments in natural gas infrastructure and continue to see significant opportunity in renewable energy. Our focus areas in renewable energy remain in offshore wind and utility-scale onshore projects. We are also taking a leadership role in other low-carbon platforms like CCS, H2 and RNG where we can leverage our infrastructure capability and stakeholder relationships to accelerate growth and extend the value of our existing assets. Additionally, all new investments that we make will need to have a clear path to achieve net zero emissions.

We recognize our customer's expectations of a transition to a lower-carbon economy and are working actively to be a differentiated service provider by leveraging our ESG leadership and world-class execution capabilities.

STRATEGIC ENABLERS

Our success in executing on our strategic priorities is enabled by our commitment to ESG, the quality and capabilities of our people, and the extent to which we embrace technology and innovation as a competitive advantage.

ESG

Sustainability is integral to our ability to safely and reliably deliver the energy people need and want. How well we perform as a steward of our environment; as a safe operator of essential energy infrastructure; as a diverse and inclusive employer; and as a responsible corporate citizen is inextricably linked to our ability to achieve our strategic priorities and create long-term value for all stakeholders.

Our commitment to strong ESG practices and performance has long been core to how we do business and we are proud to be recognized as a leader amongst our peers. In 2020, we set out ambitious goals[1] including:

- Net zero GHG emissions by 2050 with an interim target to reduce GHG emissions intensity 35% by 2030 compared to the 2018 baseline.
- Increased representation of diverse groups within our workforce by 2025, including representation goals of 40% women and 28% racial and ethnic groups, along with new initiatives to enhance supplier diversity.
- Strengthening diversity on our Board with representation goals of 40% women and 20% racial and ethnic groups by 2025.
- Annual safety and reliability targets that drive continuous improvement towards our goal of zero incidents, injuries, and implementation of robust cyber defense programs.

Beginning in 2021, we began linking ESG performance to incentive compensation and are making meaningful progress toward these targets by executing on specific action plans. In addition, we issued our first sustainability-linked loan and sustainability-linked bond that ties our financing to our ESG goals.

1 *All percentages or specific goals regarding inclusion, diversity, equity and accessibility are aspirational goals which we intend to achieve in a manner compliant with state, local, provincial and federal law, including, but not limited to, US federal regulations, Equal Employment Opportunity Commission, Department of Labor and Office of Federal Contract Compliance Programs.*

Enbridge aims to continuously strengthen its approach to emissions reporting and reduction and is expanding its approach to include the following additional actions:

- Ensure that investment decision making aligns with Enbridge's interim and long-term emissions reduction goals.
- Continue to proactively work with the organizations developing science-based guidelines for emissions targets in the midstream sector.
- Work with key suppliers to support the further reduction of Scope 3 emissions.
- Further develop low carbon energy partnerships to drive innovation across our business, with a focus on renewable power, renewable natural gas, hydrogen and carbon capture.

Achieving our goals will put us in a better position to successfully transition to a low-carbon, more diverse, and inclusive future.

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 diverse thought, and have embedded inclusive practices in our programs and approach to people management. Furthermore, we strive to maintain industry competitive compensation, flexibility, 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 to achieve our strategic objectives. We're committed to pursuing innovation and technology solutions that further improve our safety performance, maximize revenues, improve efficiencies, and enable transition to new, cleaner energy solutions. Our two Technology and Innovation labs, located in Calgary and Houston, embody our commitment to technology enabled 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, along with our assumptions and other relevant information, in our annual Sustainability Report which can be found at https://www.enbridge.com/sustainability-reports. ***Unless otherwise specifically stated, none of the information contained on, or connected to, the Enbridge website, including our annual Sustainability Report, 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.

LIQUIDS PIPELINES

Liquids Pipelines consists of pipelines and terminals in Canada and the US that transport and export 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 crude oil and other liquid hydrocarbons within western Canada and from western Canada to the Canada/US border near Gretna, Manitoba and Neche, North Dakota and from the US/Canada border near Port Huron, Michigan and Sarnia, Ontario to eastern Canada and the northeastern US. The Canadian Mainline includes six adjacent pipelines with a combined operating capacity of approximately 3.1 million barrels per day (mmbpd) that connect with the Lakehead System at the Canada/US border, as well as five pipelines that deliver crude oil and refined products into eastern Canada and the northeastern US. We have operated, and frequently expanded, the Canadian Mainline since 1949. The Lakehead System is the portion of the Mainline System in the US. It is an interstate common carrier pipeline system regulated by the Federal Energy Regulatory Commission (FERC) and is the primary transporter of crude oil and liquid petroleum from western Canada to the US.

Tolling Framework

The Competitive Toll Settlement (CTS) which governed tolls paid for products shipped on the Canadian Mainline, with the exception of Lines 8 and 9 which are tolled on a separate basis, expired on June 30, 2021. The CTS was a 10-year negotiated agreement and provided 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 US, via the Lakehead System, and into eastern Canada. The IJT tolls were denominated in US dollars.

On December 19, 2019, we submitted an application to the Canada Energy Regulator (CER) to implement contracting on our Canadian Mainline System. On November 26, 2021, the CER denied the application on the basis that, among other things, contracting as proposed would result in a significant change to access the Canadian Mainline and potentially inequitable outcomes to some shippers and non-shippers without a compelling justification.

Effective July 1, 2021, the Mainline System is on Interim Tolls which will remain in effect until new tolls are approved by the CER. In accordance with the terms of the CTS, Interim Tolls are equal to the CTS exit tolls on June 30, 2021 and are subject to finalization and adjustment applicable to the interim period, if any. We are currently exploring, with customers and other stakeholders, alternatives that may include: a modified and extended CTS, a new incentive rate-making agreement, or a cost-of-service rate-making structure. Any negotiated settlement would require CER approval before implementation. New tolling framework clarity is expected by 2023.

Shippers continue to nominate volumes on a monthly basis and we continue to allocate capacity to maximize the efficiency of the Mainline System.

Local tolls for service on the Lakehead System are not affected by Interim Tolls and continue to be established pursuant to the Lakehead System's existing toll agreements, as described below. Under Interim Tolls, the Canadian Mainline's share of the toll relating to pipeline transportation of a batch from any western Canada receipt point to the US border is equal to the toll applicable to that batch's US delivery point less the Lakehead System's local toll to that delivery point. While on Interim Tolls, we will continue to refer to this amount as the Canadian Mainline IJT Residual Benchmark Toll which is denominated in US dollars.

Lakehead System Local Tolls
Transportation rates are governed by the FERC for deliveries from the Canada/US 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 inflationary adjustment which cannot exceed established ceiling rates as approved by the FERC. The Facilities Surcharge Mechanism allows the Lakehead System to recover costs associated with certain shipper-requested projects through an incremental surcharge in addition to the existing base rates and is subject to annual adjustment on April 1 of each year. To the extent that the Lakehead System transportation rates materially under-recover the Lakehead System cost of service, an application can be made with the FERC to seek approval to increase the rates in order to bring recoveries in-line with costs.

On May 21, 2021, we filed a cost-of-service application to raise our base rates effective July 1, 2021. On June 30, 2021, the FERC issued an order to accept the rates subject to refund. This matter is currently in the FERC settlement process.

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 currently provide access for oil sands production from twelve producing oil sands projects.

The combined capacity of the intra-Alberta long-haul pipelines is approximately 1,090 kbpd to Edmonton and 1,370 kbpd into Hardisty, with Norlite providing approximately 218 kbpd of diluent capacity into the Fort McMurray region. We have a 50% interest in the Woodland Pipeline and a 70% interest in Norlite. The Regional Oil Sands System is anchored by long-term agreements with multiple oil sands producers that provide cash flow stability and also 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, Gray Oak Pipeline and the Enbridge Ingleside Energy Center (EIEC), as well as the Mid-Continent System (Cushing Terminal).

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. Total aggregate capacity on the Seaway Pipeline system is approximately 950 kbpd. Seaway Pipeline also includes 8.8 million barrels of crude oil storage tank capacity on the Texas Gulf Coast.

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 has a capacity of approximately 600 kbpd.

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 has a capacity of approximately 193 kbpd.

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 US Gulf Coast. The Gray Oak pipeline has an expected average annual capacity of 900 kbpd 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 service achieved in the second quarter of 2020.

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 to 570 thousand 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.

In October 2021, we acquired a 100 percent operating interest in the Ingleside Energy Center (renamed the Enbridge Ingleside Energy Center (EIEC)), located near Corpus Christi, Texas. This terminal is comprised of 15.6 million barrels of storage and 1.5 million barrels per day of export capacity. We also acquired a 20% interest in the 670-kbpd Cactus II Pipeline, a 100% interest in the 300-kbpd Viola pipeline, and a 100% interest in the 350-thousand-barrel Taft Terminal.

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

Southern Lights Pipeline is a single stream 180 kbpd 16/18/20-inch diameter 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. Both the Canadian portion of Southern Lights Pipeline and the US portion of Southern Lights Pipeline receive tariff revenues under long-term contracts with committed shippers. Southern Lights Pipeline capacity is 90% contracted with the remaining 10% of the capacity assigned for shippers to ship uncommitted volumes.

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) long crude oil transportation system, which begins at Hardisty, Alberta, and terminates at Wood River, Illinois. The 310 kbpd Express pipeline carries crude oil to US refining markets in the Rocky Mountains area, including Montana, Wyoming, Colorado and Utah. The 145 to 164 kbpd Platte pipeline, which interconnects with the Express pipeline at 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.

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 US and Canadian components that extend from Berthold, North Dakota into Cromer, Manitoba.

Tariffs on the US portion of the North Dakota System are governed by the FERC. 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 US Gulf Coast. The Bakken Pipeline System consists of the DAPL 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 750 kbpd 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 includes a number of liquids storage assets and pipeline systems in Canada and the US.

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. We have an effective 65% interest in the 300 kbpd SAX pipeline of which the majority of its capacity is 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 thousand barrels of shell capacity located in Patoka, Illinois. The 101 kbpd Toledo pipeline system connects with the Lakehead System and delivers to Ohio and Michigan. The 45 kbpd 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

Competition to our liquids pipelines network comes primarily from infrastructure or logistics alternatives that transport liquid hydrocarbons from production basins in, which we operate, to markets in Canada, the US and internationally. Competition from existing and proposed pipelines is based primarily on access to supply, end use markets, the cost of transportation, contract structure and the quality and reliability of service. 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 served by pipelines.

We believe that our liquids pipelines systems will continue to provide competitive and attractive options to producers in the Western Canadian Sedimentary Basin (WCSB), North Dakota, and more recently the Permian Basin, due to our market access, 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 will provide additional competitive solutions for liquids transportation. We have a proven track record of successfully executing projects to meet the needs of our customers.

SUPPLY AND DEMAND

We have an established and successful history of being the largest transporter of crude oil to the US, the world’s largest market for crude oil. While US 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, both domestic and global.

The COVID-19 pandemic had a significant negative impact on the crude oil market in 2020 with decreased demand from the economic slowdown and government imposed mobility restrictions. However, 2021 has seen global crude oil demand recover to levels close to pre-pandemic highs. International prices have strengthened to multi-year highs as global demand has outpaced the return of supply as publicly traded producers have adopted a more disciplined approach to capital allocation for new drilling.

Our Mainline System throughput, as measured at the Canada/US border at Gretna, Manitoba ended the year delivering 3.1 million barrels per day, as the Line 3 Replacement program has come into service. Refinery demand in the upper Midwest PADD II market has been strong given the economic recovery and enhanced mobility demand. On the US Gulf Coast, lower supply of heavy crude from Latin America and the Middle East is driving increased demand for Canadian heavy crude.

Global crude oil demand in most base case forecasts is expected to grow into the next decade, primarily driven by emerging economies in regions outside the Organization for Economic Cooperation and Development (OECD), such as India and China. In North America, demand growth for transportation fuels is expected to moderate over time due to vehicle fuel efficiency improvement and increasing sales of electric vehicles.

New supply to meet this growing demand will primarily come from Organization of the Petroleum Exporting Countries (OPEC) countries and North America. Growth in supply from OPEC will be led by Saudi Arabia and the United Arab Emirates with their significant low cost reserves and could be supplemented by the return of sanctioned Iranian production. Growth in North America will be driven by the Permian Basin which is a large and cost competitive light crude oil resource base. In addition, heavy crude oil growth is expected from the WCSB as additional egress availability will support expansion of existing projects and some potential new greenfield facilities.

The combination of long term demand growth in non-OECD nations, domestic demand contraction over time, and continued production growth in the Permian Basin and WCSB highlights the importance of our strategic asset footprint and reinforces the need for additional export oriented infrastructure. We are well positioned to meet these evolving supply and demand fundamentals through expansion of system capacity for incremental access to the US Gulf Coast, and through further development of our new Enbridge Ingleside Energy Center in Corpus Christi, the largest crude oil export facility in North America.

Opposition to fossil fuel development in conjunction with evolving consumer preferences and new technology could underpin accelerated energy transition scenarios impacting long term supply and demand of crude oil. We continue to closely monitor the evolution of all of these factors to be able to pro-actively adapt our business to help meet our customers' and society's energy needs.

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 US, including US Gas Transmission, Canadian Gas Transmission, US Midstream and other assets.

US GAS TRANSMISSION
US Gas Transmission includes ownership interests in Texas Eastern Transmission, L.P. (Texas Eastern), Algonquin Gas Transmission, LLC (Algonquin), Maritimes & Northeast (M&N) (US and Canada), East Tennessee Natural Gas, LLC (East Tennessee), Gulfstream Natural Gas System, L.L.C. (Gulfstream), Sabal Trail Transmission (Sabal Trail), NEXUS Gas Transmission Pipeline (NEXUS), Valley Crossing Pipeline, LLC. (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 US.

The Texas Eastern natural gas transmission system extends from supply and demand centers in the Gulf Coast region of Texas and Louisiana to supply and demand centers in Ohio, Pennsylvania, New Jersey and New York. Texas Eastern's onshore system has a peak day capacity of 13.09 billion cubic feet per day (bcf/d) of natural gas on approximately 13,807-kilometers (8,579-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 through New Jersey, New York, Connecticut, Rhode Island and Massachusetts where it connects to M&N US. The system has a peak day capacity of 3.09 bcf/d of natural gas on approximately 1,820-kilometers (1,131-miles) of pipeline with associated compressor stations.

M&N US has a peak day capacity of 0.83 bcf/d of natural gas on approximately 552-kilometers (343-miles) of 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 Canada has a peak day capacity 0.55 bcf/d on approximately 885-kilometers (550-miles) of interprovincial natural gas transmission mainline system that extends from Goldboro, Nova Scotia to the US border near Baileyville, Maine. We have a 78% interest in M&N US and M&N Canada.

East Tennessee’s natural gas transmission system has a peak day capacity of 1.86 bcf/d of natural gas, crosses Texas Eastern’s system at two locations in Tennessee and consists of two mainline systems totaling approximately 2,456-kilometers (1,526-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. Gulfstream has a peak day capacity of 1.31 bcf/d of 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 832-kilometer (517-mile) pipeline that provides firm natural gas transportation. Facilities include a pipeline, laterals and various compressor stations. The pipeline infrastructure is located in Alabama, Georgia and Florida, and adds approximately 1.0 bcf/d of capacity enabling the access of onshore gas supplies. We have a 50% interest in Sabal Trail.

NEXUS is an approximately 414-kilometer (257-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 peak day capacity of 1.4 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 285-kilometer (177-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 of design capacity to the Comisión Federal de Electricidad, Mexico's state-owned utility.

SESH is an approximately 462-kilometer (287-mile) natural gas transmission system with associated compressor stations. 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 and has a peak day capacity of 1.1 bcf/d of natural gas. We have a 50% interest in SESH.

Vector is an approximately 560-kilometer (348-mile) pipeline travelling between Joliet, Illinois in the Chicago area and Ontario. Vector can deliver 1.745 bcf/d of natural gas, of which 455 million cubic feet per day (mmcf/d) is leased to NEXUS. 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, 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

Canadian Gas Transmission is comprised of Westcoast Energy Inc.'s (Westcoast) British Columbia (BC) Pipeline, Alliance Pipeline and other minor midstream gas gathering pipelines.

BC Pipeline has a peak day capacity of 3.6 bcf/d of natural gas on approximately 2,950-kilometers (1,833-miles) of transmission pipeline in BC and Alberta that includes associated mainline compressor stations. It provides cost-of-service based natural gas transmission services.

Alliance Pipeline is an approximately 3,000-kilometer (1,864-mile) integrated, high-pressure natural gas transmission pipeline with approximately 860-kilometers (534-miles) of lateral pipelines and related infrastructure. It transports liquids-rich natural gas from northeast BC, 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 system has a peak day capacity of 1.8 bcf/d of natural gas. 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 connected to Alliance Pipeline that facilitate delivery of liquids-rich natural gas for 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 BC, comprising the Septimus Pipeline. Aux Sable Canada also owns a facility which processes refinery/upgrader offgas in Fort Saskatchewan, Alberta.

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 36 plants and approximately 90,123-kilometers (56,000-miles) of natural gas and natural gas liquids pipelines, with operations in nine states across major producing regions.

OTHER
Other consists primarily of our offshore assets. Enbridge Offshore Pipelines is comprised of 11 natural gas gathering and FERC regulated transmission pipelines and four 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 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, nuclear 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 markets that our businesses serve. Competitors include interstate/interprovincial and intrastate/intraprovincial 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 supply and demand markets over the last decade and will continue to play a part as the energy landscape evolves.

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 47.5 bcf/d of natural gas on a combined basis. Improved technology and increased shale gas drilling have 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 bi-directional supply to the northeast, southeast, midwest, Gulf Coast and LNG markets on a fully subscribed and highly utilized basis.

The northeast market continues its role as a predominantly supply constrained region with steady demand. The bi-directional capabilities offered by our US Gas Transmission system allows us to deliver in an efficient manner to our regional customers. The region has seen an increase in natural gas supply due to the development of the Marcellus and Utica shales in the Appalachia region.

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 2.0 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.

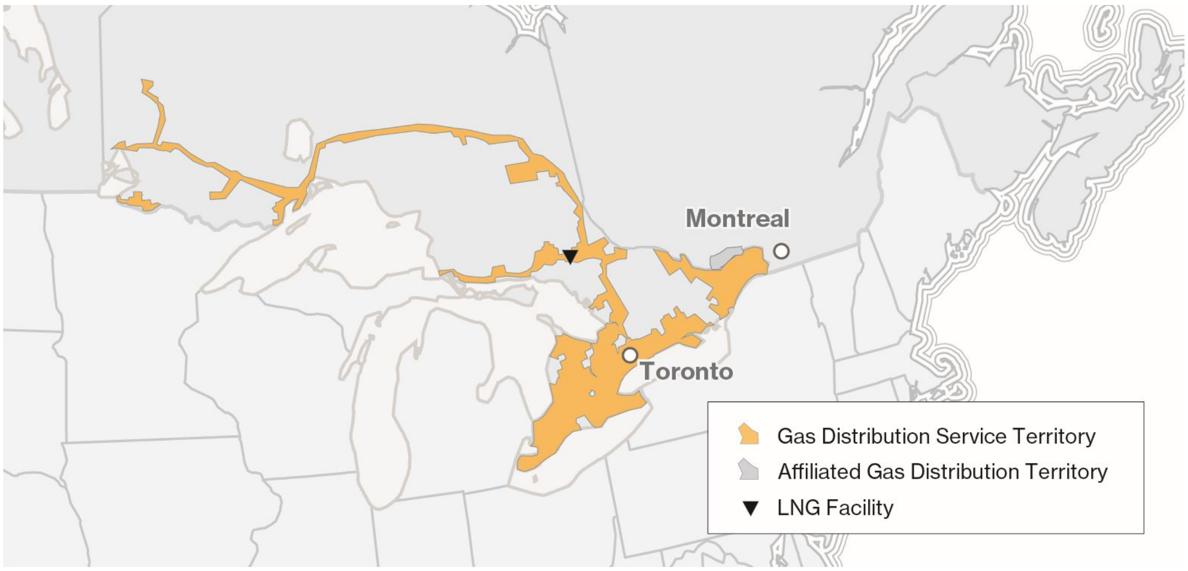
Gulf Coast demand growth is being driven by an increase in the volume of LNG exports, an ongoing wave of gas-intensive petrochemical facilities, along with power generation and additional pipeline exports to Mexico. Demand to these markets in the region is anticipated to grow by more than 23.0 bcf/d 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 and LNG exports continue their growth trajectory. The US exported over 11 bcf/d of natural gas to LNG markets, primarily from the Gulf Coast region, at the end of 2021.

Western Canada, not unlike other supply hubs, is a source of low-cost supply seeking access to premium markets in North America and globally. One of the few vital links to demand centers in the pacific northwest are our own systems in the region, which are highly utilized.

Global energy demand is expected to increase approximately 27% 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 23% 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. Opposition to natural gas development, including new pipeline projects, has been increasing in recent years. This may challenge continued growth of the North American gas market and the ability to efficiently connect supply and demand. We are responding to the need for regional infrastructure with additional investments in Canadian and US 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 previously included an investment in Noverco Inc. (Noverco) which was sold on December 30, 2021. Please refer to Part II. *Item 8. Financial Statements and Supplementary data - Note 8 - Acquisitions and Dispositions* for further details.



ENBRIDGE GAS

Enbridge Gas is a rate-regulated natural gas distribution utility with storage and transmission services that has been in operation for 173 years. Enbridge Gas serves approximately 75% of Ontario residents via approximately 3.8 million residential, commercial and industrial meter connections.

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

In 2021, Enbridge Gas implemented a voluntary RNG pilot program, whereby customers can voluntarily contribute towards the incremental cost of low carbon RNG to displace regular natural gas, and a pilot project which allows regular natural gas to be blended with H2, in an isolated portion of the existing distribution system, in an effort to gain insight into the use of H2 as a method for decarbonizing natural gas for the purpose of reducing GHG emissions.

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 primarily 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 147,000-kilometers (91,342-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 to points upstream of the distribution system or directly 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 and NEXUS, 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 and 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 US markets, and forms an important link in moving natural gas from western Canada and US supply basins to central Canadian and northeastern US 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 US. Enbridge Gas delivered 1,943 bcf of gas through its distribution and transmission system in 2021. 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 15 years and the longest remaining contract term being 19 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 281 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 180 bcf of the total working capacity is available to Enbridge Gas for utility operations. Enbridge Gas also has storage contracts with third parties for 21 bcf of storage capacity.

Dawn offers customers an important link in the movement of natural gas from western Canadian and US supply basins to markets in central Canada and the northeast US. 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 2021, 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 15 years.

NOVERCO

Noverco is a holding company that wholly-owns Énergir, LP (Énergir), formerly known as Gaz Metro Limited Partnership, a natural gas distribution company operating in Québec, with interests in subsidiary companies operating gas transmission, gas distribution and power distribution businesses in Québec and Vermont. Énergir 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 an investment in our common shares. We owned an equity interest in Noverco through ownership of 38.9% of its common shares and an investment in its preferred shares. On December 30, 2021, we sold our 38.9% non-operating minority ownership interest in Noverco to Trencap L.P. for $1.1 billion in cash.

GAZIFÈRE

We wholly own Gazifère, a natural gas distribution company that serves approximately 44,000 customers in western Québec, a market not served by Énergir. Gazifère is regulated by the Québec Régie de l'énergie.

COMPETITION

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 distribution competition within its 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 including the federal carbon pricing law, 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 steady annual growth over the long term with continued growth in peak day demands, however there are risks to the natural gas market that may challenge its growth prospects. Evolving customer preferences for lower-carbon fuels and more efficient technologies, combined with increasing opposition to natural gas development in North America, may reduce the markets' ability to efficiently deploy capital to connect supply and demand. We monitor these factors closely to be able to develop our business strategy to align with shifts in customer preferences.

We expect demand for natural gas connections in Ontario to maintain its recent growth profile due to continued population growth and with competitively priced natural gas expected to continue to provide a significant price advantage relative to alternate energy options, even with increasing carbon charges. Specific interest in natural gas connections is expected to come from communities that are not currently serviced by natural gas in Ontario.

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 and sourcing supply with a smaller carbon footprint. In addition to our existing RNG programs, we are also expanding our efforts in other low-carbon supply sourcing such as Responsibly Sourced Natural Gas, and Hydrogen Gas.

The storage and transportation marketplace continues to respond to changing natural gas supply dynamics, including a recovering supply environment which was negatively impacted by the global pandemic.

Over the past decade, growth in the North American gas supply landscape, driven mainly by the development of unconventional gas resources in the Montney, Permian, Marcellus and Utica supply basins, has resulted in lower annual commodity prices and narrower seasonal price spreads. Unregulated storage values are primarily determined by the difference in value between winter and summer natural gas prices. Storage values have been relatively stable as 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. We are also developing several solar self-power projects along our oil and gas rights-of-way in North America. In Europe, we hold equity interests in operating offshore wind facilities in the coastal waters of the United Kingdom and Germany, as well as interests in several offshore wind projects under construction and active development in France. Further, we are pursuing new European offshore wind development opportunities through Maple Power Ltd., a joint venture in which we hold a 50% interest.

Combined Renewable Power Generation investments represent approximately 2,178 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;
- 309 MW will be generated by the Saint-Nazaire, Fécamp and Calvados Offshore Wind projects, all of which are currently under construction;
- 6 MW will be generated by the Provence Grand Large Floating Offshore Wind project, which secured funding in 2021 and continues to prepare onshore construction; and
- 93 MW is generated by North American solar facilities in operation, with an additional 97 MW in projects in early construction and under-construction.

The vast majority of the power produced from these facilities is sold under long-term Power Purchase Agreements (PPAs).

Renewable Power Generation also includes our 25% interest in the East-West Tie, a 450-MW transmission line in northwestern Ontario, which is currently under construction and is expected to reach commercial operation in the first half of 2022.

JOINT VENTURES / EQUITY INVESTMENTS

The investments in the Canadian wind and solar assets (excluding self-power) and two of the US renewable assets are held within a joint venture in which we maintain a 51% interest and which we manage and operate.

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

- a 24.9% interest in Rampion Offshore Wind, located in the United Kingdom;
- a 25.4% interest in Hohe See Offshore and its subsequent expansion, located in Germany;
- a 25.5% interest in the Saint-Nazaire Offshore Wind project, under construction in France;
- a 25% interest in the Provence Grande Large Floating Offshore Wind project, in pre-construction in France;
- a 17.9% interest in the Fécamp Offshore Wind project, under construction in France; and
- a 21.7% interest in the Calvados Offshore Wind project, in pre-construction in France.

The ownership interest percentages in the Saint-Nazaire, Fécamp, and Calvados Offshore Wind projects reflect the sale of 49% of an entity that holds our 50% interest in Éolien Maritime France SAS (EMF) to the Canada Pension Plan Investment Board (CPP Investments) which closed in the first half of 2021.

COMPETITION

Renewable Power Generation operates 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 PPAs (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 and Europe is expected to grow significantly over the next 20 years due to the replacement of older fossil fuel-based sources of electricity generation in support of announced governmental carbon emissions reduction targets. Any additional governmental actions toward reducing emissions and/or increasing electrification will further accelerate renewable electricity demand growth and electrification across all sectors.

On the demand side, North American economic growth over the longer term and the continued electrification and transition to low-carbon strategies within the residential, transportation and industrial sectors are expected to drive growing electricity demand. Furthermore, voluntary GHG emissions targets are becoming increasingly expected by stakeholders, which is driving significant demand from corporate electricity end-users for clean electricity and environmental attributes. However, continued efficiency gains are expected to make the economy less energy-intensive and temper overall demand growth.

On the supply side in North America, legislation is accelerating the retirement of aging coal-fired generation, while generation from conventional nuclear power is also forecast to decline. As a result, North America requires significant new generation capacity from preferred technologies. Gas-fired and renewable energy facilities, including solar and wind (which make up the bulk of our renewable power assets), are generally the preferred sources to replace coal-fired generation due to their low carbon intensities.

The falling capital and operating costs of wind and solar, combined with their improving capacity factors, are expected to continue the ongoing trend of making renewable energy more competitive and support investment over the long-term, regardless of available government incentives. Generation from renewable sources is expected to double over the next two decades in North America. Aside from the construction of new wind and solar facilities, other growth opportunities include repowering projects to increase output from, and extending the project-life of, our existing facilities.

In Europe, the renewable energy outlook is robust. Demand for electricity is expected to gradually increase over the next two decades, driven by electrification of transportation and buildings. Energy efficiency gains will temper, but not eliminate, demand growth. Renewable power will play a significant role in the United Kingdom’s ability to meet their aggressive low-carbon and renewable energy targets, particularly offshore wind.

On the supply side, the International Energy Agency expects coal to fall by more than 90% from 2020 levels, while nuclear falls by one-third, by 2040. Over the same period, it anticipates power generation from renewable sources will more than double, including installed (onshore and offshore) wind more than doubling and photovoltaics solar power nearly tripling. We, through our European joint ventures, continue to invest in offshore wind projects in the United Kingdom, France and Germany, and to explore opportunities, to meet the growing demand.

ENERGY SERVICES

The Energy Services businesses in Canada and the US provide physical commodity marketing and logistical 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, 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 that are not allocated to business segments and the impact of foreign exchange hedge settlements. Eliminations and Other also includes new business development activities and corporate investments.

REGULATION

GOVERNMENT REGULATION

Pipeline Regulation

Our Liquids Pipelines and Gas Transmission and Midstream assets 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 US, our interstate pipeline operations are subject to pipeline safety laws and regulations administered by the Pipeline and Hazardous Materials Safety Administration (PHMSA), an agency within the United States Department of Transportation. 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 to operate them at permissible pressures.

PHMSA continues to review existing regulations and establish new regulations to support safety standards that are designed to improve and expand operations integrity management processes. 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, capital expenditures, earnings, cash flows, financial condition and competitive advantage.

Our ability to establish transportation and storage rates on our US interstate natural gas facilities are subject to regulation by the FERC, whose rulings and policies could have an adverse impact on the ability of such pipeline and storage assets to recover their respective full cost of operating, including a reasonable rate of return. Regulatory or administrative actions by FERC such as rate proceedings, applications to certify construction of new facilities, and depreciation and amortization policies can affect our business, including decreasing tariff rates and revenues and increasing our costs of doing business.

In Canada, our pipeline operations are subject to pipeline safety regulations administered 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 US, 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.

A key component of pipeline safety and reliability is the approach to integrity management that uses reliability targets and safety case assessments. A long history of extensive inline inspection has provided detailed knowledge of the assets in our pipeline systems. Our pipelines are assessed and maintained, in a proactive manner, such that the probability of a release is sufficiently low and that our reliability targets are met. Furthermore, the integrity management program has an independent step to check the results of our integrity assessments to validate the effectiveness of the program and to ensure that the operational risk remains as low as reasonably practicable throughout the integrity inspection and assessment cycle. As inspection technology, pipeline materials and construction practices improve with time, and new data on threats and pipeline condition are gathered, our methods of maintaining fitness for service evolves, with a strong focus on continual improvement in every aspect of integrity management.

Our 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 or policies, including permits and regulatory approvals for both new and existing projects or agreements, upon which future and current operations are dependent. Our Mainline System and other liquids pipelines and gas transmission facilities are subject to the actions of various regulators, including the CER and the FERC, with respect to the tariffs and tolls of those pipelines. The changing or rejecting of commercial arrangements, including decisions by regulators on the applicable permits and tariff structure or changes in interpretations of existing regulations by courts or regulators, could have an adverse effect on our revenues and earnings.

Gas Distribution and Storage

Our gas distribution and storage utility operations are regulated by the OEB and the Québec Régie de l’énergie, among others. 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 the absence of the effects of regulation, could be different from the amounts that are eventually recovered or refunded.

Enbridge Gas' distribution rates, commencing 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).

We retain dedicated professional staff and maintain strong relationships with customers, intervenors and regulators. This strong regulatory relationship continued in 2021 following OEB Decisions and Orders approving Phase 2 of Enbridge Gas’ application for 2021 rates and Phase 1 of Enbridge Gas’ application for 2022 rates. The Phase 2 Decision and Order approved the funding of $124 million in 2021 discrete incremental capital investment requested through the incremental capital module, while the Phase 1 Decision and Order approved 2022 base rate escalation under the price cap mechanism.

Enbridge Gas continues to develop opportunities to support a low-carbon future in Ontario. In 2021, we received OEB approval of an Integrated Resource Planning (IRP) framework. The framework requires Enbridge Gas to consider facility and non-pipe demand and/or supply side alternatives (IRP alternatives) to address systems needs of its regulated operations, where certain parameters have been met. The framework will also allow Enbridge Gas to pursue an IRP alternative (or combination of IRP and facility alternative) where it is found to be in the best interest of Enbridge Gas and its customers, taking into account reliability and safety, cost-effectiveness, public policy, optimized scoping, and risk management.

Renewable Power Generation

Renewable Power Generation is 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.

The North American Reliability Council (NERC) is an international regulatory authority responsible for establishing and enforcing Reliability Standards to reduce risks to the reliability and security of the grid in Canada, the United States, and Mexico. It is subject to oversight from the FERC and provincial governments in Canada. The FERC has authority over many markets in the US and is tasked with ensuring safe, reliable, and secure interstate transmission of electricity, natural gas, and oil. This includes establishing reliability standards and determining certain pricing aspects of transmission development and access, among others. NERC and FERC standards and pricing decisions are also updated from time to time and could impact our operations, capital expenditures, earnings, and cash flows, though some of these impacts could be positive for our business.

At the US federal level, our Renewable Power Generation assets are subject to legislation overseen by the US Fish and Wildlife Service, which is aimed at reducing the impact of development and human activity on wildlife, along with other federal environmental permitting legislation. These federal environmental laws are subject to change from time to time which could require Enbridge to obtain new permits, update practices, or amend operations and operating expenditures.

In Canada, the Federal Government does not generally regulate the electricity sector though it has imposed a federal carbon price on other sectors via its output-based pricing system (OBPS) and may seek to impose emissions standards on the electricity sector in the future.

Our Renewable Power Generation assets in France and Germany each have federal policies in place and are subject to directives and regulations established and enforced by the European Union (EU). These include the Renewable Energy Directive (RED II most recently passed set targets through 2030), the European Green Deal, and ongoing work on financing mechanisms and transmission directives and programs. The EU is also responsible for establishing environmental protection rules and permitting standards. All of these are subject to change from time to time, which could impact our operations and related expenditures; however the EU's general direction is to facilitate increased renewable power integration to its grid.

The United Kingdom (UK) government is responsible for establishing renewable energy and carbon pricing policies for the entire UK, as well as long-term electricity sector planning and procurement mechanisms and structure for auctions that are administered at the national level, e.g., England, Scotland, within the UK. Each country within the UK is also responsible for establishing its own environmental and permitting regulations. This process is still ongoing following Brexit and in some cases continues to result in more volatile merchant power prices; however, expanded interconnectors to Europe and policies aimed at increasing domestic renewable capacity are in progress.

Energy Services

Energy Services is regulated by government authorities in the areas of commodity trading, import and export compliance and the transportation of commodities. Non-compliance with governing rules and regulations could result in fines, penalties and operating restrictions. These consequences would have an adverse effect on operations, earnings, cash flows, financial condition and competitive advantage. Energy Services retains dedicated professional staff and has a robust regulatory compliance program to mitigate these potential risks associated with the business.

In the US, commodity marketing is regulated by the Commodity Futures Trading Commission, the SEC, the Federal Trade Commission, the various commodity exchanges, the US Department of Justice and state regulators. The interstate marketing of electricity and natural gas is also regulated by the FERC. The provincial and territorial securities regulators similarly regulate commodity marketing within Canada and are members of the Canadian Securities Administrators. In addition, the Regional Transmission Organizations and Independent System Operators in both US and Canada regulate commodity marketing. These various regulators enforce, among other things, the prohibition of market manipulation, fraud and disruptive trading. To mitigate risks related to commodity trading, Energy Services has implemented a robust regulatory compliance program that includes targeted training.

The export of natural gas out of Alberta is regulated by the Alberta Energy Regulator. The import and export of commodities between Canada and the US is subject to regulation by the CER and the US Department of Energy, as well as customs authorities. In particular, import and export permits are required, with associated regular reporting requirements. Breaches of such import and export rules could result in an inability to perform day to day operations, and therein negatively impact the earnings of the business.

The transportation of crude oil and natural gas liquids by railcar or truck is regulated by the US Department of Transportation, Transport Canada and provincial regulation. Each jurisdiction requires compliance with security, safety, emergency management, and environmental laws and regulations related to ground transportation of commodities. Risks associated with transportation of crude or natural gas liquids include unplanned releases. In the event of a release, remediation of the affected area would be required. Energy Services engages third parties, such as the Emergency Response Assistance Canada, Chemical Transportation Emergency Center and Canadian Transport Emergency Center to assist in such remediation.

ENVIRONMENTAL REGULATION

Pipeline Regulation

Our Liquids Pipelines and Gas Transmission and Midstream assets are subject to numerous federal, state and provincial environmental laws and regulations affecting many aspects of our present and future operations, including air emissions, water quality, water discharge and 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 US, 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 US, climate change action is evolving at federal, state and regional 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. The new US presidential administration has also announced that policies designed to combat climate change and reduce GHG emissions will be a key legislative and regulatory priority, and thus stricter emissions limits and air quality enforcement actions are likely. 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 on climate action with that of the US. In 2019, the Government of Canada implemented a federal system of carbon pricing. The pricing applies to provinces and territories that do not have a carbon pricing system in place that meets the federal benchmark. The Canadian Net-Zero Emissions Accountability Act, which received royal assent in April 2021, requires national targets for the reduction of GHG emissions in Canada be set, with the objective of attaining net-zero emissions by 2050. As of April 2021, the federal carbon price was raised to $40 per tonne. This will increase to $65 per tonne in 2023 and rise to $170 per tonne of carbon dioxide equivalent in 2030.

Due to the speculative outlook regarding any US 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.

Gas Distribution and Storage

Our Gas Distribution and Storage operations, facilities and workers 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 spills and emissions to air, land and water; hazardous waste management; the assessment and management of contaminated sites; protection of environmentally sensitive areas, and species at risk and their habitat; 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 releases or emissions exceeding permitted levels. These events could result in injuries to workers or the public, adverse impacts to the environment, property damage and/or regulatory infractions including orders 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 a small volume of oil and brine production in southwestern Ontario. Environmental risk associated with these facilities has 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 landowners.

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 Annual Written Summary Reports for Environmental Compliance Approvals (ECAs) are submitted to the Ontario Ministry of the Environment, Conservation and Parks (MECP) and other regulators to demonstrate we are in good standing with our environmental requirements. 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 is expected to increase.

As in previous years, in 2021, we reported operational GHG emissions, including emissions from stationary combustion, flaring, venting and fugitive sources to Environment and Climate Change Canada (ECCC), the Ontario MECP, and a number of voluntary reporting programs. In accordance with the provincial GHG regulations, stationary combustion and flaring emissions related to storage and transmission operations were verified in detail by a third-party accredited verifier with no material discrepancies found.

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 our systems 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: a carbon charge levied on fossil fuels, including natural gas, and an OBPS.

The federal carbon charge took effect on April 1, 2019 at a rate of 3.91 cents/cubic meter (m3) of natural gas and is applicable to the majority of customers. Enbridge Gas is registered as a natural gas distributor with the Canada Revenue Agency and remits the federal carbon charge on a monthly basis. The charge increases annually on April 1 of each year by 1.96 cents/m3, rising up to 9.79 cents/m3 in 2022. In December 2020, the federal government announced plans to increase the federal carbon price by $15 per tonne each year in 2023, rising to $170 per tonne of carbon dioxide equivalent in 2030. Enbridge Gas estimates that this will equate to a federal carbon charge on natural gas of approximately 33.31 cents/m3 in 2030. Enbridge Gas applies for approval from the OEB on an annual basis to pass through federal carbon charges.

The OBPS component came into effect on January 1, 2019. Under OBPS, a registered facility has a compliance obligation for the portion of their emissions that exceeds their annual facility emissions limit, which is calculated based on the sector specific output-based standard and annual production. Enbridge Gas is registered with ECCC as an emitter in the OBPS program and has an annual compliance obligation associated with the combustion and flaring emissions associated with its natural gas pipeline transmission system. As a registered facility under OBPS, Enbridge Gas submitted an annual report along with the required verification report from an accredited third-party verifier who found no material misstatements. Enbridge Gas is required to remit payment for facility emissions that exceed its annual facility emissions limit. Due to COVID-19, ECCC delayed the payment deadline for the 2019 compliance obligation from December 15, 2020 to April 15, 2021. Enbridge Gas made payment for the 2019 compliance obligation in March 2021 and for the 2020 compliance obligation in November 2021.

In September 2020, Ontario and the federal government announced that the federal government has accepted that Ontario's Emission Performance Standards (EPS) will replace the federal OBPS for industrial facilities. In March 2021, the federal government announced that the federal OBPS will stand down in Ontario at the end of 2021 and Ontario will transition to the EPS effective January 1, 2022. In September 2021, the Greenhouse Gas Pollution Pricing Act was amended to remove Ontario as a covered province effective January 1, 2022. Beginning January 1, 2022, Enbridge Gas will have a compliance obligation under the EPS program for its facility-related emissions, as well as the federal carbon charge for its customer-related emissions.

HUMAN CAPITAL RESOURCES

WORKFORCE SIZE AND COMPOSITION

As at December 31, 2021, we had approximately 10,900 regular employees, including approximately 1,500 unionized employees across our North American operations. This total rises to nearly 13,000 if temporary employees and contractors are included. We have a strong preference for direct employment relationships but where we have collectively bargained-for employees, 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.

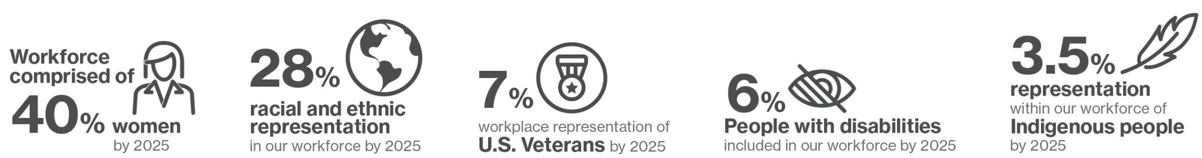
SAFETY

We believe all injuries, incidents and occupational illnesses are preventable. Our overall focus on employee and contractor safety, including through the COVID-19 pandemic, continues to result in strong performance compared against industry benchmarks and we are actively engaged in continuous improvement exercises as we pursue our goal of zero incidents.

DIVERSITY AND INCLUSION

To ensure our workforce is reflective of the communities where we operate, we have pursued efforts to increase the representation of women, underrepresented ethnic and racial groups, people with disabilities and veterans. In 2021 we set diversity representation goals and shared these goals with employees and external stakeholders. Consistent with our culture, we remain committed to open, two-way dialogue related to our goals, enhancing transparency and accountability for all stakeholders.

Diversity Representation Goals



In 2021, we added Inclusion to our core values of Safety, Integrity and Respect to demonstrate this commitment. We are building an organization where people feel safe and welcome and have the opportunity to thrive and grow based on merit. As part of our evolving ESG strategy, we created a tighter link between our success and the workforce related ESG measures – including safety, emissions reduction efforts and diversity & inclusion – that enable it. As a result, beginning in 2021, key metrics in these areas are embedded in our scorecards and directly impact compensation.

PRODUCTIVITY AND DEVELOPMENT
We continually invest in our people's personal and professional development because we recognize their success is our success. Every year, employees are provided access to a range of development and re-skilling opportunities through a variety of channels, including: extensive catalog of self-directed learning (10,000+ external courses plus proprietary Enbridge University courses); on-the-job learning opportunities and rotational assignments; curated leadership development programs; educational reimbursement; and developmental relationships with mentors through our formal mentor-protégé matching program.

EXECUTIVE OFFICERS

The following table sets forth information regarding our executive officers as at February 11, 2022:

Name	Age	Position
Al Monaco	62	President & Chief Executive Officer
Vern D. Yu	55	Executive Vice President & Chief Financial Officer
Colin K. Gruending	52	Executive Vice President & President, Liquids Pipelines
Cynthia L. Hansen	57	Executive Vice President & President, Gas Distribution and Storage
Byron C. Neiles	56	Executive Vice President, Corporate Services
Robert R. Rooney	65	Executive Vice President & Chief Legal Officer
William T. Yardley	57	Executive Vice President & President, Gas Transmission and Midstream
Matthew Akman	54	Senior Vice President, Strategy, Power & New Energy Technologies
Allen C. Capps	51	Senior Vice President, Corporate Development & Energy Services

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.

Vern D. Yu was appointed Executive Vice President and Chief Financial Officer on October 1, 2021, with oversight for all of Enbridge's financial affairs including investor relations, financial reporting, financial planning, treasury, tax, insurance, risk and audit management functions as well as implementation of our ERP transformation system. Previously, Mr. Yu served as Executive Vice President and President, Liquids Pipelines and prior to that served as President and Chief Operating Officer for Liquids Pipelines and as Executive Vice President and Chief Development Officer. Effective March 1, 2022, Mr. Yu will be appointed as Executive Vice President, Corporate Development and Chief Financial Officer.

Colin K. Gruending was appointed Executive Vice President and President, Liquids Pipelines on October 1, 2021. Mr. Gruending is responsible for the overall leadership and operations of Enbridge's Liquids Pipelines business. Previously, he served as our Executive Vice President and Chief Financial Officer and as Senior Vice President, Corporate Development and Investment Review.

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 Enbridge Gas Distribution Inc. (EGD) and Union Gas Limited (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. Effective March 1, 2022, Ms. Hansen will be appointed as the Executive Vice President and President of Gas Transmission and Midstream and Michele E. Harradence will be appointed as Senior Vice President and President, Gas Distribution and Storage. Ms. Harradence most recently held the role of Senior Vice President and Chief Operations Officer, Gas Transmission and Midstream.

Byron C. Neiles was appointed Executive Vice President, Corporate Services on May 2, 2016. Mr. Neiles has oversight of our information technology, human resources, real estate, supply chain management, safety, environment, land & right-of-way, and public affairs, communications and sustainability functions.

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

William T. Yardley was named Executive Vice President and President, Gas Transmission and Midstream on February 27, 2017. Mr. Yardley was previously President of Spectra Energy Corp's (Spectra Energy) US Transmission and Storage business, leading the business development, project execution, operations and environment, health and safety efforts associated with Spectra Energy's US portfolio of assets. Mr. Yardley will retire on May 31, 2022.

Matthew Akman was appointed Senior Vice President, Strategy & Power on June 1, 2019 and he is currently Senior Vice President, Strategy, Power & New Energy Technologies. He is responsible for the corporate strategic planning process and all renewable power operations and development globally, as well as for our New Energy Technologies team formed in 2021. Mr. Akman joined Enbridge in early 2016 as our head of Corporate Strategy and also previously held responsibilities for Corporate Development and Investor Relations.

Allen C. Capps was appointed Senior Vice President, Corporate Development and Energy Services in September 2020. He is responsible for capital allocation, investment review, corporate business development including Mergers & Acquisitions and Energy Services. Prior to assuming his current role, Mr. Capps served as Senior Vice President, Corporate Development and Investment Review. Mr. Capps has also served as Senior Vice President and Chief Accounting Officer and before that Vice President and Controller of Spectra Energy. Effective March 1, 2022, Mr. Capps will be appointed as the Senior Vice President and Chief Commercial Officer of Gas Transmission & Midstream.

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 Exchange Act, as well as proxy statements, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. Reports, proxy statements and other information filed with the SEC may also be obtained through the SEC's website (www.sec.gov).

ENBRIDGE GAS 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, 2021, 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, 2021, 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 can be found in its annual information form, financial statements and MD&A for the year ended December 31, 2021, 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 and are publicly available on SEDAR at www.sedar.com. These documents are not, unless otherwise specifically stated, incorporated by reference into this Annual Report on Form 10-K.

ITEM 1A. RISK FACTORS

The following risk factors could materially and adversely affect our business, operations, financial results, market price or value of our securities. This list is not exhaustive, and we place no priority or likelihood based on order of presentation or grouping under sub-captions.

RISKS RELATED TO CLIMATE CHANGE

Climate change risks could adversely affect our business, operations and financial results, and these effects could be material.

Climate change presents both physical and transition risks to our organization. A summary of these risks is discussed below. Given the interconnected nature of climate impacts, however, we also discuss these risks within the context of other risks impacting Enbridge throughout Item 1A - *Risk Factors*. Climate change and its associated impacts may increase our exposure to, and magnitude of, the other risks identified in Item 1A - *Risk Factors*. Our business, financial condition, results of operations, cash flows, reputation, access to and cost of capital or insurance, business plans or strategy may all be adversely impacted as a result of climate change and its associated impacts.

PHYSICAL RISKS

Physical risks relate to the physical impacts of climate change. These risks could damage our assets or affect the safety and reliability of our operations.

Climate change could result in extreme variability in weather patterns, such as increased frequency and severity of extreme weather events, heavy snowfall, heavy rainfall, floods, landslides, fires, hurricanes, tropical storms, ice storms, rising mean temperature and sea levels, and long-term changes in precipitation patterns. Our assets and operations are exposed to potential interruption or damage from these kinds of events, and we may also experience reduced access to our assets or increased risk of loss of life or injury or damage to property and the environment. We have experienced operational interruptions and damage to our assets from such weather events in the past, and we expect to experience climate related physical risks in the future, potentially with increasing frequency or severity. Operational risk is intensified by changing climate and more extreme weather events. Any of these physical risks could result in substantial losses for which our insurance may not be sufficient or available and for which we may bear a part or all of the cost.

TRANSITION RISKS

Transition risks relate to the transition to a lower-emission economy, which may increase our cost of operations, impact our business plans, and influence stakeholder decisions about our company, each of which could adversely impact our strategic plan, business, operations or financial results. These transition risks include:

Policy and legal risks

Foreign and domestic governments continue to evaluate and implement policy, legislation, and regulations focused on reducing GHG emissions, promoting adaptation to climate change, transitioning to a low-carbon economy, and disclosure of climate-related matters. Such policies, laws and regulations vary at the federal, state, provincial and municipal levels in which Enbridge operates and can be highly variable and subject to change. It is expected that further investments will be required to meet new regulatory requirements. In addition, in recent years there has been an increase in climate and disclosure-related litigation against governments as well as companies involved in the energy industry. There is no assurance that our company will not be impacted by such litigation.

Technology risks
Our success in executing our strategic plan, including our role in the transition to a lower-carbon economy, and attaining our GHG emissions reduction goals and targets, depends, in part, on technology (including technology still under development), innovation and continued diversification with renewable power and other low carbon energy infrastructure as well as modernization of our infrastructure to reduce GHG emissions. Achieving our GHG emissions reductions goals and targets could require significant capital expenditures and resources, with the potential that the costs required to achieve our goals and targets materially differ from our original estimates and expectations. Similarly, there is a risk that emissions reduction technology – like battery storage, CCS or direct air capture – do not materialize as expected, making it more difficult to reduce emissions.

Market risks
Climate change concerns, increase in demand for low-carbon and zero-emissions energy, alternative and new energy sources and technologies, changing customer behavior and reduced energy consumption could impact the demand for our services or securities. The pace and scale of the transition to a lower carbon economy may pose a climate-related transition risk if Enbridge diversifies either too quickly or too slowly. Similarly, uncertainty in market signals, such as abrupt and unexpected shifts in energy costs and demands, including due to climate change concerns, can impact revenue through reduced throughput volumes on our pipeline transportation systems.

Reputational risks
We have long been committed to strong ESG practices and performance, and in November 2020, we introduced a set of ESG goals to strengthen transparency and accountability. We have set GHG emissions reduction goals and a strategic priority to adapt to the energy transition over time. If we are not able to achieve our GHG emissions reduction goals, we are not able to meet future climate, emissions or other reporting requirements of regulators, or we are not able to meet or manage current and future expectations and issues important to investors or other stakeholders, including those related to climate change, it could negatively impact our reputation and our business, operations or financial results.

RISKS RELATED TO OPERATIONAL DISRUPTION OR CATASTROPHIC EVENTS

Pipeline operations involve numerous risks that may adversely affect our business, financial results and the environment.
Operation of complex pipeline systems, gathering, treating, storing and processing operations involves many risks, hazards and uncertainties.

These operational risks include adverse weather conditions, natural disasters, accidents, the breakdown or failure of equipment or processes, and the performance of the facilities below expected levels of capacity and efficiency and catastrophic events. Climate change presents physical risks relating to the physical impacts of climate change, which can affect the safety and reliability of our operations. Climate change could result in extreme variability in weather patterns, such as increased frequency and severity of extreme weather events, extreme hot and cold weather, heavy snowfall, heavy rainfall, floods, landslides, fires, hurricanes, tropical storms, ice storms, rising mean temperature and sea levels, and long-term changes in precipitation patterns.

Our assets and operations are exposed to potential interruption or damage from these kinds of events, and we may also experience reduced access to our assets, increased risk of loss of life or injury, damage to our property and our assets, environmental pollution or impairment of our operations. These kinds of events could also result in rupture or release of product from our pipeline systems and facilities. Such events could 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. Operational risk is also intensified by changing climate and more extreme weather events.

An environmental incident is an event that may cause environmental harm and could lead to an increased cost of operating and insuring our assets, thereby negatively impacting earnings. An environmental incident could have lasting reputational impacts 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 events could be greater.

We have experienced such events in the past, including in 2010 on Lines 6A and 6B of the Lakehead System; in October 2018 at the BC Pipeline T-South system; in January 2019, August 2019 and May 2020 at the Texas Eastern Pipeline; impacts from the winter storm in February 2021 in Texas and from wildfires in July 2021 and flooding in November 2021 in BC. We have incurred and expect to continue to incur significant costs in preparing for or responding to operational risks and events. We expect to continue to experience climate related physical risks, potentially with increasing frequency and severity, and we cannot guarantee that we will not experience catastrophic or other 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.

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, availability of gas supply or distribution or other reasons could have a significant impact on our operations and negatively impact financial results, relationships with stakeholders, our reputation or the safety of our end customers. Service interruptions that impact our crude oil and natural gas transportation services can negatively impact shippers' operations and earnings as they are dependent on our services to move their product to market or fulfill their own contractual arrangements. We have experienced, and may again experience, service interruptions including in connection with the kinds of operational incidents referred to in the previous risk factor.

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, which we have experienced in the past and, despite the precautions we take, may experience in the future, 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, pipelines and other assets, 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 and distribute, or releases of hydrocarbon products for which we could be held liable. Furthermore, we and some of our vendors collect and store sensitive data in the ordinary course of our business, including personal information of our employees and residential gas distribution customers as well as our proprietary business information and that of our customers, suppliers, investors and other stakeholders.

Cybersecurity risks have increased in recent years as a result of the proliferation of new technologies and the increased sophistication, magnitude and frequency of cyber-attacks and data security breaches, as well as due to international and national political factors. Because of the critical nature of our infrastructure and our use of information systems and other digital technologies to control our assets, we face a heightened risk of cyber-attacks. New cybersecurity regulations have been recently implemented resulting in additional regulatory oversight and compliance requirements.

During the normal course of business, we have experienced and expect to continue to experience attempts to gain unauthorized access, compromise our information systems or to disrupt our operations through cyber-attacks or security breaches, although none to our knowledge have had a material adverse effect on our business, operations or financial results. Despite our security measures, our information systems or those of our vendors are expected to become the target of further cyber-attacks or security breaches which could compromise our systems, affect our ability to correctly record, process and report transactions, result in the loss of information, or cause operational disruption. 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, incur additional costs for remediation, litigation or other costs, all of which could materially adversely affect our reputation, business, operations or financial results.

Pandemics, epidemics or disease outbreaks, such as the COVID-19 pandemic, may adversely affect local and global economies and our business, operations or financial results.
Disruptions caused by pandemics, epidemics or disease outbreaks, in locations in which we operate or globally, could materially adversely affect our business, operations, financial results and forward-looking expectations.

In response to the rapid global spread of COVID-19, governments continue to enact emergency measures to combat the spread of the virus. These measures include restrictions on business activity and travel, as well as requirements to isolate or quarantine. Certain of our operations and projects have been deemed essential services in critical infrastructure sectors and are currently exempt from certain business activity restrictions. COVID-19 and government responses have interrupted business activities and supply chains, disrupted travel, and contributed to significant volatility in the financial and commodity markets.

Given the ongoing and dynamic nature of the COVID-19 pandemic, further impacts will depend on future developments and factors outside of our control, which are uncertain, evolving and cannot be predicted, including new information which may emerge concerning the severity or duration of this pandemic (including new COVID-19 strains and the efficacy of vaccines) and actions taken by governments and others to contain or end the COVID-19 pandemic or its impact. Such developments include disruptions, which have had or may have an adverse effect on our customers, suppliers, regulators, business, operations and financial results.

There can be no assurance that our strategies to address potential disruptions will mitigate these risks or the adverse impacts to our business, operations and financial results. In addition, disruptions related to the COVID-19 pandemic have had, or could continue to have, the effect of heightening many of the other risks described in this Item 1A. *Risk Factors*.

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 (which may take the form of cyber-attacks), 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 US, 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 US 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.

RISKS RELATED TO OUR BUSINESS AND INDUSTRY

There are utilization risks with respect to our assets.
With respect to our Liquids Pipelines assets, we may be exposed to throughput risk on the Canadian Mainline depending upon the tolling framework we adopt for that system, and we are exposed to throughput risk 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, regulatory restrictions, maintenance and operational incidents on our system and upstream or downstream facilities 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 and new energy sources and technologies, 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.

With respect to our Gas Transmission and Midstream assets, gas supply and demand dynamics continue to change due to shifts in regional production and consumption. These shifts can lead to fluctuations in commodity prices and price differentials, resulting in oversupply of pipeline takeaway capacity in some areas and an adverse effect to the utilization of our systems. Other factors affecting system utilization include operational incidents, regulatory restrictions, system maintenance, and increased competition.

With respect to our Gas Distribution and Storage assets, customers are billed on both a fixed charge and volumetric basis and our ability to collect the 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. 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.

With 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.

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 US 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 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. Renewable Power Generation business faces competition in the procurement of long-term power purchase agreements and from other fuel sources in the markets in which we operate. 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, operational and market risks that may affect our financial results.

Our ability to successfully bring our secured capital growth program into service is exposed to risks including:

- the ability to obtain or amend necessary approvals and permits from governments and regulatory agencies on a timely basis and with acceptable terms and conditions and to maintain those issued approvals and permits and satisfy the terms and conditions imposed therein;
- opposition by third parties, physical protests, interference with or damage to our property or infrastructure, litigation or increased execution and stakeholder engagement complexity;
- new or incremental changes in federal, state, provincial and local laws and regulations after projects are sanctioned;
- inflationary pressures on labor, materials and equipment, which have decreased price predictability;
- bottlenecked global supply chains and logistics, which have increased delivery times of materials and equipment;
- timely acquisition or renewal of rights-of-way or land rights with acceptable terms and conditions;
- extreme weather events (e.g. hurricanes, forest fires, floods); or
- contractor or supplier non-performance, weather, geological or other factors beyond our control.

Any of these risks could prevent a project from proceeding, delay its completion or increase its anticipated cost.

New projects may not achieve their expected investment return, which could affect our financial results, reputation and hinder our ability to secure future projects. Recent projects that have experienced various degrees of impacts include the US L3R Program that was placed into service in the third quarter of 2021, Line 5 projects (tunnel and reroute), Texas Eastern Modernization, East-West Tie and Offshore Wind. 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.*

Changing expectations from stakeholders regarding ESG practices and climate change or erosion of stakeholder trust or confidence could damage our reputation and influence actions or decisions about our company and industry and have negative impacts on our business, operations or financial results.

Companies across all sectors and industries are facing changing expectations or increasing scrutiny from stakeholders related to their approach to ESG matters of greatest relevance to their business and to their stakeholders. For energy companies, climate change, safety, stakeholder and Indigenous relations remain primary focus areas, while other environmental elements such as biodiversity are ascendant; changing expectations of our practices and performance across these and other ESG areas may impose additional costs or create exposure to new or additional risks.

Our operations, projects and growth opportunities require us to have strong relationships with key stakeholders, including local communities, Indigenous groups and communities and other groups directly impacted by our activities, as well as governments and government agencies, investor advocacy groups, institutional investors, investment funds, financial institutions, insurers and others, which are increasingly focused on ESG practices.

Enhanced public awareness of climate change has driven an increase in demand for low-carbon and zero-emissions energy. Enbridge has a long history of diversifying its portfolio of businesses to align with the mix of energy that people need and want. However, the pace and scale of the transition to a lower emissions economy may pose a climate-related transition risk if Enbridge diversifies either too quickly or too slowly. Similarly, unexpected shifts in energy demands, including due to climate changes concerns, can impact revenue through reduced throughput volumes on our pipeline transportation system.

We have long been committed to strong ESG practices, performance and reporting, and in late 2020 introduced a set of ESG goals to strengthen transparency and accountability. The goals include increasing diversity and inclusion within our organization and reducing emissions from our operations to net zero by 2050, with corporate and business unit action plans aligned to our strategic priority to adapt to the energy transition over time. Given elevated long-term risks associated with climate change, there have also been efforts in recent years by the investment community, including increased engagement with companies on climate change and decreasing the carbon intensity of their portfolios. If we are not able to achieve our GHG emissions reduction goals, are not able to meet future climate, emissions or other reporting requirements of regulators, or are not able to meet or manage current and future expectations or issues important to investors or other stakeholders including those related to climate change, it could negatively impact stakeholder trust and confidence, our reputation, and our business, operations or financial results, including:

- 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;
- loss of 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;
- restricted access to and cost of capital and insurance; 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 organized opposition to oil and gas extraction and shipment of oil and gas products.

Our forecasted assumptions may not materialize as expected, including 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, and changes in cost estimates, project scoping and risk assessment could result in a loss of our profits. Similarly, uncertainty in market signals, such as abrupt and unexpected shifts in energy costs and demands, as we saw in 2020 resulting from the COVID-19 pandemic, have impacted, and may in the future impact, revenue through reduced throughput volumes on our pipeline transportation system.

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, and in some cases have caused, 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 that in the 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.

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. 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. It is possible that customer payment defaults, if significant, could adversely affect our earnings and cash flows.

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 financial derivatives to manage risks associated with changes 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 financial derivatives are associated with an underlying asset, liability and/or forecasted transaction and not intended for speculative purposes.

These policies cannot, however, eliminate all risk including unauthorized trading. Although this activity is monitored independently by our risk management function, we can provide no assurance that we will detect and prevent all unauthorized trading and other violations, particularly if deception, collusion or other intentional misconduct is involved, and any such violations could adversely affect our business, operations or financial results.

Our business requires the retention and recruitment of a skilled and diverse workforce, and difficulties in 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 and diverse workforce, including engineers, technical personnel and other professionals. We and our affiliates compete with other companies in the energy industry, and for some jobs the broader labor market, 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 costs to retain and recruit these professionals.

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 beyond 2022, 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.

Our business is undergoing significant changes driven by technological advancements and the energy transition, which could impact our strategic plan, business, operations or financial results.
Our success in executing our strategic plan, including our role in the transition to a low-carbon economy, and attaining our GHG emissions reduction goals and targets depends, in part, on technology (including technology still under development), innovation and continued diversification with renewable power and other low carbon energy infrastructure as well as modernization of our infrastructure to reduce GHG emissions, all of which could require significant capital expenditures and resources. Public policy relating to climate change can drive investment in lower-emissions technologies which could impact both the supply of and demand for crude oil and other liquid hydrocarbons transported on our pipelines.

Our Liquids Pipelines growth rate and results may be directly and indirectly affected by commodity prices and government policy.
This intervention had a negligible impact on the Mainline System throughput, as enough inventory existed 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. Effective December 31, 2021, the Government of Alberta lifted the oil production curtailment that was imposed in December 2018.

The tight conventional oil plays of Western Canada, the Permian basin, 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 to 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 Energy Services and Gas Transmission and Midstream results may be adversely affected by commodity price volatility.
Within our US Midstream assets, through our investments in DCP Midstream and Aux Sable, we are engaged in the businesses of gathering, treating and processing natural gas and natural gas liquids. The financial results of these businesses are directly impacted by changes in commodity prices.

Energy Services generates margin by capitalizing on quality, time and location differentials when opportunities arise. Lower commodity prices due to changing market conditions could limit margin opportunities and impede Energy Services' ability to cover capacity commitments.

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. An inability to access capital may limit our ability to pursue enhancements 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.

RISKS RELATED TO GOVERNMENT REGULATION AND LEGAL RISKS

Many of our operations are regulated and failure to secure timely regulatory approval for our proposed projects, or loss of required approvals for our existing operations, could have a negative impact on our business, operations or financial results.
The nature and degree of regulation and legislation affecting energy companies in Canada and the US have changed significantly in recent years.

In Canada, the passing of the Canadian Energy Regulator Act and the Impact Assessment Act under Bill C-69, which came into force on August 28, 2019, adds steps in the regulatory process and extends overall timelines associated with regulatory approvals for new projects which trigger a federal impact assessment. Changes to the BC regulatory framework have also been made, including a new Environmental Assessment Act, which came into force in December 2019, affecting provincially-regulated projects in a similar manner as those that are federally-regulated. Within the US and in Canada, pipelines companies continue to face opposition from anti-pipeline activists, Indigenous and tribal groups and communities, citizens, environmental groups and politicians concerned with either the safety of pipelines or environmental effects. In the US, several federal agencies made changes to regulations that were designed to streamline permitting, including changes that the Environmental Protection Agency made in June 2020 to regulations implementing Section 401 of the Clean Water Act and the July 2020 Council on Environmental Quality revisions to regulations implementing the National Environmental Policy Act. These and many other regulations adopted during the previous US presidential administration are not only being challenged in multiple courts, but have now been expressly targeted for rollback by the new US administration, which is expected to modify or reverse the regulations.

These actions could adversely impact permitting of a wide range of energy projects. 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, including those relating to climate change and GHG emissions and climate-related disclosure, as well as internal initiatives to reduce GHG emissions, 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.

Foreign and domestic governments continue to evaluate and implement policy, legislation, and regulations focused on restricting GHG emissions, promoting adaptation to climate change and the transition to a low-carbon economy, and disclosure of climate-related matters. Such policies, laws and regulations vary at the federal, state, and provincial levels in which Enbridge operates and can be highly variable and subject to change. International multilateral agreements, the obligations adopted thereunder, increasing physical impacts of climate change, changing political and public opinion and legal challenges concerning the adequacy of climate-related policy brought against governments and corporations, among other factors, are expected to accelerate the implementation of these measures.

Enbridge is required to adhere to a number of implicit and explicit carbon-pricing mechanisms. These mechanisms may present climate-related transition risk to our business strategy, impacting both commodity demand and the overall energy mix we deliver.

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, such as costs to monitor and report our emissions and install new emission controls to reduce emissions. We may not be able to include some or all of such increased costs in the rates charged by our pipelines or other facilities. Efforts to regulate or restrict GHG emissions could also drive down demand for the products we transport.

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.

In November 2020, we set new ESG goals for the future related to GHG emissions reduction. Our ability to achieve these goals depends on many factors, including our ability to reduce emissions from our operations through modernization and innovation, reduce the emissions intensity of the electricity we buy, invest in renewables and low carbon energy and balance residual emissions through carbon offset credits. The cost associated with our GHG emissions reduction goals could be significant. There is also a risk that some or all of the expected benefits and opportunities of achieving the various GHG emissions reduction and energy transition goals may fail to materialize, may cost more to achieve or may not occur within the anticipated time periods. Similarly, there is a risk that emissions reduction technology – like battery storage or direct air capture – do not materialize as expected making it more difficult to reduce emissions. Failure to achieve our emissions targets could result in reputational harm, changing investor sentiment regarding investment in Enbridge or a negative impact on access to and cost of capital, including penalties associated with our sustainability-linked bond offerings.

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 reputation, business, operations or financial results.

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. We do not own all of the land on which our pipelines, facilities and other assets are located and we obtain the rights to construct and operate our pipelines and other assets from third parties or government entities. In addition, some of our pipelines, facilities and other assets cross Indigenous lands pursuant to rights-of-way or other land tenure interests. Our loss of these rights could have an adverse effect on our reputation, operations and financial results. Regulator scrutiny over our assets and operations has the potential to increase operating costs or limit future projects. Regulatory enforcement actions issued by regulators for non-compliant findings can increase operating costs and negatively impact reputation. 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 actively 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 disrupt our operations or have an adverse 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, operations or financial results.
Our liquids pipelines, gas transmission and gas distribution assets 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 or policies, including permits and regulatory approvals for both new and existing projects or agreements, upon which future and current operations are dependent. Our Mainline System, other liquids pipelines and gas transmission assets are subject to the actions of various regulators, including the CER and the FERC, with respect to the tariffs and tolls of those pipelines. The changing or rejecting of commercial arrangements, including decisions by regulators on the applicable permits and tariff structure or changes in interpretations of existing regulations by courts or regulators such as with respect to Mainline Contracting, could have an adverse effect on our revenues and earnings.

We could be subject to changes in our tax rates, the adoption of new US, Canadian or international tax legislation or exposure to additional tax liabilities.
We are subject to taxes in the US, 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. In particular, we are anticipating interest deductibility rules to be tabled in Canada, possible new tax legislation to be passed in the US and a minimum tax rate to be introduced on a global basis for OECD countries. All of these measures could cause our effective tax rate to increase.

We are also subject to the examination of our tax returns and other tax matters by the US 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 US 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.

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. In recent years there has been an increase in climate and disclosure-related litigation against governments as well as companies involved in the energy industry. There is no assurance that we will not be impacted by such litigation. 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 or affect our reputation. 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 certain legal proceedings with recent developments.

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 Part 1. *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 pipeline 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 pipeline systems have natural gas compressor stations, of which the vast majority are located on land that is owned by us, with the remainder used by us under easements, leases or permits.

Titles to Enbridge owned properties or affiliate entities may be 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 certain legal proceedings with recent developments.

SEC regulations require the disclosure of any proceeding under environmental laws to which a governmental authority is a party unless the registrant reasonably believes it will not result in monetary sanctions over a certain threshold. Given the size of our operations, we have elected to use a threshold of US$1 million for the purposes of determining proceedings requiring disclosure.

The Minnesota Department of Natural Resources (DNR) issued an Administrative Penalty Order on September 16, 2021 due to an uncontrolled groundwater flow at Clearbrook. The groundwater flow was stopped in January 2022 after diligently implementing the steps required under the remedial action plan. We have also provided all required information to date. A contested case was not sought in this matter; instead, the penalty and mitigation amounts will be paid as directed for the Clearbrook site. A separate US$2.75 million escrow account is being established for any potential future monitoring and mitigation. In total, Enbridge will direct US$3.3 million to address this matter. With work complete at Clearbrook and a second site, Enbridge continues to work with the DNR towards a corrective action plan for the final location, including ongoing restoration, monitoring, and mitigation for all three sites.

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

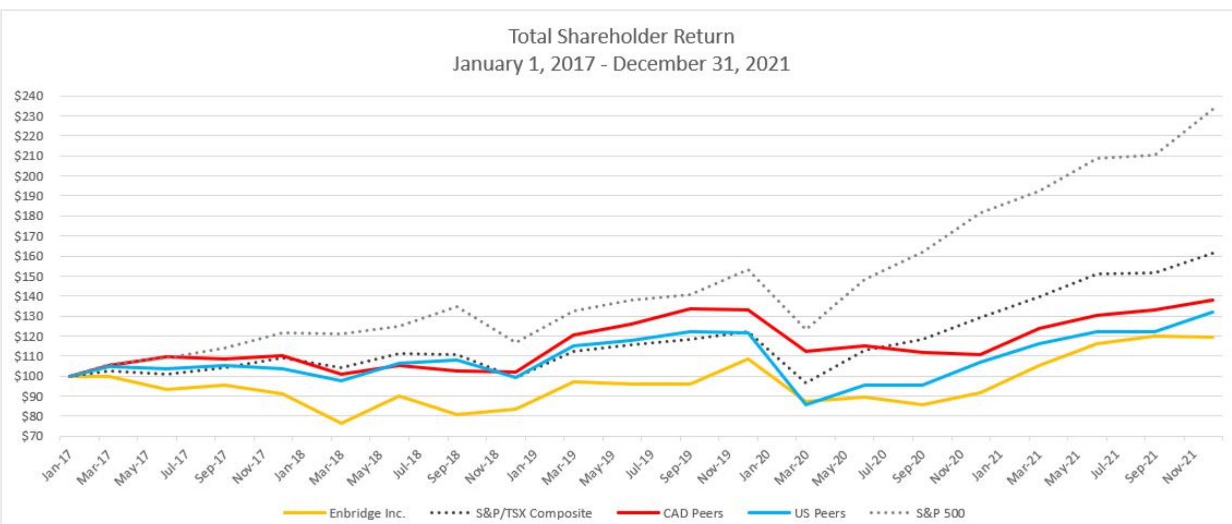
Common Stock
Enbridge common stock is traded on the TSX and NYSE under the symbol “ENB.” As at February 4, 2022, there were 80,754 registered shareholders of record of Enbridge common stock. A substantially greater number of holders of Enbridge common stock are "street name" or beneficial holders, whose shares are held by banks, brokers and other financial institutions.

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, 2021.

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, 2017 through December 31, 2021 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 US peer group (comprising CNP, D, DTE, DUK, EPD, ET, KMI, MMP, NEE, NI, OKE, PAA, PCG, SO, SRE and WMB) and (5) our Canadian peer group (comprising CU, FTS, PPL and TRP). The amounts included in the table were calculated assuming the reinvestment of dividends at the time dividends were paid.



	January 1, 2017	December 31, 2017	2018	2019	2020	2021
Enbridge Inc.	100.00	91.20	83.64	108.32	91.84	119.50
S&P/TSX Composite	100.00	109.10	99.40	122.14	128.98	161.34
S&P 500 Index	100.00	121.83	116.49	153.17	181.35	233.41
US Peers[1]	100.00	103.37	99.41	121.77	107.12	131.86
Canadian Peers	100.00	110.39	101.93	133.27	110.56	138.14

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

ITEM 6. [Reserved]

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" and "Non-GAAP and Other Financial Measures", 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 2021 and 2020 items and year-over-year comparisons between 2021 and 2020. For discussion of 2019 items and year-over-year comparisons between 2020 and 2019, refer to Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations* of our Annual Report on Form 10-K for the year ended December 31, 2020.

RECENT DEVELOPMENTS

ACQUISITION OF MODA MIDSTREAM OPERATING, LLC

On October 12, 2021, we acquired Moda Midstream Operating, LLC (Moda) for $3.7 billion (US$3.0 billion) of cash plus potential contingent payments dependent on performance of the assets (the Acquisition). Moda owns and operates a vertically-integrated crude export system of pipeline and storage assets on the US Gulf Coast, including the EIEC located near Corpus Christi, Texas. EIEC, North America's largest crude export terminal, controls 15.6 million barrels of storage and 1.6 million barrels per day (mmbpd) of export capacity and volumes are underpinned by 925- thousand barrels per day (kbpd) of long-term take-or-pay vessel loading contracts and 15.3 million barrels of long-term storage contracts. The Acquisition aligns with and advances our US Gulf Coast export strategy and connectivity to low-cost and long-lived reserves in the Permian and Eagle Ford basins.

NORMAL COURSE ISSUER BID

On December 31, 2021, we announced that the Toronto Stock Exchange (TSX) had approved our normal course issuer bid (NCIB) to purchase, for cancellation, up to 31,062,331 of the outstanding common shares of Enbridge to an aggregate amount of up to $1.5 billion, subject to certain restrictions on the number of common shares that may be purchased on a single day.

Purchases under the NCIB may be made through the facilities of the TSX, the New York Stock Exchange (NYSE) and other designated exchanges and alternative trading systems, commencing on January 5, 2022 and continuing until January 4, 2023, when the bid expires, or such earlier date on which Enbridge has either acquired the maximum number of common shares allowable under the NCIB or otherwise decide not to make any further repurchases under the NCIB. The maximum number of common shares that Enbridge may repurchase for cancellation represents approximately 1.53% of the 2,026,085,179 common shares issued and outstanding as at December 22, 2021.

MAINLINE SYSTEM CONTRACTING

On December 19, 2019, we submitted an application to the Canada Energy Regulator (CER) to implement contracting on our Canadian Mainline System. On November 26, 2021, the CER denied the application on the basis that, among other things, contracting as proposed would result in a significant change to access the Canadian Mainline and potentially inequitable outcomes to some shippers and non-shippers without a compelling justification.

We are currently exploring with customers and other stakeholders alternatives that may include: a modified and extended Competitive toll Settlement (CTS), a new incentive rate-making agreement or a cost-of-service rate-making structure. Any negotiated settlement would require CER approval before implementation.

In accordance with the terms of the CTS, which expired on June 30, 2021, the tolls in place on June 30, 2021 will continue on an interim basis, subject to finalization and adjustment applicable to the interim period, if any.

GAS TRANSMISSION AND MIDSTREAM RATE PROCEEDINGS

Texas Eastern Transmission

Texas Eastern Transmission, LP (Texas Eastern) filed a rate case on July 30, 2021. On August 31, 2021 the Federal Energy Regulatory Commission (FERC) issued an order rejecting the July 30, 2021 filing in its entirety noting the proposed US federal income tax rate in the filing was not known and measurable ("August 2021 Order"). Additionally, the August 31, 2021 order directed Texas Eastern to show cause that its reservation charge crediting process is in accordance with FERC policy.

In response to the August 2021 Order, on September 30, 2021 Texas Eastern responded to the show cause directive and filed a new rate case using the current US federal income tax rate. On October 29, 2021, the FERC issued an order accepting and suspending tariff records, subject to refund, conditions, and establishing hearing procedures for the new rate case filed on September 30, 2021.

Texas Eastern also filed for rehearing of the August 2021 Order. On January 20, 2022 the FERC issued an "Order Addressing Arguments Raised On Rehearing And Setting Aside Prior Order, In Part" ("January 2022 Order"). The January 2022 Order set aside the August 2021 Order, and accepted and suspended Texas Eastern's proposed rates from its initial rate case filing to be effective upon motion on February 1, 2022, subject to refund, conditions, and the outcome of hearing proceedings. In addition, the January 2022 Order directed Texas Eastern to remove its proposed income tax adjustment and include the actual tax rate in the computation of its rates when it files to motion the suspended rates into effect.

Finally, the FERC left to the discretion of the Chief Administrative Law Judge whether to consolidate the two rate case proceedings.

East Tennessee

East Tennessee Natural Gas, LLC (ETNG) filed a rate case in the second quarter of 2020 and an agreement in principle was reached with shippers in April 2021. A Stipulation and Agreement was filed on May 21, 2021, approved by the FERC on September 10, 2021 and was effective on November 1, 2021.

Maritimes & Northeast Pipeline

The US portion of Maritimes & Northeast Pipeline filed a rate case in the second quarter of 2020 and an agreement in principle was reached with shippers in December 2020. A Stipulation and Agreement was filed on February 17, 2021, approved by the FERC on April 30, 2021 and was effective on June 1, 2021. In December 2021, the CER approved interim rates for the Canadian portion of Maritimes & Northeast Pipeline effective January 1, 2022, which were based on the negotiated 2022 rates in the 2022-2023 settlement agreement and unanimously supported by shippers. A decision from the CER on the 2022-2023 settlement agreement is expected in the first quarter of 2022.

Alliance Pipeline
The US portion of Alliance Pipeline filed a rate case in the second quarter of 2020 and an agreement in principle was reached with shippers in January 2021. A Stipulation and Agreement was filed on March 31, 2021, approved by the FERC on July 15, 2021 and was effective on September 1, 2021.

British Columbia (BC) Pipeline
The settlement agreement for our BC Pipeline system expired in December 2021. The CER has approved 2022 interim tolls for BC Pipeline and settlement agreement negotiations are ongoing, with an expected agreement to be reached in the first half of 2022.

GAS DISTRIBUTION AND STORAGE RATE APPLICATIONS

2021 Rate Application
Enbridge Gas Inc.'s (Enbridge Gas) rate applications are filed in two phases. As part of an Ontario Energy Board (OEB) Decision and Order issued in November 2020, Phase 1 of the application for 2021 rates (the 2021 Application), exclusive of 2021 capital investment funding requested through the incremental capital module (ICM) mechanism, was approved on an interim basis effective January 1, 2021. Through a subsequent OEB Rate Order issued in June 2021, Phase 2 of the 2021 Application, inclusive of funding for $124 million of requested 2021 ICM amounts, was approved effective July 1, 2021, and interim rates in effect for 2021 were made final. The 2021 Application, which represented the third year of a five-year term, was filed in accordance with the parameters of the Enbridge Gas OEB approved Price Cap Incentive Regulation (IR) rate setting mechanism.

2022 Rate Application
In June 2021, Enbridge Gas filed Phase 1 of the application with the OEB for the setting of rates for 2022 (the 2022 Application). The 2022 Application was filed in accordance with the parameters of the Enbridge Gas OEB approved Price Cap IR rate setting mechanism which represents the fourth year of a five-year term. In October 2021, the OEB approved a Phase 1 Settlement Proposal and Interim Rate Order effective January 1, 2022. Phase 2 of the 2022 Application addressing ICM funding requirements was filed in October 2021, with a decision from the OEB expected in the second quarter of 2022.

FINANCING UPDATE

We completed long-term debt issuances totaling US$3.9 billion and $3.2 billion during the year ended December 31, 2021, including an inaugural US$1.0 billion 12-year sustainability-linked senior notes issuance in June 2021 and an inaugural $1.1 billion Canadian 12-year sustainability-linked medium-term notes issuance in September 2021. We renewed approximately $8.0 billion of our five-year credit facilities, extending the maturity date out to July 2026. We also extended approximately $10.0 billion of our 364-day extendible credit facilities to July 2022, which includes a one-year term out provision to July 2023.

Our 2021 financing activities, in combination with the asset monetization activities noted below, provide significant liquidity that we expect will enable us to fund our current portfolio of capital projects without requiring access to the capital markets for the next 12 months should market access be restricted or pricing is unattractive. Refer to *Liquidity and Capital Resources*.

On January 19, 2022, we closed a $750 million private placement offering of non-call 10-year fixed-to-fixed subordinated notes which mature on January 19, 2082. The net proceeds from the offering will be used to redeem the Preference Shares, Series 17 at par on March 1, 2022.

On February 10, 2022 we renewed our three year $1.0 billion sustainability-linked credit facility, extending the maturity date out to July 2025.

Credit Rating Action
On June 1, 2021, Moody's Investors Service (Moody's) upgraded the credit ratings of Enbridge Inc., including our senior unsecured and issuer ratings, to Baa1 from Baa2. Moody's also upgraded the credit ratings of our subsidiaries: Enbridge Energy Partners, L.P. (EEP), Enbridge Energy Limited Partnership (EELP), Spectra Energy Partners, LP (SEP) and Texas Eastern. The outlooks of all five entities are stable.

ENERGY TRANSITION

Given the priority we are placing on low carbon investments and energy transition, we have established a dedicated New Energy Technologies team. This team will extend the capabilities we have built over the last 20 years of renewable investments and will establish priorities and co-ordinate strategy across our business units. The team will also develop new partnerships to enable access to new technology, complementary assets and skills.

During 2021, the Alberta Solar One and Heidlersburg solar self-power projects were placed into service. We also started the construction process on 10 additional solar self-power projects in Wisconsin, Illinois, Pennsylvania, Kentucky, Ohio and Minnesota, together capable of generating more than 97 megawatts (MW) MW of emissions-free electricity. These projects will provide clean power to our liquids and natural gas pipeline right-of-way and support scope 1 and 2 emission targets.

ASSET MONETIZATION

Éolien Maritime France SAS
On March 18, 2021, we sold 49% of an entity that holds our 50% interest in Éolien Maritime France SAS (EMF) to the Canada Pension Plan Investment Board (CPP Investments). CPP Investments will fund their 49% share of all ongoing future development capital. Through our investment in EMF, we own equity interests in three French offshore wind projects, including Saint-Nazaire (25.5%), Fécamp (17.9%) and Calvados (21.7%). The Calvados Offshore Wind Project reached a positive final investment decision in February 2021 and all three projects are now considered commercially secured and are under construction.

Noverco Inc.
On December 30, 2021, we sold our 38.9% non-operating minority ownership interest in Noverco Inc. (Noverco) to Trencap L.P. for $1.1 billion in cash.

RESULTS OF OPERATIONS

	Year ended December 31,		
	2021	2020	2019
(millions of Canadian dollars, except per share amounts)			
Segment earnings before interest, income taxes and depreciation and amortization[1]			
Liquids Pipelines	**7,897**	7,683	7,681
Gas Transmission and Midstream	**3,671**	1,087	3,371
Gas Distribution and Storage	**2,117**	1,748	1,747
Renewable Power Generation	**508**	523	111
Energy Services	**(313)**	(236)	250
Eliminations and Other	**356**	(113)	429
Earnings before interest, income taxes and depreciation and amortization[1]	**14,236**	10,692	13,589
Depreciation and amortization	**(3,852)**	(3,712)	(3,391)
Interest expense	**(2,655)**	(2,790)	(2,663)
Income tax expense	**(1,415)**	(774)	(1,708)
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	**(125)**	(53)	(122)
Preference share dividends	**(373)**	(380)	(383)
Earnings attributable to common shareholders	**5,816**	2,983	5,322
Earnings per common share	**2.87**	1.48	2.64
Diluted earnings per common share	**2.87**	1.48	2.63

1 Non-GAAP financial measures.

EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS

Year ended December 31, 2021 compared with year ended December 31, 2020

Earnings Attributable to Common Shareholders increased by $2.2 billion due to certain unusual, infrequent or other non-operating factors, primarily explained by the following:

- a non-cash, unrealized net gain of $53 million ($40 million after-tax) in 2021, compared with an unrealized net loss of $122 million ($92 million after-tax) in 2020 reflecting the revaluation of derivatives used to manage the profitability of transportation and storage transactions, as well as manage the exposure to movements in commodity prices;
- an impairment loss of $111 million ($83 million after-tax) in 2021 to our investment in the PennEast pipeline project after a decision by project partners to cease development, compared to a combined impairment loss of $615 million ($452 million after-tax) in 2020 to our investments in Southeast Supply Header (SESH) and Steckman Ridge, LP (Steckman);
- a gain of $303 million ($298 million after-tax) resulting from the sale of our investment in Noverco;
- employee severance, transition and transformation costs of $147 million ($112 million after-tax) in 2021, compared to $339 million ($256 million after-tax) in 2020 primarily related to our voluntary workforce reduction program offered in the second quarter of 2020;
- the absence in 2021 of a non-cash impairment to the carrying value of our investment in DCP Midstream, LLC (DCP Midstream) of $1.7 billion ($1.3 billion after-tax) and a $324 million loss ($244 million after-tax) resulting from our share of asset and goodwill impairments recognized by DCP Midstream, both recognized in 2020; and

- the absence in 2021 of a $159 million loss ($119 million after-tax) recorded in 2020 to reflect the Texas Eastern rate case settlement that re-established the Excess Accumulated Deferred Income Tax (EDIT) regulated liability that was previously eliminated in December 2018; partially offset by
- a non-cash, unrealized derivative fair value net gain of $197 million ($150 million after-tax) in 2021, compared with a net gain of $856 million ($646 million after-tax) in 2020, 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 risks.

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 $657 million increase in earnings attributable to common shareholders is primarily explained by the following significant business factors:

- stronger contributions from our Liquids Pipelines segment due to increased volumes enabled by incremental Line 3 capacity placed into service in the fourth quarter of 2021 and a higher Mainline International Joint Tariff (IJT) Benchmark Toll, partially offset by the recognition of a provision against the interim Mainline IJT for barrels shipped between July 1, 2021 and December 31, 2021;
- increased earnings from our Gas Distribution and Storage segment due to increased rates and customer base;
- higher equity earnings from our Aux Sable and DCP Midstream joint ventures in our Gas Transmission and Midstream; and
- lower interest expense for the first nine months of 2021 due to favourable interest rates on short-term borrowings, and the impact of a weaker US dollar currency that positively impacted the translation of interest payments on US dollar denominated debt.

The business factors above were partially offset by the following:

- decreased earnings from our Energy Services segment due to the significant compression of location and quality differentials in certain markets, fewer storage opportunities due to market backwardation, adverse impacts from the major winter storm experienced across the US Midwest during February 2021 and fewer opportunities to achieve profitable transportation margins on facilities in which Energy Services holds capacity obligations;
- the net unfavorable effect of translating US dollar EBITDA to Canadian dollars at a lower average exchange rate in 2021 compared to the same period in 2020;
- the absence in 2021 of the recognition of revenue in 2020 from a rate settlement on Texas Eastern, partially offset by increased revenue due to the absence of pressure restrictions that existed on the Texas Eastern system in 2020; and
- higher depreciation expense on new assets placed into service throughout 2021, including the US L3R Program, placed into service early in the fourth quarter and the EIEC, acquired in mid-October.

REVENUES

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

Transportation and other services revenues of $16.2 billion, $16.2 billion and $16.6 billion for the years ended December 31, 2021, 2020 and 2019, 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.

Gas distribution sales revenues of $4.0 billion, $3.7 billion and $4.2 billion for the years ended December 31, 2021, 2020 and 2019, 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 revenues of $26.9 billion, $19.3 billion and $29.3 billion for the years ended December 31, 2021, 2020 and 2019, 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.

BUSINESS SEGMENTS

LIQUIDS PIPELINES

	2021	2020	2019
(millions of Canadian dollars)			
Earnings before interest, income taxes and depreciation and amortization[1]	**7,897**	7,683	7,681

1 Non-GAAP financial measure.

Year ended December 31, 2021 compared with year ended December 31, 2020

EBITDA was negatively impacted by $335 million due to certain unusual, infrequent or other non-operating factors, primarily explained by a non-cash, unrealized gain of $120 million in 2021 compared with an unrealized gain of $545 million in 2020 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 risks.

The factor above was partially offset by the following:

- a property tax settlement receipt of $57 million in 2021 related to the resolution of Minnesota property tax appeals for the tax years 2012 through 2018; and
- the absence in 2021 of $30 million of asset impairment losses recognized in 2020.

After taking into consideration the factors above, the remaining $549 million increase is primarily explained by the following factors:

- higher Mainline system ex-Gretna average throughput of 2.8 million barrels per day (mmbpd) in 2021 as compared to 2.6 mmbpd in 2020 driven by the rebounding demand for crude oil and related products as economies continue to recover from the impacts of the COVID-19 pandemic;
- incremental L3R capacity that came into service October 2021 further supporting demand growth and the implementation of full L3R surcharge of US$0.93 per barrel beginning October 2021 compared to the Canadian L3R program US$0.20 per barrel;
- a higher average IJT Benchmark Toll on our Mainline System of US$4.27 in 2021, compared with US$4.24 in 2020;
- a higher foreign exchange hedge rate used to lock-in US dollar denominated Canadian Mainline revenue; and
- higher equity income from our investment in the Seaway Crude Pipeline System driven by increased volumes.

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

- the recognition of a provision in the fourth quarter against the interim Mainline IJT for barrels shipped between July 1, 2021 and December 31, 2021; and
- the net unfavorable effect of translating US dollar EBITDA to Canadian dollars at a lower average exchange rate in 2021 versus 2020.

GAS TRANSMISSION AND MIDSTREAM

	2021	2020	2019
(millions of Canadian dollars)			
Earnings before interest, income taxes and depreciation and amortization[1]	**3,671**	1,087	3,371

1 Non-GAAP financial measure.

Year ended December 31, 2021 compared with year ended December 31, 2020

EBITDA was positively impacted by $2.6 billion due to certain unusual, infrequent or other non-operating factors primarily explained by the following:

- an impairment loss of $111 million in 2021 to our investment in the PennEast pipeline project after a decision by project partners to cease development, compared to a combined impairment loss of $615 million in 2020 to our investments in SESH and Steckman;
- the absence in 2021 of a $1.7 billion non-cash impairment to the carrying value of our investment in DCP Midstream and a $324 million loss resulting from our share of asset and goodwill impairments recognized by DCP Midstream, both recognized in 2020;
- the absence in 2021 of a $159 million loss recorded in 2020 to reflect the Texas Eastern rate case settlement that re-established the EDIT regulated liability that was previously eliminated in December 2018; partially offset by
- a negative impact in equity earnings of $44 million in 2021, compared with a positive impact of $22 million in 2020 relating to changes in the mark-to-market value of derivative financial instruments within our equity method investee, DCP Midstream.

After taking into consideration the factors above, we saw a $45 million decrease to EBITDA that is primarily explained by the following business factors:

- the net unfavorable effect of translating US dollar EBITDA at a lower Canadian to US dollar average exchange rate in 2021, compared to the same period in 2020; and
- the absence in 2021 of the recognition of revenue in 2020 that related to the settlement of interim rates collected from shippers on Texas Eastern, retroactive to June 1, 2019.

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

- higher commodity prices benefiting equity earnings from our Aux Sable and DCP Midstream joint ventures;
- increased revenue due to the absence of pressure restrictions that existed on the Texas Eastern system in 2020; and
- a full year of contributions from the Atlantic Bridge Phase III project after it commenced service in January of 2021.

GAS DISTRIBUTION AND STORAGE

	2021	2020	2019
(millions of Canadian dollars)			
Earnings before interest, income taxes and depreciation and amortization[1]	**2,117**	1,748	1,747

1 Non-GAAP financial measure.

Year ended December 31, 2021 compared with year ended December 31, 2020

EBITDA was positively impacted by $338 million due to certain unusual, infrequent or other non-operating factors primarily explained by the following:

- a gain of $303 million resulting from the sale of our investment in Noverco; and
- a non-cash, unrealized gain of $14 million in 2021, compared with a loss of $10 million in 2020, 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 risks.

After taking into consideration the positive factors above, the remaining $31 million increase is primarily explained by the following significant business factors:

- higher distribution charges resulting from increases in rates and customer base; and
- higher storage revenue, mainly relating to storage optimization activities.

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

- higher operating and administrative costs largely related to operational, pipeline integrity and safety costs; and
- when compared with the normal weather forecast embedded in rates, weather was warmer in both 2021 and 2020, negatively impacting EBITDA in both years. Warmer than normal weather in 2021 negatively impacted 2021 EBITDA by approximately $55 million, while the warmer than normal weather in 2020 negatively impacted 2020 EBITDA by approximately $33 million.

RENEWABLE POWER GENERATION

	2021	2020	2019
(millions of Canadian dollars)			
Earnings before interest, income taxes and depreciation and amortization[1]	**508**	523	111

1 Non-GAAP financial measure.

Year ended December 31, 2021 compared with year ended December 31, 2020

EBITDA was negatively impacted by $15 million primarily explained by the following significant business factors:

- weaker wind resources at Canadian and United States wind facilities and the effects from the Texas winter storm in February 2021; and
- the absence in 2021 of reimbursements received in 2020 at certain Canadian wind facilities resulting from a change in operator; partially offset by
- the sale of a 49% interest of an entity that holds our 50% interest in EMF.

ENERGY SERVICES

	2021	2020	2019
(millions of Canadian dollars)			
Earnings/(loss) before interest, income taxes and depreciation and amortization[1]	**(313)**	(236)	250

1 Non-GAAP financial measure.

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, 2021 compared with year ended December 31, 2020

EBITDA was positively impacted by $164 million due to certain unusual, infrequent or other non-operating factors, primarily explained by a non-cash, unrealized net gain of $53 million in 2021, compared with a loss of $122 million in 2020, reflecting the revaluation of derivatives used to manage the profitability of transportation and storage transactions, as well as manage the exposure to movements in commodity prices.

After taking into consideration the positive factors above, the remaining $241 million decrease is primarily explained by the following significant business factors:

- significant compression of location and quality differentials in certain markets;
- limited storage opportunities in 2021 due to market backwardation compared to favorable storage opportunities in 2020;
- fewer opportunities to achieve profitable transportation margins on facilities in which Energy Services holds capacity obligations; and
- adverse impacts from the major winter storm experienced across the US Midwest during February 2021.

ELIMINATIONS AND OTHER

	2021	2020	2019
(millions of Canadian dollars)			
Earnings/(loss) before interest, income taxes and depreciation and amortization[1]	**356**	(113)	429

1 Non-GAAP financial measure.

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

Year ended December 31, 2021 compared with year ended December 31, 2020

EBITDA was positively impacted by $24 million due to certain unusual, infrequent or other non-operating factors, primarily explained by the following:

- employee severance, transition and transformation costs of $87 million in 2021 compared with $279 million in 2020 primarily related to our voluntary workforce reduction program offered in the second quarter of 2020;
- the absence in 2021 of a non-cash loss of $74 million in 2020 relating to the recognition of a corporate guarantee obligation; and
- the absence in 2021 of a loss of $43 million in 2020 relating to the write-down of certain investments in emerging energy and other technologies; partially offset by
- a non-cash, unrealized gain of $55 million in 2021 compared with a gain of $318 million in 2020 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.

After taking into consideration the factors above, the remaining $445 million increase is primarily explained by realized gains related to settlements under our enterprise-wide foreign exchange risk management program which substantially offset the foreign currency exposures realized within our business segments' results.

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[2]	Expected In-Service Date
(Canadian dollars, unless stated otherwise)					
LIQUIDS PIPELINES					
1. US Line 3 Replacement Program	100 %	US$4.0 billion	US$4.1 billion	Complete	In-service
2. Southern Access Expansion	100 %	US$0.5 billion	US$0.5 billion	Complete	In-service
3. Other - US	100 %	US$0.1 billion	US$0.1 billion	Complete	In-service
GAS TRANSMISSION AND MIDSTREAM					
4. T-South Reliability & Expansion Program	100 %	$1.0 billion	$0.9 billion	Complete	In-service
5. Spruce Ridge Project	100 %	$0.4 billion	$0.4 billion	Complete	In-service
6. Texas Eastern Modernization	100 %	US$0.4 billion	No significant expenditures to date	Pre-construction	2024 - 2026
7. Appalachia to Market II	100 %	US$0.1 billion	No significant expenditures to date	Pre-construction	2025
8. Other - US[3]	Various	US$0.6 billion	US$0.4 billion	Various stages	2021 - 2023
GAS DISTRIBUTION AND STORAGE					
9. System Enhancement Projects[4]	100 %	$0.4 billion	$0.1 billion	Various stages	2021 - 2023
10. Storage Enhancements	100 %	$0.1 billion	No significant expenditures to date	Under construction	2H - 2022
11. Natural Gas Expansion Program[5]	100 %	$0.1 billion	No significant expenditures to date	Pre-construction	2022 - 2027
RENEWABLE POWER GENERATION					
12. East-West Tie Line	25.0 %	$0.2 billion	$0.2 billion	Under construction	1H - 2022
13. Solar Self-Power Projects[6]	100 %	US$0.2 billion	No significant expenditures to date	Pre-construction	2022 - 2023
14. Saint-Nazaire France Offshore Wind Project[7]	25.5 %	$0.9 billion (€0.6 billion)	$0.5 billion (€0.3 billion)	Under construction	2H - 2022
15. Provence Grand Large Floating Offshore Wind Project[8]	25.0 %	$0.1 billion (€0.1 billion)	No significant expenditures to date	Pre-construction	2023
16. Fécamp Offshore Wind Project[9]	17.9 %	$0.7 billion (€0.5 billion)	$0.3 billion (€0.2 billion)	Under construction	2023
17. Calvados Offshore Wind Project[9]	21.7 %	$0.9 billion (€0.6 billion)	$0.1 billion (€0.1 billion)	Pre-construction	2024

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, 2021.

3 Includes the US$0.1 billion Texas Eastern Middlesex Extension placed into service in September of 2021 and the US$0.1 billion Cameron Extension Project placed into service in November of 2021.

4 Includes the $0.1 billion London Line Replacement Project placed into service in December of 2021. Total estimated capital cost consists of site restoration work expected to be completed in 2022.
5 Represents Phase 2 of the Natural Gas Expansion Program (the Program) and the estimated capital cost is presented net of the maximum funding assistance we expect to receive from the Government of Ontario. The expected in-service dates represent the expected completion dates of the leave to construct requirements.
6 Self-Power Projects consists of solar self-power projects along our liquids and gas transmission systems. All 10 projects will be located at existing pump and/or compressor stations.
7 Reflects the sale of 49% of an entity that holds our 50% interest in EMF to CPP Investments that closed in the first quarter of 2021. Our equity contribution is $0.15 billion, with the remainder of the project financed through non-recourse project level debt.
8 Reflects the sale of 50% of an entity that holds our 50% interest in Provence Grand Large to CPP Investments. Our equity contribution is $0.05 billion, with the remainder of the project financed through non-recourse project level debt for each project.
9 Each project reflects the sale of 49% of an entity that holds our 50% interest in EMF to CPP Investments that closed in the first quarter of 2021. Our equity contribution is $0.1 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 placed into service in 2021:

- **United States Line 3 Replacement Program** – replacement of the existing Line 3 crude oil pipeline between Neche, North Dakota and Superior, Wisconsin is now complete and in-service. The US L3R Program supports the safety and operational reliability of the Mainline System, enhances system flexibility and allows us to optimize throughput on the mainline. The US L3R Program restored the original capacity of 760 kbpd and brought the total Mainline System operating capacity to approximately 3.1 mmbpd.

- **Southern Access Expansion** – expansion of our existing Southern Access crude oil pipeline from 996 kbpd to approximately 1,200 kbpd.

GAS TRANSMISSION AND MIDSTREAM

The following commercially secured growth projects were placed into service in 2021:

- **Atlantic Bridge Phase III** – an expansion of the Algonquin natural gas transmission systems which transports 133 million cubic feet per day (mmcf/d) of natural gas to the New England region. The third and final phase of Atlantic Bridge fully commenced service in January 2021 with the Weymouth compressor station being brought online.

- **T-South Reliability & Expansion Program** – a natural gas pipeline expansion of Westcoast's BC Pipeline in southern BC that provides improved compressor reliability and additional capacity of approximately 190 mmcf/d into the Huntington/Sumas market at the US/Canada border.

- **Spruce Ridge Project** – a natural gas pipeline expansion of Westcoast's BC Pipeline in northern BC. The project provides additional capacity of up to 402 mmcf/d.

The following commercially secured growth projects are currently in pre-construction stages:

- **Texas Eastern Modernization Phase II –** this program is the modernization of compression facilities in Pennsylvania and New Jersey to increase safety and reliability and reduce associated greenhouse gas emissions at multiple sites on our Texas Eastern system. The program will be completed in stages over a period of years beginning in 2024.

- **Appalachia to Market II** - the expansion is designed to deliver 55 MDth per day on the Texas Eastern pipeline from the Appalachia supply basin in Southwest Pennsylvania to existing local distribution company customers in New Jersey beginning in late 2025. The project is a brown-field expansion and upgrade of existing Texas Eastern facilities in Pennsylvania.

GAS DISTRIBUTION AND STORAGE

The following commercially secured growth project was placed into service in 2021:

- **System Enhancement Projects** – The London Line Replacement Project replaced two existing pipelines known collectively as the London Line and included the construction of approximately 90.5-kilometers of natural gas pipeline and ancillary facilities in southern Ontario.

The following commercially secured growth projects are currently in various stages of construction:

- **System Enhancement Project** – The Lake Shore Kipling Oshawa Loop (KOL) Replacement Project is a replacement of approximately 4.5-kilometers of natural gas pipeline and ancillary facilities of the Cherry to Bathurst segment of the KOL along Lake Shore Boulevard in the City of Toronto. The St. Laurent Ottawa North Replacement Project is a replacement of approximately 16-kilometers of natural gas pipeline in the City of Ottawa. The first two phases of this project have already been completed. Phases 3 and 4 represent approximately 11.4-kilometers of pipeline.

- **Storage Enhancements** – Storage Enhancements are part of a larger delta pressuring project to increase deliverability and storage capacity at Enbridge Gas' storage facilities. The additional deliverability and storage capacity will be sold as part of Enbridge Gas' unregulated storage portfolio.

- **Natural Gas Expansion Program** – The Program was created under the Access to Natural Gas Act, 2018 to help expand access to natural gas to areas of Ontario that currently do not have access to the natural gas distribution system. Under Phase 2 of the Program, we will be provided up to $214 million in funding assistance to deliver 25 community expansion and two economic development projects throughout Ontario.

RENEWABLE POWER GENERATION

The following commercially secured growth projects are currently in various stages of construction:

- **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.

- **Solar Self-Power Projects** – 10 solar self-power projects under development in Wisconsin, Illinois, Pennsylvania, Kentucky, Ohio and Minnesota, with a combined estimate of 97 MW of emissions-free generating capacity. These projects will provide clean power directly to our liquids and natural gas pipeline rights-of-way.

- **Saint-Nazaire France 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 (PPA) with added power production protection.

- **Provence Grand Large Floating Offshore Wind Project** – a floating offshore wind facility off the southern coast of France that secured funding in 2021 and continues to prepare onshore construction and is expected to generate approximately 24-MW. Project revenues are underpinned by a 20-year fixed price PPA.

- **Fécamp Offshore Wind Project** – an offshore wind project located off the northwest coast of France and is expected to generate approximately 500-MW. Project revenues are underpinned by a 20-year fixed price PPA.

- **Calvados Offshore Wind Project** – an offshore wind project located off the northwest coast of France that is expected to generate approximately 448-MW. Project revenues are underpinned by a 20-year fixed price power purchase agreement.

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.

- **Enbridge Houston Oil Terminal** – the 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 Crude 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 billion cubic feet per day (bcf/d) of natural gas from the Agua Dulce supply area to NextDecade Corporation's (NextDecade) Rio Grande liquefied natural gas (LNG) export facility in the Port of Brownsville, Texas. We have executed a precedent agreement with NextDecade 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 20 years. Construction of the pipeline will be subject to the Rio Grande LNG export facility reaching a final investment decision.

- **Ridgeline Expansion Project Opportunity** – We are working on a potential expansion of the ETNG system which would provide additional natural gas for the Tennessee Valley Authority (TVA) to support the replacement of an existing coal-fired power plant as it continues to transition its generation mix towards lower-carbon fuels. The TVA environmental review scoping process has begun for this proposed plant; TVA published a Notice of Intent on the Federal Register on June 15, 2021 to initiate their review process. Several options to replace the retiring coal-fired generation would be assessed in TVA's Environmental Impact Statement (EIS). Should the onsite natural gas option of building a combined cycle plant be selected through TVA's review, we would deliver on the required expansion of the East Tennessee system. ETNG's proposed project would consist of the installation of additional pipeline primarily along the ETNG system, the installation of one electric-powered compressor station and solar facilities behind the meter, as well as other design features all contributing to minimizing greenhouse gas emissions. Should TVA's environmental assessment determine that the natural gas solution of building an onsite combined cycle plant is the optimal supply source, and pending the approval and receipt of all necessary permits, construction of the pipeline would begin in 2025 with a target in-service date of fall 2026.

- **Valley Crossing Expansion Project** – On January 10, 2022, we executed a precedent agreement with Texas LNG Brownsville LLC (Texas LNG) under which, via an expansion of our Valley Crossing Pipeline, we will provide 0.72 bcf/d firm transportation capacity to Texas LNG's proposed LNG liquefaction and export facility in the Port of Brownsville, Texas for a term of at least 20 years. Expansion of the pipeline will be subject to Texas LNG's export facility 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/d of feed gas to Venture Global's proposed Plaquemines LNG export facility located in Plaquemine Parish, Louisiana. The expansion will be subject to the Plaquemines LNG export facility reaching a final investment decision.

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

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.

Material contractual obligations arising in the normal course of business primarily consist of long-term contracts, annual debt maturities and related interest obligations, rights-of-way and leases. See Part II. *Item 8. Financial Statements and Supplementary data - Note 18 - Debt and Note 27 - Leases* for amounts outstanding at December 31, 2021, related to debt and leases.

Long-term contracts are contracts that we have signed for the purchase of services, pipe and other materials totaling $5.9 billion which are expected to be paid over the next five years. Long-term contracts 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.

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. On January 19, 2022, we closed a $750 million private placement offering of non-call 10-year fixed-to-fixed subordinated notes which mature on January 19, 2082. The net proceeds from the offering will be used to redeem the Preference Shares, Series 17 at par on March 1, 2022.

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 long-term debt issuances totaling US$3.9 billion and $3.2 billion in 2021:

Entity	Issuance Date	Type of Issuance	Amount
(in millions of Canadian dollars, unless stated otherwise)			
Enbridge Inc.	February 2021	Floating rate senior-notes	US$500
Enbridge Inc.	June 2021	Sustainability-linked senior notes	US$1,000
Enbridge Inc.	June, October 2021	Senior notes	US$2,000
Enbridge Inc.	September 2021	Medium-term notes	$1,100
Enbridge Inc.	September 2021	Sustainability-linked medium-term	$400
Enbridge Gas Inc.	September 2021	Medium-term notes	$900
Enbridge Pipelines Inc.	May 2021	Medium-term notes	$800
Spectra Energy Partners, LP[1]	September 2021	Senior notes	US$400

1 Issued through Texas Eastern, a wholly-owned operating subsidiary of 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, 2021:

	Maturity[1]	Total Facilities	Draws[2]	Available
(millions of Canadian dollars)				
Enbridge Inc.	2022-2026	**9,137**	**7,837**	**1,300**
Enbridge (U.S.) Inc.	2023-2026	**6,948**	**4,845**	**2,103**
Enbridge Pipelines Inc.	2023	**3,000**	**667**	**2,333**
Enbridge Gas Inc.	2023	**2,000**	**1,515**	**485**
Total committed credit facilities		**21,085**	**14,864**	**6,221**

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

On February 10, 2021, Enbridge Inc. entered into a three year, revolving, extendible, sustainability-linked credit facility for $1.0 billion with a syndicate of lenders and concurrently terminated our one year, revolving, syndicated credit facility for $3.0 billion.

On July 22 and 23, 2021, we renewed approximately $8.0 billion of our five-year credit facilities, extending the maturity date out to July 2026. We also extended approximately $10.0 billion of our 364-day extendible credit facilities to July 2022, which includes a one-year term out provision to July 2023.

On February 10, 2022 we renewed our three year $1.0 billion sustainability-linked credit facility, extending the maturity date out to July 2025.

In addition to the committed credit facilities noted above, we maintain $1.3 billion of uncommitted demand letter of credit facilities, of which $854 million was unutilized as at December 31, 2021. As at December 31, 2020, we had $849 million of uncommitted demand letter of credit facilities, of which $533 million was unutilized.

As at December 31, 2021, our net available liquidity totaled $6.5 billion (2020 - $12.7 billion), consisting of available credit facilities of $6.2 billion (2020 - $12.3 billion) and unrestricted Cash and cash equivalents of $286 million (2020 - $452 million) as reported in the Consolidated Statements of Financial Position.

Our credit facility agreements and term debt indentures include standard events of default and covenant provisions, whereby accelerated repayment and/or termination of the agreements may result if we were to default on payment or violate certain covenants. As at December 31, 2021, we were in compliance with all debt covenants and expect to continue to comply with such covenants.

Cash flow growth, 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.

On June 1, 2021, Moody's upgraded the credit ratings of Enbridge Inc., including our senior unsecured and issuer ratings, to Baa1 from Baa2. Moody's also upgraded the credit ratings of our subsidiaries: EEP, EELP, SEP and Texas Eastern. The outlooks of all five entities are stable.

There are no material restrictions on our cash. Total Restricted cash of $34 million, as reported on the Consolidated Statements of Financial Position, primarily includes cash collateral and future pipeline abandonment costs collected and held in trust. 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, 2021 and 2020, we had a negative working capital position of $3.1 billion and $3.7 billion, 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

Year ended December 31,	**2021**	2020	2019
(millions of Canadian dollars)			
Operating activities	**9,256**	9,781	9,398
Investing activities	**(10,657)**	(5,177)	(4,658)
Financing activities	**1,236**	(4,770)	(4,745)
Effect of translation of foreign denominated cash and cash equivalents and restricted cash	**(5)**	(20)	44
Net increase/(decrease) in cash and cash equivalents and restricted cash	**(170)**	(186)	39

Significant sources and uses of cash for the years ended December 31, 2021 and 2020 are summarized below:

Operating Activities
Typically, the primary factors impacting cash flow from operating activities year-over-year include changes in our operating assets and liabilities 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.* Cash provided by operating activities is also impacted by changes in earnings and certain unusual, infrequent and other non-operating factors, as discussed under *Results of Operations.*

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

A summary of additions to property, plant and equipment for the years ended December 31, 2021, 2020 and 2019 is set out below:

Year ended December 31,	**2021**	2020	2019
(millions of Canadian dollars)			
Liquids Pipelines	**4,051**	2,032	2,548
Gas Transmission and Midstream	**2,353**	2,066	1,695
Gas Distribution and Storage	**1,343**	1,134	1,100
Renewable Power Generation	**16**	81	23
Energy Services	**1**	2	2
Eliminations and Other	**54**	90	124
Total capital expenditures	**7,818**	5,405	5,492

2021
The increase in cash used in investing activities primarily resulted from the following factors:
- Our acquisition of Moda on October 12, 2021 and higher capital expenditures related to the completion of the US L3R Program, partially offset by higher proceeds received from dispositions in 2021 compared with 2020 due to the sale of our interest in Noverco on December 30, 2021.

2020
The increase in cash used in investing activities primarily resulted from the following factors:
- Lower proceeds from asset dispositions in 2020 compared with 2019, primarily due to the sale of the federally regulated portion of our Canadian natural gas gathering and processing businesses assets on December 31, 2019.

- The factor above was partially offset by lower contributions to the Gray Oak Holdings LLC equity investment in 2020, higher return of capital primarily from equity investments in Seaway Crude Holdings LLC, MarEn Bakken Company LLC, Gray Oak Holdings LLC and Enbridge Renewable Infrastructure Investments S.a.r.l., and lower net cash invested in affiliate loans in 2020 compared with 2019.

Financing Activities

Cash provided by and used in financing activities primarily relates to issuances and repayments of external debt, as well as transactions with our common and preference shareholders relating to dividends, share issuances and share redemptions. Cash from financing activities is also impacted by changes in distributions to, and contributions from, noncontrolling interests.

2021

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

- Increased issuances of long-term debt, commercial paper and credit facility draws and short-term borrowings, along with lower repayments of long-term debt in 2021 compared to 2020.
- The factors above were partially offset by the redemption of Westcoast Energy Inc.'s (Westcoast) preferred shares in 2021 and increased common share dividend payments primarily due to the increase in our common share dividend rate.

2020

Cash used in financing activities in 2020 was consistent with 2019 due to the following factors:

- Increased commercial paper and credit facility draws, increased short-term borrowings and lower repayments of long-term debt in 2020 compared with 2019, partially offset by lower issuances of long-term debt.
- The absence in 2020 of the redemption of Westcoast's preferred shares in 2019.
- The above factors were partially offset by increased common share dividend payments primarily due to the increase in our common share dividend rate.

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 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.

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	$450 million	4.46 %	$1.11500	$25	March 1, 2023	Series E
Series F	$500 million	4.69 %	$1.17224	$25	June 1, 2023	Series G
Series H	$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	$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	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	3.94 %	$0.98452	$25	March 1, 2025	Series 12
Series 13	$350 million	3.04 %	$0.76076	$25	June 1, 2025	Series 14
Series 15	$275 million	2.98 %	$0.74576	$25	September 1, 2025	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/number of days in a year) x three-month 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/ number of days in a year) x three-month US Government treasury bill rate + 3.1% (Series K), 3.2% (Series M), 3.1% (Series 2) or 2.8% (Series 6).*

5 *The floating quarterly dividend amount for the Series C Preference Shares was increased to $0.15501 from $0.15349 on March 1, 2021, was increased to $0.15753 from $0.15501 on June 1, 2021, was increased to $0.16081 from $0.15753 on September 1, 2021 and was decreased to $0.15719 from $0.16081 on December 1, 2021, due to reset on a quarterly basis following the issuance thereof.*

PREFERENCE SHARE REDEMPTION

We intend to exercise our right to redeem all of our outstanding cumulative redeemable minimum rate reset preference shares, Series 17, on March 1, 2022 at a price of $25 per Series 17 share, together with all accrued and unpaid dividends, if any.

Dividends
We have paid common share dividends in every year since we became a publicly traded company in 1953. In December 2021, we announced a 3% increase in our quarterly dividend to $0.86 per common share, or $3.44 annualized, effective with the dividend payable on March 1, 2022, thereby making a dividend increase for 27 straight years.

For the years ended December 31, 2021 and 2020, total dividends paid were $6.8 billion and $6.6 billion, respectively, all of which were paid in cash and reflected in financing activities.

On December 6, 2021, our Board of Directors declared the following quarterly dividends. All dividends are payable on March 1, 2022 to shareholders of record on February 15, 2022.

	Dividend per share
Common Shares[1]	$0.86000
Preference Shares, Series A	$0.34375
Preference Shares, Series B	$0.21340
Preference Shares, Series C[2]	$0.15719
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	$0.27369
Preference Shares, Series R	$0.25456
Preference Shares, Series 1	US$0.37182
Preference Shares, Series 3	$0.23356
Preference Shares, Series 5	US$0.33596
Preference Shares, Series 7	$0.27806
Preference Shares, Series 9	$0.25606
Preference Shares, Series 11	$0.24613
Preference Shares, Series 13	$0.19019
Preference Shares, Series 15	$0.18644
Preference Shares, Series 17	$0.32188
Preference Shares, Series 19	$0.30625

1 *The quarterly dividend per common share was increased 3% to $0.86 from $0.835, effective March 1, 2022.*
2 *The quarterly dividend per share paid on Series C was increased to $0.15501 from $0.15349 on March 1, 2021, was increased to $0.15753 from $0.15501 on June 1, 2021, was increased to $0.16081 from $0.15753 on September 1, 2021 and was decreased to $0.15719 from $0.16081 on December 1, 2021, due to reset on a quarterly basis following the date of issuance of the Series C Preference Shares.*

SUMMARIZED FINANCIAL INFORMATION

On January 22, 2019, Enbridge entered into supplemental indentures with its wholly-owned subsidiaries, SEP and EEP (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. The Partnerships have also entered into supplemental indentures with Enbridge pursuant to which the Partnerships have issued full and unconditional guarantees, on a senior unsecured basis, of senior notes issued by Enbridge subsequent to January 22, 2019. As a result of the guarantees, holders of any of the outstanding guaranteed notes of the Partnerships (the Guaranteed Partnership Notes) 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 (the Guaranteed Enbridge 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]
4.750% Senior Notes due 2024	5.875% Notes due 2025
3.500% Senior Notes due 2025	5.950% Notes due 2033
3.375% Senior Notes due 2026	6.300% Notes due 2034
5.950% Senior Notes due 2043	7.500% Notes due 2038
4.500% Senior Notes due 2045	5.500% Notes due 2040
	7.375% Notes due 2045

1 As at December 31, 2021, the aggregate outstanding principal amount of SEP notes was approximately US$3.2 billion.
2 As at December 31, 2021, the aggregate outstanding principal amount of EEP notes was approximately US$2.4 billion.

Enbridge Notes under Guarantees

US Dollar Denominated[1]	Canadian Dollar Denominated[2]
Floating Rate Senior Notes due 2022	4.850% Senior Notes due 2022
Floating Rate Senior Notes due 2023	3.190% Senior Notes due 2022
2.900% Senior Notes due 2022	3.940% Senior Notes due 2023
4.000% Senior Notes due 2023	3.940% Senior Notes due 2023
0.550% Senior Notes due 2023	3.950% Senior Notes due 2024
3.500% Senior Notes due 2024	2.440% Senior Notes due 2025
2.500% Senior Notes due 2025	3.200% Senior Notes due 2027
4.250% Senior Notes due 2026	6.100% Senior Notes due 2028
1.600% Senior Notes due 2026	2.990% Senior Notes due 2029
3.700% Senior Notes due 2027	7.220% Senior Notes due 2030
3.125% Senior Notes due 2029	7.200% Senior Notes due 2032
2.500% Sustainability-linked Senior Notes due 2033	3.100% Sustainability-linked Senior Notes due 2033
4.500% Senior Notes due 2044	5.570% Senior Notes due 2035
5.500% Senior Notes due 2046	5.750% Senior Notes due 2039
4.000% Senior Notes due 2049	5.120% Senior Notes due 2040
3.400% Senior Notes due 2051	4.240% Senior Notes due 2042
	4.570% Senior Notes due 2044
	4.870% Senior Notes due 2044
	4.100% Senior Notes due 2051
	4.560% Senior Notes due 2064

1 As at December 31, 2021, the aggregate outstanding principal amount of the Enbridge US dollar denominated notes was approximately US$11 billion.
2 As at December 31, 2021, the aggregate outstanding principal amount of the Enbridge Canadian dollar denominated notes was approximately $9.2 billion.

Rule 3-10 of the US Securities and Exchange Commission's (SEC) Regulation S-X provides an exemption from the reporting requirements of the Securities Exchange Act of 1934, as amended (Exchange Act) for fully consolidated subsidiary issuers of guaranteed securities and subsidiary guarantors and allows for summarized financial information in lieu of filing separate financial statements for each of the Partnerships.

The following Summarized Combined Statement of Earnings and the Summarized Combined Statements of Financial Position combines the balances of EEP, SEP and Enbridge.

Summarized Combined Statement of Earnings

	Year ended December 31, 2021
(millions of Canadian dollars)	
Operating loss	**(64)**
Earnings	**4,970**
Earnings attributable to common shareholders	**4,604**

Summarized Combined Statements of Financial Position

	December 31, 2021	December 31, 2020
(millions of Canadian dollars)		
Accounts receivable from affiliates	**3,442**	2,108
Short-term loans receivable from affiliates	**4,947**	4,926
Other current assets	**605**	375
Long-term loans receivable from affiliates	**51,983**	43,217
Other long-term assets	**3,732**	4,237
Accounts payable to affiliates	**1,982**	1,267
Short-term loans payable to affiliates	**2,891**	4,117
Other current liabilities	**8,110**	5,628
Long-term loans payable to affiliates	**41,370**	32,035
Other long-term liabilities	**41,353**	41,353

The Guaranteed Enbridge Notes and the Guaranteed Partnership Notes are structurally subordinated to the indebtedness of the Subsidiary Non-Guarantors in respect of the assets of those Subsidiary Non-Guarantors.

Under US bankruptcy law and comparable provisions of state fraudulent transfer laws, a guarantee can be voided, or claims may be subordinated to all other debts of that guarantor if, among other things, the guarantor, at the time the indebtedness evidenced by its guarantee or, in some states, when payments become due under the guarantee:

- received less than reasonably equivalent value or fair consideration for the incurrence of the guarantee and was insolvent or rendered insolvent by reason of such incurrence;
- was engaged in a business or transaction for which the guarantor's remaining assets constituted unreasonably small capital; or
- intended to incur, or believed that it would incur, debts beyond its ability to pay those debts as they mature.

The guarantees of the Guaranteed Enbridge Notes contain provisions to limit the maximum amount of liability that the Partnerships could incur without causing the incurrence of obligations under the guarantee to be a fraudulent conveyance or fraudulent transfer under US federal or state law.

Each of the Partnerships is entitled to a right of contribution from the other Partnership for 50% of all payments, damages and expenses incurred by that Partnership in discharging its obligations under the guarantees for the Guaranteed Enbridge Notes.

Under the terms of the guarantee agreement and applicable supplemental indentures, the guarantees of either of the Partnerships of any Guaranteed Enbridge Notes will be unconditionally released and discharged automatically upon the occurrence of any of the following events:

- any direct or indirect sale, exchange or transfer, whether by way of merger, sale or transfer of equity interests or otherwise, to any person that is not an affiliate of Enbridge, of any of Enbridge's direct or indirect limited partnership of other equity interests in that Partnership as a result of which the Partnership ceases to be a consolidated subsidiary of Enbridge;
- the merger of that Partnership into Enbridge or the other Partnership or the liquidation and dissolution of that Partnership;
- the repayment in full or discharge or defeasance of those Guaranteed Enbridge Notes, as contemplated by the applicable indenture or guarantee agreement;

- with respect to EEP, the repayment in full or discharge or defeasance of each of the consenting EEP notes listed above;
- with respect to SEP, the repayment in full or discharge or defeasance of each of the consenting SEP notes listed above; or
- with respect to any series of Guaranteed Enbridge Notes, with the consent of holders of at least a majority of the outstanding principal amount of that series of Guaranteed Enbridge Notes.

The guarantee obligations of Enbridge of the Guaranteed Partnership Notes will terminate with respect to any series of Guaranteed Partnership Notes if that series is discharged or defeased.

The Partnerships also guarantee the obligations of Enbridge under its existing credit facilities**.**

LEGAL AND OTHER UPDATES

LIQUIDS PIPELINES

Michigan Line 5 Dual Pipelines - Straits of Mackinac Easement
In 2019, the Michigan Attorney General filed a complaint in the Michigan Ingham County Circuit Court (the Court) that requests the Court to declare the easement granted in 1953 that we have for the operation of Line 5 in the Straits of Mackinac (the Straits) to be invalid and to prohibit continued operation of Line 5 in the Straits "as soon as possible after a reasonable notice period to allow orderly adjustments by affected parties". On December 15, 2021, we removed the case to the US District Court in the Western District of Michigan (US District Court), where it was assigned to Judge Janet T. Neff. The removal of the Attorney General's case to federal court follows a November 16, 2021 ruling (further described below) which held that the similar (and now dismissed) 2020 lawsuit brought by the Governor to force Line 5's shutdown raised important federal issues that should be heard in federal court. On December 21, 2021, the Attorney General made a request to file a remand motion and on December 28, 2021, we responded to her request to file that motion. On January 5, 2022, the court issued an Order allowing the Attorney General to file a motion to remand the 2019 case. The Attorney General's motion and brief was filed on January 14, 2022, and our response is due on February 11, 2022. The motion is expected to be fully briefed by March 2022.

On November 13, 2020, the Governor of Michigan and the Director of the Michigan Department of Natural Resources notified us that the State of Michigan (the State) was revoking and terminating the easement granted in 1953 that allows Line 5 to operate across the Straits. The notice demanded that the portion of Line 5 that crosses the Straits must be shut down by May 2021. On November 24, 2020, we filed in the US District Court for the Western District of Michigan a Notice of Removal, which removed the State's November Complaint to federal court, and a Complaint for Declaratory and Injunctive Relief that requests the US District Court to enjoin the Governor from taking any action to prevent or impede the operation of Line 5. US District Court Judge Neff was assigned to the cases and on November 16, 2021, Judge Neff issued an order denying the State's motion to remand its 2020 case back to Ingham County Circuit Court ,finding that the case should remain in federal court. Judge Neff also ruled in our favor on our motion for additional briefing and granted the Government of Canada's motion to file a supplemental brief, which reiterated that the 1977 Transit Pipelines Treaty between the US and Canada had been invoked in October and that the matter is of great importance to Canada. Subsequently, the Governor voluntarily dismissed the State's lawsuit on November 30, 2021.

Our lawsuit to prohibit the Governor of Michigan and Director of the Michigan Department of Natural Resources from interfering with the operation of Line 5, remains in federal court. On November 30, 2021 the State made a request to Judge Neff to file a motion to dismiss the complaint. On the same date, we made a request to file a motion for summary judgment. Briefing on these motions began on January 18, 2022 and is scheduled to be complete by April 2022.

In 2021, we completed the engineering and design phase of the Great Lakes Tunnel Project and we have begun the process of hiring a contractor to construct the tunnel. We continue to actively pursue state and federal regulatory permits from the US Army Corps of Engineers (Army Corps), the Michigan Department of Environment, Great Lakes & Energy (EGLE) and the Michigan Public Service Commission (MPSC). The EGLE permits were granted in the first quarter of 2021; one of the EGLE permits was challenged by the Bay Mills Indian Community. Dispositive motions are fully briefed and with the Administrative Law Judge for decision.

On June 23, 2021, the Army Corps announced they would proceed with an EIS for the Great Lakes Tunnel Project to replace Line 5 at the Straits. On June 23, 2021, we issued a statement stating that construction on this project would be delayed due to the EIS.

In the MPSC contested case proceeding, testimony has been filed, and the hearing took place during January 2022, with briefing scheduled to be complete by March 2022.

Dakota Access Pipeline

We own an effective interest of 27.6% in the Bakken Pipeline System, which is inclusive of DAPL. The Standing Rock Sioux Tribe and the Cheyenne River Sioux Tribe filed lawsuits in 2016 with the US Court for the District of Columbia (the District Court) contesting the lawfulness of the Army Corps easement for DAPL, including the adequacy of the Army Corps' environmental review and tribal consultation process. The Oglala Sioux and Yankton Sioux Tribes also filed lawsuits alleging similar claims in 2018.

On June 14, 2017, the District Court found the Army Corps' environmental review to be deficient and ordered the Army Corps to conduct further study concerning spill risks from DAPL. In August 2018, the Army Corps completed on remand the further environmental review ordered by the District Court and reaffirmed the issuance of the easement for DAPL. All four plaintiff Tribes subsequently amended their complaints to include claims challenging the adequacy of the Army Corps' August 2018 remand decision.

On March 25, 2020, in response to amended complaints from the Tribes, the District Court found the Army Corps' environmental review on remand was deficient and ordered the Army Corps to prepare an EIS to address unresolved controversy pertaining to potential spill impacts resulting from DAPL. On July 6, 2020, the District Court issued an order vacating the Army Corps' easement for DAPL and ordering that the pipeline be shut down by August 5, 2020. Dakota Access, LLC and the Army Corps appealed the decision and filed a motion for a stay pending appeal with the US Court of Appeals for the District of Columbia Circuit. On August 5, 2020, the US Court of Appeals stayed the District Court's July 6 order to shut down and empty the pipeline, but did not stay the District Court's March 25 order requiring the Army Corps to prepare an EIS or the District Court's July 6 order vacating the DAPL easement.

On January 26, 2021, the US Court of Appeals affirmed the District Court's decision, holding that the Army Corps is required to prepare an EIS and that the Army Corps' easement for DAPL is vacated. Dakota Access, LLC has since filed a petition asking the US Supreme Court to review the decision that an EIS is required. The US Court of Appeals also determined that, absent considering the closure of DAPL in the context of an injunction proceeding, the District Court could not order DAPL's operations to cease. While not an issue before the US Court of Appeals, the US Court of Appeals also recognized that the Army Corps could consider whether to allow DAPL to continue to operate in the absence of an easement. On September 20, 2021, DAPL requested that the US Supreme Court review the US Court of Appeals decision. That request, opposed by the US Government and the Tribes, remands pending.

On May 21, 2021, the District Court dismissed the plaintiff Tribes' request for an injunction enjoining DAPL from operating until the Army Corps has completed its EIS. The right of the plaintiff Tribes to appeal the denial of the injunction request expired on July 20, 2021. The Army Corps earlier indicated that it did not intend, at that time, to exercise its authority to bar DAPL's continued operation, notwithstanding the absence of an easement and that it anticipates completing its EIS by March 2022.

On July 22, 2021, the Army Corps filed a notice with the District Court advising that the Pipeline and Hazardous Materials Safety Administration (PHMSA) issued a notice asserting violations of federal safety regulations resulting from the operation of DAPL. The Army Corps stated that it would consider PHMSA's notice as part of its ongoing consideration of whether and how the Army Corps will enforce its rights on property crossed by the pipeline and in the context of the ongoing EIS. The Army Corps also granted the request from the Tribes to extend the EIS completion date to September 2022.

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 (US 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.

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 impairment assessment annually on April 1 at the reporting unit level. Reporting units are determined 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 assessment. 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 assessment is performed.

The quantitative goodwill impairment assessment 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 models 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 include significant judgments and assumptions relating to discount rates and expected future capital expenditures. 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 assessment of the goodwill balance was performed on April 1, 2021. As at April 1, 2021, our reporting units were equivalent to our reportable segments. We performed a quantitative goodwill impairment assessment for the Gas Transmission and Midstream reporting unit and qualitative assessments for the Liquids Pipelines and Gas Distribution and Storage reporting units. Our goodwill impairment assessments did not result in an impairment charge. Also, we did not identify any indicators of goodwill impairment during the remainder of 2021.

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.

With respect to equity method investments, we assess at each balance sheet date whether there is objective evidence that the investment is impaired by completing a quantitative or qualitative analysis of factors impacting the investment. If there is objective evidence of impairment, we 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 investment.

Asset fair value is 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 asset 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 US GAAP for non-rate-regulated entities. Key determinants in the ratemaking process are:

- Costs of providing service, including operating costs, capital invested, depreciation expense and taxes;
- 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, 2021 and 2020, our regulatory assets totaled $5.9 billion and $5.6 billion, respectively, and regulatory liabilities totaled $3.4 billion and $3.4 billion, respectively.

Depreciation
Depreciation of property, plant and equipment, our largest asset with a net book value at December 31, 2021 and 2020, of $100.1 billion and $94.6 billion, 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, 2021 Consolidated Financial Statements of a 0.5% change in key pension and other postretirement benefit obligations (OPEB) assumptions:

	Canada		United States	
	Obligation	Expense	Obligation	Expense
(millions of Canadian dollars)				
Pension				
Decrease in discount rate	378	31	70	5
Decrease in expected return on assets	—	21	—	5
Decrease in rate of salary increase	(71)	(15)	(6)	(2)
OPEB				
Decrease in discount rate	21	1	8	—
Decrease in expected return on assets	N/A	N/A	—	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
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. The discount rates used to estimate the present value of the expected future cash flows for the year ended December 31, 2021 ranged from 0.9% to 9.0% (2020 - 1.8% to 9.0%). 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.

The Minnesota Public Utilities Commission (MPUC), in its June 28, 2018 decision granting the Line 3 Replacement Project's Certificate of Need, required Enbridge to establish and fund a decommissioning trust (Decommissioning Trust Fund) for the purpose of funding the cost of retiring Line 3 Replacement Project assets at the end of their useful lives. Further to the Certificate of Need decision, in late 2021 the MPUC established a process for the purpose of determining the terms and conditions of the Decommissioning Trust Fund. Enbridge anticipates this MPUC process to be completed in 2022, with a decision from the MPUC in the second half of 2022. Enbridge expects to recover contributions necessary to fund the Decommissioning Trust Fund from its shippers through rates.

CHANGES IN ACCOUNTING POLICIES

Refer to Part II. *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 US dollar denominated investments and subsidiaries using foreign currency derivatives and US 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 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 3.9%.

We are exposed to changes in the fair value of fixed rate debt that arise as a result of 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 fair value via execution of fixed to floating interest rate swaps. As at December 31, 2021, 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 including 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 2.0%.

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, 2021. 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, 2021 and 2020 CFaR was $103 million and $128 million or 0.9% and 1.2%, 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 US 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, 2021. 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 reduce our credit risk exposure on financial derivative asset positions outstanding with the counterparties in those circumstances.

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.

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, 2021 and 2020, 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, 2021, 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, 2021, 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, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021 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, 2021, 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.

PricewaterhouseCoopers LLP
111-5th Avenue SW, Suite 3100, Calgary, Alberta, Canada T2P 5L3
T: +1 403 509 7500, F: +1 403 781 1825

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 assessment

As described in Notes 2 and 16 to the consolidated financial statements, the Company's goodwill balance was $32,775 million at December 31, 2021. As disclosed by management, an annual goodwill impairment assessment is performed 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 assessment. 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 assessment 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 and earnings multiples techniques. The determination of fair value using the discounted cash flow technique requires the use of estimates and assumptions related to discount rates, projected operating income, 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 assessment was performed for the Gas Transmission and Midstream (Gas Transmission) reporting unit, while the qualitative goodwill impairment assessments were performed for the Liquids Pipelines and Gas Distribution and Storage reporting units.

The principal considerations for our determination that performing procedures relating to the goodwill impairment assessment is a critical audit matter are the 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 Transmission 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 Transmission reporting unit. This led to a high degree of auditor judgment, effort and subjectivity in performing procedures to evaluate the reasonableness of management's significant assumptions used in the qualitative assessment and the quantitative assessment of the Gas Transmission 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 assessment, including controls over (i) the development of significant assumptions related to operating income trends used in the qualitative assessment and (ii) the determination of the fair value estimate of the Gas Transmission reporting unit. These procedures also included, among others (i) 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 (ii) testing management's process for developing the fair value estimate of the Gas Transmission reporting unit. Testing management's process for developing the fair value estimate of the Gas Transmission 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 determining the fair value estimate including discount rates, projected operating income, expected future capital expenditures and earnings multipliers.

Assessing the reasonableness of projected operating income and its trends, and expected future capital expenditures, involved evaluating 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. Professionals with specialized skill and knowledge were used 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 multipliers.

/s/PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Canada
February 11, 2022

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

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	**2021**	2020	2019
(millions of Canadian dollars, except per share amounts)			
Operating revenues			
Commodity sales	**26,873**	19,259	29,309
Gas distribution sales	**4,026**	3,663	4,205
Transportation and other services	**16,172**	16,165	16,555
Total operating revenues *(Note 4)*	**47,071**	39,087	50,069
Operating expenses			
Commodity costs	**26,608**	18,890	28,802
Gas distribution costs	**2,094**	1,779	2,202
Operating and administrative	**6,712**	6,749	6,991
Depreciation and amortization	**3,852**	3,712	3,391
Impairment of long-lived assets	**—**	—	423
Total operating expenses	**39,266**	31,130	41,809
Operating income	**7,805**	7,957	8,260
Income from equity investments *(Note 13)*	**1,711**	1,136	1,503
Impairment of equity investments *(Note 13)*	**(111)**	(2,351)	—
Other income/(expense)			
Net foreign currency gain	**286**	181	477
Gain/(loss) on dispositions	**319**	(17)	(300)
Other	**374**	74	258
Interest expense *(Note 18)*	**(2,655)**	(2,790)	(2,663)
Earnings before income taxes	**7,729**	4,190	7,535
Income tax expense *(Note 25)*	**(1,415)**	(774)	(1,708)
Earnings	**6,314**	3,416	5,827
Earnings attributable to noncontrolling interests	**(125)**	(53)	(122)
Earnings attributable to controlling interests	**6,189**	3,363	5,705
Preference share dividends	**(373)**	(380)	(383)
Earnings attributable to common shareholders	**5,816**	2,983	5,322
Earnings per common share attributable to common shareholders *(Note 6)*	**2.87**	1.48	2.64
Diluted earnings per common share attributable to common shareholders *(Note 6)*	**2.87**	1.48	2.63

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

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2021**	2020	2019
(millions of Canadian dollars)			
Earnings	**6,314**	3,416	5,827
Other comprehensive income/(loss), net of tax			
Change in unrealized gain/(loss) on cash flow hedges	**162**	(457)	(437)
Change in unrealized gain on net investment hedges	**49**	102	281
Other comprehensive income/(loss) from equity investees	**(12)**	(1)	40
Excluded components of fair value hedges	**(5)**	5	—
Reclassification to earnings of loss on cash flow hedges	**235**	198	127
Reclassification to earnings of pension and other postretirement benefits (OPEB) amounts	**21**	13	13
Reclassification to earnings of gain on equity investees	**(62)**	—	—
Actuarial gain/(loss) on pension and OPEB	**394**	(167)	(96)
Foreign currency translation adjustments	**(507)**	(853)	(3,035)
Other comprehensive income/(loss), net of tax	**275**	(1,160)	(3,107)
Comprehensive income	**6,589**	2,256	2,720
Comprehensive income attributable to noncontrolling interests	**(95)**	(22)	(7)
Comprehensive income attributable to controlling interests	**6,494**	2,234	2,713
Preference share dividends	**(373)**	(380)	(383)
Comprehensive income attributable to common shareholders	**6,121**	1,854	2,330

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

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

Year ended December 31,	**2021**	2020	2019
(millions of Canadian dollars, except per share amounts)			
Preference shares *(Note 21)*			
Balance at beginning and end of year	**7,747**	7,747	7,747
Common shares *(Note 21)*			
Balance at beginning of year	**64,768**	64,746	64,677
Shares issued on exercise of stock options	**31**	22	69
Balance at end of year	**64,799**	64,768	64,746
Additional paid-in capital			
Balance at beginning of year	**277**	187	—
Stock-based compensation	**28**	30	34
Repurchase of noncontrolling interest	**—**	—	65
Options exercised	**(23)**	(21)	(61)
Change in reciprocal interest	**98**	76	117
Other	**(15)**	5	32
Balance at end of year	**365**	277	187
Deficit			
Balance at beginning of year	**(9,995)**	(6,314)	(5,538)
Earnings attributable to controlling interests	**6,189**	3,363	5,705
Preference share dividends	**(373)**	(380)	(383)
Common share dividends declared	**(6,818)**	(6,612)	(6,125)
Dividends paid to reciprocal shareholder	**8**	17	18
Modified retrospective adoption of *ASU 2016-13 Financial Instruments - Credit Losses*	**—**	(66)	—
Other	**—**	(3)	9
Balance at end of year	**(10,989)**	(9,995)	(6,314)
Accumulated other comprehensive income/(loss) *(Note 23)*			
Balance at beginning of year	**(1,401)**	(272)	2,672
Other comprehensive income/(loss) attributable to common shareholders, net of tax	**305**	(1,129)	(2,992)
Other	**—**	—	48
Balance at end of year	**(1,096)**	(1,401)	(272)
Reciprocal shareholding			
Balance at beginning of year	**(29)**	(51)	(88)
Change in reciprocal interest	**29**	22	37
Balance at end of year	**—**	(29)	(51)
Total Enbridge Inc. shareholders' equity	**60,826**	61,367	66,043
Noncontrolling interests *(Note 20)*			
Balance at beginning of year	**2,996**	3,364	3,965
Earnings attributable to noncontrolling interests	**125**	53	122
Other comprehensive loss attributable to noncontrolling interests, net of tax			
Change in unrealized loss on cash flow hedges	**(15)**	(6)	(7)
Foreign currency translation adjustments	**(15)**	(25)	(108)
	(30)	(31)	(115)
Comprehensive income attributable to noncontrolling interests	**95**	22	7
Distributions	**(271)**	(300)	(254)
Contributions	**15**	23	12
Redemption of noncontrolling interests	**(293)**	(112)	(300)
Repurchase of noncontrolling interest	**—**	—	(65)
Other	**—**	(1)	(1)
Balance at end of year	**2,542**	2,996	3,364
Total equity	**63,368**	64,363	69,407
Dividends paid per common share	**3.34**	3.24	2.95

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

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	**2021**	2020	2019
(millions of Canadian dollars)			
Operating activities			
Earnings	**6,314**	3,416	5,827
Adjustments to reconcile earnings to net cash provided by operating activities:			
Depreciation and amortization	**3,852**	3,712	3,391
Deferred income tax expense *(Note 25)*	**1,091**	447	1,156
Unrealized derivative fair value gain, net *(Note 24)*	**(173)**	(756)	(1,751)
Income from equity investments	**(1,711)**	(1,136)	(1,503)
Distributions from equity investments	**1,630**	1,392	1,804
Impairment of long-lived assets	**—**	—	423
Impairment of equity investments	**111**	2,351	—
(Gain)/loss on dispositions	**(319)**	(6)	254
Other	**77**	268	56
Changes in operating assets and liabilities *(Note 28)*	**(1,616)**	93	(259)
Net cash provided by operating activities	**9,256**	9,781	9,398
Investing activities			
Capital expenditures	**(7,818)**	(5,405)	(5,492)
Long-term investments and restricted long-term investments	**(640)**	(487)	(1,159)
Distributions from equity investments in excess of cumulative earnings	**533**	705	417
Additions to intangible assets	**(275)**	(215)	(200)
Acquisitions	**(3,785)**	(24)	—
Proceeds from dispositions	**1,263**	265	2,110
Affiliate loans, net	**65**	(16)	(314)
Other	**—**	—	(20)
Net cash used in investing activities	**(10,657)**	(5,177)	(4,658)
Financing activities			
Net change in short-term borrowings	**394**	223	(127)
Net change in commercial paper and credit facility draws	**2,960**	1,542	825
Debenture and term note issues, net of issue costs	**8,032**	5,230	6,176
Debenture and term note repayments	**(2,264)**	(4,463)	(4,668)
Contributions from noncontrolling interests	**15**	23	12
Distributions to noncontrolling interests	**(271)**	(300)	(254)
Common shares issued	**5**	5	18
Preference share dividends	**(367)**	(380)	(383)
Common share dividends	**(6,766)**	(6,560)	(5,973)
Redemption of preferred shares held by subsidiary *(Note 20)*	**(415)**	—	(300)
Other	**(87)**	(90)	(71)
Net cash provided by/(used in) financing activities	**1,236**	(4,770)	(4,745)
Effect of translation of foreign denominated cash and cash equivalents and restricted cash	**(5)**	(20)	44
Net increase/(decrease) in cash and cash equivalents and restricted cash	**(170)**	(186)	39
Cash and cash equivalents and restricted cash at beginning of year	**490**	676	637
Cash and cash equivalents and restricted cash at end of year	**320**	490	676
Supplementary cash flow information			
Cash paid for income taxes	**489**	524	571
Cash paid for interest, net of amount capitalized	**2,427**	2,538	2,738
Property, plant and equipment non-cash accruals	**831**	801	730

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

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	**2021**	2020
(millions of Canadian dollars; number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents	**286**	452
Restricted cash	**34**	38
Accounts receivable and other *(Note 9)*	**6,862**	5,258
Accounts receivable from affiliates	**107**	66
Inventory *(Note 10)*	**1,670**	1,536
	8,959	7,350
Property, plant and equipment, net *(Note 11)*	**100,067**	94,571
Long-term investments *(Note 13)*	**13,324**	13,818
Restricted long-term investments *(Note 14)*	**630**	553
Deferred amounts and other assets	**8,613**	8,446
Intangible assets, net *(Note 15)*	**4,008**	2,080
Goodwill *(Note 16)*	**32,775**	32,688
Deferred income taxes *(Note 25)*	**488**	770
Total assets	**168,864**	160,276
Liabilities and equity		
Current liabilities		
Short-term borrowings *(Note 18)*	**1,515**	1,121
Accounts payable and other *(Note 17)*	**9,767**	9,228
Accounts payable to affiliates	**90**	22
Interest payable	**693**	651
Current portion of long-term debt *(Note 18)*	**6,164**	2,957
	18,229	13,979
Long-term debt *(Note 18)*	**67,961**	62,819
Other long-term liabilities	**7,617**	8,783
Deferred income taxes *(Note 25)*	**11,689**	10,332
	105,496	95,913
Commitments and contingencies *(Note 30)*		
Equity		
Share capital *(Note 21)*		
Preference shares	**7,747**	7,747
Common shares *(2,026 outstanding at December 31, 2021 and 2020)*	**64,799**	64,768
Additional paid-in capital	**365**	277
Deficit	**(10,989)**	(9,995)
Accumulated other comprehensive loss *(Note 23)*	**(1,096)**	(1,401)
Reciprocal shareholding	**—**	(29)
Total Enbridge Inc. shareholders' equity	**60,826**	61,367
Noncontrolling interests *(Note 20)*	**2,542**	2,996
	63,368	64,363
Total liabilities and equity	**168,864**	160,276

Variable Interest Entities (VIE) *(Note 12)*
The accompanying notes are an integral part of these consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
INDEX

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 terminals in Canada and the United States (US) 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. This segment also includes Moda Midstream Operating, LLC (Moda) which was acquired on October 12, 2021 *(Note 8)* and is a component of Gulf Coast and Mid-Continent.

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 US, 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 Inc. (Enbridge Gas), which serves residential, commercial and industrial customers located throughout Ontario. This business segment also includes natural gas distribution activities in Québec and an investment in Noverco Inc. (Noverco). We sold our investment in Noverco to Trencap L.P. on December 30, 2021 *(Note 13)*.

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. We also have offshore wind assets in operation and under development in the United Kingdom, Germany and France.

ENERGY SERVICES
Our Energy Services businesses in Canada and the US 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 business segments noted above, Eliminations and Other includes operating and administrative costs that are not allocated to business segments as well as a foreign exchange hedging program. Eliminations and Other also includes new business development activities and corporate investments.

2. SIGNIFICANT ACCOUNTING POLICIES

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

BASIS OF PRESENTATION AND USE OF ESTIMATES

The preparation of financial statements in conformity with US 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: variable consideration included in revenue *(Note 4);* carrying values of regulatory assets and liabilities *(Note 7)*; purchase price allocations *(Note 8)*; unbilled revenues; expected credit losses; depreciation rates and carrying value of property, plant and equipment *(Note 11)*; amortization rates and carrying value of intangible assets *(Note 15)*; measurement of goodwill *(Note 16)*; fair value of asset retirement obligations (ARO) *(Note 19)*; valuation of stock-based compensation *(Note 22)*; fair value of financial instruments *(Note 24)*; provisions for income taxes *(Note 25)*; assumptions used to measure retirement benefits and 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.

Certain comparative figures in our consolidated financial statements have been reclassified to conform to the current year's presentation.

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. 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. 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.

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. 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 Canada Energy Regulator (CER), the Federal Energy Regulatory Commission (FERC), the Alberta Energy Regulator, the Ontario Energy Board (OEB) and La Régie de l’energie du Québec. Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under US 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 Land Matters Consultation Initiative (LMCI). 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. We believe that the recovery of our regulatory assets as at December 31, 2021 is probable over the periods described in *Note 7 - Regulatory Matters*.

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/(expense) 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.

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.

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.

For certain regulated operations to which US 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 US 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 US GAAP and no regulatory asset is recorded.

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 creditworthiness 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 ratably 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. 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 us to provide transportation services for the life of the underlying producing fields. Under these arrangements, shippers pay us 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, 2021, 2020 and 2019, cash received net of revenue recognized for contracts under make-up rights and similar deferred revenue arrangements was $127 million, $292 million and $169 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 utility revenues are recorded based on 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 areas.

Our Energy Services segment enters into commodity purchase and sale arrangements that are recorded on a gross basis as the related contracts are not held for trading purposes and we are acting as the principal in the transactions.

Our largest non-affiliated customer accounted for approximately 13.5% of our third-party revenues for the year ended December 31, 2021 and 13.6% for the year ended December 31, 2020. No non-affiliated customer exceeded 10% of our third-party revenues for the year ended December 31, 2019.

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 Commodity sales, Transportation and other services revenue, Commodity costs, Operating and administrative expense, Net foreign currency gain/(loss) 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 us 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 Other comprehensive income/(loss) (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 the translation of our 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 currently have designated a portion of our US dollar denominated debt, as well as a portfolio of foreign exchange forward contracts in prior periods, as a hedge of our net investment in US dollar denominated investments and subsidiaries. As a result, the change in fair value of the foreign currency derivatives as well as the translation of US 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 the disposal of a foreign operation.

Classification of Derivatives

We recognize the fair value of derivative instruments in the Consolidated Statements of Financial Position as current and non-current assets or liabilities depending on the timing of 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 in 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 reduction to Long-term debt in the Consolidated 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 investee. 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 in 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 using the fair value measurement alternative (FVMA). These investments are recorded at cost minus impairment, if any, plus or minus the impact of observable price changes occurring in orderly transactions for an identical or similar investment of the same issuer. Investments in equity securities measured using the FVMA are reviewed for impairment each reporting period and written down to their fair value if objective evidence of impairment is identified. Equity investments with readily determinable fair values are measured at fair value through earnings. 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 as available-for-sale and measured at fair value through OCI.

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 that taxes can be recovered through rates. Any interest and/or penalty incurred related to tax is reflected in Income tax expense.

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 to 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 exchange rate in effect as at the balance sheet date. Exchange gains and losses resulting from the 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 the 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 as at 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 in 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. Interest income is recognized in earnings as it is earned with the passage of time.

CURRENT EXPECTED CREDIT LOSSES
For accounts receivable, a loss allowance matrix is utilized to measure lifetime expected credit losses. The matrix contemplates historical credit losses by age of receivables, adjusted for any forward-looking information and management expectations. Other loan receivables and applicable off-balance sheet commitments utilize a discounted cash flow methodology which calculates the current expected credit losses based on historical default probability rates associated with the credit rating of the counterparty and the related term of the loan or commitment, adjusted for forward-looking information and management expectations.

NATURAL GAS IMBALANCES
The Consolidated Statements of Financial Position include balances as a result of differences in gas volumes received from, and delivered for, customers. As 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 held in storage by Enbridge Gas, crude oil and natural gas held primarily by businesses in the Energy Services segment and materials and supplies. Natural gas held in storage by 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 gas purchased is deferred as a liability for future refund, or as an asset for collection as approved by the OEB. Other 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 in the Consolidated Statements of Earnings at the weighted average cost of inventory, including any adjustments recorded to reduce inventory to market value. Materials and supplies inventory is recorded at the lower of average cost or net realizable 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.

LEASES
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 in the Consolidated Statements 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 applied for other long-lived assets.

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.

DEFERRED AMOUNTS AND OTHER ASSETS
Deferred amounts and other assets primarily consists of costs that regulatory authorities have permitted, or are expected to permit, to be recovered through future rates, including: deferred income taxes; the fair value adjustment to long-term debt; actual cost of removal of previously retired or decommissioned plant assets; 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. 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 upon 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 assessment. 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, the assessment of macroeconomic trends, regulatory environments, capital accessibility, operating income trends and industry conditions. Based on our assessment of qualitative factors, if we determine it is more likely than not that the fair value of the reporting unit is less than its carrying amount, a quantitative goodwill impairment assessment is performed.

The quantitative goodwill impairment assessment involves determining the fair value of our reporting units and comparing those values to the carrying value of each reporting unit. If the carrying value of a reporting unit, including allocated goodwill, exceeds its fair value, goodwill impairment is measured at the amount by which the reporting unit’s carrying value exceeds its fair value. This amount should not exceed the carrying amount of goodwill. The fair value of our reporting units is estimated using a combination of discounted cash flow and earnings multiples techniques. The determination of fair value using the discounted cash flow 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. Cash flow projections include significant judgments and assumptions relating to discount rates and expected future capital expenditures. 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 relevant reporting unit.

On April 1, 2021, we performed a quantitative goodwill impairment assessment for the Gas Transmission and Midstream reporting unit and qualitative assessments for the Liquids Pipelines and Gas Distribution and Storage reporting units. Our goodwill impairment assessments did not result in an impairment charge. Also, we did not identify any indicators of goodwill impairment during the remainder of 2021.

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 its expected undiscounted cash flows, we will calculate fair value based on the discounted cash flows and write the asset 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. We determine whether the decline below carrying value is other-than-temporary for equity method investments or is due to a credit loss for investments in debt securities. If the decline is determined to be other-than-temporary for equity method investments or is due to a credit loss for investments in debt securities, an impairment charge is recorded in earnings with an offsetting reduction to the carrying value of the asset.

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. 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. Currently, for the majority of our assets, it is not possible to make a reasonable estimate of ARO due to the indeterminate timing and scope of the asset retirements.

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 US (revised in 2021) and the Canadian Institute of Actuaries (revised in 2014) to measure the benefit obligations of our US pension plans (the US Plans) 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 (for 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 the 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 the 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 (for 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 the 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 the 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 one-third annually from the grant date. 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 is 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 Accounts payable and other and Other long-term liabilities in the Consolidated Statements of Financial Position at their undiscounted amounts. There is always a potential of incurring additional costs in connection with environmental liabilities due to variations in any or all of the categories described above, including modified or revised requirements from regulatory agencies, in addition to fines and penalties, as well as expenditures associated with litigation and settlement of claims. We evaluate recoveries from insurance coverage separately from the liability and, when recovery is probable, we record and report an asset separately from the associated liability in the Consolidated Statements of Financial Position.

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

3. CHANGES IN ACCOUNTING POLICIES

CHANGES IN ACCOUNTING POLICIES
There were no changes in accounting policies during the year ended December 31, 2021.

ADOPTION OF NEW ACCOUNTING STANDARDS
Accounting for Contract Assets and Liabilities from Contracts with Customers in a Business Combination
Effective November 1, 2021, we adopted Accounting Standards Update (ASU) 2021-08 on a retrospective basis beginning January 1, 2021. The new standard was issued in October 2021 to amend business combination accounting specific to contract assets and contract liabilities resulting from contracts with customers, requiring measurement in accordance with Accounting Standards Codification (ASC) 606. The ASU is also applicable to contract assets and contract liabilities from other contracts to which ASC 606 applies, such as contract liabilities from the sale of nonfinancial assets within the scope of ASC 610-20. The adoption of this ASU did not have a material impact on our consolidated financial statements.

Reference Rate Reform
For eligible hedging relationships existing as at January 1, 2021 and prospectively, we have applied the optional expedient in ASU 2020-04 whereby the modification of the hedging instrument does not result in an automatic hedging relationship de-designation. The adoption of this ASU did not have a material impact on our consolidated financial statements.

Clarifying Interaction Between Equity Securities, Equity Method Investments and Derivatives
Effective January 1, 2021, we adopted ASU 2020-01 on a prospective basis. The new standard was issued in January 2020 and clarifies that observable transactions should be considered for the purpose of applying the measurement alternative in accordance with ASC 321 *Investments - Equity Securities* immediately before the application or upon discontinuance of the equity method of accounting. Furthermore, the ASU clarifies that forward contracts or purchased options on equity securities are not out of scope of ASC 815 *Derivatives and Hedging* guidance only because, upon the contracts' exercise, the equity securities could be accounted for under the equity method of accounting or fair value option. The adoption of this ASU did not have a material impact on our consolidated financial statements.

Accounting for Income Taxes
Effective January 1, 2021, we adopted ASU 2019-12 on a prospective basis. The new standard 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 *Income Taxes* as well as provides simplification by clarifying and amending existing guidance. The adoption of this ASU did not have a material impact on our consolidated financial statements.

FUTURE ACCOUNTING POLICY CHANGES
Disclosures About Government Assistance
ASU 2021-10 was issued in November 2021 to increase the transparency of government assistance to business entities. The ASU adds new disclosure requirements for transactions with government that are accounted for using a grant or contribution accounting model by analogy. The required disclosures include information about the nature of transactions, accounting policy applied, impacted financial statement line items and significant terms and conditions. ASU 2021-10 is effective January 1, 2022 and can be applied either prospectively or retrospectively with early adoption permitted. The adoption of ASU 2021-10 is not expected to have a material impact on our consolidated financial statements.

Accounting for Certain Lessor Leases with Variable Lease Payments
ASU 2021-05 was issued in July 2021 to amend lessor accounting for certain leases with variable lease payments that do not depend on a reference index or a rate and would have resulted in the recognition of a loss at lease commencement if classified as a sales-type or a direct financing lease. The ASU amends the classification requirements of such leases for lessors to result in an operating lease classification. ASU 2021-05 is effective January 1, 2022 and can be applied either retrospectively or prospectively with early adoption permitted. The adoption of ASU 2021-05 is not expected to have a material impact on our consolidated financial statements.

Accounting for Modifications or Exchanges of Certain Equity-Classified Contracts
ASU 2021-04 was issued in May 2021 to clarify issuer accounting for modifications or exchanges of freestanding equity-classified written call options that remain equity classified after modification or exchange. The ASU requires an issuer to determine the accounting for the modification or exchange based on the economic substance of the modification or exchange. ASU 2021-04 is effective January 1, 2022 and should be applied prospectively. The adoption of ASU 2021-04 is not expected to have a material impact on our consolidated financial statements.

Accounting for Convertible Instruments and Contracts in an Entity's Own Equity
ASU 2020-06 was issued in August 2020 to simplify accounting for certain financial instruments. The ASU eliminates the current models that require separation of beneficial conversion and cash conversion features from convertible instruments and simplifies the derivative scope exception guidance pertaining to equity classification of contracts in an entity's own equity. The ASU also introduces additional disclosures for convertible debt and freestanding instruments that are indexed to and settled in an entity's own equity. The ASU amends the diluted earnings per share guidance, including the requirement to use if-converted method for all convertible instruments and an update for instruments that can be settled in either cash or shares. ASU 2020-06 is effective January 1, 2022 and should be applied on a full or modified retrospective basis. The adoption of ASU 2020-06 is not expected 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, 2021	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	**9,492**	**4,364**	**676**	**—**	**—**	**—**	**14,532**
Storage and other revenue	**147**	**255**	**246**	**—**	**—**	**—**	**648**
Gas gathering and processing revenue	**—**	**49**	**—**	**—**	**—**	**—**	**49**
Gas distribution revenue	**—**	**—**	**4,026**	**—**	**—**	**—**	**4,026**
Electricity and transmission revenue	**—**	**—**	**—**	**177**	**—**	**—**	**177**
Total revenue from contracts with customers	**9,639**	**4,668**	**4,948**	**177**	**—**	**—**	**19,432**
Commodity sales	**—**	**—**	**—**	**—**	**26,873**	**—**	**26,873**
Other revenue[1,2]	**375**	**42**	**13**	**336**	**—**	**—**	**766**
Intersegment revenue	**567**	**1**	**19**	**(1)**	**44**	**(630)**	**—**
Total revenue	**10,581**	**4,711**	**4,980**	**512**	**26,917**	**(630)**	**47,071**

Year ended December 31, 2020	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	9,161	4,523	674	—	—	—	14,358
Storage and other revenue	94	274	203	—	—	—	571
Gas gathering and processing revenue	—	27	—	—	—	—	27
Gas distribution revenue	—	—	3,663	—	—	—	3,663
Electricity and transmission revenue	—	—	—	198	—	—	198
Total revenue from contracts with customers	9,255	4,824	4,540	198	—	—	18,817
Commodity sales	—	—	—	—	19,259	—	19,259
Other revenue[1,2]	584	44	17	389	—	(23)	1,011
Intersegment revenue	584	2	12	—	24	(622)	—
Total revenue	10,423	4,870	4,569	587	19,283	(645)	39,087

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

1 *Includes mark-to-market gains from our hedging program for the year ended December 31, 2021 of $59 million, (2020 - $265 million, 2019 - $346 million).*
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. 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, 2021	**2,369**	**213**	**1,898**
Balance as at December 31, 2020	2,042	226	1,815

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, 2021 included in contract liabilities at the beginning of the period is $305 million. Increases in contract liabilities from cash received, net of amounts recognized as revenue during the year ended December 31, 2021 were $397 million.

Performance Obligations

Segment	Nature of Performance Obligation
Liquids Pipelines	• Transportation and storage of crude oil and natural gas liquids (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, 2021 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 US 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 are recorded as contract liabilities. 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 $59.8 billion, of which $7.4 billion is expected to be recognized during the year ended December 31, 2022.

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.

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.

During the year ended December 31, 2021, revenue for the Canadian Mainline has been recognized in accordance with the terms of the Competitive Tolling Settlement (CTS), which expired on June 30, 2021. The tolls in place on June 30, 2021 continue on an interim basis until a new commercial arrangement is implemented and are subject to finalization and adjustment applicable to the interim period, if any. Due to the uncertainty of adjustment to tolling pursuant to a CER decision and potential customer negotiations, interim toll revenue recognized during the year ended December 31, 2021 is considered variable consideration.

Recognition and Measurement of Revenue

Year ended December 31, 2021	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Consolidated
(millions of Canadian dollars)					
Revenue from products transferred at a point in time	**—**	**—**	**70**	**—**	**70**
Revenue from products and services transferred over time[1]	**9,639**	**4,668**	**4,878**	**177**	**19,362**
Total revenue from contracts with customers	**9,639**	**4,668**	**4,948**	**177**	**19,432**

Year ended December 31, 2020	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Consolidated
(millions of Canadian dollars)					
Revenue from products transferred at a point in time	—	—	60	—	60
Revenue from products and services transferred over time[1]	9,255	4,824	4,480	198	18,757
Total revenue from contracts with customers	9,255	4,824	4,540	198	18,817

Year ended December 31, 2019	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	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.*

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 transportation and gas processing 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, 2021, 2020 and 2019 is as follows:

Year ended December 31, 2021	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues	**10,581**	**4,711**	**4,980**	**512**	**26,917**	**(630)**	**47,071**
Commodity and gas distribution costs	**(25)**	**—**	**(2,147)**	**—**	**(27,174)**	**644**	**(28,702)**
Operating and administrative	**(3,431)**	**(1,877)**	**(1,143)**	**(180)**	**(48)**	**(33)**	**(6,712)**
Income/(loss) from equity investments	**759**	**813**	**42**	**101**	**—**	**(4)**	**1,711**
Impairment of equity investments	**—**	**(111)**	**—**	**—**	**—**	**—**	**(111)**
Other income/(expense)	**13**	**135**	**385**	**75**	**(8)**	**379**	**979**
Earnings/(loss) before interest, income tax expense and depreciation and amortization	**7,897**	**3,671**	**2,117**	**508**	**(313)**	**356**	**14,236**
Depreciation and amortization							**(3,852)**
Interest expense							**(2,655)**
Income tax expense							**(1,415)**
Earnings							**6,314**
Capital expenditures[1]	**4,051**	**2,420**	**1,343**	**16**	**1**	**54**	**7,885**
Total property, plant and equipment, net	**52,530**	**27,028**	**16,904**	**3,315**	**23**	**267**	**100,067**

Year ended December 31, 2020	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues	10,423	4,870	4,569	587	19,283	(645)	39,087
Commodity and gas distribution costs	(20)	—	(1,810)	(2)	(19,450)	613	(20,669)
Operating and administrative	(3,331)	(1,859)	(1,091)	(191)	(67)	(210)	(6,749)
Income/(loss) from equity investments	558	479	9	94	(3)	(1)	1,136
Impairment of equity investments	—	(2,351)	—	—	—	—	(2,351)
Other income/(expense)	53	(52)	71	35	1	130	238
Earnings/(loss) before interest, income tax expense and depreciation and amortization	7,683	1,087	1,748	523	(236)	(113)	10,692
Depreciation and amortization							(3,712)
Interest expense							(2,790)
Income tax expense							(774)
Earnings							3,416
Capital expenditures[1]	2,033	2,130	1,134	81	2	90	5,470
Total property, plant and equipment, net	48,799	25,745	16,079	3,495	24	429	94,571

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

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)*.

GEOGRAPHIC INFORMATION

Revenues[1]

Year ended December 31,	**2021**	2020	2019
(millions of Canadian dollars)			
Canada	**20,474**	16,453	19,954
US	**26,597**	22,634	30,115
	47,071	39,087	50,069

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

Property, Plant and Equipment[1]

December 31,	**2021**	2020
(millions of Canadian dollars)		
Canada	**47,102**	46,499
US	**52,965**	48,072
	100,067	94,571

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 2 million as at December 31, 2021, 5 million as at December 31, 2020, and 6 million as at December 31, 2019, resulting from our reciprocal investment in Noverco. On December 30, 2021, we closed the sale of our non-operating minority ownership of Noverco. Refer to *Note 13 - Long-term Investments* for more information.

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,	**2021**	2020	2019
(number of shares in millions)			
Weighted average shares outstanding	**2,023**	2,020	2,017
Effect of dilutive options	**2**	1	3
Diluted weighted average shares outstanding	**2,025**	2,021	2,020

For the years ended December 31, 2021, 2020 and 2019, 18.6 million, 29.8 million and 17.8 million, respectively, of anti-dilutive stock options with a weighted average exercise price of $52.89, $51.42 and $53.56, respectively, were excluded from the diluted earnings per common share calculation.

7. REGULATORY MATTERS

We record assets and liabilities that result from regulated ratemaking processes that would not be recorded under US GAAP for non-regulated entities. See *Note 2 - Significant Accounting Policies* for further discussion. Our significant regulated businesses and the related accounting impacts are described below.

Under the current authorized rate structure for certain operations, income tax costs are recovered in rates 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 temporary differences that created the deferred income taxes, it is expected that rates will be adjusted to recover these taxes. Since most of these temporary differences are related to property, plant and equipment costs, this recovery is expected to occur over the life of the related assets.

LIQUIDS PIPELINES

Canadian Mainline

Canadian Mainline includes the Canadian portion of our mainline system and is subject to regulation by the CER. Tolls, excluding Lines 8 and 9, are governed by the 10-year CTS which expired on June 30, 2021 *(Note 4).* The CTS established a Canadian Local Toll for all volumes shipped on the Canadian Mainline and an International Joint Tariff for all volumes shipped from western Canadian receipt points to delivery points on our Lakehead System. Under the CTS, we have recognized a regulatory asset of $2.1 billion as at December 31, 2021 (2020 - $1.9 billion) 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 US and Canadian portions of the Southern Lights Pipeline are regulated by the FERC and CER, respectively. 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 return on equity (ROE) of 10%.

GAS TRANSMISSION AND MIDSTREAM

British Columbia Pipeline and Maritimes & Northeast Canada

British Columbia (BC) Pipeline and Maritimes & Northeast (M&N) Canada are regulated by the CER. Rates are approved by the CER through negotiated toll settlement agreements based on cost-of-service. Both our BC Pipeline and M&N Canada systems operate under the terms of their respective negotiated toll settlements, which stipulate an allowable ROE and the continuation and establishment of certain deferral and variance accounts. As both settlement agreements expired in December 2021, we are currently operating under CER-approved interim tolls and negotiating the terms of new toll settlements for periods beginning in 2022.

US Gas Transmission

Most of our US 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. The FERC regulates natural gas transmission in US interstate commerce including the establishment of rates for services, while rates for intrastate commerce and/or gathering services are regulated by the state gas commissions. Cost-of-service is the basis for the calculation of regulated tariff rates, although the FERC also allows the use of negotiated and discounted rates within contracts with shippers that may result in a rate that is above or below the FERC-regulated recourse rate for that service.

GAS DISTRIBUTION AND STORAGE

Enbridge Gas

Enbridge Gas' distribution rates, commencing 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% stretch 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 ROE.

FINANCIAL STATEMENT EFFECTS

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

December 31,	**2021**	2020	Recovery/Refund Period Ends
(millions of Canadian dollars)			
Current regulatory assets			
Under-recovery of fuel costs	**114**	86	2022
Other current regulatory assets	**145**	146	2022
Total current regulatory assets[1] *(Note 9)*	**259**	232	
Long-term regulatory assets			
Deferred income taxes[2]	**4,176**	3,890	Various
Long-term debt[3]	**398**	429	2023-2046
Negative salvage[4]	**243**	246	Various
Purchase gas variance	**215**	—	2023
Accounting policy changes[5]	**157**	169	Various
Pension plan receivable[6]	**78**	402	Various
Other long-term regulatory assets	**339**	261	Various
Total long-term regulatory assets[1]	**5,606**	5,397	
Total regulatory assets	**5,865**	5,629	
Current regulatory liabilities			
Purchase gas variance	**—**	153	2021
Other current regulatory liabilities	**106**	117	2022
Total current regulatory liabilities[7]	**106**	270	
Long-term regulatory liabilities			
Future removal and site restoration reserves[8]	**1,543**	1,455	Various
Regulatory liability related to US income taxes[9]	**895**	941	2050-2072
Pipeline future abandonment costs *(Note 14)*	**649**	578	Various
Other long-term regulatory liabilities	**234**	150	Various
Total long-term regulatory liabilities[7]	**3,321**	3,124	
Total regulatory liabilities	**3,427**	3,394	

1 Current regulatory assets are included in Accounts receivable and other, while long-term regulatory assets are included in Deferred amounts and other assets.

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

3 Represents our regulatory offset to the fair value adjustment to debt acquired in our merger with Spectra Energy Corp. (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.

4 The negative salvage balance represents the recovery in future rates of the actual cost of removal of previously retired or decommissioned plant assets, as approved by the FERC.

5 This deferral reflects unamortized accumulated actuarial gains/losses and past service costs incurred by Union Gas Limited, relating to the period up to our merger with Spectra Energy, which were previously recorded in AOCI. The amortization of this balance is recognized as a component of accrual-based pension expenses, which are included in Other income/(expense) and recovered in rates, as previously approved by the OEB.

6 Represents the regulatory offset to our pension liability to the extent that it is expected to be included in regulator-approved future rates and recovered from customers. The settlement period for this balance is not determinable. In the absence of rate-regulated accounting, this regulatory balance and the related pension expense would be recorded in earnings and OCI.

7 Current regulatory liabilities are included in Accounts payable and other, while long-term regulatory liabilities are included in Other long-term liabilities.

8 Future removal and site restoration reserves consists of amounts collected from customers, with the approval of the OEB, to fund future costs of removal and site restoration relating to property, plant and equipment. These costs are collected as part of the depreciation expense charged on property, plant and equipment that is reflected in rates. The settlement of this balance will occur over the long-term as costs are incurred. In the absence of rate-regulated accounting, depreciation rates would not include a charge for removal and site restoration and costs would be charged to earnings as incurred with recognition of revenue for amounts previously collected.

9 The regulatory liability related to US income taxes resulted from the US tax reform legislation dated December 22, 2017. These balances will be refunded to customers in accordance with the respective rate settlements approved by the FERC.

8. ACQUISITIONS AND DISPOSITIONS

ACQUISITION

Moda Midstream Operating, LLC

On October 12, 2021, through a wholly-owned US subsidiary, we acquired all of the outstanding membership interests in Moda for $3.7 billion (US$3.0 billion) of cash plus potential contingent payments of up to US$150 million dependent on performance of the assets (the Acquisition). The Acquisition is also subject to customary closing and working capital adjustments. Moda owns and operates a light crude export platform with very large crude carrier capability. The Acquisition aligns with and advances our US Gulf Coast export strategy and enables connectivity to low-cost and long-lived reserves in the Permian and Eagle Ford basins.

We accounted for the Acquisition using the acquisition method as prescribed by ASC 805 *Business Combinations*. In accordance with valuation methodologies described in ASC 820 *Fair Value Measurements*, the acquired assets and assumed liabilities were recorded at their estimated fair values as at the date of acquisition.

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

	October 12, 2021
(millions of Canadian dollars)	
Fair value of net assets acquired:	
Current assets	**62**
Property, plant and equipment (a)	**1,480**
Long-term investments (b)	**427**
Intangible assets (c)	**1,781**
Current liabilities	**59**
Long-term liabilities	**17**
Goodwill (d)	**268**
Purchase price:	
Cash	**3,755**
Contingent consideration (e)	**187**
	3,942

a) Due to the specialized nature of Moda's property, plant and equipment, which includes groups of assets configured for use as storage facilities, pipelines and export terminals, the depreciated replacement cost approach was adopted as the primary valuation methodology. In determining replacement cost, both indirect costing using relevant inflation indices and direct costing using relevant market quotes were utilized. Adjustments were then applied for physical deterioration as well as functional and economic obsolescence. The fair value of land was determined using a market approach, which is based on rents and offerings for comparable properties.

b) Long-term investments represent Moda's 20% equity interest in Cactus II Pipeline, LLC (Cactus II). The fair value of Cactus II was determined using the discounted cash flow method. The discounted cash flow method is an income-based approach to valuation which estimates the present value of future projected benefits from the investment.

c) Intangible assets consist primarily of customer relationships associated with long-term take-or-pay contracts. Fair value was determined using an income-based approach by estimating the present value of the after-tax earnings attributable to the contracts, including earnings associated with expected renewal terms, and will be amortized on a straight-line basis over an expected useful life of 10 years.

d) Goodwill is primarily attributable to uncontracted future revenues, existing assembled assets that cannot be duplicated at the same cost by a new entrant, and enhanced scale and geographic diversity which provide greater optionality and platforms for future growth. The goodwill balance recognized has been assigned to our Liquids Pipelines segment and is tax deductible over 15 years.

e) We agreed to pay additional contingent consideration of up to US$150 million to Moda's former membership interest holders if Moda's monthly volumes of crude oil loaded onto a vessel equal or exceed specified throughput levels. These performance requirements terminate the earlier of December 31, 2023 or the date the final contingent payment is made. The US$150 million of contingent consideration recognized in the purchase price represents the fair value of contingent consideration at the date of acquisition. As at December 31, 2021, there were no changes to the amount of contingent consideration recognized.

Acquisition-related expenses incurred were approximately $21 million for the year ended December 31, 2021 and are included in Operating and administrative expense in the Consolidated Statements of Earnings.

Upon completion of the Acquisition, we began consolidating Moda. For the period beginning October 12, 2021 through to December 31, 2021, Moda generated approximately $80 million in operating revenues and $9 million in earnings attributable to common shareholders.

Our supplemental pro forma consolidated financial information for the years ended December 31, 2021 and 2020, including the results of operations for Moda as if the Acquisition had been completed on January 1, 2020, are as follows:

Year ended December 31,	2021	2020
(unaudited; millions of Canadian dollars)		
Operating revenues	**47,339**	39,435
Earnings attributable to common shareholders[1,2]	**5,771**	2,938

1 Acquisition-related expenses of $21 million (after-tax $16 million) were excluded from earnings attributable to common shareholders for the year ended December 31 2021 and deducted for the year ended December 31, 2020.

2 Includes the amortization of fair value adjustments recorded for acquired property, plant and equipment, long-term investments and intangible assets of $193 million and $207 million (after-tax of $145 million and $155 million) for the years ended December 31, 2021 and 2020, respectively.

DISPOSITIONS

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 Enbridge Energy Partners, L.P. (EEP), owned the Canadian and US portions of Line 10, respectively, and the related assets were included in our Liquids Pipelines segment. The transaction closed on June 1, 2020. No gain or loss on disposition was recorded.

Montana-Alberta Tie Line
In the fourth quarter of 2019, we committed to a plan to sell the Montana-Alberta Tie Line (MATL) transmission asset, a 345 kilometer transmission line from Great Falls, Montana to Lethbridge, Alberta. MATL was included in our Renewable Power Generation segment. The purchase and sale agreement was signed in January 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 in the Consolidated Statements of Earnings for the year ended December 31, 2019.

On May 1, 2020, we closed the sale of MATL for cash proceeds of approximately $189 million. After closing adjustments, a gain on disposal of $4 million was included in Other income/(expense) in the Consolidated Statements of Earnings.

Ozark Gas Transmission
In the first quarter of 2020, we agreed to sell our Ozark Gas Transmission and Ozark Gas Gathering assets (Ozark assets). The Ozark assets are composed of a transmission system that extends from southeastern Oklahoma through Arkansas to southeastern Missouri, and a fee-based gathering system that accesses Fayetteville Shale and Arkoma production. These assets were included in our Gas Transmission and Midstream segment.

On April 1, 2020, we closed the sale of the Ozark assets for cash proceeds of approximately $63 million. After closing adjustments, a gain on disposal of $1 million was included in Other income/(expense) in the Consolidated Statements of Earnings.

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); these assets were part of our Gas Transmission and Midstream segment.

On October 1, 2018, we closed the sale of the provincially regulated facilities. 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.

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. After closing adjustments, a loss on disposal of $10 million was included in Other income/(expense) in the Consolidated Statements of Earnings for the year ended December 31, 2019.

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 for the year ended December 31, 2019.

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.

9. ACCOUNTS RECEIVABLE AND OTHER

December 31,	**2021**	2020
(millions of Canadian dollars)		
Trade receivables and unbilled revenues[1]	**4,957**	3,923
Short-term portion of derivative assets *(Note 24)*	**529**	323
Regulatory assets *(Note 7)*	**259**	232
Taxes receivable	**407**	374
Other	**710**	406
	6,862	5,258

1 Net of allowance for expected credit losses of $87 million as at December 31, 2021 and $70 million as at December 31, 2020.

10. INVENTORY

December 31,	**2021**	2020
(millions of Canadian dollars)		
Natural gas	**953**	710
Crude oil	**624**	744
Other	**93**	82
	1,670	1,536

11. PROPERTY, PLANT AND EQUIPMENT

December 31,	Weighted Average Depreciation Rate	**2021**	2020
(millions of Canadian dollars)			
Pipelines	2.8 %	**62,997**	57,459
Facilities and equipment	3.1 %	**34,331**	30,149
Land and right-of-way[1]	2.3 %	**3,320**	2,896
Gas mains, services and other	2.7 %	**13,606**	12,813
Storage	2.4 %	**3,099**	2,936
Wind turbines, solar panels and other	4.0 %	**4,912**	4,877
Other	8.2 %	**1,507**	1,558
Under construction	— %	**2,268**	5,762
Total property, plant and equipment		**126,040**	118,450
Total accumulated depreciation		**(25,973)**	(23,879)
Property, plant and equipment, net		**100,067**	94,571

1 The measurement of weighted average depreciation rate excludes non-depreciable assets.

Depreciation expense for the years ended December 31, 2021, 2020 and 2019 was $3.5 billion, $3.4 billion and $3.0 billion, respectively.

IMPAIRMENT
Access Northeast Project
In 2019, we announced that we terminated the agreements with Eversource Energy and National Grid USA Service Company, Inc. 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
Our consolidated VIEs consist of legal entities where we are the primary beneficiary. We are the primary beneficiary when our variable interest(s) provide us with (i) the power to direct the activities of the VIE that most significantly impact the VIE’s economic performance and (ii) the obligation to absorb losses of the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. We determine whether we are the primary beneficiary of a VIE by considering qualitative and quantitative factors, including, but not limited to: 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.

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,	**2021**[1]	2020[1]
(millions of Canadian dollars)		
Assets		
Cash and cash equivalents	**247**	215
Restricted cash	**4**	1
Accounts receivable and other	**99**	65
Inventory	**9**	7
	359	288
Property, plant and equipment, net	**3,052**	3,201
Long-term investments	**16**	14
Restricted long-term investments	**101**	84
Deferred amounts and other assets	**2**	3
Intangible assets, net	**108**	115
	3,638	3,705
Liabilities		
Accounts payable and other	**84**	52
Other long-term liabilities	**182**	175
Deferred income taxes	**5**	5
	271	232
	3,367	3,473

1 *Excludes assets and liabilities of EEP and Spectra Energy Partners, L.P. (SEP) following the subsidiary guarantees agreement entered on January 22, 2019. See Part II.* Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Summarized Financial Information.

We do not have obligations to provide additional financial support to any of our consolidated VIEs.

UNCONSOLIDATED VARIABLE INTEREST ENTITIES

We currently hold interests in several non-consolidated VIEs where we are not the primary beneficiary as we do not have the power to direct the activities of the VIEs that most significantly impact the VIEs' economic performance. These interests include investments in limited partnerships that are assessed to be VIEs due to the limited partners not having substantive kick-out rights or participating rights. The power to direct the activities of a majority of these non-consolidated limited partnership 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 significant decisions unilaterally.

The carrying amount of these VIEs and our estimated maximum exposure to loss as at December 31, 2021 and 2020 are presented below:

December 31, 2021	Carrying Amount of the VIE	Maximum Exposure to Loss
(millions of Canadian dollars)		
Aux Sable Liquid Products L.P.[1]	**113**	**195**
EIH S.á r.l.[2, 8]	**38**	**664**
Enbridge Renewable Infrastructure Investments S.á r.l.[3]	**54**	**2,121**
Rampion Offshore Wind Limited[5]	**450**	**508**
Vector Pipeline L.P.[6]	**189**	**374**
Other[4,7]	**210**	**426**
	1,054	**4,288**

December 31, 2020	Carrying Amount of the VIE	Maximum Exposure to Loss
(millions of Canadian dollars)		
Aux Sable Liquid Products L.P.[1]	106	187
Éolien Maritime France SAS[2, 8]	96	949
Enbridge Renewable Infrastructure Investments S.á r.l.[3]	100	2,516
PennEast Pipeline Company, LLC[4]	116	371
Rampion Offshore Wind Limited[5]	599	650
Vector Pipeline L.P.[6]	201	390
Other[7]	133	361
	1,351	5,424

1 *At December 31, 2021 and 2020, the maximum exposure to loss includes guarantees by us for our respective share of the VIE's borrowing on a bank credit facility.*

2 *At December 31, 2021, the maximum exposure to loss includes our parental guarantees that have been committed in connection with the three French offshore wind projects for which we would be liable in the event of default by the VIE and an outstanding affiliate loan receivable for $73 million held by us as at December 31, 2021. On March 18, 2021, Enbridge Renewable Infrastructure Holdings S.á r.l. (ERIH) closed the sale of 49% of its interest in EIH S.á r.l. to the Canada Pension Plan Investment Board (CPP Investments).*

3 *At December 31, 2021 and 2020, the maximum exposure to loss includes our parental guarantees that have been committed in connection with the project for which we would be liable in the event of default by the VIE and an outstanding affiliate loan receivable for $807 million and $904 million held by us as at December 31, 2021 and 2020, respectively.*

4 *At December 31, 2021, the maximum exposure to loss is limited to our equity investment and at December 31, 2020, the maximum exposure to loss includes the remaining expected contributions to the joint venture.*

5 *At December 31, 2021 and 2020, the maximum exposure to loss includes our parental guarantees that have been committed in project contracts in which we would be liable for in the event of default by the VIE.*

6 *At December 31, 2021 and 2020, the maximum exposure to loss includes the carrying value of outstanding affiliate loans receivable for $80 million and $84 million held by us as at December 31, 2021 and 2020, respectively, and an outstanding credit facility for $105 million as at December 31, 2021 and 2020.*

7 *At December 31, 2021, the maximum exposure to loss includes our parental guarantees that have been committed in connection with the project for which we would be liable in the event of default by the VIE.*

8 *At December 31, 2020, the maximum exposure to loss includes our parental guarantees that have been committed in connection with the project for which we would be liable for in the event of default by the VIE and an outstanding affiliate loan receivable for $132 million held by us as at December 31, 2020. In relation to the sale of 49% of EIH S.á r.l.'s interest to CPP Investments, Eolien Maritime France SAS is now reported under EIH S.á r.l. in 2021.*

We do not have an obligation to and did not provide any additional financial support to the VIEs during the years ended December 31, 2021 and 2020.

13. LONG-TERM INVESTMENTS

December 31,	Ownership Interest	**2021**	2020
(millions of Canadian dollars)			
EQUITY INVESTMENTS			
Liquids Pipelines			
MarEn Bakken Company LLC[1]	75.0%	**1,728**	1,795
Gray Oak Holdings LLC[2]	35.0%	**469**	502
Seaway Crude Holdings LLC	50.0%	**2,634**	2,668
Illinois Extension Pipeline Company, L.L.C.[3]	65.0%	**593**	623
Cactus II Pipeline, LLC[4]	20.0%	**434**	—
Other	30.0% - 43.8%	**71**	73
Gas Transmission and Midstream			
Alliance Pipeline[5]	50.0%	**504**	269
Aux Sable[6]	42.7% - 50.0%	**238**	251
DCP Midstream, LLC[7]	50.0%	**397**	331
Gulfstream Natural Gas System, L.L.C.	50.0%	**1,180**	1,175
Nexus Gas Transmission, LLC	50.0%	**1,724**	1,745
PennEast Pipeline Company, LLC	20.0%	**12**	116
Sabal Trail Transmission, LLC	50.0%	**1,464**	1,510
Southeast Supply Header, LLC	50.0%	**82**	84
Steckman Ridge, LP	50.0%	**88**	90
Vector Pipeline[8]	60.0%	**189**	201
Offshore - various joint ventures	22.0% - 74.3%	**309**	338
Other	33.3%	**2**	4
Gas Distribution and Storage			
Noverco Common Shares[9]	38.9%	**—**	156
Other	47.6% - 50%	**20**	13
Renewable Power Generation			
EIH S.a.r.l.[10]	51.0%	**38**	96
Enbridge Renewable Infrastructure Investments S.a.r.l.	51.0%	**54**	100
Rampion Offshore Wind Limited	24.9%	**450**	599
NextBridge Infrastructure LP	25.0%	**186**	122
Other	12.0% - 50.0%	**93**	74
Eliminations and Other			
Other	42.7% - 50.0%	**23**	32
OTHER LONG-TERM INVESTMENTS			
Gas Distribution and Storage			
Noverco Preferred Shares[9]		**—**	567
Renewable Power Generation			
Emerging Technologies and Other		**32**	32
Eliminations and Other			
Other[11]		**310**	252
		13,324	13,818

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 Owns 65% interest in Gray Oak Pipeline, LLC resulting in a 22.8% effective interest in Gray Oak Pipeline, LLC.
3 Owns the Southern Access Extension Project.
4 In October 2021 we acquired an effective 20.0% interest in Cactus II Pipeline, LLC through the acquisition of Moda Midstream Operating, LLC. See Note 8 - Acquisitions and Dispositions for further discussion.
5 Includes Alliance Pipeline Limited Partnership in Canada and Alliance Pipeline L.P. in the US.
6 Includes Aux Sable Canada LP in Canada and Aux Sable Liquid Products LP and Aux Sable Midstream LLC in the US.

7 Our ownership in DCP Midstream, LLC (DCP Midstream) holds an interest of 56.5% in DCP Midstream, LP.
8 Includes Vector Pipeline Limited Partnership in Canada and Vector Pipeline L.P. in the US.
9 On December 30, 2021, we sold our 38.9% common share and preferred share interest of Noverco Inc.
10 On March 18, 2021, we sold 49% of EIH S.a.r.l., an entity that holds our 50% interest in Éolien Maritime France SAS (EMF), to the CPP Investments. This resulted in a 25.5% effective interest in EMF. Through our investment in EMF, we own equity interests in three French offshore wind projects, including Saint-Nazaire (25.5%), Fécamp (17.9%) and Calvados (21.7%).
11 Includes investments held and valued at fair value through net income.

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, 2021, this basis difference was $2.5 billion (2020 - $2.4 billion), of which $730 million (2020 - $657 million) was amortizable.

For the years ended December 31, 2021, 2020 and 2019, distributions received from equity investments were $2.2 billion, $2.1 billion and $2.2 billion, respectively.

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

Year ended December 31,	**2021**	2020	2019
(millions of Canadian dollars)			
Operating revenues	**19,891**	13,987	15,687
Operating expenses	**16,514**	12,223	13,153
Earnings	**2,952**	2,306	3,016
Earnings attributable to Enbridge	**1,711**	1,136	1,503

December 31,	**2021**	2020
(millions of Canadian dollars)		
Current assets	**3,581**	3,136
Non-current assets	**44,497**	45,955
Current liabilities	**3,678**	3,539
Non-current liabilities	**16,950**	19,639
Noncontrolling interests	**3,786**	3,810

Noverco Inc.

On June 7, 2021, IPL System Inc., a wholly owned subsidiary of Enbridge, entered into a purchase and sale agreement to sell its 38.9% common share and preferred share interest in Noverco to Trencap L.P. for $1.1 billion in cash.

On December 30, 2021, we closed the sale of Noverco for cash proceeds of $1.1 billion. After closing adjustments, a gain on disposal of $303 million before tax was included in Other income/(expense) in the Consolidated Statements of Earnings for the year ended December 31, 2021. Noverco was previously included in our Gas Distribution and Storage segment.

IMPAIRMENT OF EQUITY INVESTMENTS

PennEast Pipeline Company, LLC

PennEast Pipeline Company, LLC (PennEast) is a joint venture formed to develop a natural gas transmission pipeline to serve local distribution companies and power generators in Southeastern Pennsylvania and New Jersey, is owned 20% by Enbridge, and is recorded as an equity method investment. In the third quarter of 2021, PennEast determined further development of the project was no longer viable and development of the project was ceased. As a result, we recorded an other-than-temporary impairment loss of $111 million on our investment for the year ended December 31, 2021 based on the estimated fair value of our share of the net assets. The carrying value of this investment as at December 31, 2021 and 2020 was $12 million and $116 million, respectively.

Steckman Ridge, LP
Steckman Ridge, LP (Steckman Ridge) is engaged in the storage of natural gas, is owned 50% by Enbridge and is recorded as an equity method investment. During the year ended December 31, 2020, Steckman Ridge's forecasted performance was adjusted for the expectation that future available capacity will be re-contracted at lower than expected rates and an other than temporary impairment loss on our investment of $221 million for the year ended December 31, 2020 was recorded based on a discounted cash flow analysis. The carrying value of this investment as at December 31, 2021 and 2020 was $88 million and $90 million, respectively.

Southeast Supply Header, L.L.C.
Southeast Supply Header, L.L.C. (SESH) provides natural gas transmission services from east Texas and northern Louisiana to the southeast markets of the Gulf Coast. SESH is owned 50% by Enbridge and is recorded as an equity method investment. The forecasted performance of SESH was revised during the year ended December 31, 2020 to reflect downward revisions to future negotiated rates as well as higher than expected available capacity levels, caused primarily by a significant contract expiry. An other than temporary impairment loss on our investment of $394 million for the year ended December 31, 2020 was recorded based on a discounted cash flow analysis. The carrying value of this investment as at December 31, 2021 and 2020 was $82 million and $84 million, respectively.

DCP Midstream, LLC
DCP Midstream, a 50% owned equity method investment of Enbridge, holds an equity interest in DCP Midstream, LP. A decline in the market price of DCP Midstream, LP's publicly traded units during the first quarter of 2020 resulted in an other than temporary impairment loss on our investment in DCP Midstream of $1.7 billion for the year ended December 31, 2020. In addition, we incurred losses of $324 million through our equity earnings pick up in relation to asset and goodwill impairment losses recorded by DCP Midstream, LP. The carrying value of our investment in DCP Midstream as at December 31, 2021 and 2020 was $397 million and $331 million, respectively.

Our investments in PennEast, Steckman, SESH and DCP Midstream form part of our Gas Transmission and Midstream segment. The impairment losses were recorded within Impairment of Equity Investments in the Consolidated Statements of Earnings.

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 US and Canada.

As at December 31, 2021 and 2020, we had restricted long-term investments held in trust and classified as available-for-sale of $630 million and $553 million, respectively. The cost basis of our debt securities classified as available-for-sale and recorded as part of our restricted long-term investment balance was $383 million and $322 million as at December 31, 2021 and 2020, respectively. Within Other long-term liabilities we had estimated future abandonment costs related to LMCI of $649 million and $578 million as at December 31, 2021 and 2020, respectively *(Note 7)*.

15. INTANGIBLE ASSETS

December 31, 2021	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	12.0 %	**2,067**	**(1,148)**	**919**
Power purchase agreements	4.5 %	**63**	**(21)**	**42**
Project agreement[1]	4.0 %	**152**	**(27)**	**125**
Customer relationships	8.5 %	**2,532**	**(215)**	**2,317**
Other intangible assets	3.9 %	**475**	**(116)**	**359**
Under development	— %	**246**	**—**	**246**
		5,535	**(1,527)**	**4,008**

December 31, 2020	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	10.5 %	2,043	(1,299)	744
Power purchase agreements	4.5 %	63	(18)	45
Project agreement[1]	4.0 %	153	(21)	132
Customer relationships	5.0 %	724	(139)	585
Other intangible assets	2.7 %	456	(96)	360
Under development	— %	214	—	214
		3,653	(1,573)	2,080

1 Represents a project agreement acquired from the merger of Enbridge and Spectra Energy.

For the years ended December 31, 2021, 2020 and 2019, our amortization expense related to intangible assets totaled $348 million, $294 million and $296 million, respectively. Our expected amortization expense associated with existing intangible assets for each of the years 2022 to 2026 is $492 million.

16. GOODWILL

	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Energy Services	Consolidated
(millions of Canadian dollars)					
Balance at January 1, 2020	7,951	19,844	5,356	2	33,153
Foreign exchange and other	(123)	(364)	—	—	(487)
Acquisition	—	—	22	—	22
Balance at December 31, 2020[1,2]	7,828	19,480	5,378	2	32,688
Foreign exchange and other	**(55)**	**(145)**	**—**	**—**	**(200)**
Acquisition[3]	**268**	**—**	**19**	**—**	**287**
Balance at December 31, 2021[1,2]	**8,041**	**19,335**	**5,397**	**2**	**32,775**

1 Gross cost of goodwill as at December 31, 2021 and 2020 was $34.4 billion and $34.3 billion, respectively.
2 Accumulated impairment as at December 31, 2021 and 2020 was $1.6 billion.
3 In 2021, we recorded $268 million of goodwill related to the acquisition of Moda. See Note 8 - Acquisitions and Dispositions for further discussion.

17. ACCOUNTS PAYABLE AND OTHER

December 31,	**2021**	2020
(millions of Canadian dollars)		
Trade payables and operating accrued liabilities	**4,470**	3,497
Dividends payable	**1,773**	1,728
Current deferred credits	**853**	978
Construction payables and contractor holdbacks	**844**	855
Current derivative liabilities *(Note 24)*	**717**	896
Taxes payable	**478**	622
Other	**632**	652
	9,767	9,228

18. DEBT

December 31,	Weighted Average Interest Rate[9]	Maturity	**2021**	2020
(millions of Canadian dollars)				
Enbridge Inc.				
US dollar senior notes	3.2 %	2022 - 2051	**10,992**	8,536
Medium-term notes	3.9 %	2022 - 2064	**8,123**	8,323
Sustainability-linked bonds	1.1 %	2033	**2,363**	—
Fixed-to-fixed subordinated term notes[1]	5.8 %	2080	**1,263**	1,274
Fixed-to-floating rate subordinated term notes[2]	5.8 %	2023 - 2028	**6,442**	6,477
Floating rate notes[3]		2022 - 2023	**1,579**	956
Commercial paper and credit facility draws	1.0 %	2022 - 2026	**7,837**	8,719
Other[4]			**5**	5
Enbridge (U.S.) Inc.				
Commercial paper and credit facility draws	0.4 %	2023 - 2026	**4,845**	492
Other[4]			**7**	7
Enbridge Energy Partners, L.P.				
Senior notes	6.5 %	2025 - 2045	**3,095**	3,886
Enbridge Gas Inc.				
Medium-term notes	3.8 %	2022 - 2051	**9,010**	8,485
Debentures	9.1 %	2024 - 2025	**210**	210
Commercial paper and credit facility draws	0.5 %	2023	**1,515**	1,121
Enbridge Pipelines (Southern Lights) L.L.C.				
Senior notes	4.0 %	2040	**949**	1,038
Enbridge Pipelines Inc.				
Medium-term notes[5]	4.0 %	2022 - 2051	**5,575**	4,775
Debentures	8.2 %	2024	**200**	200
Commercial paper and credit facility draws	0.7 %	2023	**667**	1,278
Enbridge Southern Lights LP				
Senior notes	4.0 %	2040	**240**	257
Spectra Energy Capital, LLC				
Senior notes	7.0 %	2032 - 2038	**218**	220
Spectra Energy Partners, LP				
Senior notes	3.9 %	2022 - 2048	**8,451**	8,332
Westcoast Energy Inc.				
Medium-term notes	4.5 %	2022 - 2041	**1,475**	1,625
Debentures	8.1 %	2025 - 2026	**275**	275
Fair value adjustment			**667**	750
Other[6]			**(363)**	(344)
Total debt[7]			**75,640**	66,897
Current maturities			**(6,164)**	(2,957)
Short-term borrowings[8]			**(1,515)**	(1,121)
Long-term debt			**67,961**	62,819

1 *For the initial 10 years, the notes carry a fixed interest rate. Subsequently, the interest rate will be set to equal to the Five-Year US Treasury Rate plus a margin of 5.31% from years 10 to 30 and a margin of 6.06% from years 30 to 60.*
2 *For the initial 10 years, the notes carry a fixed interest rate. Subsequently, the interest rate will be floating and set to equal to the Canadian Dollar Offered Rate (CDOR) or the London Interbank Offered Rate (LIBOR) plus a margin. The notes would be converted automatically into Conversion Preference Shares in the event of bankruptcy and related events.*
3 *The notes carry an interest rate equal to the three-month LIBOR plus a margin of 50 basis points and Secured Overnight Financing Rate (SOFR) plus a margin of 40 basis points.*
4 *Primarily finance lease obligations.*
5 *Included in medium-term notes is $100 million with a maturity date of 2112.*
6 *Primarily unamortized discounts, premiums and debt issuance costs.*
7 *2021 - $36 billion and US$31 billion; 2020 - $35 billion and US$24 billion. Totals exclude capital lease obligations, unamortized discounts, premiums and debt issuance costs and fair value adjustment.*
8 *Weighted average interest rates on outstanding commercial paper were 0.5% as at December 31, 2021 (2020 - 0.3%).*
9 *Calculated based on term notes, debentures, commercial paper and credit facility draws outstanding as at December 31, 2021.*

As at December 31, 2021, all outstanding debt was unsecured.

CREDIT FACILITIES

The following table provides details of our committed credit facilities as at December 31, 2021:

	Maturity[1]	Total Facilities	Draws[2]	Available
(millions of Canadian dollars)				
Enbridge Inc.	2022-2026	**9,137**	**7,837**	**1,300**
Enbridge (U.S.) Inc.	2023-2026	**6,948**	**4,845**	**2,103**
Enbridge Pipelines Inc.	2023	**3,000**	**667**	**2,333**
Enbridge Gas Inc.	2023	**2,000**	**1,515**	**485**
Total committed credit facilities		**21,085**	**14,864**	**6,221**

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

On February 10, 2021, Enbridge Inc. entered into a three year, revolving, extendible, sustainability-linked credit facility for $1.0 billion with a syndicate of lenders and concurrently terminated our one year, revolving, syndicated credit facility for $3.0 billion.

On February 25, 2021, two term loans with an aggregate total of US$500 million were repaid with proceeds from a floating rate notes issuance.

On July 22 and 23, 2021, we renewed approximately $8.0 billion of our five-year credit facilities, extending the maturity date out to July 2026. We also extended approximately $10.0 billion of our 364-day extendible credit facilities to July 2022, which includes a one-year term out provision to July 2023.

On February 10, 2022 we renewed our three year $1.0 billion sustainability-linked credit facility, extending the maturity date out to July 2025.

In addition to the committed credit facilities noted above, we maintain $1.3 billion of uncommitted demand letter of credit facilities, of which $854 million was unutilized as at December 31, 2021. As at December 31, 2020, we had $849 million of uncommitted demand letter of credit facilities, of which $533 million was 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 2022 to 2026.

As at December 31, 2021 and 2020, commercial paper and credit facility draws, net of short-term borrowings and non-revolving credit facilities that mature within one year, of $11.3 billion and $9.9 billion, respectively, were 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 year ended December 31, 2021, we completed the following long-term debt issuances totaling US$3.9 billion and $3.2 billion:

Company	Issue Date		Principal Amount
(millions of Canadian dollars unless otherwise stated)			
Enbridge Inc.			
	February 2021	Floating rate senior-notes due February 2023[1]	US$500
	June 2021	2.50% Sustainability-linked senior notes due August 2033	US$1,000
	June 2021	3.40% senior notes due August 2051	US$500
	September 2021	3.10% Sustainability-linked medium-term notes due September 2033	$1,100
	September 2021	4.10% medium-term notes due September 2051	$400
	October 2021	0.55% senior notes due October 2023	US$500
	October 2021	1.60% senior notes due October 2026	US$500
	October 2021	3.40% senior notes due August 2051	US$500
Enbridge Gas Inc.			
	September 2021	2.35% medium-term notes due September 2031	$475
	September 2021	3.20% medium-term notes due September 2051	$425
Enbridge Pipelines Inc.			
	May 2021	2.82% medium-term notes due May 2031	$400
	May 2021	4.20% medium-term notes due May 2051	$400
Spectra Energy Partners, LP			
	September 2021	2.50% senior notes due September 2031[2]	US$400

1 Notes carry an interest rate equal to the SOFR plus a margin of 40 basis points.
2 Issued through Texas Eastern Transmission, LP, a wholly-owned operating subsidiary of SEP.

On January 19, 2022, we closed a $750 million private placement offering of non-call 10-year fixed-to-fixed subordinated notes which mature on January 19, 2082. The net proceeds from the offering will be used to redeem the Preference Shares, Series 17 at par on March 1, 2022.

LONG-TERM DEBT REPAYMENTS

During the year ended December 31, 2021, we completed the following long-term debt repayments totaling $1.1 billion and US$914 million, respectively:

Company	Repayment Date		Principal Amount
(millions of Canadian dollars unless otherwise stated)			
Enbridge Inc.			
	February 2021	4.26% medium-term notes	$200
	March 2021	3.16% medium-term notes	$400
Enbridge Energy Partners, L.P.			
	June 2021	4.20% senior notes	US$600
Enbridge Gas Inc.			
	May 2021	2.76% medium-term notes	$200
	December 2021	4.77% medium-term notes	$175
Enbridge Pipelines (Southern Lights) L.L.C.			
	June and December 2021	3.98% senior notes	US$64
Enbridge Southern Lights LP			
	June and December 2021	4.01% senior notes	$16
Spectra Energy Partners, LP			
	March 2021	4.60% senior notes	US$250
Westcoast Energy Inc.			
	October 2021	3.88% medium-term notes	$150

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, 2021, we were in compliance with all debt covenants.

INTEREST EXPENSE

Year ended December 31,	**2021**	2020	2019
(millions of Canadian dollars)			
Debentures and term notes	**2,850**	2,913	2,783
Commercial paper and credit facility draws	**70**	123	273
Amortization of fair value adjustment	**(50)**	(54)	(67)
Capitalized interest	**(215)**	(192)	(326)
	2,655	2,790	2,663

19. ASSET RETIREMENT OBLIGATIONS

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

The discount rates used to estimate the present value of the expected future cash flows for the year ended December 31, 2021 ranged from 0.9% to 9.0% (2020 - 1.8% to 9.0%).

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

December 31,	**2021**	2020
(millions of Canadian dollars)		
Obligations at beginning of year	**496**	520
Liabilities disposed	**—**	—
Liabilities incurred	**—**	—
Liabilities settled	**(67)**	(30)
Change in estimate and other	**70**	—
Foreign currency translation adjustment	**(3)**	(6)
Accretion expense	**6**	12
Obligations at end of year	**502**	496
Presented as follows:		
Accounts payable and other	**160**	56
Other long-term liabilities	**342**	440
	502	496

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,	**2021**	2020
(millions of Canadian dollars)		
Algonquin Gas Transmission, L.L.C	**377**	384
Maritimes & Northeast Pipeline, L.L.C	**546**	558
Renewable energy assets	**1,503**	1,646
Westcoast Energy Inc.[1]	**116**	408
	2,542	2,996

1 Includes nil and 12 million cumulative redeemable preferred shares as at December 31, 2021 and 2020, respectively.

Westcoast Energy Inc. Preferred Shares Redemption

On March 20, 2019, Westcoast Energy Inc. (Westcoast) 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 per Series 7 Share and $25 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 for the year ended December 31, 2019.

On January 15, 2021, Westcoast redeemed its Cumulative Five-Year Minimum Rate Reset Redeemable First Preferred Shares, Series 10 with a par value of $115 million. The par value of $115 million was included in Accounts payable and other in the Consolidated Statements of Financial Position as at December 31, 2020.

On October 15, 2021, Westcoast redeemed its Cumulative Five-Year Minimum Rate Reset Redeemable First Preferred Shares, Series 12 with a par value of $300 million. As a result, we recorded a decrease of $293 million, which represents the par value less related issuance costs, in Noncontrolling interests for the year ended December 31, 2021.

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

	2021		2020		2019	
December 31,	Number Shares	Amount	Number Shares	Amount	Number of Shares	Amount
(millions of Canadian dollars; number of shares in millions)						
Balance at beginning of year	**2,026**	**64,768**	2,025	64,746	2,022	64,677
Shares issued on exercise of stock options	**—**	**31**	1	22	3	69
Balance at end of year	**2,026**	**64,799**	2,026	64,768	2,025	64,746

PREFERENCE SHARES

December 31,	2021 Number of Shares	2021 Amount	2020 Number of Shares	2020 Amount	2019 Number of Shares	2019 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:

(Canadian dollars unless otherwise stated)	Dividend Rate	Dividend[1]	Per Share Base Redemption Value[2]	Redemption and Conversion Option Date[2,3]	Right to Convert Into[3,4]
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	4.38 %	$1.09476	$25	March 1, 2024	Series Q
Preference Shares, Series R	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	3.74 %	$0.93425	$25	September 1, 2024	Series 4
Preference Shares, Series 5	5.38 %	US$1.34383	US$25	March 1, 2024	Series 6
Preference Shares, Series 7	4.45 %	$1.11224	$25	March 1, 2024	Series 8
Preference Shares, Series 9	4.10 %	$1.02424	$25	December 1, 2024	Series 10
Preference Shares, Series 11	3.94 %	$0.98452	$25	March 1, 2025	Series 12
Preference Shares, Series 13	3.04 %	$0.76076	$25	June 1, 2025	Series 14
Preference Shares, Series 15	2.98 %	$0.74576	$25	September 1, 2025	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/number of days in a year) x three-month 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/ number of days in a year) x three-month US Government treasury bill rate + 3.1% (Series K), 3.2% (Series M), 3.1% (Series 2) or 2.8% (Series 6).

5 The floating quarterly dividend amount for the Series C Preference Shares was increased to $0.15501 from $0.15349 on March 1, 2021, was increased to $0.15753 from $0.15501 on June 1, 2021, was increased to $0.16081 from $0.15753 on September 1, 2021 and was decreased to $0.15719 from $0.16081 on December 1, 2021, due to reset on a quarterly basis following the issuance thereof.

PREFERENCE SHARE REDEMPTION

We intend to exercise our right to redeem all of our outstanding cumulative redeemable minimum rate reset preference shares, Series 17, on March 1, 2022 at a price of $25 per Series 17 share, together with all accrued and unpaid dividends, if any.

SHAREHOLDER RIGHTS PLAN

The Shareholder Rights Plan is designed to encourage the fair treatment of our shareholders in connection with any takeover offer. 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 three long-term incentive compensation plans: the ISO Plan, the PSU Plan and the RSU Plan. Total stock-based compensation expense recorded for the years ended December 31, 2021, 2020 and 2019 was $157 million, $145 million and $117 million, respectively. Disclosure of activity and assumptions for material stock-based compensation plans are included below.

INCENTIVE STOCK OPTIONS

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

December 31, 2021	Number	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value
(options in thousands; intrinsic value in millions of Canadian dollars; weighted average exercise price in Canadian dollars)				
Options outstanding at beginning of year	**35,494**	**48.65**		
Options granted	**4,072**	**43.86**		
Options exercised[1]	**(4,142)**	**41.85**		
Options cancelled or expired	**(1,407)**	**50.74**		
Options outstanding at end of year	**34,017**	**49.28**	**5.7**	**128**
Options vested at end of year[2]	**22,029**	**49.84**	**4.5**	**64**

1 *The total intrinsic value of ISOs exercised during the years ended December 31, 2021, 2020 and 2019 was $24 million, $13 million and $58 million, respectively, and cash received on exercise was $2 million, $4 million and $1 million, respectively.*

2 *The total fair value of ISOs exercised during the years ended December 31, 2021, 2020 and 2019 was $25 million, $30 million and $32 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,	**2021**	2020	2019
Fair value per option *(Canadian dollars)*[1]	**4.10**	4.01	4.37
Valuation assumptions			
Expected option term *(years)*[2]	**6**	6	5
Expected volatility[3]	**25.5 %**	18.3 %	19.9 %
Expected dividend yield[4]	**7.6 %**	5.9 %	6.1 %
Risk-free interest rate[5]	**0.7 %**	1.3 %	2.0 %

1 Options granted to US employees are based on NYSE prices. The option value and assumptions shown are based on a weighted average of the US and the Canadian options. The fair values per option for the years ended December 31, 2021, 2020 and 2019 were $3.91, $3.75 and $4.04, respectively, for Canadian employees and US$3.65, US$3.62 and US$4.09, respectively, for US employees.

2 The expected option term is six years based on historical exercise practice and five 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 US Treasury Bond Yields.

Compensation expense recorded for the years ended December 31, 2021, 2020 and 2019 for ISOs was $16 million, $24 million and $32 million, respectively. As at December 31, 2021, unrecognized compensation expense related to non-vested stock-based compensation arrangements granted under the ISO Plan was $11 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 Enbridge'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 the performance targets. The performance multiplier is derived through a calculation of our Total Shareholder Return percentile rank, in each case relative to a specified peer group of companies and our distributable cash flow per share, adjusted for unusual, non-operating or non-recurring items, relative to targets established at the time of grant. To calculate the 2021 expense, a multiplier of 0.5 was used for 2021 PSU grants, 0.5 for 2020 PSU grants and 1.3 for the 2019 PSU grants.

December 31, 2021	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	**3,056**		
Units granted	**1,895**		
Units cancelled	**(76)**		
Units matured[1]	**(1,664)**		
Dividend reinvestment	**218**		
Units outstanding at end of year	**3,429**	**1.1**	**181**

1 The total amount paid during the years ended December 31, 2021, 2020 and 2019 for PSUs was $70 million, $14 million and $19 million, respectively.

Compensation expense recorded for the years ended December 31, 2021, 2020 and 2019 for PSUs was $56 million, $76 million and $40 million, respectively. As at December 31, 2021, unrecognized compensation expense related to non-vested PSUs was $31 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 vesting in equal installments on each of the first, second and third anniversaries of the grant date. Share settled awards are given to certain senior management employees following a three year maturity period. RSU holders receive cash or shares 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, 2021	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	**2,453**		
Units granted	**1,514**		
Units cancelled	**(75)**		
Units matured[1]	**(1,433)**		
Dividend reinvestment	**246**		
Units outstanding at end of year	**2,705**	**1.1**	**129**

1 *The total amount paid during the years ended December 31, 2021, 2020 and 2019 for RSUs was $72 million, $27 million and $34 million, respectively.*

Compensation expense recorded for the years ended December 31, 2021, 2020 and 2019 for RSUs was $85 million, $44 million and $41 million, respectively. As at December 31, 2021, unrecognized compensation expense related to non-vested RSUs was $62 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, 2021, 2020 and 2019 are as follows:

	Cash Flow Hedges	Excluded Components of Fair Value Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Adjustment	Total
(millions of Canadian dollars)							
Balance at January 1, 2021	**(1,326)**	**5**	**(215)**	**568**	**66**	**(499)**	**(1,401)**
Other comprehensive income/(loss) retained in AOCI	**238**	**(5)**	**49**	**(492)**	**(12)**	**520**	**298**
Other comprehensive (income)/loss reclassified to earnings							
Interest rate contracts[1]	**296**	**—**	**—**	**—**	**—**	**—**	**296**
Commodity contracts[2]	**1**	**—**	**—**	**—**	**—**	**—**	**1**
Foreign exchange contracts[3]	**5**	**—**	**—**	**—**	**—**	**—**	**5**
Other contracts[4]	**2**	**—**	**—**	**—**	**—**	**—**	**2**
Equity investment disposal	**—**	**—**	**—**	**—**	**(66)**	**—**	**(66)**
Amortization of pension and OPEB actuarial loss and prior service costs[5]	**—**	**—**	**—**	**—**	**—**	**28**	**28**
Other	**17**	**—**	**—**	**(20)**	**3**	**—**	**—**
	559	**(5)**	**49**	**(512)**	**(75)**	**548**	**564**
Tax impact							
Income tax on amounts retained in AOCI	**(61)**	**—**	**—**	**—**	**—**	**(126)**	**(187)**
Income tax on amounts reclassified to earnings	**(69)**	**—**	**—**	**—**	**4**	**(7)**	**(72)**
	(130)	**—**	**—**	**—**	**4**	**(133)**	**(259)**
Balance at December 31, 2021	**(897)**	**—**	**(166)**	**56**	**(5)**	**(84)**	**(1,096)**

	Cash Flow Hedges	Excluded Components of Fair Value Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Adjustment	Total
(millions of Canadian dollars)							
Balance at January 1, 2020	(1,073)	—	(317)	1,396	67	(345)	(272)
Other comprehensive income/(loss) retained in AOCI	(591)	5	115	(828)	(2)	(221)	(1,522)
Other comprehensive (income)/loss reclassified to earnings							
Interest rate contracts[1]	253	—	—	—	—	—	253
Foreign exchange contracts[3]	5	—	—	—	—	—	5
Other contracts[4]	(2)	—	—	—	—	—	(2)
Amortization of pension and OPEB actuarial loss and prior service costs[5]	—	—	—	—	—	17	17
	(335)	5	115	(828)	(2)	(204)	(1,249)
Tax impact							
Income tax on amounts retained in AOCI	140	—	(13)	—	1	54	182
Income tax on amounts reclassified to earnings	(58)	—	—	—	—	(4)	(62)
	82	—	(13)	—	1	50	120
Balance at December 31, 2020	(1,326)	5	(215)	568	66	(499)	(1,401)

	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)

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

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

3 Reported within Transportation and other services revenue and Net foreign currency gain 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.

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 US dollar denominated investments and subsidiaries using foreign currency derivatives and US 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 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 3.9%.

We are exposed to changes in the fair value of fixed rate debt that arise as a result of 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 fair value via execution of fixed to floating interest rate swaps. As at December 31, 2021, 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 including 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 2.0%.

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.

December 31, 2021	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment Hedges	Derivative Instruments Used as Fair Value Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)							
Accounts receivable and other							
Foreign exchange contracts	**—**	**—**	**—**	**259**	**259**	**(41)**	**218**
Interest rate contracts	**64**	**—**	**—**	**—**	**64**	**—**	**64**
Commodity contracts	**—**	**—**	**—**	**204**	**204**	**(129)**	**75**
Other contracts	**—**	**—**	**—**	**2**	**2**	**—**	**2**
	64	**—**	**—**	**465**	**529**	**(170)**	**359**
Deferred amounts and other assets							
Foreign exchange contracts	**—**	**—**	**—**	**240**	**240**	**(61)**	**179**
Interest rate contracts	**88**	**—**	**—**	**—**	**88**	**(1)**	**87**
Commodity contracts	**—**	**—**	**—**	**29**	**29**	**(13)**	**16**
Other contracts	**—**	**—**	**—**	**3**	**3**	**—**	**3**
	88	**—**	**—**	**272**	**360**	**(75)**	**285**
Accounts payable and other							
Foreign exchange contracts	**(15)**	**—**	**(112)**	**(176)**	**(303)**	**41**	**(262)**
Interest rate contracts	**(150)**	**—**	**—**	**—**	**(150)**	**—**	**(150)**
Commodity contracts	**(14)**	**—**	**—**	**(250)**	**(264)**	**129**	**(135)**
Other contracts	**—**	**—**	**—**	**—**	**—**	**—**	**—**
	(179)	**—**	**(112)**	**(426)**	**(717)**	**170**	**(547)**
Other long-term liabilities							
Foreign exchange contracts	**—**	**—**	**—**	**(423)**	**(423)**	**61**	**(362)**
Interest rate contracts	**(1)**	**—**	**—**	**(23)**	**(24)**	**1**	**(23)**
Commodity contracts	**(17)**	**—**	**—**	**(67)**	**(84)**	**13**	**(71)**
Other contracts	**—**	**—**	**—**	**—**	**—**	**—**	**—**
	(18)	**—**	**—**	**(513)**	**(531)**	**75**	**(456)**
Total net derivative asset/(liability)							
Foreign exchange contracts	**(15)**	**—**	**(112)**	**(100)**	**(227)**	**—**	**(227)**
Interest rate contracts	**1**	**—**	**—**	**(23)**	**(22)**	**—**	**(22)**
Commodity contracts	**(31)**	**—**	**—**	**(84)**	**(115)**	**—**	**(115)**
Other contracts	**—**	**—**	**—**	**5**	**5**	**—**	**5**
	(45)	**—**	**(112)**	**(202)**	**(359)**	**—**	**(359)**

December 31, 2020	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment Hedges	Derivative Instruments Used as Fair Value Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)							
Accounts receivable and other							
Foreign exchange contracts	—	—	—	180	180	(28)	152
Interest rate contracts	—	—	—	—	—	—	—
Commodity contracts	—	—	—	143	143	(81)	62
Other contracts	—	—	—	—	—	—	—
	—	—	—	323	323	(109)	214
Deferred amounts and other assets							
Foreign exchange contracts	14	—	—	452	466	(218)	248
Interest rate contracts	56	—	—	—	56	(25)	31
Commodity contracts	—	—	—	39	39	(9)	30
Other contracts	—	—	—	—	—	—	—
	70	—	—	491	561	(252)	309
Accounts payable and other							
Foreign exchange contracts	(5)	—	(29)	(151)	(185)	28	(157)
Interest rate contracts	(423)	—	—	(2)	(425)	—	(425)
Commodity contracts	(2)	—	—	(278)	(280)	81	(199)
Other contracts	(1)	—	—	(3)	(4)	—	(4)
	(431)	—	(29)	(434)	(894)	109	(785)
Other long-term liabilities							
Foreign exchange contracts	—	—	(87)	(673)	(760)	218	(542)
Interest rate contracts	(218)	—	—	(23)	(241)	25	(216)
Commodity contracts	(1)	—	—	(57)	(58)	9	(49)
Other contracts	—	—	—	—	—	—	—
	(219)	—	(87)	(753)	(1,059)	252	(807)
Total net derivative asset/(liability)							
Foreign exchange contracts	9	—	(116)	(192)	(299)	—	(299)
Interest rate contracts	(585)	—	—	(25)	(610)	—	(610)
Commodity contracts	(3)	—	—	(153)	(156)	—	(156)
Other contracts	(1)	—	—	(3)	(4)	—	(4)
	(580)	—	(116)	(373)	(1,069)	—	(1,069)

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

	2021							2020
As at December 31,	2022	2023	2024	2025	2026	Thereafter	Total	Total
Foreign exchange contracts - US dollar forwards - purchase *(millions of US dollars)*	**2,508**	**—**	**—**	**—**	**—**	**—**	**2,508**	3,522
Foreign exchange contracts - US dollar forwards - sell *(millions of US dollars)*	**9,245**	**5,596**	**4,346**	**3,174**	**2,574**	**492**	**25,427**	17,859
Foreign exchange contracts - British pound (GBP) forwards - sell *(millions of GBP)*	**28**	**29**	**30**	**30**	**28**	**32**	**177**	265
Foreign exchange contracts - Euro forwards - sell *(millions of Euro)*	**104**	**92**	**91**	**86**	**85**	**343**	**801**	885
Foreign exchange contracts - Japanese yen forwards - purchase *(millions of yen)*	**72,500**	**—**	**—**	**—**	**—**	**—**	**72,500**	72,500
Interest rate contracts - short-term pay fixed rate *(millions of Canadian dollars)*	**395**	**47**	**35**	**30**	**26**	**64**	**597**	4,635
Interest rate contracts - long-term pay fixed rate *(millions of Canadian dollars)*	**2,363**	**1,784**	**1,132**	**—**	**—**	**—**	**5,279**	5,396
Equity contracts *(millions of Canadian dollars)*	**20**	**26**	**21**	**—**	**—**	**—**	**67**	62
Commodity contracts - natural gas *(billions of cubic feet)*	**165**	**18**	**5**	**11**	**—**	**—**	**199**	173
Commodity contracts - crude oil *(millions of barrels)*	**12**	**—**	**—**	**—**	**—**	**—**	**12**	15
Commodity contracts - power *(megawatt per hour (MW/H)*	**(43)**	**(43)**	**(43)**	**(43)**	**—**	**—**	**(43)** [1]	(35) [1]

1 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:

	2021	2020	2019
(millions of Canadian dollars)			
Amount of unrealized gain/(loss) recognized in OCI			
Cash flow hedges			
Foreign exchange contracts	**(29)**	(1)	(19)
Interest rate contracts	**252**	(595)	(559)
Commodity contracts	**(28)**	2	(25)
Other contracts	**1**	(3)	10
Fair value hedges			
Foreign exchange contracts	**(5)**	5	—
Net investment hedges			
Foreign exchange contracts	**—**	13	2
	191	(579)	(591)
Amount of (gain)/loss reclassified from AOCI to earnings			
Foreign exchange contracts[1]	**5**	5	5
Interest rate contracts[2]	**296**	253	157
Commodity contracts[3]	**1**	—	(1)
Other contracts[4]	**2**	(2)	(3)
	304	256	158

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

We estimate that a loss of $47 million from AOCI related to cash flow hedges will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the foreign exchange rates, interest rates and commodity prices in effect when derivative contracts that are currently outstanding mature. For all forecasted transactions, the maximum term over which we are hedging exposures to the variability of cash flows is 36 months as at December 31, 2021.

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,	**2021**	2020
(millions of Canadian dollars)		
Unrealized gain/(loss) on derivative	**8**	(116)
Unrealized gain/(loss) on hedged item	**(15)**	133
Realized loss on derivative	**(41)**	(12)
Realized gain on hedged item	**45**	—

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,	**2021**	2020	2019
(millions of Canadian dollars)			
Foreign exchange contracts[1]	**92**	902	1,626
Interest rate contracts[2]	**2**	(25)	178
Commodity contracts[3]	**71**	(114)	(62)
Other contracts[4]	**8**	(7)	9
Total unrealized derivative fair value gain/(loss), net	**173**	756	1,751

1 *For the respective annual periods, reported within Transportation and other services revenue (2021 - $98 million gain; 2020 - $533 million gain; 2019 - $930 million gain) and Net foreign currency gain/(loss) (2021 - $6 million loss; 2020 - $369 million gain; 2019 - $696 million gain) in the Consolidated Statements of Earnings.*

2 *Reported as an increase within Interest expense in the Consolidated Statements of Earnings.*

3 *For the respective annual periods, reported within Transportation and other services revenue (2021 - $9 million gain; 2020 - $2 million loss; 2019 - $26 million loss), Commodity sales (2021 - $160 million gain; 2020 - $321 million loss; 2019 - $544 million loss), Commodity costs (2021 - $105 million loss; 2020 - $207 million gain; 2019 - $459 million gain) and Operating and administrative expense (2021 - $7 million gain; 2020 - $2 million gain; 2019 - $49 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 US 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, 2021. 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,	**2021**	2020
(millions of Canadian dollars)		
Canadian financial institutions	**424**	481
US financial institutions	**130**	99
European financial institutions	**181**	28
Asian financial institutions	**30**	167
Other[1]	**122**	97
	887	872

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

As at December 31, 2021, 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, 2021 and December 31, 2020.

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 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 physical forward commodity contracts. 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, 2021	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	**—**	**259**	**—**	**259**
Interest rate contracts	**—**	**64**	**—**	**64**
Commodity contracts	**38**	**71**	**95**	**204**
Other contracts	**—**	**2**	**—**	**2**
	38	**396**	**95**	**529**
Long-term derivative assets				
Foreign exchange contracts	**—**	**240**	**—**	**240**
Interest rate contracts	**—**	**88**	**—**	**88**
Commodity contracts	**—**	**21**	**8**	**29**
Other contracts	**—**	**3**	**—**	**3**
	—	**352**	**8**	**360**
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	**—**	**(303)**	**—**	**(303)**
Interest rate contracts	**—**	**(150)**	**—**	**(150)**
Commodity contracts	**(52)**	**(66)**	**(146)**	**(264)**
Other contracts	**—**	**—**	**—**	**—**
	(52)	**(519)**	**(146)**	**(717)**
Long-term derivative liabilities				
Foreign exchange contracts	**—**	**(423)**	**—**	**(423)**
Interest rate contracts	**—**	**(24)**	**—**	**(24)**
Commodity contracts	**—**	**(19)**	**(65)**	**(84)**
Other contracts	**—**	**—**	**—**	**—**
	—	**(466)**	**(65)**	**(531)**
Total net financial asset/(liability)				
Foreign exchange contracts	**—**	**(227)**	**—**	**(227)**
Interest rate contracts	**—**	**(22)**	**—**	**(22)**
Commodity contracts	**(14)**	**7**	**(108)**	**(115)**
Other contracts	**—**	**5**	**—**	**5**
	(14)	**(237)**	**(108)**	**(359)**

December 31, 2020	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	—	180	—	180
Interest rate contracts	—	—	—	—
Commodity contracts	43	33	67	143
Other contracts	—	—	—	—
	43	213	67	323
Long-term derivative assets				
Foreign exchange contracts	—	466	—	466
Interest rate contracts	—	56	—	56
Commodity contracts	1	24	14	39
Other contracts	—	—	—	—
	1	546	14	561
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	—	(185)	—	(185)
Interest rate contracts	—	(425)	—	(425)
Commodity contracts	(39)	(18)	(223)	(280)
Other contracts	—	(4)	—	(4)
	(39)	(632)	(223)	(894)
Long-term derivative liabilities				
Foreign exchange contracts	—	(760)	—	(760)
Interest rate contracts	—	(241)	—	(241)
Commodity contracts	(1)	(8)	(49)	(58)
Other contracts	—	—	—	—
	(1)	(1,009)	(49)	(1,059)
Total net financial asset/(liability)				
Foreign exchange contracts	—	(299)	—	(299)
Interest rate contracts	—	(610)	—	(610)
Commodity contracts	4	31	(191)	(156)
Other contracts	—	(4)	—	(4)
	4	(882)	(191)	(1,069)

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

December 31, 2021	Fair Value	Unobservable Input	Minimum Price	Maximum Price	Weighted Average Price	Unit of Measurement
(fair value in millions of Canadian dollars)						
Commodity contracts - financial[1]						
Natural gas	**(19)**	**Forward gas price**	**3.12**	**9.05**	**4.49**	**$/mmbtu[2]**
Crude	**3**	**Forward crude price**	**76.02**	**98.99**	**91.73**	**$/barrel**
Power	**(60)**	**Forward power price**	**31.00**	**125.13**	**76.23**	**$/MW/H**
Commodity contracts - physical[1]						
Natural gas	**(56)**	**Forward gas price**	**2.65**	**9.25**	**4.63**	**$/mmbtu[2]**
Crude	**24**	**Forward crude price**	**68.66**	**97.00**	**87.97**	**$/barrel**
	(108)					

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,	**2021**	2020
(millions of Canadian dollars)		
Level 3 net derivative liability at beginning of period	**(191)**	(69)
Total gain/(loss)		
Included in earnings[1]	**(39)**	(123)
Included in OCI	**(29)**	2
Settlements	**151**	(1)
Level 3 net derivative liability at end of period	**(108)**	(191)

1 Reported within Transportation and other services revenue, Commodity costs and Operating and administrative expenses in the Consolidated Statements of Earnings.

There were no transfers into or out of Level 3 as at December 31, 2021 or 2020.

NET INVESTMENT HEDGES

We have designated a portion of our US dollar denominated debt, as well as a portfolio of foreign exchange forward contracts, as a hedge of our net investment in US dollar denominated investments and subsidiaries.

During the years ended December 31, 2021 and 2020, we recognized unrealized foreign exchange gains of $49 million and $117 million, respectively, on the translation of US dollar denominated debt and an unrealized gain on the change in fair value of our outstanding foreign exchange forward contracts of nil and $13 million, respectively, in OCI. During the years ended December 31, 2021 and 2020, we recognized a realized loss of nil and $15 million, respectively, in OCI associated with the settlement of foreign exchange forward contracts. No realized gains or losses associated with the settlement of US dollar denominated debt that had matured during the period were recognized in OCI during the years ended December 31, 2021 and 2020.

FAIR VALUE OF OTHER FINANCIAL INSTRUMENTS

Certain long-term investments in other entities with no actively quoted prices are classified as FVMA investments and are recorded at cost less impairment. The carrying value of FVMA investments totaled $52 million as at December 31, 2021 and 2020.

We have Restricted long-term investments held in trust totaling $630 million and $553 million as at December 31, 2021 and 2020, respectively, which are recognized at fair value.

As at December 31, 2021 and 2020, our long-term debt had a carrying value of $74.4 billion and $66.1 billion, respectively, before debt issuance costs and a fair value of $82.0 billion and $75.1 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, 2021 and 2020, the non-current notes receivable had a carrying value of $1.0 billion and $1.1 billion, 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.

25. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	**2021**	2020	2019
(millions of Canadian dollars)			
Earnings before income taxes	**7,729**	4,190	7,535
Canadian federal statutory income tax rate	**15%**	15%	15%
Expected federal taxes at statutory rate	**1,159**	629	1,130
Increase/(decrease) resulting from:			
Provincial and state income taxes[1]	**228**	288	415
Foreign and other statutory rate differentials[2]	**134**	(53)	129
Effects of rate-regulated accounting[3]	**(139)**	(145)	(63)
Foreign allowable interest deductions[4]	**—**	(4)	(29)
Part VI.1 tax, net of federal Part I deduction[5]	**73**	76	78
US Minimum Tax[6]	**—**	44	67
Non-taxable portion of gain on sale of investment[7]	**(23)**	—	—
Valuation allowance[8]	**5**	(6)	26
Intercorporate investments[9]	**—**	—	(14)
Noncontrolling interests	**(17)**	(8)	(13)
Other	**(5)**	(47)	(18)
Income tax expense	**1,415**	774	1,708
Effective income tax rate	**18.3%**	18.5%	22.7%

1 The change in provincial and state income taxes from 2020 to 2021 reflects the 2020 impact of state tax apportionment and rate changes in both the US and Canada offset by the increase in earnings from US and Canadian operations in 2021.

2 The change in foreign and other statutory rate differentials from 2020 to 2021 reflects the increase in earnings from US operations partially offset by higher rate benefits from foreign operations.

3 The amount in 2019 included the federal component of the tax benefit of the write-off of regulatory assets.

4 The decrease in foreign allowable interest deductions from 2019 to 2021 was due to changes in the related loan portfolio.

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

6 There was no US Minimum Tax in 2021 as a result of tax losses from bonus tax depreciation.

7 The amount in 2021 relates to the federal impact of the gain on sale of the investment in Noverco.

8 The increase in 2021 is due to the federal component of the tax effect of a valuation allowance on additional deferred tax assets that are not more likely than not to be realized.

9 The amount in 2019 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.

COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES

Year ended December 31,	**2021**	2020	2019
(millions of Canadian dollars)			
Earnings before income taxes			
Canada	**3,399**	2,789	3,560
US	**3,336**	407	3,115
Other	**994**	994	860
	7,729	4,190	7,535
Current income taxes			
Canada	**162**	165	347
US	**80**	64	107
Other	**82**	98	98
	324	327	552
Deferred income taxes			
Canada	**344**	378	490
US	**741**	66	672
Other	**6**	3	(6)
	1,091	447	1,156
Income tax expense	**1,415**	774	1,708

COMPONENTS OF DEFERRED INCOME TAXES

Deferred income 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,	**2021**	2020
(millions of Canadian dollars)		
Deferred income tax liabilities		
Property, plant and equipment	**(8,721)**	(7,786)
Investments	**(6,097)**	(4,649)
Regulatory assets	**(1,245)**	(1,156)
Other	**(208)**	(127)
Total deferred income tax liabilities	**(16,271)**	(13,718)
Deferred income tax assets		
Financial instruments	**315**	518
Pension and OPEB plans	**110**	251
Loss carryforwards	**3,081**	2,005
Other	**1,648**	1,461
Total deferred income tax assets	**5,154**	4,235
Less valuation allowance	**(84)**	(79)
Total deferred income tax assets, net	**5,070**	4,156
Net deferred income tax liabilities	**(11,201)**	(9,562)
Presented as follows:		
Total deferred income tax assets	**488**	770
Total deferred income tax liabilities	**(11,689)**	(10,332)
Net deferred income tax liabilities	**(11,201)**	(9,562)

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, 2021, we recognized the benefit of unused tax loss carryforwards of $1.9 billion (2020 - $2.6 billion) in Canada which expire in 2026 and beyond.

As at December 31, 2021, we recognized the benefit of unused tax loss carryforwards of $11.0 billion (2020 - $5.8 billion) in the US. Unused tax loss carryforwards of $3.5 billion (2020 - $2.4 billion) begin to expire in 2023, and unused tax loss carryforwards of $7.5 billion (2020 - $3.4 billion) have no expiration.

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 $4.3 billion and $5.5 billion for the periods December 31, 2021 and 2020, 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 US and other foreign jurisdictions. The material jurisdictions in which we are subject to potential examinations include the US (Federal) and Canada (Federal, Alberta and Ontario). We are open to examination by Canadian tax authorities for the 2012 to 2021 tax years and by US tax authorities for the 2018 to 2021 tax years. We are currently under examination for income tax matters in Canada for the 2014 to 2018 tax years. We are not currently under examination for income tax matters in any other material jurisdiction where we are subject to income tax.

UNRECOGNIZED TAX BENEFITS

Year ended December 31,	**2021**	2020
(millions of Canadian dollars)		
Unrecognized tax benefits at beginning of year	**121**	129
Gross increases for tax positions of current year	**1**	1
Gross decreases for tax positions of prior year	**(26)**	(1)
Change in translation of foreign currency	**(1)**	(3)
Lapses of statute of limitations	**(19)**	(5)
Unrecognized tax benefits at end of year	**76**	121

The unrecognized tax benefits as at December 31, 2021, 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. Interest and penalties included in income taxes for the years ended December 31, 2021 and 2020 were a $5 million recovery and $3 million expense, respectively. As at December 31, 2021 and 2020, interest and penalties of $12 million and $17 million, respectively, have been accrued.

26. PENSION AND OTHER POSTRETIREMENT BENEFITS

PENSION PLANS

We sponsor Canadian and US 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 US Plans provide defined benefit pension benefits to our US employees. We also sponsor supplemental non-contributory defined benefit pension plans, which provide non-registered benefits for certain employees in Canada and the US.

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		US	
December 31,	**2021**	2020	**2021**	2020
(millions of Canadian dollars)				
Change in projected benefit obligation				
Projected benefit obligation at beginning of year	**4,855**	4,446	**1,243**	1,230
Service cost	**139**	148	**44**	44
Interest cost	**101**	128	**17**	31
Participant contributions	**28**	31	**—**	—
Actuarial (gain)/loss[1]	**(329)**	292	**(21)**	95
Benefits paid	**(194)**	(190)	**(84)**	(128)
Foreign currency exchange rate changes	**—**	—	**(11)**	(23)
Other	**—**	—	**(4)**	(6)
Projected benefit obligation at end of year[2]	**4,600**	4,855	**1,184**	1,243
Change in plan assets				
Fair value of plan assets at beginning of year	**4,077**	3,827	**1,062**	1,104
Actual return on plan assets	**505**	288	**151**	83
Employer contributions	**120**	121	**43**	27
Participant contributions	**28**	31	**—**	—
Benefits paid	**(194)**	(190)	**(84)**	(128)
Foreign currency exchange rate changes	**—**	—	**(8)**	(18)
Other	**—**	—	**(4)**	(6)
Fair value of plan assets at end of year[3]	**4,536**	4,077	**1,160**	1,062
Underfunded status at end of year	**(64)**	(778)	**(24)**	(181)
Presented as follows:				
Deferred amounts and other assets	**250**	35	**98**	—
Accounts payable and other	**(9)**	(9)	**(4)**	(3)
Other long-term liabilities	**(305)**	(804)	**(118)**	(178)
	(64)	(778)	**(24)**	(181)

1 Primarily due to increase in the discount rate used to measure the benefit obligations (2020 - primarily due to decrease in the discount rate used to measure the benefit obligations).

2 The accumulated benefit obligation for our Canadian pension plans was $4.3 billion and $4.5 billion as at December 31, 2021 and 2020, respectively. The accumulated benefit obligation for our US pension plans was $1.1 billion and $1.2 billion as at December 31, 2021 and 2020, respectively.

3 Assets in the amount of $13 million (2020 - $11 million) and $84 million (2020 - $59 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 accumulated benefit obligations in excess of the fair value of plan assets. For these plans, the accumulated benefit obligation and fair value of plan assets were as follows:

	Canada		US	
December 31,	**2021**	2020	**2021**	2020
(millions of Canadian dollars)				
Accumulated benefit obligation	**440**	4,094	**115**	1,207
Fair value of plan assets	**247**	3,621	**—**	1,062

Certain of our pension plans have projected benefit obligations in excess of the fair value of plan assets. For these plans, the projected benefit obligation and fair value of plan assets were as follows:

	Canada		US	
December 31,	**2021**	2020	**2021**	2020
(millions of Canadian dollars)				
Projected benefit obligation	**1,272**	4,434	**121**	1,243
Fair value of plan assets	**1,020**	3,621	**—**	1,062

Amount Recognized in Accumulated Other Comprehensive Income

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

	Canada		US	
December 31,	**2021**	2020	**2021**	2020
(millions of Canadian dollars)				
Net actuarial loss	**226**	542	**92**	233
Prior service credit	**—**	—	**(1)**	(1)
Total amount recognized in AOCI[1]	**226**	542	**91**	232

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			US		
Year ended December 31,	**2021**	2020	2019	**2021**	2020	2019
(millions of Canadian dollars)						
Service cost	**139**	148	149	**44**	44	45
Interest cost[1]	**101**	128	139	**17**	31	41
Expected return on plan assets[1]	**(252)**	(260)	(245)	**(73)**	(88)	(78)
Amortization/settlement of net actuarial loss[1]	**54**	42	41	**11**	1	2
Amortization/curtailment of prior service credit[1]	**—**	—	—	**—**	(1)	(1)
Net periodic benefit (credit)/cost	**42**	58	84	**(1)**	(13)	9
Defined contribution benefit cost	**7**	6	8	**—**	—	—
Net pension (credit)/cost recognized in Earnings	**49**	64	92	**(1)**	(13)	9
Amount recognized in OCI:						
Effect of plan combination	**—**	—	—	**—**	—	(6)
Amortization/settlement of net actuarial loss	**(25)**	(21)	(26)	**(11)**	(1)	(2)
Amortization/curtailment of prior service credit	**—**	—	—	**—**	1	1
Net actuarial (gain)/loss arising during the year	**(291)**	118	115	**(99)**	100	8
Total amount recognized in OCI	**(316)**	97	89	**(110)**	100	1
Total amount recognized in Comprehensive income	**(267)**	161	181	**(111)**	87	10

1 Reported within Other income/(expense) in the Consolidated Statements of Earnings.

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			US		
	2021	2020	2019	**2021**	2020	2019
Projected benefit obligation						
Discount rate	**3.2 %**	2.6 %	3.0 %	**2.6 %**	2.2 %	3.0 %
Rate of salary increase	**2.9 %**	2.3 %	3.2 %	**2.8 %**	2.7 %	2.9 %
Cash balance interest credit rate	**N/A**	N/A	N/A	**4.3 %**	4.3 %	4.5 %
Net periodic benefit cost						
Discount rate	**2.6 %**	3.0 %	3.8 %	**2.2 %**	3.0 %	3.9 %
Rate of return on plan assets	**6.2 %**	6.8 %	7.0 %	**7.3 %**	7.9 %	8.0 %
Rate of salary increase	**2.3 %**	3.2 %	3.2 %	**2.7 %**	2.9 %	2.9 %
Cash balance interest credit rate	**N/A**	N/A	N/A	**4.3 %**	4.5 %	4.5 %

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		US	
December 31,	**2021**	2020	**2021**	2020
(millions of Canadian dollars)				
Change in accumulated postretirement benefit obligation				
Accumulated postretirement benefit obligation at beginning of year	**321**	293	**254**	288
Service cost	**6**	5	**1**	2
Interest cost	**7**	8	**3**	7
Participant contributions	**—**	—	**8**	4
Actuarial (gain)/loss[1]	**(51)**	21	**(69)**	17
Benefits paid	**(9)**	(6)	**(22)**	(28)
Plan amendments	**—**	—	**—**	(33)
Foreign currency exchange rate changes	**—**	—	**(3)**	(4)
Other	**—**	—	**1**	1
Accumulated postretirement benefit obligation at end of year	**274**	321	**173**	254
Change in plan assets				
Fair value of plan assets at beginning of year	**—**	—	**188**	188
Actual return on plan assets	**—**	—	**22**	14
Employer contributions	**9**	6	**6**	12
Participant contributions	**—**	—	**8**	4
Benefits paid	**(9)**	(6)	**(22)**	(28)
Foreign currency exchange rate changes	**—**	—	**(3)**	(3)
Other	**—**	—	**2**	1
Fair value of plan assets at end of year	**—**	—	**201**	188
Overfunded/(underfunded) status at end of year	**(274)**	(321)	**28**	(66)
Presented as follows:				
Deferred amounts and other assets	**—**	—	**71**	19
Accounts payable and other	**(12)**	(13)	**—**	(6)
Other long-term liabilities	**(262)**	(308)	**(43)**	(79)
	(274)	(321)	**28**	(66)

1 Primarily due to increase in the discount rate used to measure the benefit obligations (2020 - primarily due to decrease in the discount rate used to measure the benefit obligations).

Certain of our OPEB plans have accumulated benefit obligations in excess of the fair value of plan assets. For these plans, the accumulated benefit obligation and fair value of plan assets were as follows:

	Canada		US	
December 31,	**2021**	2020	**2021**	2020
(millions of Canadian dollars)				
Accumulated benefit obligation	**274**	321	**94**	191
Fair value of plan assets	**—**	—	**51**	106

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

	Canada		US	
December 31,	**2021**	2020	**2021**	2020
(millions of Canadian dollars)				
Net actuarial (gain)/loss	**(35)**	15	**(104)**	(7)
Prior service credit	**(1)**	(1)	**(37)**	(44)
Total amount recognized in AOCI[1]	**(36)**	14	**(141)**	(51)

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			US		
Year ended December 31,	**2021**	2020	2019	**2021**	2020	2019
(millions of Canadian dollars)						
Service cost	**6**	5	5	**1**	2	2
Interest cost[1]	**7**	8	10	**3**	7	10
Expected return on plan assets[1]	**—**	—	—	**(10)**	(12)	(12)
Amortization/settlement of net actuarial gain[1]	**—**	(1)	(7)	**(1)**	(1)	—
Amortization/curtailment of prior service credit[1]	**—**	—	(1)	**(7)**	(2)	(2)
Net periodic benefit (credit)/cost recognized in Earnings	**13**	12	7	**(14)**	(6)	(2)
Amount recognized in OCI:						
Amortization/settlement of net actuarial gain	**—**	1	7	**1**	1	—
Amortization/curtailment of prior service credit	**—**	—	1	**7**	2	2
Net actuarial (gain)/loss arising during the year	**(50)**	21	15	**(80)**	15	(8)
Prior service credit	**—**	—	—	**—**	(33)	—
Total amount recognized in OCI	**(50)**	22	23	**(72)**	(15)	(6)
Total amount recognized in Comprehensive income	**(37)**	34	30	**(86)**	(21)	(8)

1 Reported within Other income/(expense) in the Consolidated Statements of Earnings.

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			US		
	2021	2020	2019	**2021**	2020	2019
Accumulated postretirement benefit obligation						
Discount rate	**3.2 %**	2.6 %	3.1 %	**2.4 %**	2.0 %	2.8 %
Net periodic benefit cost						
Discount rate	**2.6 %**	3.1 %	3.8 %	**2.0 %**	2.8 %	4.0 %
Rate of return on plan assets	**N/A**	N/A	N/A	**6.0 %**	6.7 %	6.7 %

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		US	
	2021	2020	**2021**	2020
Health care cost trend rate assumed for next year	**4.0 %**	4.0 %	**7.0 %**	6.8 %
Rate to which the cost trend is assumed to decline (ultimate trend rate)	**4.0 %**	4.0 %	**4.5 %**	4.5 %
Year that the rate reaches the ultimate trend rate	**N/A**	N/A	**2037**	2037

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			US		
	Target Allocation	December 31,		**Target Allocation**	December 31,	
Asset Category		**2021**	2020		**2021**	2020
Equity securities	**43.8 %**	**46.7 %**	47.2 %	**45.0 %**	**52.5 %**	55.6 %
Fixed income securities	**28.9 %**	**29.8 %**	29.6 %	**20.1 %**	**18.4 %**	17.2 %
Alternatives[1]	**27.3 %**	**23.5 %**	23.2 %	**34.9 %**	**29.1 %**	27.2 %

1 *Alternatives include investments in private debt, private equity, infrastructure and real estate funds. Fund values are based on the net asset value of the funds that invest directly in the aforementioned underlying investments. The values of the investments have been estimated using the capital accounts representing the plan's ownership interest in the 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				US			
	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, 2021								
Cash and cash equivalents	**180**	**—**	**—**	**180**	**10**	**—**	**—**	**10**
Equity securities								
Canada	**198**	**228**	**—**	**426**	**—**	**—**	**—**	**—**
US	**1**	**—**	**—**	**1**	**—**	**—**	**—**	**—**
Global	**—**	**1,693**	**—**	**1,693**	**—**	**609**	**—**	**609**
Fixed income securities								
Government	**258**	**459**	**—**	**717**	**—**	**86**	**—**	**86**
Corporate	**—**	**453**	**—**	**453**	**—**	**118**	**—**	**118**
Alternatives[4]	**—**	**—**	**1,064**	**1,064**	**—**	**—**	**337**	**337**
Forward currency contracts	**—**	**2**	**—**	**2**	**—**	**—**	**—**	**—**
Total pension plan assets at fair value	**637**	**2,835**	**1,064**	**4,536**	**10**	**813**	**337**	**1,160**
December 31, 2020								
Cash and cash equivalents	213	—	—	213	5	—	—	5
Equity securities								
Canada	178	188	—	366	—	—	—	—
US	2	—	—	2	—	—	—	—
Global	—	1,556	—	1,556	—	590	—	590
Fixed income securities								
Government	207	378	—	585	—	75	—	75
Corporate	—	410	—	410	—	103	—	103
Alternatives[4]	—	—	912	912	—	—	289	289
Forward currency contracts	—	33	—	33	—	—	—	—
Total pension plan assets at fair value	600	2,565	912	4,077	5	768	289	1,062

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		US	
December 31,	**2021**	2020	**2021**	2020
(millions of Canadian dollars)				
Balance at beginning of year	**912**	852	**289**	276
Unrealized and realized gains/(losses)	**77**	(27)	**38**	7
Purchases and settlements, net	**75**	87	**10**	6
Balance at end of year	**1,064**	912	**337**	289

OPEB Plans

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

	Level 1[1]	Level 2[2]	Level 3[3]	Total
(millions of Canadian dollars)				
December 31, 2021				
Cash and cash equivalents	**4**	**—**	**—**	**4**
Equity securities				
US	**—**	**39**	**—**	**39**
Global	**—**	**75**	**—**	**75**
Fixed income securities				
Government	**47**	**6**	**—**	**53**
Corporate	**—**	**8**	**—**	**8**
Alternatives[4]	**—**	**—**	**22**	**22**
Total OPEB plan assets at fair value	**51**	**128**	**22**	**201**
December 31, 2020				
Equity securities				
US	—	35	—	35
Global	—	79	—	79
Fixed income securities				
Government	38	6	—	44
Corporate	—	8	—	8
Alternatives[4]	—	—	22	22
Total OPEB plan assets at fair value	38	128	22	188

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 US funded OPEB plan assets classified as Level 3 in the fair value hierarchy were as follows:

December 31,	**2021**	2020
(millions of Canadian dollars)		
Balance at beginning of year	**22**	18
Unrealized and realized gains	**2**	1
Purchases and settlements, net	**(2)**	3
Balance at end of year	**22**	22

EXPECTED BENEFIT PAYMENTS

Year ending December 31,	2022	2023	2024	2025	2026	2027-2031
(millions of Canadian dollars)						
Pension						
Canada	197	203	208	212	217	1,163
US	80	78	78	76	77	374
OPEB						
Canada	12	12	12	13	13	67
US	17	15	14	13	12	51

EXPECTED EMPLOYER CONTRIBUTIONS

In 2022, we expect to contribute approximately $110 million and $4 million to the Canadian and US pension plans, respectively, and $12 million and $6 million to the Canadian and US 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 US employees. Employees may participate in a matching contribution where we match a certain percentage of before-tax employee contributions of up to 6.0% of eligible pay per pay period. For the years ended December 31, 2021, 2020 and 2019, pre-tax employer matching contribution costs were $27 million each year, 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 5 months to 25 years as at December 31, 2021.

For the years ended December 31, 2021 and 2020, we incurred operating lease expenses of $95 million and $107 million, respectively. Operating lease expenses are reported under Operating and administrative expense in the Consolidated Statements of Earnings.

For the years ended December 31, 2021 and 2020, operating lease payments to settle lease liabilities were $118 million and $133 million, respectively. Operating lease payments are reported under Operating activities in the Consolidated Statements of Cash Flows.

Supplemental Statements of Financial Position Information

	December 31, 2021	December 31, 2020
(millions of Canadian dollars, except lease term and discount rate)		
Operating leases[1]		
Operating lease right-of-use assets, net[2]	**645**	**708**
Operating lease liabilities - current[3]	**92**	**80**
Operating lease liabilities - long-term[3]	**612**	**681**
Total operating lease liabilities	**704**	**761**
Finance leases		
Finance lease right-of-use assets, net[4]	**49**	**57**
Finance lease liabilities - current[5]	**13**	**11**
Finance lease liabilities - long-term[3]	**33**	**42**
Total finance lease liabilities	**46**	**53**
Weighted average remaining lease term		
Operating leases	**12 years**	13 years
Finance leases	**7 years**	7 years
Weighted average discount rate		
Operating leases	**4.1 %**	4.1 %
Finance leases	**3.8 %**	3.8 %

1 *Affiliate right-of-use assets, current lease liabilities and long-term lease liabilities as at December 31, 2021 were $51 million (December 31, 2020 - $65 million), $5 million (December 31, 2020 - $5 million) and $47 million (December 31, 2020 - $52 million), respectively.*

2 *Operating lease right-of-use assets are reported under Deferred amounts and other assets in the Consolidated Statements of Financial Position.*

3 *Current operating lease liabilities and long-term operating and finance lease liabilities are reported under Accounts payable and other and Other long-term liabilities, respectively, in the Consolidated Statements of Financial Position.*

4 *Finance lease right-of-use assets are reported under Property, plant and equipment, net in the Consolidated Statements of Financial Position.*

5 *Current finance lease liabilities are reported under Current portion of long-term debt in the Consolidated Statements of Financial Position.*

As at December 31, 2021, our operating and finance lease liabilities are expected to mature as follows:

	Operating leases	Finance leases
(millions of Canadian dollars)		
2022	**117**	**15**
2023	**98**	**13**
2024	**91**	**9**
2025	**84**	**2**
2026	**72**	**1**
Thereafter	**455**	**11**
Total undiscounted lease payments	**917**	**51**
Less imputed interest	**(213)**	**(5)**
Total	**704**	**46**

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 1 month to 30 years as at December 31, 2021.

Year ended December 31,	**2021**	2020
(millions of Canadian dollars)		
Operating lease income	**263**	265
Variable lease income	**333**	361
Total lease income[1]	**596**	626

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

As at December 31, 2021, 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)	
2022	**235**
2023	**215**
2024	**205**
2025	**196**
2026	**191**
Thereafter	**1,938**
Future lease payments	**2,980**

28. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	**2021**	2020	2019
(millions of Canadian dollars)			
Accounts receivable and other	**(1,228)**	1,546	(547)
Accounts receivable from affiliates	**(38)**	8	6
Inventory	**(118)**	(254)	(24)
Deferred amounts and other assets	**(195)**	(586)	133
Accounts payable and other	**(63)**	(770)	63
Accounts payable to affiliates	**52**	1	(24)
Interest payable	**43**	31	(41)
Other long-term liabilities	**(69)**	117	175
	(1,616)	93	(259)

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.

We provide transportation services to several significantly influenced investees which we record as transportation and other services revenue. We also purchase and sell natural gas and crude oil with several of our significantly influenced investees. These revenues and costs are recorded as commodity sales and commodity costs. We contract for firm transportation services to meet our annual natural gas supply requirements which we record as gas distribution costs.

Our transactions with significantly influenced investees are as follows:

Year ended December 31,	2021	2020	2019
(millions of Canadian dollars)			
Transportation and other services	**149**	133	140
Commodity sales	**20**	21	107
Operating and administrative[1]	**292**	252	241
Commodity costs[2]	**790**	518	773
Gas distribution costs	**131**	135	133

1 During the years December 31, 2021, 2020 and 2019, we had Operating and administrative costs from the Seaway Crude Pipeline System of $389 million, $342 million and $327 million, respectively. These costs are a result of an operational contract where we utilize capacity on Seaway Crude Pipeline System assets for use in our Liquids Pipelines business. The costs are offset by recoveries recorded on expenses incurred by us on behalf of our significantly influenced investees of $104 million, $94 million and $86 million for the years ended December 31, 2021, 2020 and 2019.

2 During the years December 31, 2021, 2020 and 2019, we had Commodity costs from the Aux Sable Canada LP. of $447 million, $91 million and $272 million, respectively.

LONG-TERM NOTES RECEIVABLE FROM AFFILIATES

As at December 31, 2021, amounts receivable from affiliates include a series of loans totaling $954 million ($1,108 million as at December 31, 2020), which require quarterly or semi-annual interest payments at annual interest rates ranging from 3% to 8%. Interest income recognized from these notes totaled $39 million, $44 million and $40 million for the years ended December 31, 2021, 2020 and 2019, respectively. The amounts receivable from affiliates are included in Deferred amounts and other assets in the Consolidated Statements of Financial position.

30. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

As at December 31, 2021, 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]	73,809	6,164	7,910	4,559	4,357	11,007	39,812
Interest obligations[2]	36,044	2,531	2,389	2,229	2,073	1,925	24,897
Purchase of services, pipe and other materials, including transportation[3]	7,876	2,945	1,010	736	561	607	2,017
Maintenance agreements	346	41	20	20	21	21	223
Right-of-ways commitments	1,249	35	35	35	36	37	1,071
Total	119,324	11,716	11,364	7,579	7,048	13,597	68,020

1 Includes debentures, term notes, commercial paper and credit facility draws based on the facility's maturity date and excludes short-term borrowings, debt discounts, debt issuance costs, finance lease obligations and fair value adjustment. 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. 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 its affiliates are, at times, subject to environmental remediation 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 liabilities arising from environmental incidents associated with our operating activities.

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 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.

31. GUARANTEES

In the normal course of conducting business, we may 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 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, 2021 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.

32. QUARTERLY FINANCIAL DATA (UNAUDITED)

	Q1	Q2	Q3	Q4	Total
(unaudited; millions of Canadian dollars, except per share amounts)					
2021					
Operating revenues	**12,187**	**10,948**	**11,466**	**12,470**	**47,071**
Operating income	**2,548**	**1,816**	**1,388**	**2,053**	**7,805**
Earnings	**2,014**	**1,521**	**814**	**1,965**	**6,314**
Earnings attributable to controlling interests	**1,992**	**1,484**	**780**	**1,933**	**6,189**
Earnings attributable to common shareholders	**1,900**	**1,394**	**682**	**1,840**	**5,816**
Earnings per common share					
Basic	**0.94**	**0.69**	**0.34**	**0.91**	**2.87**
Diluted	**0.94**	**0.69**	**0.34**	**0.91**	**2.87**
2020					
Operating revenues	12,013	7,956	9,110	10,008	39,087
Operating income	1,513	2,098	2,095	2,251	7,957
Earnings/(loss)	(1,364)	1,777	1,104	1,899	3,416
Earnings/(loss) attributable to controlling interests	(1,333)	1,741	1,084	1,871	3,363
Earnings/(loss) attributable to common shareholders	(1,429)	1,647	990	1,775	2,983
Earnings/(loss) per common share					
Basic	(0.71)	0.82	0.49	0.88	1.48
Diluted	(0.71)	0.82	0.49	0.88	1.48

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 US securities law. As at December 31, 2021, 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 Exchange Act). 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 US 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 US 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, 2021, 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, 2021.

The effectiveness of our internal control over financial reporting as at December 31, 2021 has been audited by PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm 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 at December 31, 2021.

Changes in Internal Control Over Financial Reporting
During the three months ended December 31, 2021, there has been no material change in our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

NORMAL COURSE ISSUER BID

On December 31, 2021, we announced that the TSX had approved our NCIB to purchase, for cancellation, up to 31,062,331 of the outstanding common shares of Enbridge to an aggregate amount of up to $1.5 billion, subject to certain restrictions on the number of common shares that may be purchased on a single day.

Purchases under the NCIB may be made through the facilities of the TSX, the NYSE and other designated exchanges and alternative trading systems, commencing on January 5, 2022 and continuing until January 4, 2023, when the bid expires, or such earlier date on which Enbridge has either acquired the maximum number of common shares allowable under the NCIB or otherwise decide not to make any further repurchases under the NCIB. The maximum number of common shares that Enbridge may repurchase for cancellation represents approximately 1.53% of the 2,026,085,179 common shares issued and outstanding as at December 22, 2021.

A copy of our notice of intention to make a normal course issuer bid may be obtained, free of charge, by contacting Investor Relations by email, phone or mail at:

Email: investor.relations@enbridge.com
Phone Within North America: 1-800-481-2804
Phone Outside North America: 1-403-231-3960
Mail: Enbridge Inc. Investor Relations, 200, 425 – 1st Street S.W., Calgary, Alberta, Canada T2P 3L8

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Directors of Registrant
The information required by this Item will be disclosed in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2021. This information will also be disclosed 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 disclosed in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2021. This information will also be disclosed 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 disclosed in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2021. This information will also be disclosed 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 disclosed in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2021. This information will also be disclosed 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 disclosed in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2021. This information will also be disclosed 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 disclosed in our Form 10-K/A, which will be filed no later than 120 days after December 31, 2021. This information will also be disclosed 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 (PCAOB ID 271)
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

Not applicable.

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
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		Certificate and Articles of Amendment, dated July 6, 2020 (incorporated by reference to Exhibit 3.1 to Enbridge's Current Report on Form 8-K filed July 8, 2020)
3.40	*	General By-Law No. 1 of Enbridge Inc.
3.41		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		Seventh Supplemental Indenture to the Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated July 8, 2020 (incorporated by reference to Exhibit 4.1 to Enbridge's Current Report on Form 8-K filed July 8, 2020)
4.9		Eighth Supplemental Indenture to the Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated June 28, 2021 (incorporated by reference to Exhibit 4.4 to Enbridge's Current Report on Form 8-K filed June 28, 2021)
4.10		Shareholder Rights Plan Agreement between Enbridge Inc. and Computershare Trust Company of Canada dated as of November 9, 1995 and Amended and Restated as of May 5, 2020 (incorporated by reference to Exhibit 4.1 to Enbridge's Current Report on Form 8-K filed May 6, 2020).
4.11		Description of Securities Registered Under Section 12 of the Securities Exchange Act, as amended (incorporated by reference to Exhibit 4.9 to Enbridge's Form 10-K filed February 14, 2020)
		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 US 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 US 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 (2021) (incorporated by reference to Exhibit 10.1 to Enbridge's Form 10-Q filed May 7, 2021)
10.14		Form of Enbridge Inc. 2019 Long Term Incentive Plan Performance Stock Unit Grant Notice and Performance Stock Unit Award Agreement (2021) (incorporated by reference to Exhibit 10.2 to Enbridge's Form 10-Q filed May 7, 2021)
10.15		Form of Enbridge Inc. 2019 Long Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Stock Unit Award Agreement (2021 Share-settled) (incorporated by reference to Exhibit 10.3 to Enbridge's Form 10-Q filed May 7, 2021)
10.16		Form of Enbridge Inc. 2019 Long Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Stock Unit Award Agreement (2021 Cash-settled) (incorporated by reference to Exhibit 10.4 to Enbridge's Form 10-Q filed May 7, 2021)
10.17		Form of Enbridge Inc. 2019 Long Term Incentive Plan Restricted Stock Unit - Energy Marketers Grant Notice and Restricted Stock Unit Award Agreement (2021) (incorporated by reference to Exhibit 10.5 to Enbridge's Form 10-Q filed May 7, 2021)
10.18	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Stock Option Grant Notice and Stock Option Award Agreement (2020) (incorporated by reference to Exhibit 10.1 to Enbridge's Form 10-Q filed May 7, 2020)
10.19	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Performance Stock Unit Grant Notice and Performance Stock Unit Award Agreement (2020) (incorporated by reference to Exhibit 10.2 to Enbridge's Form 10-Q filed May 7, 2020)
10.20	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Stock Unit Award Agreement (2020 Share-settled) (incorporated by reference to Exhibit 10.3 to Enbridge's Form 10-Q filed May 7, 2020)
10.21	+	Form of Enbridge Inc. 2019 Long Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Stock Unit Award Agreement (2020 Cash-settled) (incorporated by reference to Exhibit 10.4 to Enbridge's Form 10-Q filed May 7, 2020)
10.22	+	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)
10.23	+	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)

10.24	+	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)
10.25	+	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)
10.26	+	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)
10.27	+	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)
10.28	+	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)
10.29	+	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)
10.30		Enbridge Inc. Directors' Compensation Plan dated February 9, 2021, effective April 1, 2021 (incorporated by reference to Exhibit 10.6 to Enbridge's Form 10-Q filed May 7, 2021)
10.31	+	Enbridge Inc. Directors' Compensation Plan dated February 11, 2020, effective January 1, 2020 (incorporated by reference to Exhibit 10.1 to Enbridge's Form 10-Q filed July 29, 2020),
10.32	+	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)
10.33	+	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)
10.34		Enbridge Inc. Directors' Compensation Plan, November 3, 2015, effective January 1, 2016 (incorporated by reference as Exhibit 10.16 to Enbridge's Form 10-K filed February 16, 2018)
10.35	+	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)
10.36	+	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)
10.37	+	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)
10.38	+	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)
10.39	+	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)
10.40	+	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)

10.41	+	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)
10.42	+	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)
10.43	+	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)
10.44	+	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)
10.45	+	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)
10.46	+	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
22.1	*	Subsidiary Guarantors
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	*	Inline XBRL Document Set for the consolidated financial statements and accompanying notes in Part II. Item 8 "Financial Statements and Supplementary Data" of this Annual Report on Form 10-K
104	*	Cover Page Interactive Date File – the cover page XBRL tags are embedded within the Inline XBRL document (included in Exhibit 101).

SIGNATURES

POWER OF ATTORNEY

Each person whose signature appears below appoints Robert R. Rooney, Vern D. Yu 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 11, 2022	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 11, 2022 by the following persons on behalf of the registrant and in the capacities indicated.

/s/ Al Monaco
Al Monaco
President, Chief Executive Officer and Director
(Principal Executive Officer)

/s/ Vern D. Yu
Vern D. Yu
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ Patrick R. Murray
Patrick R. Murray
Senior Vice President and Chief Accounting Officer
(Principal Accounting Officer)

/s/ Gregory L. Ebel
Gregory L. Ebel
Chairman of the Board of Directors

/s/ Mayank (Mike) M. Ashar
Mayank (Mike) M. Ashar
Director

/s/ Gaurdie E. Banister
Gaurdie E. Banister
Director

/s/ Pamela L. Carter
Pamela L. Carter
Director

/s/ Susan M. Cunningham
Susan M. Cunningham
Director

/s/ J. Herb England
J. Herb England
Director

/s/ Teresa S. Madden
Teresa S. Madden
Director

/s/ Stephen S. Poloz
Stephen S. Poloz
Director

/s/ S. Jane Rowe
S. Jane Rowe
Director

/s/ Dan C. Tutcher
Dan C. Tutcher
Director

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

Annual Meeting

The Annual Meeting of Shareholders will be held on May 4, 2022 at 1:30 p.m. MDT. Due to the COVID-19 pandemic, the Meeting will be held virtually via live audio webcast. A replay will be available on enbridge.com. Webcast details will be available on the Company's website closer to the Meeting date.

Registrar and Transfer Agent

For information relating to shareholdings, 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

2022 Enbridge Inc. Common Share Dividends

	Q1	Q2	Q3	Q4
Dividend	$0.86	$ – [2]	$ – [2]	$ – [2]
Payment date	Mar 01	Jun 01	Sep 01	Dec 01
Record date[1]	Feb 15	May 13	Aug 15	Nov 15

[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.

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 19 – ENB.PF.K

Forward-looking information

This Annual Report includes references to forward-looking information, including with regards to the supply of and demand for energy, energy transition and low-carbon energy, ESG goals, growth opportunities and outlook, financial guidance and investment capacity. 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 and Analysis, included in this Annual Report and available on both sedar.com and sec.gov.

Non-GAAP measures

This Annual Report makes reference to non-GAAP financial measures and non-GAAP ratios, including EBITDA, adjusted EBITDA and distributable cash flow (DCF) per share. Management believes the presentation of these metrics gives useful information to investors and shareholders as they provide increased transparency and insight into the performance of Enbridge. EBITDA represents earnings before interest, tax, depreciation and amortization. Adjusted EBITDA represents EBITDA adjusted for unusual, infrequent or other non-operating factors. Management uses EBITDA and adjusted EBITDA to set targets and to assess the performance of the Company and its business units. DCF is defined as cash flow provided by operating activities before the impact of changes in operating assets and liabilities (including changes in environmental liabilities) less distributions to non-controlling interests, preference share dividends and maintenance capital expenditures, and further adjusted for unusual, infrequent or other non-operating factors. Management uses DCF to assess the performance of the Company and to set its dividend payout target. Debt to EBITDA is a non-GAAP ratio used as a liquidity measure to indicate the amount of adjusted earnings available to pay debt (as calculated on a GAAP basis) before covering interest, tax, depreciation and amortization. Adjusted earnings is a non-GAAP financial measure that represents earnings attributable to common shareholders adjusted for unusual, infrequent or other non-operating factors included in adjusted EBITDA, as well as adjustments for unusual, infrequent or other non-operating factors in respect of depreciation and amortization expense, interest expense, income taxes and noncontrolling interests on a consolidated basis.

Our non-GAAP metrics described above are not measures that have standardized meaning prescribed by generally accepted accounting principles (GAAP) in the United States of America and are not U.S. GAAP measures. Therefore, these metrics may not be comparable with similar measures presented by other issuers. A reconciliation of historical non-GAAP financial measures to the most directly comparable GAAP measures is available on the Company's website. Additional information on non-GAAP financial measures and non-GAAP ratios may be found in the Company's earnings news releases or in additional information on the Company's website, sedar.com and sec.gov. Reconciliations of forward-looking non-GAAP financial measures to comparable GAAP measures are not available due to the challenges and impracticability with estimating some items, particularly certain contingent liabilities and non-cash unrealized derivative fair value losses and gains which are subject to market variability. Because of these challenges, reconciliations of forward-looking non-GAAP financial measures are not available without unreasonable effort.

Front cover

Images from across Enbridge's business.

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.

RECYCLED
Paper made from recycled material
FSC® C015495