Tomorrow is on

2022 Annual Report




ENBRIDGE

Life Takes Energy

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, 2022

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 001-15254

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, a smaller reporting company, or an emerging growth 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 ☐

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to § 240.10D-1(b). ☐

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, 2022, was approximately US$85.6 billion.

As at February 3, 2023, the registrant had 2,024,907,965 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 (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
Aii	Athabasca Indigenous Investments Limited Partnership
AOCI	Accumulated other comprehensive income/(loss)
ARO	Asset retirement obligations
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
Aux Sable	US Midstream ownership interest in Aux Sable Liquid Products LP, Aux Sable Midstream LLC, Aux Sable Canada LP
BC	British Columbia
bcf/d	Billion cubic feet per day
the Board	Board of Directors
Cactus II	Cactus II Pipeline, LLC
CER	Canada Energy Regulator, created by the Canadian Energy Regulator Act which also repealed the National Energy Board Act, on August 28, 2019
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	DCP Midstream, LP
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
Enbridge Gas	Enbridge Gas Inc.
EPS	Emission Performance Standards
ESG	Environment, Social and Governance
Exchange Act	United States Securities Exchange Act of 1934
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse gas
Gray Oak	Gray Oak Pipeline, LLC
H2	Hydrogen gas
IJT	International Joint Tariff
IR	Incentive Regulation
kbpd	Thousand barrels per day
L3R	Line 3 Replacement
LMCI	Land Matters Consultation Initiative
LNG	Liquefied natural gas
Magic Valley	Magic Valley Wind Farm
M&N	Maritimes & Northeast Pipeline

M&N Canada	Canadian portion of our Maritimes & Northeast Pipeline
the Court	United States District Court for the Western District of Wisconsin
MD&A	Management's Discussion and Analysis
MW	Megawatts
NCIB	Normal course issuer bid
NEXUS	NEXUS Gas Transmission Pipeline
NGL	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
P66	Phillips 66
the Partnerships	Spectra Energy Partners, LP and Enbridge Energy Partners, L.P
PennEast	PennEast Pipeline Company, L.L.C.
PHMSA	Pipeline and Hazardous Materials Safety Administration
PPA	Power purchase agreement
PSU	Performance Stock Units
the Reservation	Bad River Reservation
RNG	Renewable natural gas
ROE	Return on equity
ROU	Right-of-use
RSU	Restricted Stock Units
SEC	US Securities and Exchange Commission
SEP	Spectra Energy Partners, LP
SESH	Southeast Supply Header, L.L.C.
Spectra Energy	Spectra Energy Corp
Texas Eastern	Texas Eastern Transmission, L.P.
TGE	Tri Global Energy, LLC
TSX	Toronto Stock Exchange
UK	The United Kingdom
US	United States of America
US GAAP	Generally accepted accounting principles in the United States of America
Vector	Vector Pipeline L.P.
VIEs	Variable interest entities
Westcoast	Westcoast Energy Inc.
Woodfibre	Woodfibre LNG Limited Partnership

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; expected supply of, demand for, exports of and prices of crude oil, natural gas, natural gas liquids (NGL), liquified natural gas (LNG) and renewable energy; energy transition and lower-carbon energy, and our approach thereto; environmental, social and governance (ESG) goals, practices and performance; industry and market conditions; anticipated utilization of our assets; 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, benefits and in-service dates related to announced projects and projects under construction; expected capital expenditures; investable capacity and capital allocation priorities; share repurchases under our normal course issuer bid; expected equity funding requirements for our commercially secured growth program; expected future growth, development and expansion opportunities; expected optimization and efficiency 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; expected future actions of regulators and courts, and the timing and impact thereof; toll and rate cases discussions and proceedings and anticipated timeline and impact therefrom, including Mainline Contracting and those relating to the Gas Transmission and Midstream and Gas Distribution and Storage businesses; operational, industry, regulatory, climate change and other risks associated with our businesses; and our assessment of the potential impact of the various risk factors identified herein.

Although we believe these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about the following: the expected supply of, demand for, export of and prices of crude oil, natural gas, NGL, LNG and renewable energy; anticipated utilization of assets; exchange rates; inflation; interest rates; the COVID-19 pandemic and the duration and impact thereof; availability and price of labor and construction materials; the stability of our supply chain; operational reliability; 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 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 earnings before interest, income taxes, and depreciation and amortization (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, NGL, LNG and renewable energy, and the prices of these commodities, are material to and underlie all forward-looking statements, as they may impact current and future levels of demand for our services. Similarly, exchange rates, inflation and interest rates 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. 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 stability of our supply chain; the effects of inflation and foreign exchange rates on labor and material costs; the effects of interest rates on borrowing costs; the impact of weather and customer, government, 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; acquisitions, dispositions and other transactions and the realization of anticipated benefits therefrom; operational dependence on third parties; 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; inflation; interest rates; commodity prices; access to and cost of capital; political decisions; global geopolitical conditions; the supply of, demand for and prices of commodities and other alternative energy; 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 assumption, 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 and 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 are not measures that have a standardized meaning prescribed by the accounting principles generally accepted 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

Enbridge is a leading North American energy infrastructure company. Our core businesses include Liquids Pipelines, which consists of pipelines and terminals in Canada and the US that transport and export various grades of crude oil and other liquid hydrocarbons; Gas Transmission and Midstream, which consists of investments in natural gas pipelines and gathering and processing facilities in Canada and the US; Gas Distribution and Storage, which consists of natural gas utility operations that serve residential, commercial and industrial customers in Ontario and Québec; and Renewable Power Generation, which consists primarily of investments in wind and solar assets, as well as geothermal, waste heat recovery and transmission assets, in North America and Europe.

Enbridge is a public company, with common shares that 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 people's quality of life in a safe, clean, and socially responsible manner. Our vision to be the leading energy infrastructure company in North America and beyond supports this purpose. In pursuing this vision, we seek to play a critical role in enabling the economic and social well-being of people across the world by providing access to affordable, reliable, and secure energy. Our infrastructure franchises transport, distribute, and generate energy, including liquids, natural gas, renewable power, and lower-carbon fuels. We recognize that the energy system is changing, and we aim to bridge to a cleaner energy future by investing in lower-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 (PPAs), and other low-risk commercial arrangements.

In addition, we strive to be a leader in worker and public safety, ESG, stakeholder relations, customer service, community investment, and employee engagement and satisfaction.

STRATEGY

Our strategy is underpinned by a deep understanding of energy supply and demand fundamentals. Through disciplined capital allocation that is aligned with our outlook on energy markets, we have become an industry leader with a diversified portfolio across both conventional and lower-carbon energies. Our assets have reliably generated low-risk, resilient cash flows through many commodity and economic cycles.

In order to 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 business strategy. We test various value enhancement and maximization options, and we regularly engage with our Board of Directors (the Board) to ensure alignment and maintain active oversight, including updates and discussions throughout the year and a dedicated annual Strategic Planning session. Going forward, we plan to use this comprehensive approach to guide our investment and portfolio decisions.

Predictable growth is a hallmark of our investor value proposition. Our robust portfolio of project development opportunities and ongoing efficiency improvements should help drive mid-single digit growth in our distributable cash flow per share for years to come. We remain confident in our two-pronged growth strategy and expect to selectively invest in our diversified footprint of both conventional businesses and complementary lower-carbon platforms, such as renewables, Carbon Capture and Storage (CCS), Hydrogen (H2), and Renewable Natural Gas (RNG). Additionally, ESG continues to be integral to our strategy; we are committed to reducing our emissions, building lasting relationships with our stakeholders, and promoting diversity, equity, and inclusion.

In alignment with our strategy, we progressed several of our priorities in 2022. For example:

- Our Liquids Pipelines business delivered record Mainline volumes, increased ownership in and operatorship of the Gray Oak pipeline, and permitted a 2 million barrels (mmbl) storage expansion at Enbridge Ingleside Energy Center (EIEC), further bolstering our presence in the US Gulf Coast and global export markets.

- Our Gas Transmission and Midstream business successfully expanded our secured capital program notably with the T-South Expansion Program and T-North Expansion Program and acquired an equity stake in Woodfibre LNG Limited Partnership to capitalize on increasing global gas demand and supporting coal-to-gas conversions that are expected to help lower global energy emissions.

- Our Gas Distribution and Storage business added over 45,000 new customers, filed the rate rebasing application for 2024-2028 which proposes continuation of Incentive Rate-setting mechanisms, completed the Pathways to Net-Zero Emissions Study for Ontario, and progressed construction of three RNG projects and development of a green hydrogen blending project at Gazifère Inc. (Gazifère), a wholly-owned natural gas distribution company in Québec.

- Our Renewable Power Generation business accelerated its growth strategy with the acquisition of the renewable developer Tri Global Energy, LLC (TGE), securing 3.9 gigawatts (GW) of conditionally sold renewable generation projects and an additional 3 GW in development projects. In addition, the 480 megawatts (MW) Saint-Nazaire project, France’s first commercial-scale offshore wind in which Enbridge holds a stake, became fully operational in 2022. We are continuing to advance construction of three additional offshore wind projects in Europe.

- Our New Energy Technologies team, in collaboration with all of our business units, advanced our lower-carbon strategy, including building strategic partnerships to progress the Wabamun Carbon Hub in Alberta and lower-carbon hydrogen and ammonia production and export facilities in the US Gulf Coast.

- We have made meaningful progress towards our ESG goals, advancing construction of ten solar self-power projects, signing a landmark sale of a non-operating interest in pipelines in our Regional Oil Sands System to 23 Indigenous communities, and publishing our Indigenous Reconciliation Action Plan to further our engagement.

- We continue to recycle capital at attractive valuations, further optimizing and diversifying our portfolio. In addition, we are focused on improving efficiencies to increase 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 our assets, protecting the environment, and maintaining reliability of our system remain our top priorities. We are focused on enhancing the value of our existing assets, capitalizing on our extensive infrastructure, prioritizing in-franchise organic growth and export-driven opportunities, and developing lower-carbon platforms across all our businesses. We will continue to invest where we can advance our strategy, build sustainable competitive advantage, and achieve attractive risk-adjusted returns.

Our key strategic priorities include:

Safety and Operational Reliability
Safety and operational reliability are the foundation of our strategy. We strive to achieve and maintain industry leadership in all facets of safety - process, public, and personal - and ensure the highest standards of reliability and integrity across our system to protect our communities and the environment.

Extend Growth
The cornerstone of our growth lies in the successful execution of our slate of secured projects (currently $18 billion through 2028) on schedule and at the lowest practical cost, while maintaining the highest standards for safety, quality, customer satisfaction, and environmental and regulatory compliance. For a discussion of our current portfolio of capital projects refer to Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Growth Projects - Commercially Secured Projects*.

Beyond that, we seek to continually identify additional high-quality growth opportunities across all our platforms. We expect to have sufficient equity self-funding capacity of about $5 to $6 billion per year to invest in growth without issuing any additional common equity and maintaining key credit metrics. We will remain disciplined and will strive to 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 what we believe are the most value-enhancing opportunities available to us, including further organic growth, complementary accretive "tuck-in" acquisitions that improve our competitive positioning, share repurchases, or further deleveraging of 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, we expect that:

- 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 transmission business will seek extension and expansion opportunities driven by new load demand from gas-fired power generation, industrial growth, and coastal LNG plants. Looking forward, blending RNG and H2 production into our system should enhance asset longevity and enable us to offer a differentiated lower-carbon solution to customers.

- Our gas distribution and storage business will continue to grow through productivity enhancements, modernization investments, and facilities that blend H2 and RNG into the gas supply. We expect to continue to add customers over the next regulatory framework period to 2028. Additionally, we expect to expand our offerings to customers, including additional demand-side management, as well as resiliency and hybrid heating programs.

- Our enhanced renewable power capabilities position us well to capitalize on strong renewables growth in Europe and North America and execute on our large development program. We also plan to continue to progress our multi-year self-power program across our liquids and gas systems.

In addition, we aim to drive growth through an ongoing focus on optimization, modernization, productivity, and efficiency across all our businesses. Examples include: the application of drag-reducing agents and pump station modifications 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 lower-carbon offerings to utility customers and investments in lower-carbon supply connections to the gas grid, and more generally, the creation of sustainable cost savings across the organization through innovation, process improvement and/or system enhancements.

Maintain a Strong Balance Sheet

The maintenance of our balance sheet strength is critical to our strategy. Our financing strategies are designed to retain strong, investment-grade credit ratings to ensure we have the financial capacity to meet our capital funding needs and the flexibility to manage capital market disruptions. Our current secured capital program can be readily financed through internally generated cash flow and available balance sheet capacity without issuance of additional common equity. 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 capital deployment opportunity set. We screen, analyze, and assess opportunities using a disciplined investment framework with the objective of effectively deploying capital to grow while achieving attractive risk-adjusted returns, within our low-risk "utility-like" business model.

All investment opportunities are evaluated based on their potential to advance our strategy, mitigate risks, support our ESG goals, and create additional financial flexibility. Our primary emphasis in the near term is on low capital intensity opportunities to enhance returns in existing businesses (organic expansions and optimizations), modernization of our systems, and utility rate-based investments. We also remain focused on larger projects where commercial constructs fit our investor value proposition and where we can effectively manage risks during the execution phase. In addition, we continue to assess other value-enhancing opportunities, such as accretive acquisitions that can complement our portfolio.

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 repurchases.

Lead in Energy Transition Over Time

As the global population grows and standards of living continue to improve around the world, we expect energy demand to rise. At the same time, we, and our society, increasingly recognize the need for secure and reliable energy while reducing global greenhouse gas (GHG) emissions. Accordingly, energy systems around the world are being reshaped as industry participants, regulators, and consumers seek to lower emissions. As a diversified energy infrastructure company, we believe we are well positioned to play a key role in the energy transition by leading the development of the future energy systems with regulators and policy makers and partnering with customers on their lower-carbon strategies, while reducing our own carbon footprint.

We believe that diversification and innovation will play a significant role in the transition to a lower-carbon future. To date, we have made large investments in natural gas infrastructure and renewable energy assets, helping to decrease our emissions and further expand our platforms to enable energy transition across the globe. Our focus areas in renewable energy remain in offshore wind, utility-scale onshore projects, and integrated clean-energy offerings and solutions for customers. We are also taking a leadership role in other lower-carbon platforms like CCS, H2 and RNG where we can leverage our infrastructure, capabilities, and stakeholder relationships to accelerate growth and extend the value of our existing assets. Additionally, our new investments are expected to have a clear path to achieve net-zero emissions, in alignment with our ESG goals.

We work closely with our customers to maintain a pulse on the pace of the energy transition and are actively leveraging our ESG leadership and world-class execution capabilities to advance our positioning as a differentiated energy provider. We regularly test our assets under various transition scenarios to assess resiliency of our business.

STRATEGIC ENABLERS

Our commitment and progress on ESG, the capabilities and skills of our people, and how we utilize technology are core to executing our strategy and maintaining our competitive advantages.

Environmental, Social and Governance

Sustainability is integral to our ability to deliver energy in a safe and reliable manner. 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 our stakeholders.

In 2022, we published our 21st annual Sustainability Report outlining our progress against our ESG goals[1]. In particular, we:

- Made meaningful progress towards our interim emissions intensity and net-zero GHG emissions goals through modernization and innovation of our system, efficiency improvements, and continued investment in solar self-power;
- Enhanced our efforts to ensure that our workforce and Board better reflect the diversity of our communities, empowering our workforce through employee resource groups and advancing on our diversity, equity, and inclusion commitments; and
- Continued to drive improvements towards our goal of zero safety incidents and injuries and progressed implementation of robust cyber defense programs.

Since setting our ESG targets in 2020, we have made considerable progress integrating sustainability into our strategy, governance, operations, and decision-making. We have linked ESG performance to incentive compensation and are making meaningful progress towards these targets by executing on our action plans.

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.

At Enbridge, we aim to continuously strengthen our ESG approach and are undertaking the following additional actions:

- Proactively working with organizations advancing science-based guidelines for the midstream sector;
- Collaborating with key suppliers on emissions reduction plans; and
- Further developing lower-carbon energy partnerships to drive innovation across our businesses, with a focus on renewable power, RNG, H2 and CCS.

People
Our employees are essential to our success and our focus remains on enhancing the capabilities and skills of our people. We are evolving our people strategy to ensure we attract and retain the talent and leadership needed for today and tomorrow. This includes growing our focus on learning and development, and additional focus on overall well-being. We value diversity, and diverse thought, and have embedded inclusive practices in our programs, processes, and approach to people management. Furthermore, we strive to maintain industry competitive compensation, flexibility, and retention programs that provide both short- and long-term performance incentives.

Technology
We recognize the vital role technology plays in helping us achieve our strategic objectives. We are committed to pursuing innovation and technology solutions that further our safety and reliability, maximize revenues, improve efficiencies, and enable transition to new, cleaner energy solutions. We continue to strive to be on the leading edge of cyber security, by enhancing our capabilities and educating our workforce to protect our critical infrastructure system from increasing threats.

Our two Technology and Innovation labs, located in Calgary and Houston, embody our commitment to technology enabled business solutions and how we strive to entrench technology in our everyday operations.

We provide annual progress updates 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. Through our predecessors, 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 on 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 in 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. 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, which is comprised of the IJT Benchmark Toll, the CTS Surcharges and the Line 3 Replacement IJT Surcharge, 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 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 thousand barrels per day (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.

On October 5, 2022, we completed a transaction with Athabasca Indigenous Investments Limited Partnership (Aii), a newly created entity representing 23 First Nation and Metis communities, pursuant to which Aii acquired an 11.6% non-operating interest in seven Regional Oil Sands pipelines in the Regional Oil Sands System. Pipelines included in the transaction are the Athabasca Pipeline, Wood Buffalo Extension/Athabasca Twin pipeline system and associated tanks, Norlite, Waupisoo Pipeline, Wood Buffalo Pipeline, Woodland Pipeline, and Woodland Extension.

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 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 660 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. As of August 17, 2022, our effective economic interest in Gray Oak increased to 58.5% from 22.8% as a result of a joint venture merger transaction with Phillips 66 (P66) and we will be assuming operatorship of Gray Oak in the second quarter of 2023.

The Mid-Continent System is comprised of storage terminals at Cushing, Oklahoma (Cushing Terminal), consisting of over 110 individual storage tanks ranging in size from 78 to 570 thousand barrels. Total storage shell capacity of Cushing Terminal is approximately 26 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, and blending fees.

In October 2021, we acquired Moda Midstream Operating, LLC, which included the Ingleside Energy Center (renamed the Enbridge Ingleside Energy Center or 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. In November 2022, we acquired an additional 10% ownership interest in Cactus II Pipeline, bringing our total non-operating ownership to 30%.

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 Dakota Access Pipeline (DAPL) from the Bakken area in North Dakota to Patoka, Illinois, and the Energy Transfer Crude Oil Pipeline (ETCO) 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. The majority of the SAX pipeline's 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 for 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 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. 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 we expect 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, since 2021, global crude oil demand has been recovering 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 mmbpd. 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 is expected to primarily come from Organization of the Petroleum Exporting Countries (OPEC) countries and North America. Growth in supply from OPEC is anticipated to 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 is expected to 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 anticipated 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 believe that 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 EIEC 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.

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, LLC (Sabal Trail), NEXUS Gas Transmission Pipeline, LLC (NEXUS), Valley Crossing Pipeline, LLC. (Valley Crossing), Southeast Supply Header, LLC (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 interstate 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 12.04 billion cubic feet per day (bcf/d) of natural gas on approximately 13,765 kilometers (8,553 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 interstate 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 of 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 interstate 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 2,449 kilometers (1,522 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 1.39 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) interstate 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) interstate 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 provides natural gas transmission services, transporting processed natural gas from facilities located primarily in northeastern BC to markets in BC and the US Pacific Northwest. It 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, as well as associated mainline compressor stations. BC Pipeline is regulated by the CER under cost-of-service regulation.

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 Liquid Products LP natural gas liquids (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 a 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.

As of August 17, 2022, US Midstream also includes a 13.2% effective economic interest in DCP Midstream, LP (DCP). Prior to August 17, 2022, we had a 28.3% effective economic interest in DCP. DCP 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 NGL; and recovering and selling condensate. DCP owns and operates more than 36 plants and approximately 86,905 kilometers (54,000 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 NGL. 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 we expect to continue to play a part as the energy landscape evolves.

Natural gas production in the Appalachian and Permian basins has grown dramatically in the past decade. Today, these regions produce more than 47 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 both producers and consumers. Our US Gas Transmission systems were initially designed to transport natural gas from the Gulf Coast to the supply-constrained 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 allow 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 over 2.0 bcf/d over the next decade, 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 in these markets in the region is anticipated to grow by more than 20.0 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. In 2022, the US exported over 10.6 bcf/d of natural gas to LNG markets, primarily from the Gulf Coast region.

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. The continental supply profile has shifted to natural gas shale plays such as the Montney and Duvernay within western Canada. These supply shifts have shaped our growth strategies and affect the nature of the projects anticipated in the capital expenditures discussed below in Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Growth Projects - Commercially Secured Projects.*

Global energy demand is expected to increase approximately 24% by 2050, according to the recently released International Energy Agency's Stated Policy Scenario, driven primarily by economic growth in non-OECD countries. According to the Stated Policy Scenario, natural gas will play an important role in meeting this energy demand, and gas consumption is anticipated to grow by approximately 13% during this period as one of the world's most significant energy sources. North American exports are expected to 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, as well as further build-out of export facilities to meet international demand.

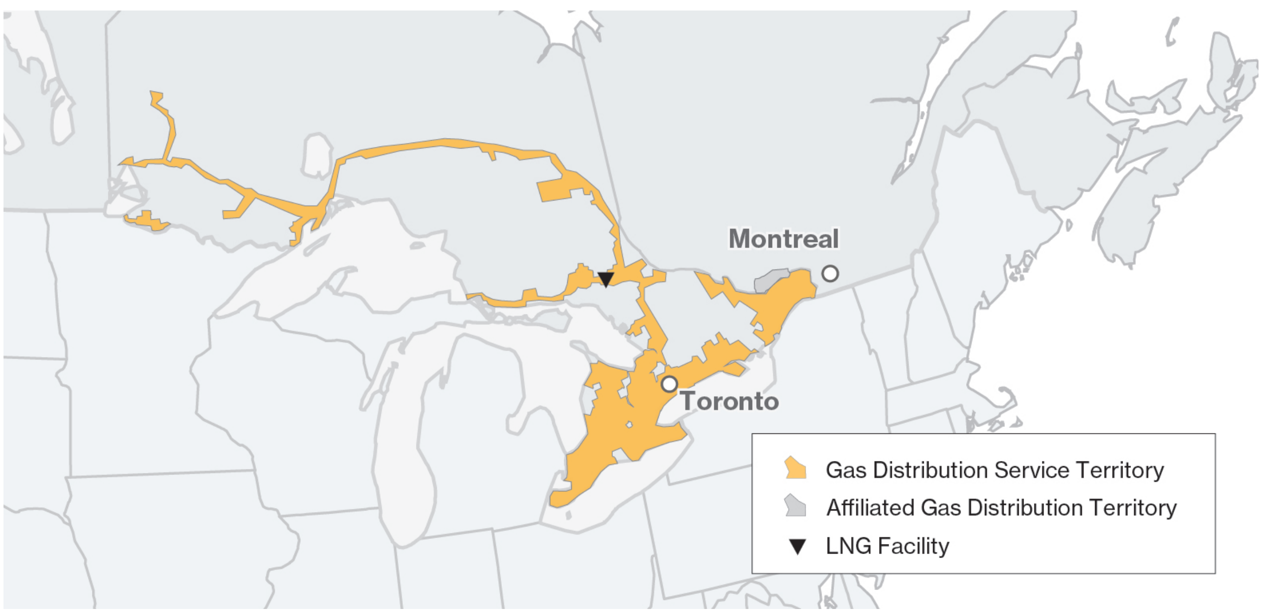
The long-term impacts of the Ukraine conflict on global gas markets are still unclear. Europe has experienced a rapid increase in natural gas prices, largely as a result of reduced natural gas supply from Russia. Global LNG markets have responded, and natural gas storage volumes entering the winter season in Europe were strong. However, these LNG cargos have largely been diverted from Asian markets, and over time the LNG market is expected to normalize.

Europe continues to seek lower-carbon gas supplies and has accelerated plans to develop hydrogen as an alternative to natural gas. The global hydrogen market is still relatively immature, but with incentives being put in place such as those in the US Inflation Reduction Act, hydrogen production at large scale is becoming increasingly commercialized, which has led to a growing export market. Given its proximity to low-cost natural gas supplies and suitable geologic storage for carbon dioxide (CO_2), the US Gulf Coast is well positioned to be a leading export hub to supply blue hydrogen to international markets. Given these rapidly changing global fundamentals, and coupled with growing appetite for lower-carbon hydrogen, we believe we are well positioned to provide value-added solutions to shippers and meet both regional and international demand.

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.



ENBRIDGE GAS
Enbridge Gas is a rate-regulated natural gas distribution utility with storage and transmission services. Enbridge Gas' distribution system, supported by storage and compression assets, carries natural gas from the point of local supply to customers and serves residential, commercial and industrial customers across Ontario.

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

Distribution
Enbridge Gas' principal source of revenue arises from distribution of natural gas to customers. The services provided to residential, small commercial and industrial heating customers are primarily on a general service basis, without a specific fixed term or fixed price contract. The services provided to larger commercial and industrial customers are usually on an annual contract basis under firm or interruptible service contracts. Under a firm contract, Enbridge Gas is obligated to deliver natural gas to the customer up to a maximum daily volume. The service provided under an interruptible contract is similar to that of a firm contract, except that it allows for service interruption at Enbridge Gas' option 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 149,000 kilometers (92,584 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 has continued to grow, there has been 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 2,162 bcf of gas through its distribution and transmission system in 2022. 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 18 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 284 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 2022, 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 14 years.

GAZIFÈRE
We wholly own Gazifère, a natural gas distribution company that serves approximately 44,000 customers in western Québec. 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 anticipate that demand for natural gas in North America will stabilize 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. Net-zero carbon policies, 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 and public policy requirements.

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 strong 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 and proposed RNG programs, we are also expanding our efforts to source other lower-carbon supplies, such as responsibly sourced natural gas, and H2.

The storage and transportation marketplace continues to respond to changing natural gas supply dynamics, including a recovered 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. However, over the past year, geopolitical unrest has increased and lead to elevated concerns with energy security in regions such as Europe and Asia. In response, one of the key supply sources supporting global energy security has been US LNG, which has introduced additional competition for North American supply. These market dynamics have resulted in higher and more volatile natural gas prices across many US and Canadian natural gas trading points. Unregulated storage values are primarily determined by the difference in value between winter and summer natural gas prices. Despite the recent volatility exhibited in natural gas prices, storage values have been relatively stable.

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, France, and Germany, as well as interests in several offshore wind projects under construction and active development in France and the United Kingdom.

Combined Renewable Power Generation investments represent approximately 2,175 MW of net generation capacity, which primarily consists of approximately:

- 1,389 MW generated by North American wind facilities;
- 377 MW generated by European offshore wind facilities;
- 187 MW to be generated by the Fécamp and Calvados Offshore Wind projects in France, both of which are currently under construction;
- 6 MW to be generated by the Provence Grand Large Floating Offshore Wind project in France, which is under construction; and
- 93 MW generated by North American solar facilities in operation, with an additional 97 MW in projects in pre-construction and under construction.

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

In September 2022, we acquired renewable energy project developer TGE with a development portfolio of wind, solar, and energy storage projects in Texas, Nebraska, Illinois, Indiana, Virginia, Pennsylvania, and Wyoming. TGE's development portfolio includes 3.9 GW of conditionally sold renewable generation projects and an additional 3 GW of wholly-owned projects in development. Following its acquisition of TGE, Enbridge became one of the top 15 renewable energy project developers in the US.

Renewable Power Generation also includes our 25% interest in the East-West Tie, a 450-MW transmission line in northwestern Ontario, which entered operations in March 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 and Albatros Offshore Wind, located in Germany;
- a 25.5% interest in the Saint-Nazaire Offshore Wind project, located in France;
- a 25% interest in the Provence Grande Large Floating Offshore Wind project, under 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, under construction in France.

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 have expertise in completing and delivering large scale infrastructure projects.

SUPPLY AND DEMAND
Renewable power generation 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 lower-carbon strategies within the residential, transportation and industrial sectors are expected to drive growing electricity demand. Furthermore, voluntary GHG emissions reduction 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 lower-carbon intensities. Governments are also proposing tax incentives to support low-emission and renewable energy generation resource development.

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, and the desire to reduce reliance on gas sourced from Russia. Energy efficiency gains are expected to temper, but not eliminate, demand growth. Renewable power is expected to play a significant role in Europe's ability to meet its aggressive lower-carbon and renewable energy targets.

On the supply side, the International Energy Agency expects coal to fall by more than 90% from 2020 levels, while nuclear is expected to fall 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, the impact of foreign exchange hedge settlements and the activities of our wholly-owned captive insurance subsidiaries. The principal activity of our captive insurance subsidiaries is providing insurance and reinsurance coverage for certain insurable property and casualty risk exposures of our operating subsidiaries and certain equity investments. 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 (DOT). These laws and regulations require us to comply with a significant set of requirements for the design, construction, maintenance and operation of our interstate pipelines. These laws and regulations, among other things, include requirements to monitor and maintain the integrity of our pipelines and to operate them within permissible pressures.

PHMSA continues to review existing regulations and establish new regulations to support safety standards that are designed to improve operations integrity management processes. There remains uncertainty as to how these standards will be implemented, but it is expected that the changes will result in 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 is subject to regulation by the FERC, whose rulings and policies could have an adverse impact on the ability to recover the full cost of operating these pipeline and storage assets, 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 pipelines are subject to 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, laws and regulations addressing pipeline safety in Canada were enacted over the past few years. The changes demonstrate an increased focus on the implementation of management systems to address key areas, such as emergency management, integrity management, safety, security and environmental protection. The CER also has authority 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 ensuring reliability targets are met. Furthermore, the integrity management program has an independent step to check the results of 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 regulatory risk. Broadly defined, economic regulatory risk is the risk that governments or regulatory agencies reject proposed commercial arrangements, applications or policies, upon which future and current operations are dependent. Our pipelines are subject to the actions of various regulators, including the CER and the FERC, with respect to the tariffs and tolls. The rejection of applications for approval of new tariff structures or proposed commercial arrangements and changes in interpretation 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 in the Consolidated Statements of Financial Position, or amounts that would have been recorded in 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).

In October 2022, Enbridge Gas filed its application with the OEB to establish a 2024 through 2028 rate setting framework. The application and framework seek approval to establish 2024 base rates on a cost-of-service basis and to establish a price cap IR rate setting mechanism to be used for the remainder of the term (2025 - 2028). The OEB has determined it will hear the application in two phases, with Phase 1 addressing items that affect rates effective January 1, 2024, and Phase 2 addressing items that will affect rates subsequent to January 1, 2024. An OEB decision is expected on Phase 1 of the application in the second half of 2023.

Enbridge Gas continues to develop opportunities to support a lower-carbon future in Ontario. In 2021, we received OEB approval of an Integrated Resource Planning (IRP) framework and integrated the framework into our planning practices. The framework requires Enbridge Gas to consider facility and non-pipe demand and/or supply side alternatives (IRP alternatives) to address the systems needs of its regulated operations, where certain parameters have been met. The framework also allows Enbridge Gas to pursue an IRP alternative (or combination of IRP alternatives and facility alternative) where it is found to be in the best interests of Enbridge Gas and its customers, taking into account reliability and safety, cost-effectiveness, public policy, optimized scoping, and risk management. Enbridge Gas has reviewed its system needs as part of its 2023-2032 Asset Management Plan and is now evaluating the technical and economic feasibility of IRP alternatives for the projects. A summary of the IRP evaluation statuses has been filed as part of Enbridge Gas' 2024 Rebasing Application.

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 Electric 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 US, and Mexico. It is subject to oversight from the FERC in the US 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 has proposed a Clean Electricity Regulation (CE Regulation) that would require Canada's electricity grid reach net-zero by 2035. The CE Regulation is expected to come into effect in 2023.

Policy changes may also provide new opportunities for existing assets and new developments. The United States passed the Inflation Reduction Act in late 2022, which established long-term production and investment tax credits for renewable power generation, battery storage projects and for related manufacturing supply chains. Similarly, Canada proposed in its Fall Economic Statement competitive tax credits for renewable power generation and battery storage projects, which it anticipates passing in 2023. Changes to these tax programs could impact development plans.

Renewable Power Generation is also subject to Provincial and State regulations governing the energy resource mix on the grid, emissions levels of the electricity grid, and market regulations related to emergency operations, extreme weather preparedness, and market participation, among others. These regulations may change from time to time, which could impact Enbridge's operations and increase the costs of participating in regional electricity markets.

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 (most recently, RED II 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. During 2022, member states of the EU introduced extraordinary and temporary measures to address high energy prices including caps and demand reduction goals. As the minimum PPA prices in Germany and France will still be honored, there will not be any negative implications to our PPA prices. The federal policies and regulations in place 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. Government-imposed temporary price controls, effective January 1, 2023, were introduced during 2022 to address the significant increase in energy prices. The impact of merchant exposure on our Renewable Power Generation asset in the UK is limited by fixed revenue payments backed by the UK government.

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 (including targeted training) 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 provincial and territorial securities regulators similarly regulate commodity marketing within Canada and are members of the Canadian Securities Administrators. These various regulators enforce, among other things, the prohibition of market manipulation, fraud and disruptive trading.

The export of natural gas out of Alberta is regulated by the Alberta Energy Regulator (AER). 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 import and export rules and permits 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 DOT, 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 Emergency Response Assistance Canada, the Chemical Transportation Emergency Center and the 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 may 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 establishing new state implementation plans which have new emissions limits to comply with ozone standards regulated under the National Ambient Air Quality Standards. In 2015, the ozone standards were lowered once again 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 current 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 uncertain.

Canada has adopted a pan-Canadian approach to pricing carbon emissions to incent GHG emission reductions across all sectors of the economy. This approach was adopted in 2016 and entails both a consumer price on carbon, and an intensity-based system for industry which addresses competitiveness and carbon leakage. Provinces and territories may implement their own system of carbon pricing provided it meets the federal benchmark (and if they fail to do so the federal system will be imposed on them). In March 2022, Canada published its 2030 Emissions Reduction Plan (ERP) which builds on the Pan-Canadian Framework, and Net-Zero Emissions Accountability Act, and details the roadmap for Canada to meet its domestic climate target of a 40-45% reduction in GHG emissions by 2030 and attaining net-zero emissions by 2050. The ERP details the complementary policies and programs that Canada will enact to enable it to meet its domestic climate goal. Effective January 1, 2023, the federal carbon price was increased from $50 to $65 per tonne of carbon dioxide equivalent (tCO_2e). This will increase by $15 per tonne and rise to $170 per tCO_2e in 2030.

Gas Distribution and Storage
Our Gas Distribution and Storage operations, facilities and workers are subject to municipal, provincial and federal legislation which regulates 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 excess soil and contaminated sites; protection of environmentally sensitive areas, and species at risk and their habitats; 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 gas 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 and orders 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. Reports are submitted to our regulators as required 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 regulations continue to evolve and become more stringent, the cost to maintain compliance and the time required to obtain approvals continues to increase. A recent example includes the implementation of the new excess soil management requirements (Ontario Regulation 406/19) which has resulted in an increase in soil management costs and effort.

As in previous years, in 2022, we reported operational GHG emissions, including emissions from stationary combustion, flaring, venting and fugitive sources to Environment and Climate Change Canada (ECCC), the Ontario Ministry of Environment, Conservation and Parks, 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 are 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 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 beginning in 2023, rising to $170 per tCO2e 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.

The OBPS component came into effect in Ontario on January 1, 2019 and ended on December 31, 2021. 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. From 2019 to 2021, Enbridge Gas was registered with ECCC as an emitter in the OBPS program and has an annual compliance obligation associated with the combustion and flaring emissions from 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 was required to remit payment for facility emissions that exceed its annual facility emissions limit by December of the year following a compliance period. In accordance with the regulations, Enbridge Gas made payment for the 2021 compliance obligation in December 2022.

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 would stand down in Ontario at the end of 2021 and Ontario would 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, enabling the EPS to take effect on January 1, 2022. Effective January 1, 2022, Enbridge Gas transitioned out of the federal OBPS to the provincial EPS. Enbridge Gas is registered with the Ministry of the Environment, Conservation and Parks as a covered facility under the EPS and has an annual compliance obligation for its facility-related stationary combustion and flaring emissions associated with its transmission and storage operations. Enbridge Gas must remit payment annually on the portion of emissions that exceed its total annual emissions limit. Payment is due the year following a compliance period and as such, Enbridge Gas will remit payment for its 2022 EPS compliance obligation in 2023.

Enbridge Gas applies to the OEB annually through a Federal Carbon Pricing Program application for approval of just and reasonable rates effective April 1 each year for the Enbridge Gas Distribution Inc. and Union rate zones, to recover the costs associated with the Federal Carbon Charge and EPS Regulation as a pass-through to customers.

Renewable Power Generation

In March 2022, the Federal Government of Canada released a white paper setting out its plans for caps on emissions on Canada’s electricity grid with the intention of reaching a net-zero grid by 2035. The government subsequently proposed a CE Regulation framework and provided technical details for the program, which would cap emissions from electricity generation sources at, or near zero tCO2e per megawatt hour. Details of related compliance payments and potential credit generation opportunities are under review and the CE Regulation is expected to come into effect in 2023. Enbridge’s Renewable Power Generation resources are substantially non-emitting.

HUMAN CAPITAL RESOURCES

WORKFORCE SIZE AND COMPOSITION

As at December 31, 2022, we had approximately 11,100 regular employees, including approximately 1,600 unionized employees across our North American operations. This total rises to just over 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, EQUITY AND INCLUSION

In 2020, we announced Enbridge's ESG goals – including goals to increase representation of women, underrepresented ethnic and racial groups (including Indigenous peoples), people with disabilities and veterans – to ensure our workforce is reflective of the communities where we operate. In executing on our ESG strategy, we continue to track progress towards these representation goals in 2022. 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

Workforce comprised of **40%** women by 2025

28% from underrepresented ethnic and racial groups in our workforce by 2025

7% workplace representation of U.S. protected veterans by 2025

6% People with disabilities included in our workforce by 2025

3.5% representation within our workforce of Indigenous people by 2025

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 10, 2023:

Name	Age	Position
Gregory L. Ebel	58	President & Chief Executive Officer
Vern D. Yu	56	Executive Vice President, Corporate Development, Chief Financial Officer & President, New Energy Technologies
Colin K. Gruending	53	Executive Vice President & President, Liquids Pipelines
Cynthia L. Hansen	58	Executive Vice President & President, Gas Transmission and Midstream
Byron C. Neiles	57	Executive Vice President & Chief Administrative Officer
Robert R. Rooney	66	Executive Vice President & Chief Legal Officer
Matthew A. Akman	55	Senior Vice President, Corporate Strategy & President, Power
Michele E. Harradence	54	Senior Vice President & President, Gas Distribution
Laura J. Sayavedra	55	Senior Vice President, Safety & Reliability, Projects and Unify

Gregory L. Ebel was appointed President and Chief Executive Officer on January 1, 2023. Mr. Ebel is also a member of the Enbridge Board of Directors. Mr. Ebel served as Chair of the Enbridge Board of Directors following the merger of Enbridge and Spectra Energy Corp (Spectra Energy) in 2017 until January 1, 2023. Prior to that time, he served as Chairman, President and CEO of Spectra Energy from 2009 until February 27, 2017. Previously, Mr. Ebel also served as Spectra Energy's Group Executive and Chief Financial Officer beginning in 2007, President of Union Gas Limited from 2005 until 2007, and Vice President, Investor & Shareholder Relations of Duke Energy Corporation from 2002 until 2005.

Vern D. Yu was appointed Executive Vice President, Corporate Development, Chief Financial Officer & President, New Energy Technologies on January 1, 2023. Prior thereto, he served as Executive Vice President, Corporate Development and Chief Financial Officer from March 2022 to December 2022, and Executive Vice President and Chief Financial Officer from October 2021 to March 2022. Mr. Yu has oversight for all of Enbridge's financial affairs including investor relations, financial reporting, financial planning, treasury, tax, insurance, risk and audit management functions. He is also responsible for overseeing Enbridge's new energy technology ventures. Previously, Mr. Yu served as Executive Vice President and President, Liquids Pipelines from January 2020 to October 2021; President and Chief Operating Officer for Liquids Pipelines from June 2019 to December 2019; and Executive Vice President and Chief Development Officer from May 2016 to June 2019.

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 from June 2019 to October 2021; Senior Vice President, Corporate Development and Investment Review from May 2018 to June 2019; and Vice President, Corporate Development and Investment Review from February 2017 to May 2018.

Cynthia L. Hansen was appointed Executive Vice President and President, Gas Transmission and Midstream on March 1, 2022. Ms. Hansen is responsible for the overall leadership and operations of Enbridge's natural gas pipeline and midstream business across North America. Previously, she served as our Executive Vice President, Gas Distribution and Storage from June 2019 to March 2022 and as Executive Vice President, Utilities and Power Operations from February 2017 to June 2019. Ms. Hansen is also the Executive Sponsor for Asset and Work Management Transformation across Enbridge, working with other business unit leaders.

Byron C. Neiles was appointed Executive Vice President & Chief Administrative Officer on January 1, 2023. Prior thereto, he served as Executive Vice President, Corporate Services from May 2016 to December 2022. Mr. Neiles has oversight of our information technology, human resources, real estate, supply chain management, 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.

Matthew A. Akman was appointed Senior Vice President, Corporate Strategy & President, Power on January 1, 2023. Prior thereto, he was Senior Vice President, Strategy, Power & New Energy Technologies from October 2021 to December 2022, and Senior Vice President, Strategy & Power from June 2019 to October 2021. Mr. Akman is responsible for the overall leadership and operations of Enbridge's power business and also leads our corporate strategy efforts. Mr. Akman joined Enbridge in early 2016 as our head of Corporate Strategy and also previously held responsibilities for Corporate Development and Investor Relations.

Michele E. Harradence was appointed Senior Vice President & President, Gas Distribution and Storage on March 1, 2022. She is responsible for the overall leadership and operations of Ontario-based Enbridge Gas Inc., as well as Gazifère, which serves the Gatineau region of Québec. Prior to assuming her current role, Ms. Harradence was Senior Vice President and Chief Operations Officer of Enbridge's Gas Transmission and Midstream business unit from June 2019 to March 2022. Prior thereto, she was Senior Vice President Operations, Gas Transmission and Midstream from February 2017 to June 2019.

Laura J. Sayavedra was appointed Senior Vice President, Safety & Reliability, Projects and Unify on March 1, 2022. This includes oversight of our safety, capital project execution, environment, land, and right of way functions, and business leadership of our multi-year Unify transformation project. Prior to that, she led Finance Transformation at Enbridge, and was also Vice President & Treasurer for Spectra Energy, and CFO of Spectra Energy Partners. She has held various finance, strategy, and business development executive leadership roles.

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 MD&A for the year ended December 31, 2022, 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, 2022, 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 financial statements and MD&A for the year ended December 31, 2022, 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 is a systemic risk that presents both physical and transition risks to our organization. A summary of these risks is discussed below. Given the interconnected nature of climate impacts, 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, 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 materially adversely impacted as a result of climate change and its associated impacts.

PHYSICAL RISKS
Climate-related physical risks as a result of changing and more extreme weather, can damage our assets and affect the safety and reliability of our operations and has had such impacts in the past. Climate-related physical risks may be acute or chronic. Acute physical risks are those that are event-driven, including increased frequency and severity of extreme weather events, such as heavy snowfall, heavy rainfall, floods, landslides, fires, hurricanes, cyclones, tornados, tropical storms, ice storms, and extreme temperatures. Chronic physical risks are longer-term shifts in climate patterns, such as long-term changes in precipitation patterns, or sustained higher temperatures, which may cause sea level rises or chronic heat waves.

Our assets are exposed to potential damage or other negative impacts from these kinds of events, which could result in reduced revenue from business disruption or reduced capacity and may also lead to increased costs due to repairs and required adaptation measures. Such events may also result in 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.

TRANSITION RISKS

Transition risks relate to the transition to a lower-emissions 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 reputation, 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 regarding reduction of GHG emissions, adaptation to climate change, transition to a lower-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 are continually evolving. 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. Efforts to regulate or restrict GHG emissions could negatively impact demand for the products we transport. Significant expenditures and resources could be required in order to meet new regulatory requirements. In addition, there has been an increase in climate and disclosure-related litigation against governments as well as energy companies. There is no assurance that our company will not be impacted by such litigation.

  In addition, Enbridge is required to adhere to a number of implicit and explicit carbon-pricing mechanisms. Many jurisdictions in which we operate are either increasing the stringency of existing, or introducing new, legislation or public policy to address climate change and reduce GHG emissions. These mechanisms may present climate-related transition risk to our business strategy, impacting both commodity demand and the overall energy mix we deliver. Carbon pricing mechanisms may expose us to increased costs as well as increasing energy costs to our customers. Our operations are subject to both explicit carbon prices (i.e., in BC) and implicit carbon prices (i.e., Canadian federal OBPS). These requirements are evolving; in Canada, the federal government is considering options to cap and cut oil and gas sector GHG emissions, which may impact our business, including a new cap-and-trade system under the *Canadian Environmental Protection Act, 1999* or modification of the current carbon pricing approach under the *Greenhouse Gas Pollution Pricing Act*.

- ***Technology risks***

  Our success in executing our strategic plan, including adapting to the energy transition over time 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 lower-carbon energy infrastructure as well as modernization of our infrastructure to reduce GHG emissions. Achieving our GHG emissions reduction 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 does not materialize as expected, making it more difficult to reduce emissions.

- ***Market risks***

  Climate change concerns, increase in demand for lower-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 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 one of our strategic priorities is to adapt to the energy transition over time. 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 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.

- ***Disclosure risks***
  Finally, we currently provide certain climate-related disclosures, and from time to time, we establish and publicly announce goals and commitments to reduce our GHG emissions. These disclosures and goals, and our progress towards these commitments, may be based on standards for measuring progress that are still developing, internal controls and processes that continue to evolve, and assumptions that are subject to change in the future. There can be no assurance that our current or future disclosures and goals, the pathways by which we plan to reach our goals, or the methodologies that we currently use to support our disclosures and progress towards our goals, will satisfy any new and evolving regulations and legal requirements or expectations of our stakeholders, and the costs of aligning our current disclosures and goals to any new legal requirements may be significant. Additionally, if we fail to achieve or improperly report on our progress toward achieving our emissions reduction goals and commitments, we may be subject to reputational harm, regulatory action, or other legal action.

Companies across all sectors and industries are facing changing expectations or increasing scrutiny from stakeholders related to their approach to ESG matters, including climate change and GHG emissions. Companies in the energy industry are experiencing stakeholder opposition to new infrastructure, as well as organized opposition to oil and natural gas extraction and shipment of oil and natural gas products.

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 adapting to the energy transition over time 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 lower-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.

RISKS RELATED TO OPERATIONAL DISRUPTION OR CATASTROPHIC EVENTS

Operation of complex energy infrastructure involves many hazards and risks that may adversely affect our business, financial results and the environment.
These operational risks include adverse weather conditions, natural disasters, accidents, the breakdown or failure of equipment or processes, and lower than expected levels of operating capacity and efficiency. These operational risks could be catastrophic in nature.

Operational risk is also intensified by climate change. Climate change presents physical risks that may affect the safety and reliability of our operations. These include acute physical risks, such as heavy snowfall, heavy rainfall, floods, landslides, fires, hurricanes, cyclones, tornados, tropical storms, ice storms, and extreme temperatures, and chronic physical risks, such as long-term changes in precipitation patterns, or sustained higher temperatures.

Our assets and operations are exposed to potential damage or other negative impacts from these operational risks, which could result in reduced revenue from business disruption or reduced capacity and may also lead to increased costs due to repairs and required adaptation measures. Such events have led to, could in the future lead to, rupture or release of product from our pipeline systems and facilities, or loss of life or injury to people, which could result in substantial losses for which insurance may not be sufficient or available and for which we may bear part or all of the cost.

An environmental incident is an event that may cause environmental harm and could lead to increased operating and insurance costs, 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, security incident (cyber or physical), 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, and this has in the past and may again lead to claims against us. We have experienced, and may again experience, service interruptions, restrictions or other operational constraints, 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 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 operating and insurance costs.

Cyber attacks pose threats to our technology systems and could materially adversely affect our business, operations, reputation 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, damage to our facilities or those of our customers, or releases of hydrocarbon products for which we could be held liable, all of which could materially adversely affect our reputation, business, operations or financial results. 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 of cyber attacks and data security breaches, as well as due to international and domestic political factors including geopolitical tensions, armed hostilities, war, civil unrest, sabotage and terrorism. Human error can also contribute to a cyber incident, and cyber attacks can be internal as well as external and occur at any point in our supply chain. 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. Cyber threat actors have attacked and threatened to attack energy infrastructure, and various government agencies have increasingly stressed that these attacks are targeting critical infrastructure, and are increasing in sophistication, magnitude, and frequency. New cybersecurity legislation, regulations and orders have been recently implemented or proposed resulting in additional actual and anticipated regulatory oversight and compliance requirements, which will require significant internal and external resources. We cannot predict the potential impact to our business of potential future legislation, regulations or orders relating to cybersecurity.

We have been, and expect to continue to be, the target of cyber-attacks against which we have deployed, and continue to deploy, security measures. Our information systems or those of our vendors or other service providers are expected to become the target of further cyber attacks or security breaches which could compromise our data and systems, affect our ability to correctly record, process and report transactions, result in the loss of information, or cause operational disruption or incidents. As a result of a cyber attack or security breach, we could also be liable under laws that protect the privacy of personal information, be subject to regulatory action, fines or penalties, incur additional costs for remediation, litigation, breach of contract or indemnity claims, or other costs, all of which could materially adversely affect our reputation, business, operations or financial results.

In addition, a cyber attack could occur and persist for an extended period without detection. Any investigation of a cyber attack or other security incident may be inherently unpredictable, and it would take time before the completion of any investigation and availability of full and reliable information. During such time, we may not know the extent of the harm or how best to remediate it, and certain errors or actions could be repeated or compounded before they are discovered and remediated, all or any of which could further increase the costs and consequences of a cyber attack or other security incident, and our remediation efforts may not be successful. The inability to implement, maintain and upgrade adequate safeguards could materially and adversely affect our results of operations, cash flows, and financial condition. As cyber attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities.

Furthermore, media reports about a cyber attack or other significant security incident affecting the Company, whether accurate or not, or, under certain circumstances, our failure to make adequate or timely disclosures to the public, law enforcement, other regulatory agencies or affected individuals following any such event, whether due to delayed discovery or otherwise, could negatively impact our operating results and result in other negative consequences, including damage to our reputation or competitiveness, harm to our relationships with customers, partners, suppliers and other third parties, interruption to our management, remediation or increased protection costs, significant litigation or regulatory action, fines or penalties, all of which could materially adversely affect our business, operations, reputation or financial results.

Pandemics, epidemics or infectious 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 infectious disease outbreaks could materially adversely affect our business, operations, financial results and forward-looking expectations. Governments' emergency measures to combat the spread could include restrictions on business activity and travel, as well as requirements to isolate or quarantine. The duration and magnitude of such impacts will depend on many factors that we may not be able to accurately predict. COVID-19 and government responses interrupted business activities and supply chains, disrupted travel, and contributed to significant volatility in the financial and commodity markets.

Disruptions related to pandemics, epidemics or infectious disease outbreaks could 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, armed hostilities, war, sabotage, or 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 critical infrastructure targets, such as energy-related assets, are at greater risk of cyber attack and may be at greater risk of other future attacks than other targets in the US and Canada. The Company’s infrastructure and projects under construction could be direct targets or indirect casualties of a cyber or physical attack. In addition, increased environmental activism against pipeline construction and operation could potentially result in work delays, reduced demand for our products and services, new legislation or public policy or increased stringency thereof, or denial or delay of permits and rights-of-way.

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 and global 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. 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 causes our inspection, maintenance or repair costs to increase.

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 and construction techniques, some assets require more frequent inspections, which has resulted in and is expected to continue to 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.
Our Liquids Pipelines business faces competition from competing carriers available to ship liquid hydrocarbons to markets in Canada, the US and internationally and from proposed pipelines that seek to access basins and 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. The liquids transported in our pipelines currently, or are expected to increasingly, compete with other emerging alternatives for end-users, including, but not limited to, electric batteries, biofuels, and hydrogen. Additionally, we 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 also competes with other forms of energy available to our customers and end-users, including electricity, coal, propane, fuel oils, and renewable energy. Our 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.

Completion of our secured projects and maintenance programs are subject to various regulatory, operational and market risks, which may affect our ability to drive long-term growth.
Our project execution continues to face challenges with intense scrutiny on regulatory and environmental permit applications, politicized permitting, public opposition including protests, action to repeal permits, and resistance to land access.

Continued challenges with global supply chains have created unpredictability in materials cost and availability. Labor shortages and union strikes have increased costs of engineering and construction services.

Other events that can and have delayed project completion and increased anticipated costs include contractor or supplier non-performance, extreme weather events or geological factors beyond our control.

Changing expectations of stakeholders regarding ESG practices and climate change could erode stakeholder trust and confidence, 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, GHG emissions, safety and stakeholder and Indigenous relations remain primary focus areas, while other environmental elements such as biodiversity and supply chain are ascendant. Companies in the energy industry are experiencing stakeholder opposition to new and existing infrastructure, as well as organized opposition to oil and natural gas extraction and shipment of oil and natural gas products. Changing expectations of our practices and performance across these ESG areas may impose additional costs or create exposure to new or additional risks. We are also exposed to the risk of higher costs, delays, project cancellations, loss of ability to secure new growth opportunities, new restrictions or the cessation of operations of existing pipelines due to increasing pressure on governments and regulators, and legal action, such as the legal challenges to the operation of Line 5 in Michigan and Wisconsin.

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

Enhanced public awareness of climate change has driven an increase in demand for lower-carbon and zero-emissions energy. Over the past year, the invasion of Ukraine and inflationary pressure following the COVID-19 pandemic have underscored the critical need for access to secure affordable energy. Enbridge has a long history of diversifying its portfolio of businesses to align with the mix of energy that people need and want. The pace and scale of the transition to a lower-emission economy may pose a risk if Enbridge diversifies either too quickly or too slowly. Similarly, unexpected shifts in energy demands, including due to climate change concerns, can impact revenue through reduced throughput volumes on our pipeline transportation systems.

We have long been committed to strong ESG practices, performance and reporting, and in 2020 introduced a set of ESG goals to strengthen transparency and accountability. The goals include increasing diversity and inclusion within our organization and reducing GHG 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. The costs associated with meeting our ESG goals, including 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 our ESG goals may fail to materialize, may cost more than anticipated to achieve, may not occur within the anticipated time periods or may no longer meet changing stakeholder expectations. Similarly, there is a risk that emissions reduction technologies do not materialize as expected making it more difficult to reduce emissions. If we are not able to achieve our ESG goals, are not able to meet current and future climate, emissions or related reporting requirements of regulators, or are unable to meet or manage current and future expectations regarding issues important to investors or other stakeholders (including those related to climate change), it could erode stakeholder trust and confidence, which could negatively impact our reputation, business, operations or financial results. Potential impacts could also include changing investor sentiment regarding investment in Enbridge or impair our access to and increase our cost of capital, including penalties associated with our sustainability-linked financing.

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 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 systems.

Our insurance coverage may not fully cover our losses in the event of an accident, natural disaster or other hazardous event, and we may encounter increased cost arising from the maintenance of, or lack of availability of, insurance.
Our operations are subject to many hazards inherent in our industry. Our assets may experience physical damage as a result of an accident or natural disaster. These hazards can also cause, 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 an insurance program for us, our subsidiaries and certain of our affiliates to mitigate a certain portion of our risks. However, not all potential risks arising from our operations are insurable, or are insured by us as a result of availability, high premiums and for various other reasons. The Company self-insures a significant portion of certain risks through our wholly-owned captive insurance subsidiaries, and the Company's insurance coverage is subject to terms and conditions, exclusions and large deductibles or self-insured retentions which may reduce or eliminate coverage in certain circumstances.

The Company's insurance policies are generally renewed on an annual basis and, depending on factors such as market conditions, the premiums, terms, policy limits and/or deductibles can vary substantially. We can give no assurance that we will be able to maintain adequate insurance in the future at rates or on other terms we consider commercially reasonable. In such case, we may decide to self-insure additional risks.

A significant self-insured loss, uninsured loss, a loss significantly exceeding the limits of our insurance policies, a significant delay in the payment of a major insurance claim, or the failure to renew insurance policies on similar or favorable terms could materially and adversely affect our business, financial condition and results of operations.

We are exposed to the credit risk of our customers, counterparties, and vendors.
We are exposed to the credit risk of multiple parties 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 the creditworthiness of our customers, vendors, or counterparties. It is possible that payment or performance defaults from these entities, if significant, could adversely affect our earnings and cash flows.

Our business is exposed to changes in market prices including interest rates and foreign exchange rates. Our risk management policies cannot eliminate all risks and may result in material financial losses. In addition, any non-compliance with our risk management policies could adversely affect our business, operations or financial results.
Our use of debt financing exposes us to changes in interest rates on both future fixed rate debt issuances and floating rate debt. While our financial results are denominated in Canadian dollars, many of our businesses have foreign currency revenues or expenses, particularly the US dollar. Changes in interest rates and foreign exchange rates could materially impact our financial results.

We use financial derivatives to manage risks associated with changes in foreign exchange rates, interest rates, commodity prices, power prices and our share price to reduce volatility of our cash flows. Based on our risk management policies, substantially 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.

In addition, to the extent that we hedge our foreign exchange rates, interest rates or commodity prices, we will forego the benefits we would otherwise experience if these were to change in our favor. In addition, hedging activities can result in losses that might be material to our financial condition, results of operations and cash flows. Such losses have occurred in the past and could occur in the future. See Part II, *Item 7A. Quantitative and Qualitative Disclosures about Market Risk* and *Item 8. Financial Statements and Supplementary Data* for a discussion of our derivative instruments and related hedging activities.

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, other professionals and executive officers and senior management. 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 Liquids Pipelines growth rate and results may be directly and indirectly affected by commodity prices and government policy.

Effective December 31, 2021, the Government of Alberta lifted the oil production curtailment that was imposed in December 2018. Wide commodity price basis between Western Canada and global tidewater markets have negatively impacted producer netbacks and margins in the past years that largely resulted from pipeline infrastructure takeaway capacity from producing regions in Western Canada and North Dakota which are operating at capacity. A protracted long-term outlook for low crude oil prices could result in delay or cancellation of future projects.

The tight 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 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. To a lesser degree, the financial results of our US Transmission business are subject to fluctuation in power prices which impact electric power costs associated with operating compressor stations.

Energy Services generates margin by capitalizing on quality, time and location differentials when opportunities arise. Changing market conditions that impact the prices at which we buy and sell commodities have in the past limited margin opportunities and impeded Energy Services' ability to cover capacity commitments and could do so again in the future. Other market conditions, such as backwardation, have likewise limited margin opportunities.

We rely on access to short-term and long-term capital markets to finance capital requirements and support liquidity needs. 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 refinance investments originally financed with 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 at various entities to backstop commercial paper programs, for borrowings and for providing letters of credit. These facilities typically include financial covenants and failure to maintain these covenants at a particular entity could preclude that entity from accessing the credit facility, which could impact liquidity. 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.

Recently, interest rates have increased significantly. If we are not able to access capital at competitive rates or at all, our ability to finance operations and implement our strategy may be affected. An inability to access capital on favorable terms or at all may limit our ability to pursue enhancements or acquisitions that we may otherwise rely on for future growth or to refinance our existing indebtedness. 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 permitting and environmental review for energy infrastructure companies in Canada and the US continues to evolve.

Within the US and in Canada, pipeline companies continue to face opposition from anti-energy/anti-pipeline activists, Indigenous and tribal groups and communities, citizens, environmental groups, and politicians concerned with either the safety of pipelines or their potential environmental effects. In the US, the Environmental Protection Agency redefined the Waters of the United States under Section 401 of the Clean Water Act, and the FERC released draft policy statements on the Certification of New Interstate Natural Gas Facilities and the Consideration of Greenhouse Gas Emissions in Natural Gas Infrastructure Project Review that could introduce changes to the regulatory approval process for natural gas infrastructure. The Council for Environmental Quality published immediately applicable guidance for conducting analyses under the National Environmental Policy Act that may significantly change environmental scope and cost assessments. Many other regulations adopted during the previous US presidential administration are being challenged in multiple courts and some have been overturned by reviewing courts. The current US administration may take further action to modify or reverse regulations that were promulgated by the previous US administration.

In March of 2023, the Supreme Court of Canada will hear the Attorney General of Canada's appeal of the Alberta Court of Appeal's non-binding decision that the federal Impact Assessment Act ("IAA") is unconstitutional. The IAA includes impact assessment requirements that could apply to either federally or provincially regulated pipeline projects that fall within prescribed criteria or that the federal Minister of Environment otherwise designates for review. The potential for any pipeline project to be subject to IAA requirements adds significant uncertainty as to regulatory timelines and outcomes. The Alberta Court of Appeal found that the IAA is an impermissible federal overreach into provincial jurisdiction that would amount to a de facto expropriation of provincial natural resources and proprietary interests by the federal government. The Supreme Court of Canada will determine whether the IAA and the related Physical Activities Regulations are within the constitutional legislative authority of the Parliament of Canada, the outcome of which could impact the applicability of the legislation to provincially regulated pipeline projects.

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 significant 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 and climate laws and regulations, including those relating to climate change and GHG emissions and climate-related disclosure, 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 past, current, and future operations, including air emissions, water quality, wastewater discharges, solid waste and hazardous waste.

If we are unable to obtain or maintain all required environmental regulatory approvals and permits for our operating assets and projects or if there is a delay in obtaining any required environmental regulatory approvals or permits, the operation of existing facilities or the development of new facilities could be prevented, delayed, or become subject to additional costs. Failure to comply with environmental laws and regulations may result in the imposition of civil or criminal fines, penalties and injunctive measures affecting our operating assets. We expect that changes in environmental laws and 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 for utilization of our pipelines or other facilities.

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, permits, 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. We have experienced litigation in relation to certain Line 5 easements; refer to Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Legal and Other Updates*.

Regulatory 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, gas transmission and distribution assets are subject to the actions of various regulators, including the CER, the FERC, and the OEB with respect to the rates, tariffs, and tolls for these assets. 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 the Mainline Commercial Framework, could have an adverse effect on our revenues and earnings.

Our Renewable Power Generation assets in Europe (France, Germany and the UK) are also subject to the directives, regulations and policies established and enforced by the EU and the UK government. These measures are variable and can include price controls, caps and demand reduction goals, all of which can have a negative impact on our revenues and earnings.

We are 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, Canada has introduced interest deductibility rules, the US enacted the Inflation Reduction Act and we are anticipating 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, or by other legal proceedings. Litigation is subject to many uncertainties, and we cannot predict the outcome of individual matters with assurance. It is reasonably possible that the final resolution of some of the matters in which we are involved or new matters 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 I. *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 regulatory actions and proceedings which arise in the ordinary course of business. 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. 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.

On October 17, 2022, four separate comprehensive enforcement resolutions were announced with the Minnesota Pollution Control Agency, Minnesota Department of Natural Resources (DNR), Fond du Lac Band of Lake Superior Chippewa, and Minnesota Attorney General's Office related to alleged violations that occurred during construction of Line 3 Replacement. As part of these agreements, together with the DNR's previous Administrative Penalty Order, Enbridge will provide the various entities a total of approximately US$11 million, approximately US$7.5 million of which is to provide financial assurances and fund multiple environmental and resource enhancement projects. The Minnesota Attorney General has filed a misdemeanor criminal charge for the taking of water without a permit at the Clearbrook aquifer, with this charge against us to be dismissed following one year of compliance with the state water appropriation rules.

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 3, 2023, there were 76,001 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, 2022.

Recent Sales of Unregistered Equity Securities

None.

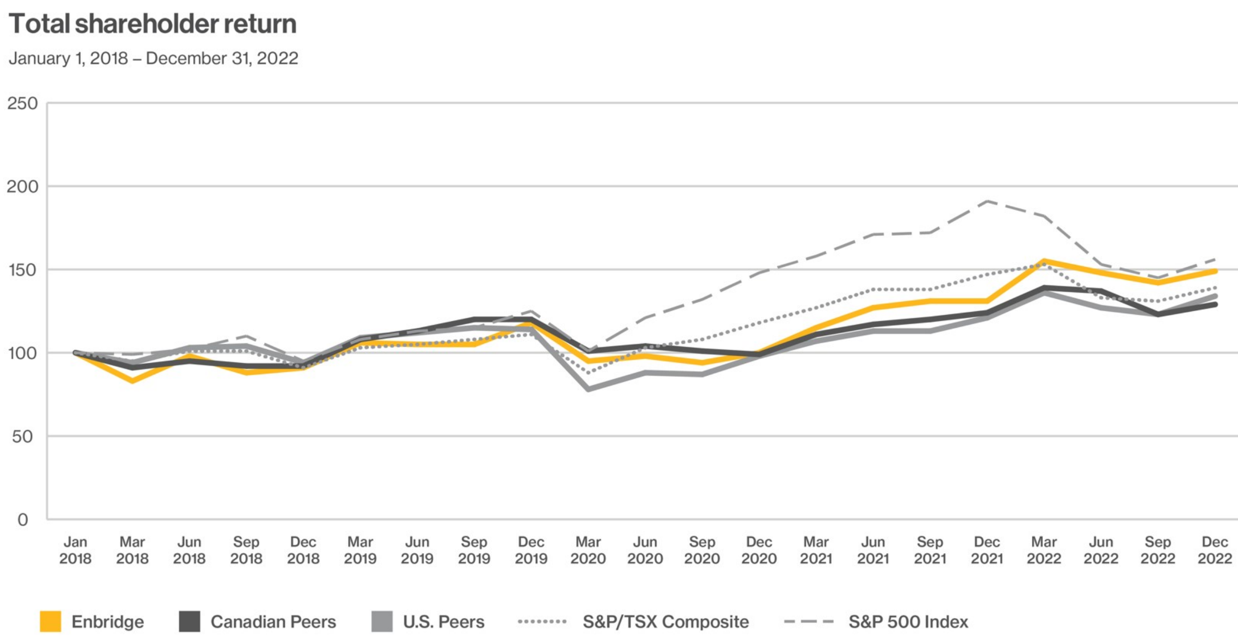
Issuer Purchases of Equity Securities

Period	Total number of shares purchased	Average price paid per share	Total number of shares purchased as part of publicly announced plans or programs	Maximum number of shares that may yet be purchased under the plans or programs[1]
October 2022 (October 1 - October 31)	—	N/A	—	28,324,366
November 2022 (November 1 - November 30)	—	N/A	—	28,324,366
December 2022 (December 1 - December 31)	—	N/A	—	28,324,366

1 On December 31, 2021, we announced that the TSX approved our prior 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. Our prior NCIB commenced on January 5, 2022 and expired on January 4, 2023. On January 4, 2023, we announced that the TSX had approved our new NCIB, which commenced on January 6, 2023 and continues until January 5, 2024. Under the new NCIB, Enbridge may purchase, for cancellation, up to 27,938,163 of its outstanding common shares to an aggregate amount of up to $1.5 billion. Purchases may be made through the facilities of the TSX, the NYSE and other designated exchanges and alternative trading systems.

Total Shareholder Return

The following graph reflects the comparative changes in the value from January 1, 2018 through December 31, 2022 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, by stock symbols, CNP, D, DTE, DUK, EPD, ET, KMI, MMP, NEE, NI, OKE, PAA, PCG, SO, SRE and WMB) and (5) our Canadian peer group (comprising, by stock symbols, CU, FTS, PPL and TRP). The amounts included in the table were calculated assuming the reinvestment of dividends.



	January 1, 2018	December 31, 2018	2019	2020	2021	2022
Enbridge Inc.	100.00	91.90	118.86	100.80	131.30	149.54
S&P/TSX Composite	100.00	91.11	111.96	118.23	147.89	139.25
S&P 500 Index	100.00	95.62	125.72	148.85	191.58	156.88
US Peers[1]	100.00	94.80	114.97	98.40	121.17	134.17
Canadian Peers	100.00	92.00	120.56	99.72	124.49	129.22

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 2022 and 2021 items and year-over-year comparisons between 2022 and 2021. For discussion of 2020 items and year-over-year comparisons between 2021 and 2020, 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, 2021.

RECENT DEVELOPMENTS

Chair of the Board and CEO Appointments

Pamela L. Carter was appointed Chair of the Board of Directors (the Board) effective January 1, 2023. Gregory L. Ebel was appointed as President and Chief Executive Officer (CEO) effective the same date. Mr. Ebel succeeds retiring President and CEO, Al Monaco. To support Mr. Ebel through the transition, Mr. Monaco will serve as an advisor until June 30, 2023. Mr. Ebel will continue as a member of the Board. Ms. Carter has served as a director of the Board since 2017 and with Spectra Energy Corp since 2007. Most recently she has served as Chair of the Human Resources & Compensation Committee of the Board, as a member of the Sustainability and Safety & Reliability Committees and as a former Chair of the Governance Committee.

ASSET TRANSACTIONS

Joint Venture Merger Transaction to Advance US Gulf Coast Oil Strategy

On August 17, 2022, we completed a joint venture merger transaction with Phillips 66 (P66) resulting in a single joint venture, DCP Midstream LLC, holding both Enbridge Inc.'s (Enbridge) and P66's indirect ownership interests in Gray Oak Pipeline, LLC (Gray Oak) and DCP Midstream, LP (DCP), as well as an agreement to realign our respective economic and governance interests in the underlying business operations. Our effective economic interest in Gray Oak has increased to 58.5% from 22.8%, and we will assume operatorship of Gray Oak in the second quarter of 2023. Simultaneously, our effective economic interest in DCP has been reduced to 13.2% from 28.3%. We received approximately $522 million (US$404 million) in cash proceeds and recorded an accounting gain of approximately $1.1 billion (US$832 million) in the Consolidated Statements of Earnings as a result of the transaction.

Acquisition of Tri Global Energy, LLC

On September 27, 2022, we acquired Tri Global Energy, LLC (TGE), a leading United States (US) renewable power project developer, for approximately US$270 million in cash and assumed debt. The acquisition of TGE enhances our renewable power platform and further builds on our inventory of North American growth opportunities for wind and solar projects.

Athabasca Indigenous Investments Partnership

On October 5, 2022, we completed a transaction with Athabasca Indigenous Investments Limited Partnership (Aii), a newly created entity representing 23 First Nation and Métis communities, in which Aii acquired an 11.6% non-operating interest in seven Regional Oil Sands pipelines in northern Alberta for $1.1 billion.

Increased Ownership in Cactus II Pipeline
On November 2, 2022, we acquired an additional 10.0% ownership in Cactus II Pipeline from Western Midstream Partners, L.P., for cash payment of $241 million (US$177 million), bringing our total non-operating ownership to 30.0%. Plains All-American Pipeline, L.P. remains the operator with a 70% ownership stake.

Woodfibre LNG Limited Partnership Agreement
On November 29, 2022, we finalized our partnership agreement with Pacific Energy Corporation Limited. We acquired, for cash payment of $533 million (US$392 million), an effective 30.0% interest in Woodfibre LNG Limited Partnership (Woodfibre), which will operate the 2.1 million tonnes per annum Woodfibre LNG facility located in Squamish, British Columbia (BC). The facility, via an interconnect with FortisBC Energy Inc., is an extension of the BC Pipeline System, which will supply gas to the facility under a 40-year transportation agreement.

GAS TRANSMISSION AND MIDSTREAM PROCEEDINGS

Texas Eastern Transmission
Texas Eastern Transmission, LP (Texas Eastern) filed two rate cases in the third quarter of 2021. These two rate proceedings have since been consolidated and settlement negotiations began during the first quarter of 2022. An uncontested settlement in principle was reached on July 7, 2022. Texas Eastern filed an uncontested Stipulation and Agreement on September 8, 2022 to resolve all issues from the rate proceedings. The Federal Energy Regulatory Commission (FERC) approved the Stipulation and Agreement on November 30, 2022, and the Stipulation and Agreement became effective on January 1, 2023.

Maritimes & Northeast Pipeline
The toll settlement agreement for the Canadian portion of our Maritimes & Northeast (M&N Canada) Pipeline system expired in December 2021. In December 2021, the Canada Energy Regulator (CER) approved interim tolls for M&N Canada effective January 1, 2022, which were based on the negotiated 2022 tolls in the 2022-2023 settlement agreement and unanimously supported by shippers. The 2022-2023 M&N Canada settlement agreement was approved by the CER in February 2022.

British Columbia Pipeline
The toll settlement agreement for our BC Pipeline system expired in December 2021. In December 2021, the CER approved interim tolls for BC Pipeline effective January 1, 2022. In the fourth quarter of 2022, a five-year 2022-2026 BC Pipeline settlement agreement was approved by shippers and subsequently approved as filed by the CER.

GAS DISTRIBUTION AND STORAGE RATE APPLICATIONS

2022 Rate Application
Enbridge Gas Inc.'s (Enbridge Gas) rate applications are filed in two phases. In June 2021, Enbridge Gas filed Phase 1 of the application with the Ontario Energy Board (OEB) for the setting of rates for 2022 (the 2022 Application). The 2022 Application was filed in accordance with the parameters of Enbridge Gas' OEB approved Price Cap Incentive Regulation (IR) rate setting mechanism and 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. In April 2022, the OEB issued its decision on Phase 2 of the 2022 Application filed in October 2021, addressing incremental capital module (ICM) funding requirements, under which $127 million of the requested capital funding was approved and incorporated into final rates, effective July 1, 2022.

2023 Rate Application
In June 2022, Enbridge Gas filed Phase 1 of the application with the OEB for the setting of rates for 2023 (the 2023 Application). The 2023 Application was filed in accordance with the parameters of Enbridge Gas' OEB approved Price Cap IR rate setting mechanism and represents the final year of a five-year term. In November 2022, the OEB approved the Phase 1 Settlement Proposal and Final Rate Order effective January 1, 2023. In addition, Enbridge Gas did not anticipate 2023 capital investments to require incremental funding during the final year of its current Price Cap IR term, and, as such, Enbridge Gas did not make a Phase 2 ICM request as part of the 2023 Application.

2024 Rebasing and Incentive Rate-Setting Mechanism Application
In October 2022, Enbridge Gas filed its application with the OEB to establish a 2024 through 2028 rate setting framework. The application and framework seek approval to establish 2024 base rates on a cost-of-service basis and to establish a price cap IR rate setting mechanism to be used for the remainder of the IR term (2025-2028). The OEB has determined it will hear the application in two phases, with Phase 1 addressing items that affect rates effective January 1, 2024, and Phase 2 addressing items that will affect rates subsequent to January 1, 2024. An OEB decision is expected on Phase 1 of the application in the second half of 2023.

Purchase Gas Variance
The Purchase Gas Variance Account (PGVA) captures the difference between actual and forecasted natural gas prices reflected in rates. Account balances are typically recovered or refunded over a prospective 12-month period through Quarterly Rate Adjustment Mechanism (QRAM) applications.

In March and June 2022, the OEB approved Enbridge Gas' April 1, 2022 and July 1, 2022 QRAM applications, respectively. Due to the significant increase in natural gas prices, the approvals have also included rate mitigation plans intended to ease bill impacts to ratepayers. Specifically, the approved rate mitigation plans extended the PGVA recovery period from 12 months to 24 months in both applications. As an additional mitigation measure, as part of the April 1, 2022 QRAM, a portion of the PGVA balance was deferred for recovery, which was subsequently approved for recovery as part of the July 1, 2022 QRAM. In September and December 2022, the October 1, 2022 and January 1, 2023 QRAM applications were filed and approved by the OEB with no adjustments to the prior period rate mitigation plans and did not include any additional rate mitigation measures.

As at December 31, 2022, Enbridge Gas' PGVA receivable balance was $434 million.

FINANCING UPDATE
We completed long-term debt issuances totaling US$3.2 billion and $3.4 billion during the year ended December 31, 2022, including $900 million of 10-year sustainability-linked medium-term notes in November 2022. We increased our credit facilities during our annual renewal process by approximately $640 million and also entered into new term loans with maturities ranging from 2023 to 2027 totaling approximately $3.2 billion.

Our 2022 financing activities have provided 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 be unattractive. Refer to *Liquidity and Capital Resources*.

As at December 31, 2022, after adjusting for the impact of floating-to-fixed interest rate swap hedges, approximately 6% of our total debt is exposed to floating rates. Refer to Part II. *Item 8. Financial Statements and Supplementary Data - Note 24. Risk Management and Financial Instruments* for more information on our interest rate hedging program.

NORMAL COURSE ISSUER BID

On January 4, 2023, we announced that the Toronto Stock Exchange (TSX) had approved our new normal course issuer bid (NCIB) to purchase for cancellation up to 27,938,163 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. The NCIB follows on the termination of our prior NCIB, which expired on January 4, 2023.

Purchases under the NCIB may be made through the facilities of the TSX, the New York Stock Exchange and other designated exchanges and alternative trading systems commencing on January 6, 2023 and continuing until January 5, 2024, when the NCIB expires, or such earlier date on which Enbridge has either acquired the maximum number of common shares allowable under the NCIB or otherwise decided not to make any further repurchases under the NCIB. The maximum number of common shares that Enbridge may purchase for cancellation under the NCIB represents approximately 1.38% of the 2,024,890,423 common shares issued and outstanding as at December 23, 2022.

RESULTS OF OPERATIONS

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars, except per share amounts)			
Segment earnings/(loss) before interest, income taxes and depreciation and amortization[1]			
Liquids Pipelines	**8,364**	7,897	7,683
Gas Transmission and Midstream	**3,126**	3,671	1,087
Gas Distribution and Storage	**1,827**	2,117	1,748
Renewable Power Generation	**262**	508	523
Energy Services	**(417)**	(313)	(236)
Eliminations and Other	**(1,124)**	356	(113)
Earnings before interest, income taxes and depreciation and amortization[1]	**12,038**	14,236	10,692
Depreciation and amortization	**(4,317)**	(3,852)	(3,712)
Interest expense	**(3,179)**	(2,655)	(2,790)
Income tax expense	**(1,604)**	(1,415)	(774)
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**65**	(125)	(53)
Preference share dividends	**(414)**	(373)	(380)
Earnings attributable to common shareholders	**2,589**	5,816	2,983
Earnings per common share attributable to common shareholders	**1.28**	2.87	1.48
Diluted earnings per common share attributable to common shareholders	**1.28**	2.87	1.48

1 Non-GAAP financial measures.

EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS

Year ended December 31, 2022 compared with year ended December 31, 2021

Earnings attributable to common shareholders decreased by $3,368 million due to certain infrequent or other non-operating factors, primarily explained by the following:

- a goodwill impairment of $2.5 billion relating to our Gas Transmission reporting unit;
- non-cash, net unrealized derivative fair value losses of $1,265 million ($964 million after-tax) in 2022, compared with unrealized gains of $197 million ($150 million after-tax) in 2021, reflecting changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange risks;
- an asset impairment loss of $227 million ($173 million after-tax) to our Magic Valley Wind Farm (Magic Valley);

- an asset impairment loss of $183 million ($137 million after-tax) on the US and Canadian components of the interstate pipeline transportation system within the North Dakota System of our Bakken System;
- a transaction cost of $114 million in relation to our investment purchase in the Woodfibre LNG project;
- an impairment of $44 million ($34 million after-tax) for lease assets due to office relocation plans;
- an asset impairment loss of $40 million ($30 million after-tax) relating to MacKay River line within our Alberta Regional Oil Sands System;
- the absence in 2022 of a gain of $303 million ($298 million after-tax) from the sale of our investment in Noverco Inc. (Noverco); and
- the absence in 2022 of a $57 million ($43 million after-tax) property tax settlement received in 2021 related to the resolution of Minnesota property tax appeals for 2012-2018.

The factors above were partially offset by:
- a gain of $1,076 million ($732 million after-tax) on the closing of the joint venture merger transaction with P66 realigning our effective economic interests in Gray Oak and DCP;
- a gain of $118 million ($89 million after-tax) on Texas Eastern recorded to reflect a settlement with a transportation customer undergoing bankruptcy;
- a deferred tax benefit of $95 million recognized as a result of the reduced Pennsylvania state corporate income tax;
- a non-cash, net negative equity earnings adjustment of $10 million ($7 million after-tax) in 2022, compared to a net negative adjustment of $44 million ($33 million after-tax) in 2021 relating to our share of changes in the mark-to-market value of derivative financial instruments of our equity method investee, DCP;
- transition and transformation costs of $66 million ($50 million after-tax) in 2022, compared to $147 million ($112 million after-tax) in 2021; and
- the absence in 2022 of an impairment loss of $111 million ($83 million after-tax) to our investment in the PennEast Pipeline Company, LLC (PennEast) pipeline project.

The non-cash, unrealized derivative fair value gains and losses discussed above generally arise as a result of our comprehensive economic hedging program to mitigate 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 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 $141 million increase in earnings attributable to common shareholders is primarily explained by the following significant business factors:
- higher throughput within our Liquids Pipelines segment driven by higher demand and incremental Line 3 Replacement (L3R) capacity that came into service October 2021;
- increased earnings within our Liquids Pipelines segment from the implementation of the full L3R surcharge when compared to the lower surcharge on the Canadian portion of the project in effect prior to October 2021, as well as from new US export assets acquired in October 2021;
- increased earnings from our Gas Transmission and Midstream segment primarily as a result of higher commodity prices benefiting our investments in DCP and Aux Sable, as well as higher contributions from projects placed into service in November 2021; and
- recognition of revenues attributable to the Texas Eastern rate case resulting from a FERC-approved Stipulation and Agreement; partially offset by
- the recognition of a provision against the interim Mainline International Joint Tariff (IJT) for barrels shipped for the full year in 2022, as compared to the barrels shipped in the second half of 2021 following the expiry of the Competitive Toll Settlement (CTS);

- higher interest expense primarily due to higher interest rates and higher average principal, as well as reduced capitalized interest associated with the US portion of the L3R Project placed into service in the fourth quarter of 2021;
- higher depreciation and amortization expense as a result of several projects placed into service in the fourth quarter of 2021, as well as for new US export assets acquired in October 2021; and
- higher income tax expense due to higher earnings, higher US minimum taxes, and the effect of rate-regulated accounting for income taxes.

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

Transportation and other services revenues of $18.5 billion, $16.2 billion and $16.2 billion for the years ended December 31, 2022, 2021 and 2020, 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 $5.7 billion, $4.0 billion and $3.7 billion for the years ended December 31, 2022, 2021 and 2020, 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 $29.2 billion, $26.9 billion and $19.3 billion for the years ended December 31, 2022, 2021 and 2020, 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 (NGL) 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

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Earnings before interest, income taxes and depreciation and amortization[1]	**8,364**	7,897	7,683

1 Non-GAAP financial measure.

Year ended December 31, 2022 compared with year ended December 31, 2021

EBITDA was negatively impacted by $710 million due to certain infrequent or other non-operating factors, primarily explained by the following:

- non-cash, net unrealized losses of $183 million in 2022, compared with unrealized gains of $120 million in 2021, 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;
- total asset impairment loss of $183 million on the US and Canadian components of the interstate pipeline transportation system within the North Dakota System of our Bakken System;
- an asset impairment loss of $40 million relating to MacKay River line within our Alberta Regional Oil Sands System; and
- the absence in 2022 of a $57 million property tax settlement received in 2021 related to the resolution of Minnesota property tax appeals for 2012-2018.

After taking into consideration the factors above, the remaining $1.2 billion increase is primarily explained by the following significant business factors:

- higher Mainline System ex-Gretna average throughput of 3.0 million barrels per day (mmbpd) in 2022 as compared to 2.8 mmbpd in 2021 driven by higher demand and incremental L3R capacity that came into service October 2021;
- implementation of the full L3R surcharge when compared to the lower surcharge on the Canadian portion of the project in effect prior to October 2021;
- higher contributions from the Gulf Coast and Mid-Continent System due primarily to the acquisition of the Enbridge Ingleside Energy Center and related assets in the fourth quarter of 2021 in addition to the increased effective economic interest in the Gray Oak pipeline during the third quarter of 2022 and higher volumes from Flanagan South Pipeline;
- higher contributions from the Bakken System due to higher volumes; and
- the favorable effect of translating US dollar EBITDA at a higher average exchange rate in 2022 compared to the same period in 2021; partially offset by
- the recognition of a provision against the interim Mainline IJT for barrels shipped for the full year in 2022, as compared to the barrels shipped in the second half of 2021 following the expiry of the CTS;
- lower contributions from the Seaway Crude Pipeline System, as well as from the Cushing and Hardisty storage assets as a result of lower demand; and
- higher power costs as a result of increased volumes and power prices.

GAS TRANSMISSION AND MIDSTREAM

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Earnings before interest, income taxes and depreciation and amortization[1]	**3,126**	3,671	1,087

1 Non-GAAP financial measure.

Year ended December 31, 2022 compared with year ended December 31, 2021

EBITDA was negatively impacted by $1.1 billion due to certain infrequent or other non-operating factors primarily explained by the following:

- a goodwill impairment of $2.5 billion; partially offset by
- a gain of $1,076 million on the closing of the joint venture merger transaction with P66 realigning our effective economic interests in Gray Oak and DCP;
- the absence of the $111 million impairment loss in 2021 to our investment in the PennEast pipeline project after a decision by project partners to cease development;
- a gain of $118 million on Texas Eastern recorded for a customer bankruptcy settlement; and
- a non-cash, net negative equity earnings adjustment of $10 million in 2022, compared to a net negative adjustment of $44 million in 2021 relating to our share of changes in the mark-to-market value of derivative financial instruments of our equity method investees, DCP and Aux Sable.

After taking into consideration the factors above, we saw a $567 million increase, primarily explained by the following significant business factors:

- higher commodity prices benefiting our DCP and Aux Sable joint ventures;
- the favorable effect of translating US dollar EBITDA at a higher average exchange rate in 2022 compared to the same period in 2021;
- recognition of revenues attributable to the Texas Eastern rate case resulting from a FERC-approved Stipulation and Agreement;
- contributions from the T-South and Spruce Ridge expansion projects, the Cameron and Middlesex Extension projects, and the Appalachia to Market project after service commenced in the fourth quarter of 2021;
- higher AECO-Chicago basis differential and lower costs benefiting earnings from our investment in Alliance; and
- recognition of revenues attributable to the BC Pipeline rate settlement; partially offset by
- higher operating costs; and
- a reduction in earnings from our investment in DCP as a result of our decreased effective economic interest due to the joint venture merger transaction with P66 that closed during the third quarter of 2022.

GAS DISTRIBUTION AND STORAGE

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Earnings before interest, income taxes and depreciation and amortization[1]	**1,827**	2,117	1,748

1 Non-GAAP financial measure.

Year ended December 31, 2022 compared with year ended December 31, 2021

EBITDA was negatively impacted by $293 million due to certain infrequent or other non-operating factors primarily explained by the absence of a gain of $303 million resulting from the sale of our investment in Noverco in 2021.

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

- higher distribution charges at Enbridge Gas resulting from increases in rates and customer base, as well as higher demand in the contract market;
- when compared with the normal weather forecast embedded in rates, colder than normal weather in 2022 positively impacted Enbridge Gas 2022 EBITDA by approximately $17 million while warmer than normal weather in 2021 negatively impacted 2021 EBITDA by approximately $55 million; and
- lower pension related costs; partially offset by
- the absence of earnings from Noverco due to the sale of our minority investment in December 2021; and
- higher operating costs at Enbridge Gas largely driven by higher employee costs and higher maintenance and integrity spend.

RENEWABLE POWER GENERATION

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Earnings before interest, income taxes and depreciation and amortization[1]	**262**	508	523

1 Non-GAAP financial measure.

Year ended December 31, 2022 compared with year ended December 31, 2021

EBITDA was negatively impacted by $272 million due to certain infrequent or non-operating factors, primarily explained by an impairment loss of $227 million to Magic Valley.

After taking into consideration the negative factor above, the remaining $26 million increase is primarily explained by the following significant business factors:

- higher energy pricing at European offshore wind facilities;
- stronger wind resources at Canadian and US onshore wind facilities; and
- the absence in 2022 of the adverse effects from the major winter storm in Texas during February 2021; partially offset by
- the absence in 2022 of a promote fee received in the first quarter of 2021 associated with the closing of the sale of 49% of our interest in three European offshore wind projects to Canada Pension Plan Investment Board.

ENERGY SERVICES

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Earnings/(loss) before interest, income taxes and depreciation and amortization[1]	**(417)**	(313)	(236)

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, 2022 compared with year ended December 31, 2021

EBITDA was negatively impacted by $100 million due to certain non-operating factors, primarily explained by non-cash, unrealized losses of $27 million in 2022, compared with unrealized gains of $53 million in 2021, reflecting the revaluation of derivatives used to manage the profitability of transportation and storage transactions, as well as to manage the exposure to movements in commodity prices.

After taking into consideration the factor above, the remaining $4 million decrease is primarily explained by the following significant business factors:

- more pronounced market structure backwardation than in 2021 and significant compression of location differentials in certain markets; partially offset by
- the absence of adverse impacts from the major winter storm experienced across the US Midwest during February 2021.

ELIMINATIONS AND OTHER

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Earnings/(loss) before interest, income taxes and depreciation and amortization[1]	**(1,124)**	356	(113)

1 Non-GAAP financial measure.

Eliminations and Other includes operating and administrative costs that are not allocated to business segments, the impact of foreign exchange hedge settlements and the activities of our wholly-owned captive insurance subsidiaries. Eliminations and Other also includes the impact of new business development activities and corporate investments.

Year ended December 31, 2022 compared with year ended December 31, 2021

EBITDA was negatively impacted by $1.2 billion due to certain infrequent or non-operating factors, primarily explained by:

- non-cash, net unrealized losses of $1,090 million in 2022, compared with unrealized gains of $55 million in 2021, reflecting the change in the mark-to-market value of derivative financial instruments used to manage foreign exchange risk;
- a transaction cost of $114 million in relation to our investment purchase in the Woodfibre LNG project; and
- an impairment of $44 million for lease assets due to office relocation plans in Houston.

After taking into consideration the non-operating factors above, we saw a $239 million decrease in EBITDA that is primarily explained by:

- the lower realized foreign exchange gains on hedge settlements in 2022; and
- higher Operating and administrative expense largely driven by an increase in employee costs.

GROWTH PROJECTS - COMMERCIALLY SECURED PROJECTS

The following table summarizes the status of our significant 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)						
GAS TRANSMISSION AND MIDSTREAM						
1.	Vito Gas & Oil	100 %	US$0.3 billion	US$0.2 billion	Complete	In-service
2.	Texas Eastern Venice Extension Project	100 %	US$0.4 billion	US$0.1 billion	Pre-construction	2023 - 2024
3.	Texas Eastern Modernization	100 %	US$0.4 billion	No significant expenditures to date	Pre-construction	2024 - 2025
4.	T-North Expansion	100 %	$1.2 billion	No significant expenditures to date	Pre-construction	2026
5.	Woodfibre LNG Project[3]	30 %	US$1.5 billion	No significant expenditures to date	Pre-construction	2027
6.	T-South Expansion	100 %	$3.6 billion	No significant expenditures to date	Pre-construction	2028
RENEWABLE POWER GENERATION						
7.	Saint-Nazaire France Offshore Wind Project[4]	25.5 %	$0.9 billion (€0.6 billion)	$0.9 billion (€0.6 billion)	Complete	In-service
8.	Fécamp Offshore Wind Project[5]	17.9 %	$0.7 billion (€0.5 billion)	$0.4 billion (€0.3 billion)	Under construction	2023
9.	Calvados Offshore Wind Project[4]	21.7 %	$0.9 billion (€0.6 billion)	$0.3 billion (€0.2 billion)	Under construction	2025

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 and status of the project are determined as at December 31, 2022.
3 Our equity contribution is US$0.9 billion, with the remainder financed through non-recourse project level debt.
4 Our equity contribution is $0.2 billion for each project, with the remainder of each project financed through non-recourse project level debt.
5 Our equity contribution is $0.1 billion, with the remainder 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.*

GAS TRANSMISSION AND MIDSTREAM

The following commercially secured growth project was placed into service in 2022:

- **Vito Gas & Oil** – Two pipelines connecting Vito Floating Production System from Mississippi Canyon to the Shell Mars System platform in West Delta 143 and Olympic Gas. Enbridge designed, fabricated, installed, and now operates, the Vito Gas & Oil export pipeline system consisting of pipeline and steel catenary riser.

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

- **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 1.5 billion cubic feet per day (bcf/d) of natural gas to Venture Global Plaquemines LNG, LLC’s LNG export facility located in Plaquemines Parish, Louisiana and is underpinned by long-term take or pay contracts.

- **Texas Eastern Modernization –** 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.

- **T-North Expansion** – An expansion of Westcoast Energy Inc.'s (Westcoast) BC Pipeline in northern BC that includes pipeline looping, additional compressor units and other ancillary station modifications to support 535 million cubic feet per day (MMcf/d) of additional capacity. The project will be underpinned by a cost-of-service commercial model with a target in-service date of 2026.

- **Woodfibre LNG Project** – Construction of liquefaction and floating storage facilities in Squamish, BC, as well as an expansion of the BC Pipeline System. The project is expected to be placed into service in 2027.

- **T-South Expansion** – An expansion of Westcoast's BC Pipeline's T-South section that includes pipeline looping, additional compressor units and other ancillary station modifications to support 300 MMcf/d of additional capacity. The project is expected to be placed in service in 2028 and will be underpinned by a cost-of-service commercial model.

RENEWABLE POWER GENERATION
The following commercially secured growth projects were placed into service in 2022:

- **Saint-Nazaire Offshore Wind Project –** A wind project located off the west coast of France that is expected to generate approximately 480 megawatts (MW). Project revenues are backed by a 20-year fixed price power purchase agreement (PPA) with added power production protection.

The following commercially secured growth projects are expected to be placed into service from 2023 to 2025:

- **Fécamp Offshore Wind Project –** An offshore wind project that will be comprised of 71 wind turbines 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 PPA.

OTHER ANNOUNCED PROJECTS UNDER DEVELOPMENT

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

GAS TRANSMISSION AND MIDSTREAM

- **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.

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, 2022, related to debt and leases.

Long-term contracts are contracts that we have signed for the purchase of services, pipe and other materials totaling $7.9 billion which are expected to be paid over the next five years. Long-term contracts primarily consists of the following purchase obligations: firm capacity payments for natural gas and crude oil transportation and storage contracts, natural gas purchase commitments, 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 common equity.

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$3.2 billion and $3.4 billion in 2022:

Entity	Issuance date	Type of issuance	Amount
(in millions of Canadian dollars, unless stated otherwise)			
Enbridge Inc.	January 2022	Fixed-to-fixed subordinated notes	$750
Enbridge Inc.	February 2022	Floating rate senior notes	US$600
Enbridge Inc.	February 2022	Senior notes	US$900
Enbridge Inc.	September 2022	Fixed-to-fixed subordinated notes	US$1,100
Enbridge Inc.	November 2022	Medium-term notes	$1,100
Enbridge Inc.	November 2022	Sustainability-linked medium-term notes	$900
Enbridge Gas Inc.	August 2022	Medium-term notes	$650
Texas Eastern Transmission LP	December 2022	Senior notes	US$600

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, inclusive of term loans, at December 31, 2022:

	Maturity[1]	Total Facilities	Draws[2]	Available
(millions of Canadian dollars)				
Enbridge Inc.	2023-2027	**10,987**	**7,984**	**3,003**
Enbridge (U.S.) Inc.	2024-2027	**8,604**	**4,199**	**4,405**
Enbridge Pipelines Inc.	2024	**2,000**	**312**	**1,688**
Enbridge Gas Inc.	2024	**2,000**	**2,000**	**—**
Total committed credit facilities		**23,591**	**14,495**	**9,096**

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

On May 17, 2022, we entered into a three year term loan with a syndicate of Japanese banks for approximately $806 million (¥84.8 billion), which will mature in May 2025 and replaces the approximately $499 million (¥52.5 billion) term loan that matured in May 2022. Additionally, on May 24, 2022, we entered into a 364-day term loan for approximately $1.9 billion, which will mature in May 2023.

On June 23, 2022, we renewed approximately $5.5 billion of our 364-day extendible credit facilities to July 2024, which includes a one-year term out provision from July 2023.

In July and August 2022, we renewed $12.7 billion of our credit facilities, extending the maturity dates of our 364-day credit facilities to July 2024, inclusive of a one year term out provision from July 2023, and our five year facilities out to July 2027. As a part of the renewals, we increased our credit facilities by approximately $640 million.

On December 16, 2022, Enbridge (U.S.) Inc. entered into a five year delay draw term loan in support of solar self-power projects for approximately $479 million, which will mature in December 2027.

In addition to the committed credit facilities noted above, we maintain $1.3 billion of uncommitted demand letter of credit facilities, of which $689 million was unutilized as at December 31, 2022. As at December 31, 2021, we had $1.3 billion of uncommitted demand letter of credit facilities, of which $854 million was unutilized.

As at December 31, 2022, our net available liquidity totaled $10.0 billion (2021 - $6.5 billion), consisting of available credit facilities of $9.1 billion (2021 - $6.2 billion) and unrestricted Cash and cash equivalents of $861 million (2021 - $286 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, 2022, we were in compliance with all debt covenants and expect to continue to comply with such covenants.

Cash flow growth, 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. In 2022, our credit ratings with DBRS Morningstar, Fitch Ratings, Moody's Investor Services, Inc. and Standard & Poor's were all affirmed. 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.

There are no material restrictions on our cash. Total Restricted cash of $46 million, as reported in 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, 2022 and 2021, we had a negative working capital position of $2.1 billion and $3.1 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,	**2022**	2021	2020
(millions of Canadian dollars)			
Operating activities	**11,230**	9,256	9,781
Investing activities	**(5,270)**	(10,657)	(5,177)
Financing activities	**(5,428)**	1,236	(4,770)
Effect of translation of foreign denominated cash and cash equivalents and restricted cash	**55**	(5)	(20)
Net change in cash and cash equivalents and restricted cash	**587**	(170)	(186)

Significant sources and uses of cash for the years ended December 31, 2022 and 2021 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 29. Changes in Operating Assets and Liabilities.* Cash provided by operating activities is also impacted by changes in earnings and certain infrequent or other non-operating factors, as discussed under *Results of Operations.*

Investing Activities
Cash used in investing activities primarily relates to capital expenditures to execute our 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, 2022, 2021 and 2020 is set out below:

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Liquids Pipelines	**1,418**	4,051	2,032
Gas Transmission and Midstream	**1,647**	2,353	2,066
Gas Distribution and Storage	**1,499**	1,343	1,134
Renewable Power Generation	**50**	16	81
Energy Services	**—**	1	2
Eliminations and Other	**33**	54	90
Total capital expenditures	**4,647**	7,818	5,405

2022
The decrease in cash used in investing activities primarily resulted from the following factors:

- lower capital expenditures due to the US L3R Program that was placed into service in the fourth quarter of 2021;
- lower cash outflows related to acquisitions in 2022 when compared to 2021; and
- proceeds received from the completion of a joint venture merger transaction for DCP Midstream LLC in August 2022.

The factors above were partially offset by:

- the absence in 2022 of proceeds received from dispositions in 2021 related to sale of our interest in Noverco in December 2021; and
- increased investments held by our wholly-owned captive insurance subsidiaries.

2021
The increase in cash used in investing activities primarily resulted from our acquisition of Moda Midstream Operating, LLC and higher capital expenditures related to the completion of the US L3R Program in 2021, partially offset by higher proceeds received from dispositions in 2021 compared to 2020 due to the sale of our interest in Noverco.

Financing Activities
Cash 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, share redemptions and common share repurchases under our NCIB. Cash flow from financing activities is also impacted by changes in distributions to, and contributions from, noncontrolling interests.

2022
The increase in cash used in financing activities primarily resulted from the following factors:

- net commercial paper and credit facility repayments in 2022 when compared to draws in 2021;
- higher long-term debt repayments along with lower long-term debt issuances in 2022 when compared to 2021;
- the redemption of Preference Shares, Series 17 and Series J in the first and second quarters of 2022, respectively;
- the repurchase and cancellation of 2,737,965 common shares under our NCIB for approximately $151 million in 2022; and
- increased common share dividend payments primarily due to the increase in our common share dividend rate.

The factors above were partially offset by:

- proceeds received from the sale of a non-operating interest in seven pipelines from our Regional Oil Sands System in October 2022;
- the absence in 2022 of the redemption of Westcoast's preferred shares in the first quarter of 2021; and
- higher short-term borrowings in 2022 when compared to 2021.

2021
The increase in cash provided by financing activities primarily resulted from 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 when compared to 2020.

The factors above were partially offset by the redemption of Westcoast's preferred shares in 2021 and 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 and can include financial guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. Please see Part II. *Item 8. Financial Statements and Supplementary Data - Note 32. Guarantees* for further discussion of guarantee arrangements.

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, please refer to Part II. *Item 8. Financial Statements and Supplementary Data - Note 31. Commitments and Contingencies* and *Note 12. Variable Interest Entities.*

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, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

PREFERENCE SHARE ISSUANCES

Characteristics of our outstanding preference shares are as follows:

	Dividend Rate	Dividend[1]	Per Share Base Redemption Value[2]	Redemption and Conversion Option Date[2,3]	Right to Convert Into[3,4]
(Canadian dollars, unless otherwise stated)					
Preference Shares, Series A	5.50%	$1.37500	$25	—	—
Preference Shares, Series B[5]	5.20%	$1.30052	$25	June 1, 2027	Series C
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 L[6]	5.86%	US$1.46448	US$25	September 1, 2027	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 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 Preference Shares, Series A, such fixed dividend rate resets every five years beginning on the initial redemption and conversion option date. The Preference Shares, Series 19 contain a feature where the fixed dividend rate, when reset every five years, will not be less than 4.90%. No other series of Preference Shares has this feature.*

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

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

4 *With the exception of Preference Shares, Series A, 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 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), or 3.2% (Series 20); or US$25 x (number of days in quarter/number of days in year) x Three-Month US Government treasury bill rate + 3.2% (Series M), 3.1% (Series 2) or 2.8% (Series 6).*

5 *The quarterly dividend per share paid on Preference Shares, Series B was increased to $0.32513 from $0.21340 on June 1, 2022 due to reset of the annual dividend on June 1, 2022. On June 1, 2022, all outstanding Preference Shares, Series C were converted to Preference Shares, Series B.*

6 *The quarterly dividend per share paid on Preference Shares, Series L was increased to US$0.36612 from US$0.30993 on September 1, 2022, due to reset of the annual dividend on September 1, 2022.*

PREFERENCE SHARE REDEMPTIONS

On March 1, 2022, we redeemed our $750 million outstanding Cumulative Redeemable Minimum Rate Reset Preference Shares, Series 17. On June 1, 2022, we also redeemed our US$200 million outstanding Cumulative Redeemable Preference Shares, Series J. Dividends are cumulative, payable quarterly and are included in Preference share dividends in the Consolidated Statements of Earnings.

DIVIDENDS

We have paid common share dividends in every year since we became a publicly traded company in 1953. In November 2022, we announced a 3.2% increase in our quarterly dividend to $0.88750 per common share, or $3.55 annualized, effective with the dividend payable on March 1, 2023, thereby declaring a dividend increase for 28 straight years.

For the years ended December 31, 2022 and 2021, total dividends paid were $7.0 billion and $6.8 billion, respectively, all of which were paid in cash and reflected in financing activities.

On November 29, 2022, our Board of Directors declared the following quarterly dividends. All dividends are payable on March 1, 2023 to shareholders of record on February 15, 2023.

	Dividend per share
Common Shares[1]	$0.88750
Preference Shares, Series A	$0.34375
Preference Shares, Series B[2]	$0.32513
Preference Shares, Series D	$0.27875
Preference Shares, Series F	$0.29306
Preference Shares, Series H	$0.27350
Preference Shares, Series L[3]	US$0.36612
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 19	$0.30625

1 The quarterly dividend per common share was increased 3.2% to $0.8875 from $0.860, effective March 1, 2023.

2 The quarterly dividend per share paid on Preference Shares Series B was increased to $0.32513 from $0.21340 on June 1, 2022, due to reset of the annual dividend on June 1, 2022 and every five years thereafter. Following the date of conversion of Preference Shares Series C, on June 1, 2022 all outstanding Preference Shares Series C were converted to Preference Shares Series B.

3 The quarterly dividend per share paid on Series L was increased to US$0.36612 from US$0.30993 on September 1, 2022, due to reset of the annual dividend on September 1, 2022, and every five years thereafter.

SUMMARIZED FINANCIAL INFORMATION

On January 22, 2019, Enbridge entered into supplemental indentures with its wholly-owned subsidiaries, Spectra Energy Partners, LP (SEP) and Enbridge Energy Partners, L.P. (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, 2022, the aggregate outstanding principal amount of SEP notes was approximately US$3.2 billion.
2 As at December 31, 2022, the aggregate outstanding principal amount of EEP notes was approximately US$2.4 billion.

Enbridge Notes under Guarantees

USD Denominated[1]	CAD Denominated[2]
Floating Rate Senior Notes due 2023	3.940% Senior Notes due 2023
Floating Rate Senior Notes due 2024	3.940% Senior Notes due 2023
4.000% Senior Notes due 2023	3.950% Senior Notes due 2024
0.550% Senior Notes due 2023	2.440% Senior Notes due 2025
3.500% Senior Notes due 2024	3.200% Senior Notes due 2027
2.150% Senior Notes due 2024	5.700% Senior Notes due 2027
2.500% Senior Notes due 2025	6.100% Senior Notes due 2028
2.500% Senior Notes due 2025	2.990% Senior Notes due 2029
4.250% Senior Notes due 2026	7.220% Senior Notes due 2030
1.600% Senior Notes due 2026	7.200% Senior Notes due 2032
3.700% Senior Notes due 2027	6.100% Sustainability-Linked Senior Notes due 2032
3.125% Senior Notes due 2029	3.100% Sustainability-Linked Senior Notes due 2033
2.500% Sustainability-Linked Senior Notes due 2033	5.570% Senior Notes due 2035
4.500% Senior Notes due 2044	5.750% Senior Notes due 2039
5.500% Senior Notes due 2046	5.120% Senior Notes due 2040
4.000% Senior Notes due 2049	4.240% Senior Notes due 2042
3.400% Senior Notes due 2051	4.570% Senior Notes due 2044
	4.870% Senior Notes due 2044
	4.100% Senior Notes due 2051
	6.510% Senior Notes due 2052
	4.560% Senior Notes due 2064

1 As at December 31, 2022, the aggregate outstanding principal amount of the Enbridge US dollar denominated notes was approximately US$11.0 billion.
2 As at December 31, 2022, the aggregate outstanding principal amount of the Enbridge Canadian dollar denominated notes was approximately $10.2 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 (the 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,	**2022**
(millions of Canadian dollars)	
Operating loss	**(179)**
Earnings	**1,921**
Earnings attributable to common shareholders	**1,507**

Summarized Combined Statements of Financial Position

December 31,	**2022**	2021
(millions of Canadian dollars)		
Cash and cash equivalents	**425**	12
Accounts receivable from affiliates	**2,486**	3,442
Short-term loans receivable from affiliates	**5,232**	4,947
Other current assets	**969**	593
Long-term loans receivable from affiliates	**43,873**	51,983
Other long-term assets	**4,111**	3,732
Accounts payable to affiliates	**1,375**	1,982
Short-term loans payable to affiliates	**1,745**	2,891
Other current liabilities	**8,752**	8,110
Long-term loans payable to affiliates	**37,626**	41,370
Other long-term liabilities	**47,447**	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 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

Line 5 Easement (Bad River Band)

On July 23, 2019, the Bad River Band of the Lake Superior Tribe of Chippewa Indians (the Band) filed a complaint in the United States District Court for the Western District of Wisconsin (the Court) over our Line 5 pipeline and right-of-way across the Bad River Reservation (the Reservation). Only a small portion of the total easements across 12 miles of the Reservation are at issue. The Band alleges that our continued use of Line 5 to transport crude oil and related liquids across the Reservation is a public nuisance under federal and state law and that the pipeline is in trespass on certain tracts of land in which the Band possesses ownership interests. The complaint seeks an Order prohibiting us from using Line 5 to transport crude oil and related liquids across the Reservation and requiring removal of the pipeline from the Reservation. Subsequently amended versions of the complaint also seek recovery of profits-based damages based on an unjust enrichment theory. Enbridge has responded to each claim in the initial and amended complaints with an answer, defenses and counterclaims.

On August 29, 2022, the Government of Canada released a statement formally invoking the dispute settlement provisions of the 1977 Transit Pipelines Treaty in respect of this litigation; reiterating its concerns about the uninterrupted transmission of hydrocarbons through Line 5. On September 7, 2022, the Court issued a decision on cross-motions for summary judgment. The Court determined that the Band's nuisance claim raised factual issues that could not be resolved on summary judgment. The Court further determined that Enbridge is in trespass on 12 parcels on the Reservation and that the Band is entitled to some measure of profits-based damages and to an injunction, with the level of damages and scope of the injunction to be determined at trial, which occurred between October 24 and November 1, 2022. While the Court reserved judgment at the conclusion of the trial, the summary judgment decision and subsequent pre-trial decisions provide that the Court will assess trespass damages calculated using a pro-rata share of Enbridge's profits from the operation of the pipeline attributable to the 12 disputed parcels compared to the pipeline as a whole rather than the profits associated with the entire length of the pipeline, as the Band sought. The Court has also stated that any injunction will not result in the immediate closure of the pipeline but also will not allow the pipeline to operate indefinitely. On November 28, 2022, the Court issued an interim Order ruling that: (a) the parties are to meet and confer by December 16 on installation of EFRDs (Emergency Flow Restriction Devices) on the Reservation, an appropriate shutdown and purge protocol should conditions worsen at the meander, and any other reasonable remediation projects that could inhibit further erosion at the meander; (b) the parties are to submit a Joint Proposal by December 23 on appropriate shutoff and purge plan for the meander, or if they cannot agree, each party must submit their own best offer on a shutdown and purge protocol; and (c) denied Enbridge's request for declaratory and injunctive relief on its counterclaims asking for Court-Ordered relief relating to access and erosion mitigation at the meander. The parties met and conferred by December 16 and a Joint Status Report, along with individual best offers on shutdown and purge protocol, were filed on December 23. We continue to wait on the Court's rulings on the issues of financial compensation and Line 5's operations.

Michigan Line 5 Dual Pipelines - Straits of Mackinac Easement
In 2019, the Michigan Attorney General (AG) filed a complaint in the Michigan Ingham County Circuit Court (the Circuit Court) that requests the Circuit 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. 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 AG's case to federal court follows a November 16, 2021 ruling which held that the similar (and now dismissed) 2020 lawsuit brought by the Governor of Michigan to force Line 5's shutdown raised important federal issues that should be heard in federal court. On December 21, 2021, the AG 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 AG to file a motion to remand the 2019 case. The AG's motion and brief were filed on January 14, 2022, and our response was filed on February 11, 2022. The motion was fully briefed in March 2022. On August 18, 2022, Judge Neff denied the AG's motion to remand which now remains in the US District Court. On August 30, 2022, the AG filed a motion to certify the US District Court's August 18 Order to pursue an appeal on the jurisdictional issue, which Enbridge opposed. We anticipate a decision on the jurisdictional issue in 2023.

Dakota Access Pipeline
We own an effective interest of 27.6% in the Bakken Pipeline System, which is inclusive of the Dakota Access Pipeline (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 Environmental Impact Statement (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. On February 22, 2022, the US Supreme Court denied the request of Dakota Access, LLC 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 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 completion of the EIS process.

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 draft EIS completion date to September 2022. The Army Corps now expects to complete the draft EIS in the spring of 2023.

OTHER LITIGATION

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

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 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. Our reporting units are Liquids Pipelines, Gas Transmission, Gas Distribution and Storage and Renewable Power Generation. The Renewable Power Generation reporting unit had goodwill starting in the third quarter of 2022.

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, changes to regulatory environments, capital accessibility, operating income trends and changes to 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, expected future capital expenditures and working capital levels, as well as terminal value growth rates for the Liquids Pipelines, Gas Transmission and Renewable Power Generation reporting units, and projected regulatory rate base and rate base multiplier for the Gas Distribution and Storage reporting unit. The determination of fair value using the earnings multiples technique requires assumptions to be made in relation to maintainable earnings and earnings multiples 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, 2022, we performed our annual goodwill impairment assessment which consisted of a qualitative assessment for the Liquids Pipelines, Gas Transmission and Gas Distribution and Storage reporting units and did not identify impairment indicators. Due to changes in the macroeconomic environment that has led to a rise in interest rates, we performed a quantitative assessment for the Liquids Pipelines, Gas Transmission, Gas Distribution and Storage, and Renewable Power Generation reporting units as at December 1, 2022, which resulted in the recognition of an impairment loss in Gas Transmission. Goodwill impairments were not identified in relation to the Liquids Pipelines, Gas Distribution, or Renewable Power Generation reporting units.

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 regularly 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, 2022 and 2021, our regulatory assets totaled $6.5 billion and $5.9 billion, respectively, and regulatory liabilities totaled $3.8 billion and $3.4 billion, respectively.

DEPRECIATION
Depreciation of property, plant and equipment, our largest asset with a net book value at December 31, 2022 and 2021, of $104.5 billion and $100.1 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, 2022 Consolidated Financial Statements of a 0.5% change in key pension and other postretirement benefit (OPEB) obligation assumptions:

	Canada		United States	
	Obligation	Expense	Obligation	Expense
(millions of Canadian dollars)				
Pension				
Decrease in discount rate	243	27	49	3
Decrease in expected return on assets	—	23	—	6
Decrease in rate of salary increase	(47)	(11)	(5)	(1)
OPEB				
Decrease in discount rate	13	1	5	—
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 31. 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, 2022 ranged from 1.5% to 9.0% (2021 - 0.9% 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.

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 cash flow, fair value 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 hedging program to partially mitigate the impact of short-term interest rate volatility on interest expense via execution of floating to fixed interest rate swaps. These hedges have an average fixed rate of 4.0%.

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, 2022, 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 partially mitigate our exposure to long-term interest rate variability on forecasted term debt issuances via execution of floating to fixed interest rate swaps with an average swap rate of 2.2%.

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 in the Consolidated Statements of Financial Position as at December 31, 2022. 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, 2022 and 2021 CFaR was $144 million and $103 million or 1.3% and 0.9%, 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. Our shelf prospectuses with securities regulators enable 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, 2022. As a result, all credit facilities are available to us and the banks are obligated to fund 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, 2022 and 2021, 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, 2022, 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, 2022, 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, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022 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, 2022, based on criteria established in *Internal Control – Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

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

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

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

Definition and Limitations of Internal Control over Financial Reporting

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

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

Critical Audit Matters

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

Goodwill Impairment Assessment

As described in Notes 2 and 16 to the consolidated financial statements, the Company's goodwill balance was $32,440 million at December 31, 2022. 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, expected future capital expenditures and working capital levels, as well as terminal value growth rates for the Liquids Pipelines, Gas Transmission and Midstream (Gas Transmission) and Renewable Power Generation reporting units and projected regulatory rate base and rate base multiple for the Gas Distribution and Storage (Gas Distribution) reporting unit. The determination of fair value using the earnings multiples technique requires assumptions to be made in relation to maintainable earnings and earnings multiples. Management elected to perform a qualitative goodwill impairment assessment as of April 1, 2022 for the following reporting units: Liquids Pipelines, Gas Transmission and Gas Distribution and did not identify impairment indicators. Due to changes in the macroeconomic environment that led to a rise in interest rates, management performed a quantitative assessment as of December 1, 2022 for the following reporting units: Liquids Pipelines, Gas Transmission, Gas Distribution and Renewable Power Generation. A goodwill impairment of $2,465 million was recorded in relation to the Gas Transmission reporting unit. Goodwill impairments were not identified in relation to the Liquids Pipelines, Gas Distribution or Renewable Power Generation 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 judgments required by management when developing such significant assumptions as discount rates, projected operating income, expected future capital expenditures, terminal value growth rates, projected regulatory rate base, rate base multiple and earnings multiples used to estimate the fair value of the reporting units, as applicable, as of December 1, 2022. 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 quantitative assessment. In addition, the audit effort involved the use of professionals with specialized skill and knowledge.

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 quantitative goodwill impairment assessment, including controls over the determination of the fair value estimates of the Company’s reporting units. These procedures also included, among others, testing management’s process for developing the fair value estimates of the Company’s reporting units. Testing management’s process for developing the fair value estimates included evaluating the appropriateness of the discounted cash flow and the earnings multiples models; testing the completeness and accuracy of underlying data used in the models; and evaluating the reasonableness of significant assumptions used by management in determining the fair value estimates including discount rates, projected operating income, expected future capital expenditures, projected regulatory rate base and rate base multiple, terminal value growth rates and earnings multiples. Assessing the reasonableness of projected operating income, expected future capital expenditures and the projected regulatory rate base 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, as applicable. 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 significant assumptions used in the models, specifically discount rates, terminal value growth rates, rate base multiple and earnings multiples.

/s/PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Canada
February 10, 2023

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

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars, except per share amounts)			
Operating revenues			
Commodity sales	**29,150**	26,873	19,259
Gas distribution sales	**5,653**	4,026	3,663
Transportation and other services	**18,506**	16,172	16,165
Total operating revenues *(Note 4)*	**53,309**	47,071	39,087
Operating expenses			
Commodity costs	**28,942**	26,608	18,890
Gas distribution costs	**3,647**	2,094	1,779
Operating and administrative	**8,219**	6,712	6,749
Depreciation and amortization	**4,317**	3,852	3,712
Impairment of long-lived assets	**541**	—	—
Impairment of goodwill *(Note 16)*	**2,465**	—	—
Total operating expenses	**48,131**	39,266	31,130
Operating income	**5,178**	7,805	7,957
Income from equity investments *(Note 13)*	**2,056**	1,711	1,136
Impairment of equity investments *(Note 13)*	**—**	(111)	(2,351)
Gain on joint venture merger transaction *(Note 13)*	**1,076**	—	—
Other income/(expense) *(Note 28)*	**(589)**	979	238
Interest expense *(Note 18)*	**(3,179)**	(2,655)	(2,790)
Earnings before income taxes	**4,542**	7,729	4,190
Income tax expense *(Note 25)*	**(1,604)**	(1,415)	(774)
Earnings	**2,938**	6,314	3,416
(Earnings)/loss attributable to noncontrolling interests	**65**	(125)	(53)
Earnings attributable to controlling interests	**3,003**	6,189	3,363
Preference share dividends	**(414)**	(373)	(380)
Earnings attributable to common shareholders	**2,589**	5,816	2,983
Earnings per common share attributable to common shareholders *(Note 6)*	**1.28**	2.87	1.48
Diluted earnings per common share attributable to common shareholders *(Note 6)*	**1.28**	2.87	1.48

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

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Earnings	**2,938**	6,314	3,416
Other comprehensive income/(loss), net of tax			
Change in unrealized gain/(loss) on cash flow hedges	**847**	162	(457)
Change in unrealized gain/(loss) on net investment hedges	**(971)**	49	102
Other comprehensive loss from equity investees	**(6)**	(12)	(1)
Excluded components of fair value hedges	**(35)**	(5)	5
Reclassification to earnings of loss on cash flow hedges	**143**	235	198
Reclassification to earnings of pension and other postretirement benefits (OPEB) amounts	**(10)**	21	13
Reclassification to earnings of (gain)/loss on equity investees	**16**	(62)	—
Actuarial gain/(loss) on pension and OPEB	**312**	394	(167)
Foreign currency translation adjustments	**4,406**	(507)	(853)
Other comprehensive income/(loss), net of tax	**4,702**	275	(1,160)
Comprehensive income	**7,640**	6,589	2,256
Comprehensive income attributable to noncontrolling interests	**(21)**	(95)	(22)
Comprehensive income attributable to controlling interests	**7,619**	6,494	2,234
Preference share dividends	**(414)**	(373)	(380)
Comprehensive income attributable to common shareholders	**7,205**	6,121	1,854

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

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars, except per share amounts)			
Preference shares *(Note 21)*			
Balance at beginning of year	**7,747**	7,747	7,747
Redemption of preference shares	**(929)**	—	—
Balance at end of year	**6,818**	7,747	7,747
Common shares *(Note 21)*			
Balance at beginning of year	**64,799**	64,768	64,746
Shares issued on exercise of stock options	**53**	31	22
Share purchases at stated value	**(88)**	—	—
Other	**(4)**	—	—
Balance at end of year	**64,760**	64,799	64,768
Additional paid-in capital			
Balance at beginning of year	**365**	277	187
Stock-based compensation	**36**	28	30
Purchase of noncontrolling interest	**(43)**	—	—
Options exercised	**(50)**	(23)	(21)
Change in reciprocal interest	**—**	98	76
Other	**(33)**	(15)	5
Balance at end of year	**275**	365	277
Deficit			
Balance at beginning of year	**(10,989)**	(9,995)	(6,314)
Earnings attributable to controlling interests	**3,003**	6,189	3,363
Preference share dividends	**(414)**	(373)	(380)
Common share dividends declared	**(7,023)**	(6,818)	(6,612)
Dividends paid to reciprocal shareholder	**—**	8	17
Modified retrospective adoption of *ASU 2016-13 Financial Instruments - Credit Losses*	**—**	—	(66)
Share purchases in excess of stated value	**(63)**	—	—
Other	**—**	—	(3)
Balance at end of year	**(15,486)**	(10,989)	(9,995)
Accumulated other comprehensive income/(loss) *(Note 23)*			
Balance at beginning of year	**(1,096)**	(1,401)	(272)
Other comprehensive income/(loss) attributable to common shareholders, net of tax	**4,616**	305	(1,129)
Balance at end of year	**3,520**	(1,096)	(1,401)
Reciprocal shareholding			
Balance at beginning of year	**—**	(29)	(51)
Change in reciprocal interest	**—**	29	22
Balance at end of year	**—**	—	(29)
Total Enbridge Inc. shareholders' equity	**59,887**	60,826	61,367
Noncontrolling interests *(Note 20)*			
Balance at beginning of year	**2,542**	2,996	3,364
Earnings/(loss) attributable to noncontrolling interests	**(65)**	125	53
Other comprehensive income/(loss) attributable to noncontrolling interests, net of tax			
Change in unrealized loss on cash flow hedges	**(28)**	(15)	(6)
Foreign currency translation adjustments	**114**	(15)	(25)
	86	(30)	(31)
Comprehensive income attributable to noncontrolling interests	**21**	95	22
Distributions	**(259)**	(271)	(300)
Contributions	**1,105**	15	23
Redemption of noncontrolling interests	**—**	(293)	(112)
Purchase of noncontrolling interest	**55**	—	—
Other	**47**	—	(1)
Balance at end of year	**3,511**	2,542	2,996
Total equity	**63,398**	63,368	64,363
Dividends paid per common share	**3.44**	3.34	3.24

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

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Operating activities			
Earnings	**2,938**	6,314	3,416
Adjustments to reconcile earnings to net cash provided by operating activities:			
Depreciation and amortization	**4,317**	3,852	3,712
Deferred income tax expense *(Note 25)*	**957**	1,091	447
Unrealized derivative fair value (gain)/loss, net *(Note 24)*	**1,280**	(173)	(756)
Income from equity investments *(Note 13)*	**(2,056)**	(1,711)	(1,136)
Distributions from equity investments	**1,827**	1,630	1,392
Impairment of long-lived assets	**541**	—	—
Impairment of equity investments *(Note 13)*	**—**	111	2,351
Impairment of goodwill *(Note 16)*	**2,465**	—	—
Gain on joint venture merger transaction *(Note 13)*	**(1,076)**	—	—
(Gain)/loss on dispositions	**12**	(319)	(6)
Other	**37**	(73)	268
Changes in operating assets and liabilities *(Note 29)*	**(12)**	(1,466)	93
Net cash provided by operating activities	**11,230**	9,256	9,781
Investing activities			
Capital expenditures	**(4,647)**	(7,818)	(5,405)
Long-term investments and restricted long-term investments	**(1,041)**	(640)	(487)
Distributions from equity investments in excess of cumulative earnings	**763**	533	705
Additions to intangible assets	**(174)**	(275)	(215)
Acquisitions	**(828)**	(3,785)	(24)
Proceeds from joint venture merger transaction *(Note 13)*	**522**	—	—
Proceeds from dispositions	**—**	1,263	265
Affiliate loans, net	**135**	65	(16)
Net cash used in investing activities	**(5,270)**	(10,657)	(5,177)
Financing activities			
Net change in short-term borrowings	**481**	394	223
Net change in commercial paper and credit facility draws	**(1,333)**	2,960	1,542
Debenture and term note issues, net of issue costs	**7,547**	8,032	5,230
Debenture and term note repayments	**(4,198)**	(2,264)	(4,463)
Sale of noncontrolling interest in subsidiary *(Note 8)*	**1,092**	—	—
Contributions from noncontrolling interests	**13**	15	23
Distributions to noncontrolling interests	**(259)**	(271)	(300)
Common shares issued	**3**	5	5
Common shares repurchased	**(151)**	—	—
Preference share dividends	**(338)**	(367)	(380)
Common share dividends	**(6,968)**	(6,766)	(6,560)
Redemption of preference shares	**(1,003)**	—	—
Redemption of preferred shares held by subsidiary	**—**	(415)	—
Other	**(314)**	(87)	(90)
Net cash provided by/(used in) financing activities	**(5,428)**	1,236	(4,770)
Effect of translation of foreign denominated cash and cash equivalents and restricted cash	**55**	(5)	(20)
Net change in cash and cash equivalents and restricted cash	**587**	(170)	(186)
Cash and cash equivalents and restricted cash at beginning of year	**320**	490	676
Cash and cash equivalents and restricted cash at end of year	**907**	320	490
Supplementary cash flow information			
Cash paid for income taxes	**495**	489	524
Cash paid for interest, net of amount capitalized	**2,920**	2,427	2,538
Property, plant and equipment and intangible assets non-cash accruals	**937**	831	801

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

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	**2022**	2021
(millions of Canadian dollars; number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents	**861**	286
Restricted cash	**46**	34
Accounts receivable and other *(Note 9)*	**8,871**	6,862
Accounts receivable from affiliates	**114**	107
Inventory *(Note 10)*	**2,255**	1,670
	12,147	8,959
Property, plant and equipment, net *(Note 11)*	**104,460**	100,067
Long-term investments *(Note 13)*	**15,936**	13,324
Restricted long-term investments *(Note 14)*	**593**	630
Deferred amounts and other assets	**9,542**	8,613
Intangible assets, net *(Note 15)*	**4,018**	4,008
Goodwill *(Note 16)*	**32,440**	32,775
Deferred income taxes *(Note 25)*	**472**	488
Total assets	**179,608**	168,864
Liabilities and equity		
Current liabilities		
Short-term borrowings *(Note 18)*	**1,996**	1,515
Accounts payable and other *(Note 17)*	**11,392**	9,767
Accounts payable to affiliates	**105**	90
Interest payable	**763**	693
Current portion of long-term debt *(Note 18)*	**6,045**	6,164
	20,301	18,229
Long-term debt *(Note 18)*	**72,939**	67,961
Other long-term liabilities	**9,189**	7,617
Deferred income taxes *(Note 25)*	**13,781**	11,689
	116,210	105,496
Commitments and contingencies *(Note 31)*		
Equity		
Share capital *(Note 21)*		
Preference shares	**6,818**	7,747
Common shares *(2,025 and 2,026 outstanding at December 31, 2022 and 2021, respectively)*	**64,760**	64,799
Additional paid-in capital	**275**	365
Deficit	**(15,486)**	(10,989)
Accumulated other comprehensive income/(loss) *(Note 23)*	**3,520**	(1,096)
Total Enbridge Inc. shareholders' equity	**59,887**	60,826
Noncontrolling interests *(Note 20)*	**3,511**	2,542
	63,398	63,368
Total liabilities and equity	**179,608**	168,864

Variable Interest Entities (VIEs) *(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 and export various grades of crude oil and other liquid hydrocarbons, including the Mainline System, Regional Oil Sands System, Gulf Coast and Mid-Continent, 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 throughout Ontario. This business segment also includes natural gas distribution activities in Québec. We sold our investment in Noverco Inc. (Noverco), previously reported in the Gas Distribution and Storage segment, 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. This segment also includes Tri Global Energy, LLC (TGE) which was acquired on September 27, 2022 *(Note 8).*

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 segments described above, Eliminations and Other includes operating and administrative costs that are not allocated to business segments, the impact of foreign exchange hedge settlements and the activities of our wholly-owned captive insurance subsidiaries. The principal activity of our captive insurance subsidiaries is providing insurance and reinsurance coverage for certain insurable property and casualty risk exposures of our operating subsidiaries and certain equity investments. 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 31)*; and estimates of losses related to environmental remediation obligations *(Note 31)*. 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 the 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 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 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, 2022 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. The equity component of AFUDC is included as a non-cash reconciling item to earnings within Cash Flows from Operating Activities in the Consolidated Statements of Cash Flows.

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 our liquids and natural 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. We also have long-term contracts where the revenue profile does not align with the cash receipt schedule, resulting in the recognition of deferred revenue.

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, 2022, 2021 and 2020, cash received net of revenue recognized for contracts under make-up rights and similar deferred revenue arrangements was $238 million, $127 million and $292 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.

No non-affiliated customer exceeded 10.0% of our third-party revenues for the year ended December 31, 2022. Our largest non-affiliated customer accounted for approximately 13.5% and 13.6% of our third-party revenues for the years ended December 31, 2021 and 2020, respectively.

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, Other income/(expense) and Interest expense.

Derivatives in Qualifying Hedging Relationships
We use derivative financial instruments to manage our exposure to changes in commodity prices, foreign exchange rates, interest rates and certain compensation tied to our share price. Hedge accounting is optional and requires 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 Cash Flows from 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. These investments are initially measured at cost and are adjusted for our proportionate share of undistributed equity earnings or loss. Our 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 less impairment, if any, and adjusted for 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 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 for the purposes of the CER's LMCI or in accordance with specific commercial arrangements are presented as Restricted cash in the Consolidated Statements of Financial Position.

LOANS AND RECEIVABLES
Long-term notes receivable from affiliates 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.

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; the difference between the actual cost and approved cost of natural gas reflected in rates; 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. Our reporting units are Liquids Pipelines, Gas Transmission, Gas Distribution and Storage, and Renewable Power Generation. The Renewable Power Generation reporting unit had goodwill beginning in the third quarter of 2022.

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, changes to regulatory environments, capital accessibility, operating income trends and changes to 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, expected future capital expenditures and working capital levels, as well as terminal value growth rates for the Liquids Pipelines, Gas Transmission and Renewable Power Generation reporting units, and projected regulatory rate base and rate base multiple for the Gas Distribution and Storage reporting unit. The determination of fair value using the earnings multiples technique requires assumptions to be made in relation to maintainable earnings and earnings multiples 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, 2022, we performed our annual goodwill impairment assessment which consisted of a qualitative assessment for the Liquids Pipelines, Gas Transmission and Gas Distribution and Storage reporting units and did not identify impairment indicators. Due to changes in the macroeconomic environment that have led to a rise in interest rates, we performed a quantitative assessment for the Liquids Pipelines, Gas Transmission, Gas Distribution and Storage, and Renewable Power Generation reporting units as at December 1, 2022, which resulted in the recognition of an impairment loss for Gas Transmission *(Note 16)*. Goodwill impairments were not identified in relation to the Liquids Pipelines, Gas Distribution and Storage or Renewable Power Generation reporting units. Also, we did not identify any indicators of goodwill impairment during the remainder of 2022.

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, as well as defined benefit OPEB plans.

Obligations and net periodic benefit costs for defined benefit pension and OPEB plans are estimated using the projected unit credit method, which is based on years of service, as well as our best estimates of actuarial assumptions such as discount rates, future salary levels, other cost escalations, employees' retirement ages, and mortality.

We determine discount rates using market yields of high-quality corporate bonds with maturities that approximate the estimated timing of future benefit payments.

Plan assets are measured at fair value. The expected return on plan assets is determined using the long-term target asset mixes in our investment policies and long-term market expectations.

Actuarial gains and losses arise from the difference between the actual and expected return on plan assets, and changes in actuarial assumptions such as discount rates. Periodic net actuarial gains and losses and prior service costs are accumulated and presented as follows in the Consolidated Statements of Financial Position:

- as a component of AOCI, for our non-utilities' defined benefit pension plans and all defined benefit OPEB plans; and
- as a component of Deferred amounts and other assets and/or Other long-term liabilities, for our utilities' defined benefit pension plans, to the extent that the net actuarial gains and losses and prior service costs have been permitted or are expected to be permitted by the regulators, to be recovered through future rates.

Net periodic benefit cost is recognized in earnings and includes:

- current service cost;
- interest cost;
- expected return on plan assets;
- amortization of prior service costs over the expected average remaining service life of the plans' active employee group; and
- amortization of net actuarial gains and losses in excess of 10% of the greater of the benefit obligation or the fair value of plan assets, over the expected average remaining service life of the plans' active employee group.

Our utility operations also record regulatory adjustments for the difference between net periodic benefit costs for accounting versus ratemaking purposes. Offsetting regulatory assets or liabilities are recorded to the extent net periodic benefit costs are expected to be recovered 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, our contributions are expensed when 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 common shares with an offset to Accounts payable and other or Other long-term liabilities. The value of the PSUs is also dependent on our performance relative to performance targets set out under the plan. We also award share settled RSUs which vest at the completion of a three-year term. During the vesting term, compensation expense is recorded based on the number of units granted and the market price of Enbridge's common shares on the day immediately preceding the grant date, with an offset to Additional paid-in capital.

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, 2022.

ADOPTION OF NEW ACCOUNTING STANDARDS
Disclosures About Government Assistance
Effective January 1, 2022, we adopted Accounting Standards Update (ASU) 2021-10 on a prospective basis. The new standard was issued in November 2021 to increase the transparency of government assistance to business entities. The ASU adds new disclosure requirements for transactions with governments 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. The adoption of this ASU did not have a material impact on our consolidated financial statements.

Accounting for Certain Lessor Leases with Variable Lease Payments
Effective January 1, 2022, we adopted ASU 2021-05 on a prospective basis. The new standard 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. The adoption of this ASU did not have a material impact on our consolidated financial statements.

Accounting for Modifications or Exchanges of Certain Equity-Classified Contracts
Effective January 1, 2022, we adopted ASU 2021-04 on a prospective basis. The new standard 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. The adoption of this ASU did not have a material impact on our consolidated financial statements.

Accounting for Convertible Instruments and Contracts in an Entity's Own Equity
Effective January 1, 2022, we adopted ASU 2020-06 on a modified retrospective basis. The new standard 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. The adoption of this ASU did not have a material impact on our consolidated financial statements.

4. REVENUE

REVENUE FROM CONTRACTS WITH CUSTOMERS

Major Products and Services

Year ended December 31, 2022	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	**11,283**	**5,012**	**782**	**—**	**—**	**—**	**17,077**
Storage and other revenue	**235**	**350**	**308**	**—**	**—**	**—**	**893**
Gas gathering and processing revenue	**—**	**22**	**—**	**—**	**—**	**—**	**22**
Gas distribution revenue	**—**	**—**	**5,643**	**—**	**—**	**—**	**5,643**
Electricity and transmission revenue	**—**	**—**	**—**	**281**	**—**	**—**	**281**
Total revenue from contracts with customers	**11,518**	**5,384**	**6,733**	**281**	**—**	**—**	**23,916**
Commodity sales	**—**	**—**	**—**	**—**	**29,150**	**—**	**29,150**
Other revenue[1,2]	**(81)**	**39**	**(20)**	**305**	**—**	**—**	**243**
Intersegment revenue	**615**	**3**	**16**	**(4)**	**25**	**(655)**	**—**
Total revenue	**12,052**	**5,426**	**6,729**	**582**	**29,175**	**(655)**	**53,309**

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

1 *Includes mark-to-market losses from our hedging program for the year ended December 31, 2022 of $431 million (2021 - $59 million gain; 2020 - $265 million gain).*
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, 2022	**3,183**	**230**	**2,241**
Balance as at December 31, 2021	2,369	213	1,898

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 have 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, 2022 included in contract liabilities at the beginning of the year is $166 million. Increases in contract liabilities from cash received, net of amounts recognized as revenue during the year ended December 31, 2022, were $453 million.

Performance Obligations

Segment	Nature of Performance Obligation
Liquids Pipelines	• Transportation and storage of crude oil and natural gas liquids (NGL)
Gas Transmission and Midstream	• Transportation, storage, gathering, compression and treating of natural gas • Transportation of NGL • Sale of crude oil, natural gas and NGL
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 during the year ended December 31, 2022 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 our US offshore business provide for us to receive a series of fixed monthly payments (FMPs) for a specified period that 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 as 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 $58.6 billion, of which $7.6 billion is expected to be recognized during the year ending December 31, 2023.

The revenues excluded from the amounts above based on optional exemptions available under Accounting Standards Codification (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, 2022, revenue for the Canadian Mainline has been recognized in accordance with the terms of the Competitive Toll 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, 2022 is considered variable consideration.

Recognition and Measurement of Revenue

Year ended December 31, 2022	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	**—**	**—**	**127**	**—**	**127**
Revenue from products and services transferred over time[1]	**11,518**	**5,384**	**6,606**	**281**	**23,789**
Total revenue from contracts with customers	**11,518**	**5,384**	**6,733**	**281**	**23,916**

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

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, 2022, 2021 and 2020 is as follows:

Year ended December 31, 2022	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues *(Note 4)*	**12,052**	**5,426**	**6,729**	**582**	**29,175**	**(655)**	**53,309**
Commodity and gas distribution costs	**—**	**—**	**(3,693)**	**(16)**	**(29,525)**	**645**	**(32,589)**
Operating and administrative	**(4,287)**	**(2,254)**	**(1,289)**	**(255)**	**(49)**	**(85)**	**(8,219)**
Impairment of long-lived assets	**(245)**	**—**	**—**	**(235)**	**(13)**	**(48)**	**(541)**
Impairment of goodwill *(Note 16)*	**—**	**(2,465)**	**—**	**—**	**—**	**—**	**(2,465)**
Income/(loss) from equity investments *(Note 13)*	**785**	**1,133**	**1**	**141**	**—**	**(4)**	**2,056**
Gain on joint venture merger transaction *(Note 13)*	**—**	**1,076**	**—**	**—**	**—**	**—**	**1,076**
Other income/(expense) *(Note 28)*	**59**	**210**	**79**	**45**	**(5)**	**(977)**	**(589)**
Earnings/(loss) before interest, income taxes and depreciation and amortization	**8,364**	**3,126**	**1,827**	**262**	**(417)**	**(1,124)**	**12,038**
Depreciation and amortization							**(4,317)**
Interest expense *(Note 18)*							**(3,179)**
Income tax expense *(Note 25)*							**(1,604)**
Earnings							**2,938**
Capital expenditures[1]	**1,418**	**1,690**	**1,499**	**50**	**—**	**33**	**4,690**
Total property, plant and equipment, net *(Note 11)*	**53,567**	**29,666**	**17,857**	**3,082**	**6**	**282**	**104,460**

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 *(Note 4)*	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 *(Note 13)*	759	813	42	101	—	(4)	1,711
Impairment of equity investments *(Note 13)*	—	(111)	—	—	—	—	(111)
Other income/(expense) *(Note 28)*	13	135	385	75	(8)	379	979
Earnings/(loss) before interest, income taxes and depreciation and amortization	7,897	3,671	2,117	508	(313)	356	14,236
Depreciation and amortization							(3,852)
Interest expense *(Note 18)*							(2,655)
Income tax expense *(Note 25)*							(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 *(Note 11)*	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 *(Note 4)*	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 *(Note 13)*	558	479	9	94	(3)	(1)	1,136
Impairment of equity investments *(Note 13)*	—	(2,351)	—	—	—	—	(2,351)
Other income/(expense) *(Note 28)*	53	(52)	71	35	1	130	238
Earnings/(loss) before interest, income taxes and depreciation and amortization	7,683	1,087	1,748	523	(236)	(113)	10,692
Depreciation and amortization							(3,712)
Interest expense *(Note 18)*							(2,790)
Income tax expense *(Note 25)*							(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

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,	**2022**	2021	2020
(millions of Canadian dollars)			
Canada	**27,498**	20,474	16,453
US	**25,811**	26,597	22,634
	53,309	47,071	39,087

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

Property, Plant and Equipment[1]

December 31,	**2022**	2021
(millions of Canadian dollars)		
Canada	**47,602**	47,102
US	**56,858**	52,965
	104,460	100,067

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. On December 30, 2021, we closed the sale of our minority ownership in Noverco. The weighted average number of common shares outstanding was reduced by our pro-rata weighted average interest in our own common shares of approximately 2 million and 5 million as at December 31, 2021 and 2020, respectively, resulting from our reciprocal investment in Noverco.

DILUTED
The treasury stock method is used to determine the dilutive impact of stock options and RSUs. This method assumes any proceeds from the exercise of stock options and vesting of RSUs 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,	**2022**	2021	2020
(number of shares in millions)			
Weighted average shares outstanding	**2,025**	2,023	2,020
Effect of dilutive options and RSUs	**4**	2	1
Diluted weighted average shares outstanding	**2,029**	2,025	2,021

For the years ended December 31, 2022, 2021 and 2020, 10.4 million, 18.6 million and 29.8 million, respectively, of anti-dilutive stock options with a weighted average exercise price of $56.49, $52.89 and $51.42, 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. In the absence of rate-regulated accounting, this regulatory Deferred income taxes balance and the related earnings impact would not be recorded.

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. The tolls in place on June 30, 2021 continue on an interim basis until new tolls are finalized and approved by the CER *(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, 2022 (2021 - $2.1 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 currently operate under the terms of their respective 2022-2026 and 2022-2023 settlement agreements, which stipulate an allowable ROE and the continuation and establishment of certain deferral and variance accounts.

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 agencies. 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,	**2022**	2021	Recovery/Refund Period Ends
(millions of Canadian dollars)			
Current regulatory assets			
Purchase gas variance	**190**	15	2023
Under-recovery of fuel costs	**109**	114	2023
Other current regulatory assets	**305**	130	2023
Total current regulatory assets[1] *(Note 9)*	**604**	259	
Long-term regulatory assets			
Deferred income taxes[2]	**4,473**	4,176	Various
Long-term debt[3]	**378**	398	2032-2046
Negative salvage[4]	**265**	243	Various
Purchase gas variance	**244**	215	2024
Accounting policy changes[5]	**219**	157	Various
Pension plan receivable[6]	**40**	78	Various
Other long-term regulatory assets	**244**	339	Various
Total long-term regulatory assets[1]	**5,863**	5,606	
Total regulatory assets	**6,467**	5,865	
Current regulatory liabilities			
Other current regulatory liabilities	**167**	106	2023
Total current regulatory liabilities[7]	**167**	106	
Long-term regulatory liabilities			
Future removal and site restoration reserves[8]	**1,615**	1,543	Various
Regulatory liability related to US income taxes[9]	**918**	895	2050-2072
Pipeline future abandonment costs *(Note 14)*	**610**	649	Various
Pension plan payable[6]	**231**	—	Various
Other long-term regulatory liabilities	**250**	234	Various
Total long-term regulatory liabilities[7]	**3,624**	3,321	
Total regulatory liabilities	**3,791**	3,427	

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 primarily consists of 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

ACQUISITIONS

Tri Global Energy, LLC

On September 27, 2022, through a wholly-owned US subsidiary, we acquired all of the outstanding common units in TGE for cash consideration of $295 million (US$215 million) plus potential contingent payments of up to $72 million (US$53 million) dependent on the achievement of performance milestones by TGE (the TGE Acquisition). The TGE Acquisition is subject to customary closing and working capital adjustments. TGE is an onshore renewable project developer in the US with a development portfolio of wind and solar projects. The TGE Acquisition enhances Enbridge's renewable power platform and accelerates our North American growth strategy.

We accounted for the TGE 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 are recorded at their estimated fair values as at the date of acquisition.

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

	September 27, 2022
(millions of Canadian dollars)	
Fair value of net assets acquired:	
Current assets	**5**
Property, plant and equipment	**3**
Long-term investments	**8**
Intangible assets (a)	**117**
Long-term assets	**3**
Current liabilities	**61**
Long-term debt *(Note 18)*	**18**
Long-term liabilities (b)	**105**
Goodwill (c)	**392**
Purchase price:	
Cash	**295**
Contingent consideration (d)	**49**
	344

a) Intangible assets consist of compensation expected to be earned by TGE on existing development contracts once certain project development milestones are met. Fair value was determined using a discounted cash flow method which is an income-based approach to valuation that estimates the present value of future projected benefits from the contracts. The intangible assets will be amortized on a straight-line basis over an expected useful life of three and a half years.

b) Long-term liabilities consist primarily of obligations payable to third parties which are contingent on the timing of milestones being met for certain projects. Fair value represents the present value of the future cash flow payments at the date of the TGE Acquisition.

c) Goodwill is primarily attributable to expected future returns from new opportunities to develop wind and solar projects, as well as enhanced scale and operational diversity of our renewable projects portfolio. The goodwill balance recognized has been assigned to our Renewable Power Generation segment and is tax deductible over 15 years.

d) We agreed to pay additional contingent consideration of up to US$53 million to TGE's former common unit holders if performance milestones are met on certain projects. The US$36 million of contingent consideration recognized in the purchase price represents the fair value of contingent consideration at the date of acquisition. The fair value was determined using an income-based approach.

Upon completion of the TGE Acquisition, we began consolidating TGE. For the period beginning September 27, 2022 through to December 31, 2022, operating revenues and earnings attributable to common shareholders generated by TGE were immaterial. The impact to our supplemental pro forma consolidated operating revenues and earnings attributable to common shareholders for the years ended December 31, 2022 and 2021, as if the TGE Acquisition had been completed on January 1, 2021, was also immaterial.

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 Moda Acquisition). The Moda Acquisition was 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 Moda 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 Moda 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 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 and was fully settled as at December 31, 2022.

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 Moda 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 Moda 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

Athabasca Regional Oil Sands System

On October 5, 2022, we closed the sale of an 11.6% non-operating interest in seven pipelines in the Athabasca region of northern Alberta from our Regional Oil Sands System to Athabasca Indigenous Investments Limited Partnership (Aii), an entity representing 23 First Nation and Métis communities, for total consideration of approximately $1.1 billion, less customary closing adjustments. No gain or loss was recognized on the sale and a noncontrolling interest was recorded in our Consolidated Statements of Financial Position as at December 31, 2022 to reflect the interest held by Aii *(Note 20)*.

Subsequent to the sale, we maintained an 88.4% controlling interest in these assets, which are a component of our Liquids Pipelines segment, and continue to manage, operate and provide administrative services to them.

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. 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

On May 1, 2020, we closed the sale of the Montana-Alberta Tie Line (MATL) transmission asset, a 345 kilometer transmission line from Great Falls, Montana to Lethbridge, Alberta, 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. MATL was included in our Renewable Power Generation segment.

Ozark Gas Transmission

On April 1, 2020, we closed the sale of our Ozark Gas Transmission and Ozark Gas Gathering assets (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. 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.

9. ACCOUNTS RECEIVABLE AND OTHER

December 31,	**2022**	2021
(millions of Canadian dollars)		
Trade receivables and unbilled revenues[1]	**5,616**	4,957
Short-term portion of derivative assets *(Note 24)*	**1,015**	529
Regulatory assets *(Note 7)*	**604**	259
Gas imbalance	**461**	276
Taxes receivable	**323**	407
Other	**852**	434
	8,871	6,862

1 Net of allowance for expected credit losses of $92 million and $87 million as at December 31, 2022 and 2021, respectively.

10. INVENTORY

December 31,	**2022**	2021
(millions of Canadian dollars)		
Natural gas	**1,491**	953
Crude oil	**652**	624
Other	**112**	93
	2,255	1,670

11. PROPERTY, PLANT AND EQUIPMENT

December 31,	Weighted Average Depreciation Rate	**2022**	2021
(millions of Canadian dollars)			
Pipelines	2.9 %	**66,528**	62,997
Facilities and equipment	3.5 %	**37,028**	34,331
Land and right-of-way[1]	2.2 %	**3,637**	3,320
Gas mains, services and other	2.6 %	**14,491**	13,606
Storage	2.3 %	**3,477**	3,099
Wind turbines, solar panels and other	4.1 %	**4,912**	4,912
Other	8.5 %	**1,611**	1,507
Under construction	— %	**2,316**	2,268
Total property, plant and equipment		**134,000**	126,040
Total accumulated depreciation		**(29,540)**	(25,973)
Property, plant and equipment, net		**104,460**	100,067

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

Depreciation expense for the years ended December 31, 2022, 2021 and 2020 was $3.8 billion, $3.5 billion and $3.4 billion, respectively.

IMPAIRMENT

Magic Valley Wind Farm

Magic Valley Wind Farm (Magic Valley) has commercial challenges caused by electricity transmission congestion and a negative price differential arising from higher transmission costs resulting in a lower electricity sale price. As a result, we have recognized an impairment loss of $227 million to our investment in Magic Valley, which is included in Impairment of long-lived assets in the Consolidated Statements of Earnings and is part of our Renewable Power Generation segment.

Bakken Pipeline System

The Bakken Pipeline System currently has long-term take-or-pay contracts that are set to expire in 2023. In connection with the upcoming expiration of the contracts, we have recognized an impairment loss of $183 million on the US and Canadian components of the interstate pipeline transportation system within the North Dakota System of our Bakken System, which is included in Impairment of long-lived assets in the Consolidated Statements of Earnings and is part of our Liquids Pipelines segment.

Impairment charges were based on the amount by which the carrying value 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. The creditors of the liabilities of our consolidated VIEs 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,	**2022**[1]	2021
(millions of Canadian dollars)		
Assets		
Cash and cash equivalents	**426**	247
Restricted cash	**12**	4
Accounts receivable and other	**199**	99
Accounts receivable from affiliates	**23**	—
Inventory	**12**	9
	672	359
Property, plant and equipment, net	**7,707**	3,052
Long-term investments	**14**	16
Restricted long-term investments	**98**	101
Deferred amounts and other assets	**158**	2
Intangible assets, net	**102**	108
	8,751	3,638
Liabilities		
Accounts payable and other	**251**	84
Accounts payable to affiliates	**21**	—
	272	84
Other long-term liabilities	**859**	182
Deferred income taxes	**5**	5
	1,136	271
	7,615	3,367

1 *Includes assets and liabilities of newly created Enbridge Athabasca Midstream Trunkline LP and Enbridge Athabasca Midstream Investor LP following the sale of a minority interest in certain Athabasca Regional Oil Sands System assets. Refer to* Note 8 - Acquisitions and Dispositions.

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 their 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, 2022 and 2021 are presented below:

December 31, 2022	Carrying Amount of the VIE	Maximum Exposure to Loss
(millions of Canadian dollars)		
Aux Sable Liquid Products L.P.[1]	**91**	**117**
EIH S.á r.l.[2]	**37**	**637**
Rampion Offshore Wind Limited[3]	**413**	**468**
Vector Pipeline L.P.[4]	**195**	**325**
Woodfibre LNG Limited Partnership[5,6]	**635**	**2,476**
Other[7]	**245**	**443**
	1,616	**4,466**

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]	38	664
Enbridge Renewable Infrastructure Investments S.á r.l.[8,9]	54	2,121
Rampion Offshore Wind Limited[3]	450	508
Vector Pipeline L.P.[4]	189	374
Other[7]	210	426
	1,054	4,288

1 *As at December 31, 2022 and 2021, the maximum exposure to loss includes a guarantee by us for our respective share of the VIE's borrowing on a bank credit facility.*
2 *As at December 31, 2022 and 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 $56 million and $73 million held by us as at December 31, 2022 and 2021, respectively.*
3 *As at December 31, 2022 and 2021, 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.*
4 *As at December 31, 2022 and 2021, the maximum exposure to loss includes the carrying value of outstanding affiliate loans receivable for $25 million and $80 million held by us as at December 31, 2022 and 2021, respectively, and an outstanding credit facility for $105 million as at December 31, 2022 and 2021.*
5 *In November 2022, Enbridge acquired a 30% interest in Woodfibre LNG Limited Partnership (Woodfibre). Refer to* Note 13 - Long-Term Investments*. Woodfibre is a VIE due to its lack of sufficient equity at risk to finance its activities. Enbridge does not hold decision-making rights to direct Woodfibre's activities that most significantly impact its economic performance.*
6 *As at December 31, 2022, 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.*
7 *As at December 31, 2022 and 2021, the maximum exposure to loss includes our parental guarantees that have been committed in connection with the projects for which we would be liable in the event of default by the VIE.*
8 *As at December 31, 2021, the maximum exposure to loss included 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 held by us as at December 31, 2021.*
9 *Following a reconsideration event in connection with an additional equity injection to facilitate debt and equity rebalancing of Enbridge Renewable Infrastructure Investments S.á r.l. (ERII) in the third quarter of 2022, ERII's equity is now sufficient for it to finance its activities without additional subordinated financial support. Therefore, it is no longer considered to be a VIE.*

We do not have an obligation to and did not provide any additional financial support to the VIEs during the years ended December 31, 2022 and 2021.

13. LONG-TERM INVESTMENTS

December 31,	Ownership Interest	**2022**	2021
(millions of Canadian dollars)			
EQUITY INVESTMENTS			
Liquids Pipelines			
MarEn Bakken Company LLC[1]	75.0%	**1,968**	1,752
DCP Midstream, LLC (Class B Units)[2]	90.0%	**1,394**	469
Seaway Crude Holdings LLC	50.0%	**2,744**	2,634
Illinois Extension Pipeline Company, L.L.C.[3]	65.0%	**622**	593
Cactus II Pipeline LLC[4]	30.0%	**658**	434
Other	30.0% - 43.8%	**76**	71
Gas Transmission and Midstream			
Alliance Pipeline[5]	50.0%	**430**	504
Aux Sable[6]	42.7% - 50.0%	**214**	238
DCP Midstream, LLC (Class A Units)[7]	23.4%	**317**	397
Gulfstream Natural Gas System, L.L.C.	50.0%	**1,274**	1,180
Nexus Gas Transmission, LLC	50.0%	**1,813**	1,724
Sabal Trail Transmission, LLC	50.0%	**1,535**	1,464
Southeast Supply Header, LLC	50.0%	**86**	82
Steckman Ridge, LP	50.0%	**91**	88
Vector Pipeline[8]	60.0%	**195**	189
Woodfibre LNG Limited Partnership	30.0%	**635**	—
Offshore - various joint ventures	22.0% - 74.3%	**314**	309
Other	20.0% - 33.3%	**—**	14
Gas Distribution and Storage			
Other	47.6% - 50.0%	**20**	20
Renewable Power Generation			
EIH S.à.r.l.[9]	51.0%	**37**	38
Enbridge Renewable Infrastructure Investments S.à.r.l.	51.0%	**163**	54
Rampion Offshore Wind Limited	24.9%	**413**	450
NextBridge Infrastructure LP	25.0%	**241**	186
Other	15.8% - 50.0%	**107**	92
OTHER LONG-TERM INVESTMENTS			
Gas Transmission and Midstream			
Fairwood Peninsula Energy Corporation		**22**	20
Gas Distribution and Storage			
Oakville Enterprises Corporation[10]		**48**	—
Renewable Power Generation			
Emerging Technologies and Other		**31**	32
Eliminations and Other			
Other[11]		**488**	290
		15,936	13,324

1 *Owns a 49.0% interest in Bakken Pipeline Investments L.L.C. Bakken Pipeline Investments L.L.C. owns 75.0% of the Bakken Pipeline System, resulting in a 27.6% effective interest in the Bakken Pipeline System by us.*
2 *We own 90.0% of the Class B units of DCP Midstream, LLC. These units track to a 65.0% ownership in Gray Oak Pipeline, LLC (Gray Oak), resulting in a 58.5% effective interest in Gray Oak by us. In 2021, we owned a 35.0% interest in Gray Oak Holdings LLC, which owned a 65.0% interest in Gray Oak, resulting in a 22.8% effective interest in Gray Oak by us.*
3 *Owns the Southern Access Extension Project.*
4 *On October 12, 2021, we acquired an effective 20.0% interest in Cactus II through the acquisition of Moda. Refer to* Note 8 - Acquisitions and Dispositions *for further discussion. On November 2, 2022, we acquired an additional 10.0% ownership in Cactus II for cash payment of $241 million (US$177 million), bringing our total non-operating ownership to 30.0%.*
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 We own 23.4% of the Class A units of DCP Midstream, LLC. These units track to a 56.5% ownership in DCP Midstream, LP (DCP), resulting in a 13.2% effective interest in DCP by us. In 2021, we owned an effective 28.3% interest in DCP.
8 Includes Vector Pipeline Limited Partnership in Canada and Vector Pipeline L.P. in the US.
9 On March 18, 2021, we sold 49.0% of EIH S.à.r.l., an entity that holds our 50.0% interest in Éolien Maritime France SAS (EMF), to the Canada Pension Plan Investment Board. 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 effective interests in Saint-Nazaire (25.5%), Fécamp (17.9%) and Calvados (21.7%).
10 On August 2, 2022, we acquired a 10.0% interest in Oakville Enterprises Corporation.
11 Consists of investments in debt and equity securities held by our wholly-owned captive insurance subsidiaries. Refer to Note 24 - Risk Management and Financial Instruments.

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, 2022, this basis difference was $3.4 billion (2021 - $2.5 billion), of which $1.5 billion (2021 - $730 million) was amortizable.

For the years ended December 31, 2022, 2021 and 2020, distributions received from equity investments were $2.6 billion, $2.2 billion and $2.1 billion, respectively.

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

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Operating revenues	**27,043**	20,021	14,096
Operating expenses	**23,043**	16,706	12,411
Earnings	**4,334**	3,022	2,324
Earnings attributable to Enbridge	**2,056**	1,711	1,136

December 31,	**2022**	2021
(millions of Canadian dollars)		
Current assets	**4,196**	3,639
Non-current assets	**53,405**	44,863
Current liabilities	**4,843**	3,741
Non-current liabilities	**18,595**	16,979
Noncontrolling interests	**3,785**	3,786

DCP Midstream, LLC

On August 17, 2022, we completed a joint venture merger transaction with Phillips 66 (P66) resulting in a single joint venture, DCP Midstream, LLC, holding both our and P66's indirect ownership interests in Gray Oak and DCP. Our ownership in DCP Midstream, LLC consists of Class A and Class B Interests which track to our investments in DCP, included in the Gas Transmission and Midstream segment, and Gray Oak, included in the Liquids Pipelines segment, respectively. Through our investment in DCP Midstream, LLC, we increased our effective economic interest in Gray Oak to 58.5% from 22.8% and reduced our effective economic interest in DCP to 13.2% from 28.3%. As a result of the transaction, Enbridge will assume operatorship of Gray Oak in the second quarter of 2023.

We determined the fair value of our decrease in economic interest in DCP based on the unadjusted quoted market price of DCP's publicly traded common units on the transaction closing date. The fair value of our increased economic interest in Gray Oak was determined using the fair value prescribed to the change in our economic interest in DCP. As a result of the merger transaction and the realignment of our economic interests in DCP and Gray Oak, we also received cash consideration of approximately $522 million (US$404 million) and recorded an accounting gain of $1.1 billion (US$832 million) to Gain on joint venture merger transaction in the Consolidated Statements of Earnings. Both DCP and Gray Oak continue to be accounted for as equity method investments.

Woodfibre LNG Limited Partnership
On November 29, 2022, Enbridge acquired, for cash payment of $533 million (US$392 million), an effective 30.0% interest in Woodfibre. Woodfibre will operate a liquified natural gas export facility in BC being constructed by us and our partners.

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. 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 20.0% 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, 2022 and 2021 was nil and $12 million, respectively.

Steckman Ridge, LP
Steckman Ridge, LP (Steckman Ridge) is engaged in the storage of natural gas, is owned 50.0% 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. As a result, we recorded an other-than-temporary impairment loss of $221 million on our investment for the year ended December 31, 2020 based on a discounted cash flow analysis. The carrying value of this investment as at December 31, 2022 and 2021 was $91 million and $88 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, is owned 50.0% 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. As a result, we recorded an other-than-temporary impairment loss of $394 million on our investment for the year ended December 31, 2020 based on a discounted cash flow analysis. The carrying value of this investment as at December 31, 2022 and 2021 was $86 million and $82 million, respectively.

DCP Midstream, LLC
DCP Midstream, LLC, an entity of which we had a 50.0% ownership interest in prior to the joint venture merger transaction with P66, holds an equity interest in DCP. A decline in the market price of DCP's publicly traded units during the first quarter of 2020 resulted in an other-than-temporary impairment loss on our investment in DCP Midstream, LLC 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. The carrying value of our investment in DCP Midstream, LLC (Class A Units) as at December 31, 2022 and 2021 was $317 million and $397 million, respectively.

Our investments in PennEast, Steckman, SESH and DCP Midstream, LLC (Class A Units) 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 in the Consolidated Statements of Earnings and Restricted long-term investments in the Consolidated Statements of Financial Position. Concurrently, we reflect the future abandonment cost as an increase to Operating and administrative expense in the Consolidated Statements of Earnings and Other long-term liabilities in 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, 2022 and 2021, we had restricted long-term investments held in trust and classified as available-for-sale of $593 million and $630 million, respectively.

We had Restricted long-term investments held in trust totaling $236 million and $217 million as at December 31, 2022 and 2021, respectively, which are classified as Level 1 in the fair value hierarchy. We also had Restricted long-term investments held in trust totaling $357 million (cost basis - $437 million) and $413 million (cost basis - $383 million) as at December 31, 2022 and 2021, respectively, which are classified as Level 2 in the fair value hierarchy. There were unrealized holding losses of $122 million and $8 million on our Restricted long-term investments for the years ended December 31, 2022 and 2021, respectively. Within Other long-term liabilities we had estimated future abandonment costs related to LMCI of $610 million and $649 million as at December 31, 2022 and 2021, respectively *(Note 7)*.

15. INTANGIBLE ASSETS

December 31, 2022	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	10.9%	**2,019**	**(1,042)**	**977**
Power purchase agreements	4.2%	**64**	**(23)**	**41**
Project agreement[1]	4.0%	**163**	**(36)**	**127**
Customer relationships	8.6%	**2,701**	**(459)**	**2,242**
Other intangible assets	5.9%	**621**	**(148)**	**473**
Under development	—%	**158**	**—**	**158**
		5,726	**(1,708)**	**4,018**

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

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

For the years ended December 31, 2022, 2021 and 2020, our amortization expense related to intangible assets totaled $483 million, $348 million and $294 million, respectively. Our expected amortization expense associated with existing intangible assets for each of the years 2023 to 2027 is $498 million.

16. GOODWILL

	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Energy Services	Consolidated
(millions of Canadian dollars)						
Balance at January 1, 2021	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
Impairment	**—**	**(2,465)**	**—**	**—**	**—**	**(2,465)**
Foreign exchange and other	**506**	**1,236**	**—**	**(4)**	**—**	**1,738**
Acquisition[4]	**—**	**—**	**—**	**392**	**—**	**392**
Balance at December 31, 2022[1,2]	**8,547**	**18,106**	**5,397**	**388**	**2**	**32,440**

1 Gross goodwill as at December 31, 2022 and 2021 was $36.5 billion and $34.4 billion, respectively.
2 Accumulated impairment as at December 31, 2022 and 2021 was $4.1 billion and $1.6 billion, respectively.
3 In 2021 we recorded $268 million of goodwill related to the acquisition of Moda. Refer to Note 8 - Acquisitions and Dispositions.
4 In 2022, we recorded $392 million of goodwill related to the acquisition of TGE. Refer to Note 8 - Acquisitions and Dispositions.

IMPAIRMENT
Gas Transmission

During the year ended December 31, 2022, we recorded goodwill impairment of $2.5 billion related to our Gas Transmission reporting unit. The fair value of the reporting unit, determined using a combination of discounted cash flow and earnings multiples techniques, was impacted by a rise in cost of capital and lower projected long term growth rates for our existing assets.

17. ACCOUNTS PAYABLE AND OTHER

December 31,	**2022**	2021
(millions of Canadian dollars)		
Trade payables and operating accrued liabilities	**5,235**	4,470
Dividends payable	**1,825**	1,773
Current deferred credits	**1,056**	853
Construction payables and contractor holdbacks	**937**	844
Current derivative liabilities *(Note 24)*	**898**	717
Taxes payable	**683**	478
Other	**758**	632
	11,392	9,767

18. DEBT

December 31,	Weighted Average Interest Rate[9]	Maturity	**2022**	2021
(millions of Canadian dollars)				
Enbridge Inc.				
US dollar senior notes	3.5%	2023 - 2051	**12,060**	10,992
Medium-term notes	3.8%	2023 - 2064	**8,223**	8,123
Sustainability-linked bonds	2.0%	2032 - 2033	**3,355**	2,363
Fixed-to-fixed subordinated term notes[1]	4.1%	2080 - 2083	**3,596**	1,263
Fixed-to-floating rate subordinated term notes[2]	5.9%	2077 - 2078	**6,736**	6,442
Floating rate notes[3]		2023 - 2024	**1,491**	1,579
Commercial paper and credit facility draws	4.8%	2023 - 2027	**7,984**	7,837
Other[4]			**15**	5
Enbridge (U.S.) Inc.				
Commercial paper and credit facility draws	4.5%	2024 - 2027	**4,199**	4,845
Other[4]			**7**	7
Enbridge Energy Partners, L.P.				
Senior notes	6.5%	2025 - 2045	**3,320**	3,095
Enbridge Gas Inc.				
Medium-term notes	4.1%	2023 - 2052	**9,535**	9,010
Debentures	9.1%	2024 - 2025	**210**	210
Commercial paper and credit facility draws	4.5%	2024	**2,000**	1,515
Other[4]			**1**	—
Enbridge Pipelines (Southern Lights) L.L.C.				
Senior notes	4.0%	2040	**921**	949
Enbridge Pipelines Inc.				
Medium-term notes[5]	4.2%	2023 - 2051	**5,425**	5,575
Debentures	8.2%	2024	**200**	200
Commercial paper and credit facility draws	4.6%	2024	**312**	667
Enbridge Southern Lights LP				
Senior notes	4.0%	2040	**222**	240
Spectra Energy Capital, LLC				
Senior notes	7.0%	2032 - 2038	**234**	218
Algonquin Gas Transmission, LLC				
Senior notes	3.3%	2024 - 2029	**1,152**	1,074
East Tennessee Natural Gas, LLC				
Senior notes	3.1%	2024	**258**	240
Texas Eastern Transmission, LP				
Senior notes	3.3%	2028 - 2048	**3,455**	3,095
Spectra Energy Partners, LP				
Senior notes	4.3%	2024 - 2045	**4,336**	4,042
Tri Global Energy, LLC				
Senior notes	12.7%	2024	**18**	—
Westcoast Energy Inc.				
Medium-term notes	4.9%	2024 - 2041	**1,225**	1,475
Debentures	8.1%	2025 - 2026	**275**	275
Fair value adjustment			**608**	667
Other[6]			**(393)**	(363)
Total debt[7]			**80,980**	75,640
Current maturities			**(6,045)**	(6,164)
Short-term borrowings[8]			**(1,996)**	(1,515)
Long-term debt			**72,939**	67,961

1 *For an initial five or 10 years, the notes carry a fixed interest rate. Subsequently, during each reset period the interest rate will be reset to equal to the Five-Year US Treasury rate or Five-Year Government of Canada bond yield plus a margin. The notes would be converted automatically into Conversion Preference Shares in the event of bankruptcy and related events.*

2 *For an initial five or 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 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 Secured Overnight Financing Rate (SOFR) plus a margin of 40 basis points and SOFR plus a margin of 63 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 *2022 - $38 billion and US$31 billion; 2021 - $36 billion and US$31 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 4.5% as at December 31, 2022 (2021 - 0.5%).*

9 *Calculated based on term notes, debentures, commercial paper and credit facility draws outstanding as at December 31, 2022.*

As at December 31, 2022, all outstanding debt was unsecured.

CREDIT FACILITIES

The following table provides details of our committed credit facilities as at December 31, 2022:

	Maturity[1]	Total Facilities	Draws[2]	Available
(millions of Canadian dollars)				
Enbridge Inc.	2023-2027	**10,987**	**7,984**	**3,003**
Enbridge (U.S.) Inc.	2024-2027	**8,604**	**4,199**	**4,405**
Enbridge Pipelines Inc.	2024	**2,000**	**312**	**1,688**
Enbridge Gas Inc.	2024	**2,000**	**2,000**	**—**
Total committed credit facilities		**23,591**	**14,495**	**9,096**

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

On May 17, 2022, we entered into a three year term loan with a syndicate of Japanese banks for approximately $806 million (¥84.8 billion), which will mature in May 2025 and replaces the approximately $499 million (¥52.5 billion) term loan that matured in May 2022. Additionally, on May 24, 2022, we entered into a 364-day term loan for approximately $1.9 billion, which will mature in May 2023.

On June 23, 2022, we renewed approximately $5.5 billion of our 364-day extendible credit facilities to July 2024, which includes a one-year term out provision from July 2023.

In July and August 2022, we renewed $12.7 billion of our credit facilities, extending the maturity dates of our 364-day credit facilities to July 2024, inclusive of a one year term out provision from July 2023, and our five year facilities out to July 2027. As a part of the renewals, we increased our credit facilities by approximately $640 million.

On December 16, 2022, Enbridge (U.S.) Inc. entered into a five year delay draw term loan in support of solar self-power projects for approximately $479 million, which will mature in December 2027.

In addition to the committed credit facilities noted above, we maintain $1.3 billion of uncommitted demand letter of credit facilities, of which $689 million was unutilized as at December 31, 2022. As at December 31, 2021, we had $1.3 billion of uncommitted demand letter of credit facilities, of which $854 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 2023 to 2027.

As at December 31, 2022 and 2021, commercial paper and credit facility draws, net of short-term borrowings and non-revolving credit facilities that mature within one year, of $10.5 billion and $11.3 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, 2022, we completed the following long-term debt issuances totaling US$3.2 billion and $3.4 billion:

Company	Issue Date			Principal Amount
(millions of Canadian dollars unless otherwise stated)				
Enbridge Inc.				
	January 2022	5.00%	fixed-to-fixed subordinated notes due January 2082[1]	$750
	February 2022	Floating rate senior notes due February 2024[2]		US$600
	February 2022	2.15%	senior notes due February 2024	US$400
	February 2022	2.50%	senior notes due February 2025	US$500
	September 2022	7.38%	fixed-to-fixed subordinated notes due January 2083[3]	US$500
	September 2022	7.63%	fixed-to-fixed subordinated notes due January 2083[4]	US$600
	November 2022	5.70%	medium-term notes due November 2027	$600
	November 2022	6.10%	sustainability-linked medium-term notes due November 2032[5]	$900
	November 2022	6.51%	medium-term notes due November 2052	$500
Enbridge Gas Inc.				
	August 2022	4.15%	medium-term notes due August 2032	$325
	August 2022	4.55%	medium-term notes due August 2052	$325
Texas Eastern Transmission LP				
	December 2022	6.20%	senior notes due December 2032	US$600

1 *For the initial 10 years, the notes carry a fixed interest rate. At year 10, the interest rate will be reset to equal to the Five-Year Government of Canada bond yield plus a margin of 3.54%. Subsequent to year 10, every five years, the Five-Year Government of Canada bond yield is reset. At year 30, the interest rate will be reset to equal to the Five-Year Government of Canada bond yield plus a margin of 4.29%.*

2 *Notes carry an interest rate set to equal the SOFR plus a margin of 63 basis points.*

3 *For the initial five years, the notes carry a fixed interest rate. At year five, the interest rate will be set to equal to the Five-Year US Treasury rate plus a margin of 3.71%. At year 10, the interest rate will be reset to equal the Five-Year US Treasury rate plus a margin of 3.96%. Subsequent to year 10, every five years, the Five-Year US Treasury rate is reset. At year 25, the interest rate will be reset to equal to the Five-Year US Treasury rate plus a margin of 4.71%.*

4 *For the initial 10 years, the notes carry a fixed interest rate. At year 10, the interest rate will be reset to equal to the Five-Year US Treasury rate plus a margin of 4.42%. Subsequent to year 10, every five years, the Five-Year US Treasury rate will be reset. At year 30, the interest rate will be reset to equal to the Five-Year US Treasury rate plus a margin of 5.17%.*

5 *The sustainability-linked medium-term notes are subject to a sustainability performance target of 35% reduction in emissions intensity at an observation date of December 31, 2030. If the target is not met, on November 9, 2031, the interest rate will be set to equal 6.10% plus a margin of 70 basis points.*

LONG-TERM DEBT REPAYMENTS

During the year ended December 31, 2022, we completed the following long-term debt repayments totaling $1.5 billion and US$2.0 billion, respectively:

Company	Repayment Date			Principal Amount
(millions of Canadian dollars, unless otherwise stated)				
Enbridge Inc.				
	February 2022	Floating rate notes[1]		US$750
	February 2022	4.85%	medium-term notes	$200
	July 2022	2.90%	senior notes	US$700
	December 2022	3.19%	medium-term notes	$350
	December 2022	3.19%	medium-term notes	$450
Enbridge Gas Inc.				
	April 2022	4.85%	medium-term notes	$125
Enbridge Pipelines (Southern Lights) L.L.C.				
	June and December 2022	3.98%	senior notes	US$72
Enbridge Pipelines Inc.				
	November 2022	2.93%	medium-term notes	$150
Enbridge Southern Lights LP				
	June and December 2022	4.01%	senior notes	$18
Texas Eastern Transmission, LP				
	October 2022	2.80%	senior notes	US$500
Westcoast Energy Inc.				
	December 2022	3.12%	medium-term notes	$250

1 Notes carried an interest rate set to equal the Three-Month LIBOR plus a margin of 50 basis points.

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, 2022, we were in compliance with all debt covenants.

INTEREST EXPENSE

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Debentures and term notes	**2,910**	2,806	2,873
Commercial paper and credit facility draws	**388**	114	163
Amortization of fair value adjustment	**(45)**	(50)	(54)
Capitalized interest	**(74)**	(215)	(192)
	3,179	2,655	2,790

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, 2022 ranged from 1.5% to 9.0% (2021 - 0.9% to 9.0%).

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

December 31,	**2022**	2021
(millions of Canadian dollars)		
Obligations at beginning of year	**502**	496
Liabilities incurred	**30**	—
Liabilities settled	**(126)**	(67)
Change in estimate and other	**51**	70
Foreign currency translation adjustment	**24**	(3)
Accretion expense	**7**	6
Obligations at end of year	**488**	502
Presented as follows:		
Accounts payable and other	**83**	160
Other long-term liabilities	**405**	342
	488	502

20. NONCONTROLLING INTERESTS

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

December 31,	**2022**	2021
(millions of Canadian dollars)		
Algonquin Gas Transmission, LLC	**400**	377
Enbridge Athabasca Midstream Investor Limited Partnership[1]	**1,106**	—
Maritimes & Northeast Pipeline, L.L.C.	**582**	546
Renewable energy assets	**1,302**	1,503
Westcoast Energy Inc.[2]	**117**	116
Other	**4**	—
	3,511	2,542

1 *On October 5, 2022, we closed the sale of an 11.6% non-operating interest in certain assets from our Regional Oil Sands System to Aii. Refer to* Note 8 - Acquisitions and Dispositions.

2 *During 2021, Westcoast Energy Inc. redeemed all of its remaining Cumulative Five-Year Minimum Rate Reset Redeemable First Preferred Shares.*

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

	2022		2021		2020	
December 31,	Number of Shares	Amount	Number of Shares	Amount	Number of Shares	Amount
(millions of Canadian dollars; number of shares in millions)						
Balance at beginning of year	**2,026**	**64,799**	2,026	64,768	2,025	64,746
Shares issued on exercise of stock options	**2**	**53**	—	31	1	22
Share purchases at stated value[1]	**(3)**	**(88)**	—	—	—	—
Other	**—**	**(4)**	—	—	—	—
Balance at end of year	**2,025**	**64,760**	2,026	64,799	2,026	64,768

1 *Reflects the repurchase and cancellation of common shares under our normal course issuer bid.*

PREFERENCE SHARES

December 31,	2022 Number of Shares	2022 Amount	2021 Number of Shares	2021 Amount	2020 Number of Shares	2020 Amount
(millions of Canadian dollars; number of shares in millions)						
Preference Shares, Series A	**5**	**125**	5	125	5	125
Preference Shares, Series B	**20**	**500**	18	457	18	457
Preference Shares, Series C[1]	**—**	**—**	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[2]	**—**	**—**	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[3]	**—**	**—**	30	750	30	750
Preference Shares, Series 19	**20**	**500**	20	500	20	500
Issuance costs		**(135)**		(155)		(155)
Balance at end of year		**6,818**		7,747		7,747

1 On June 1, 2022, all outstanding Preference Shares, Series C were converted to Preference Shares, Series B.

2 On June 1, 2022, we redeemed our US$200 million outstanding Cumulative Redeemable Preference Shares, Series J.

3 On March 1, 2022, we redeemed our $750 million outstanding Cumulative Redeemable Minimum Rate Reset Preference Shares, Series 17.

Characteristics of our outstanding preference shares are as follows:

	Dividend Rate	Dividend[1]	Per Share Base Redemption Value[2]	Redemption and Conversion Option Date[2,3]	Right to Convert Into[3,4]
(Canadian dollars unless otherwise stated)					
Preference Shares, Series A	5.50%	$1.37500	$25	—	—
Preference Shares, Series B[5]	5.20%	$1.30052	$25	June 1, 2027	Series C
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 L[6]	5.86%	US$1.46448	US$25	September 1, 2027	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 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 Preference Shares, Series A, such fixed dividend rate resets every five years beginning on the initial redemption and conversion option date. The Preference Shares, Series 19 contain a feature where the fixed dividend rate, when reset every five years, will not be less than 4.90%. No other series of Preference Shares has this feature.

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

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

4 With the exception of Preference Shares, Series A, 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 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), or 3.2% (Series 20); or US$25 x (number of days in quarter/number of days in year) x Three-Month US Government treasury bill rate + 3.2% (Series M), 3.1% (Series 2) or 2.8% (Series 6).

5 The quarterly dividend per share paid on Preference Shares, Series B was increased to $0.32513 from $0.21340 on June 1, 2022 due to reset of the annual dividend on June 1, 2022. On June 1, 2022, all outstanding Preference Shares, Series C were converted to Preference Shares, Series B.

6 The quarterly dividend per share paid on Preference Shares, Series L was increased to US$0.36612 from US$0.30993 on September 1, 2022, due to reset of the annual dividend on September 1, 2022.

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, 2022, 2021 and 2020 was $260 million, $157 million and $145 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, 2022	Number	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value
(options in thousands; weighted average exercise price in Canadian dollars; intrinsic value in millions of Canadian dollars)				
Options outstanding at beginning of year	**34,017**	**49.28**		
Options granted	**3,430**	**49.58**		
Options exercised[1]	**(8,684)**	**44.55**		
Options cancelled or expired	**(1,139)**	**51.32**		
Options outstanding at end of year	**27,624**	**48.46**	**5.7**	**133**
Options vested at end of year[2]	**17,631**	**49.20**	**4.4**	**84**

1 The total intrinsic value of ISOs exercised during the years ended December 31, 2022, 2021 and 2020 was $66 million, $24 million and $13 million, respectively, and cash received on exercise was $3 million, $2 million and $4 million, respectively.

2 The total fair value of ISOs exercised during the years ended December 31, 2022, 2021 and 2020 was $21 million, $25 million and $30 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,	**2022**	2021	2020
Fair value per option *(Canadian dollars)*[1]	**5.07**	4.10	4.01
Valuation assumptions			
Expected option term *(years)*[2]	**6**	6	6
Expected volatility[3]	**21.9%**	25.5%	18.3%
Expected dividend yield[4]	**6.5%**	7.6%	5.9%
Risk-free interest rate[5]	**1.8%**	0.7%	1.3%

1 Options granted to US employees are based on the New York Stock Exchange 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, 2022, 2021 and 2020 were $4.78, $3.91 and $3.75, respectively, for Canadian employees and US$4.62, US$3.65 and US$3.62, 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, 2022, 2021 and 2020 for ISOs was $15 million, $16 million and $24 million, respectively. As at December 31, 2022, unrecognized compensation expense related to non-vested stock-based compensation arrangements granted under the ISO Plan was $12 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 2.0 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, infrequent or other non-operating factors, relative to targets established at the time of grant. To calculate the 2022 expense, a multiplier of 1.25 was used for 2022 PSU grants, 1.25 for 2021 PSU grants and 2.00 for the 2020 PSU grants.

December 31, 2022	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	**3,429**		
Units granted	**1,467**		
Units cancelled	**(131)**		
Units matured[1]	**(1,700)**		
Dividend reinvestment	**184**		
Units outstanding at end of year	**3,249**	**1.1**	**261**

1 *The total amount paid during the years ended December 31, 2022, 2021 and 2020 for PSUs was $90 million, $70 million and $14 million, respectively.*

Compensation expense recorded for the years ended December 31, 2022, 2021 and 2020 for PSUs was $169 million, $56 million and $76 million, respectively. As at December 31, 2022, unrecognized compensation expense related to non-vested PSUs was $72 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 shares or cash equal to our weighted average share price for 20 days prior to the maturity of the grant multiplied by the units outstanding on the maturity date.

December 31, 2022	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	**2,705**		
Units granted	**1,400**		
Units cancelled	**(134)**		
Units matured[1]	**(602)**		
Dividend reinvestment	**196**		
Units outstanding at end of year	**3,565**	**1.0**	**185**

1 *The total amount paid during the years ended December 31, 2022, 2021 and 2020 for RSUs was $32 million, $72 million and $27 million, respectively.*

Compensation expense recorded for the years ended December 31, 2022, 2021 and 2020 for RSUs was $76 million, $85 million and $44 million, respectively. As at December 31, 2022, unrecognized compensation expense related to non-vested RSUs was $35 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, 2022, 2021 and 2020 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 as at January 1, 2022	**(897)**	**—**	**(166)**	**56**	**(5)**	**(84)**	**(1,096)**
Other comprehensive income/(loss) retained in AOCI	**1,125**	**(35)**	**(971)**	**4,292**	**(6)**	**411**	**4,816**
Other comprehensive loss/(income) reclassified to earnings							
Interest rate contracts[1]	**186**	**—**	**—**	**—**	**—**	**—**	**186**
Foreign exchange contracts[2]	**(4)**	**—**	**—**	**—**	**—**	**—**	**(4)**
Other contracts[3]	**4**	**—**	**—**	**—**	**—**	**—**	**4**
Amortization of pension and OPEB actuarial gain[4]	**—**	**—**	**—**	**—**	**—**	**(14)**	**(14)**
Other	**—**	**—**	**—**	**—**	**16**	**—**	**16**
	1,311	**(35)**	**(971)**	**4,292**	**10**	**397**	**5,004**
Tax impact							
Income tax on amounts retained in AOCI	**(250)**	**—**	**—**	**—**	**—**	**(99)**	**(349)**
Income tax on amounts reclassified to earnings	**(43)**	**—**	**—**	**—**	**—**	**4**	**(39)**
	(293)	**—**	**—**	**—**	**—**	**(95)**	**(388)**
Balance as at December 31, 2022	**121**	**(35)**	**(1,137)**	**4,348**	**5**	**218**	**3,520**

	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 as 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 loss/(income) reclassified to earnings							
Interest rate contracts[1]	296	—	—	—	—	—	296
Commodity contracts[5]	1	—	—	—	—	—	1
Foreign exchange contracts[2]	5	—	—	—	—	—	5
Other contracts[3]	2	—	—	—	—	—	2
Equity investment disposal	—	—	—	—	(66)	—	(66)
Amortization of pension and OPEB actuarial loss and prior service costs[4]	—	—	—	—	—	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 as 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 as 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 loss/(income) reclassified to earnings							
Interest rate contracts[1]	253	—	—	—	—	—	253
Foreign exchange contracts[2]	5	—	—	—	—	—	5
Other contracts[3]	(2)	—	—	—	—	—	(2)
Amortization of pension and OPEB actuarial loss and prior service costs[4]	—	—	—	—	—	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 as at December 31, 2020	(1,326)	5	(215)	568	66	(499)	(1,401)

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

2 *Reported within Transportation and other services revenues and Other income/(expense) in the Consolidated Statements of Earnings.*

3 *Reported within Operating and administrative expense in the Consolidated Statements of Earnings.*

4 *These components are included in the computation of net periodic benefit (credit)/cost and are reported within Other income/(expense) in the Consolidated Statements of Earnings.*

5 *Reported within Transportation and other services revenues, Commodity sales, Commodity costs and Operating and administrative 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 cash flow, fair value 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 hedging program to partially mitigate the impact of short-term interest rate volatility on interest expense via execution of floating to fixed interest rate swaps. These hedges have an average fixed rate of 4.0%.

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, 2022, 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 partially mitigate our exposure to long-term interest rate variability on forecasted term debt issuances via execution of floating to fixed interest rate swaps with an average swap rate of 2.2%.

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
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 Consolidated Statements of Financial Position location and carrying value of our derivative instruments, as well as the maximum potential settlement amounts in the event of the specific circumstances described above. All amounts are presented gross in the Consolidated Statements of Financial Position.

December 31, 2022	Derivative Instruments Used as Cash Flow 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	**—**	**—**	**46**	**46**	**(41)**	**5**
Interest rate contracts	**649**	**—**	**11**	**660**	**—**	**660**
Commodity contracts	**—**	**—**	**302**	**302**	**(182)**	**120**
Other contracts	**—**	**—**	**7**	**7**	**—**	**7**
	649	**—**	**366**	**1,015**	**(223)**	**792**
Deferred amounts and other assets						
Foreign exchange contracts	**—**	**156**	**153**	**309**	**(138)**	**171**
Interest rate contracts	**254**	**—**	**—**	**254**	**—**	**254**
Commodity contracts	**—**	**—**	**61**	**61**	**(25)**	**36**
Other contracts	**1**	**—**	**2**	**3**	**—**	**3**
	255	**156**	**216**	**627**	**(163)**	**464**
Accounts payable and other						
Foreign exchange contracts	**—**	**(42)**	**(524)**	**(566)**	**41**	**(525)**
Commodity contracts	**(48)**	**—**	**(284)**	**(332)**	**182**	**(150)**
	(48)	**(42)**	**(808)**	**(898)**	**223**	**(675)**
Other long-term liabilities						
Foreign exchange contracts	**—**	**—**	**(1,116)**	**(1,116)**	**138**	**(978)**
Interest rate contracts	**(3)**	**—**	**(1)**	**(4)**	**—**	**(4)**
Commodity contracts	**(37)**	**—**	**(133)**	**(170)**	**25**	**(145)**
	(40)	**—**	**(1,250)**	**(1,290)**	**163**	**(1,127)**
Total net derivative asset/(liability)						
Foreign exchange contracts	**—**	**114**	**(1,441)**	**(1,327)**	**—**	**(1,327)**
Interest rate contracts	**900**	**—**	**10**	**910**	**—**	**910**
Commodity contracts	**(85)**	**—**	**(54)**	**(139)**	**—**	**(139)**
Other contracts	**1**	**—**	**9**	**10**	**—**	**10**
	816	**114**	**(1,476)**	**(546)**	**—**	**(546)**

December 31, 2021	Derivative Instruments Used as Cash Flow 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)
	(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)
	(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)

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

	2022							2021
As at December 31,	2023	2024	2025	2026	2027	Thereafter	Total	Total
Foreign exchange contracts - US dollar forwards - purchase *(millions of US dollars)*	**655**	**1,000**	**500**	**—**	**—**	**—**	**2,155**	2,508
Foreign exchange contracts - US dollar forwards - sell *(millions of US dollars)*	**8,297**	**6,386**	**4,613**	**4,121**	**2,837**	**1,356**	**27,610**	25,427
Foreign exchange contracts - British pound (GBP) forwards - sell *(millions of GBP)*	**29**	**30**	**30**	**28**	**32**	**—**	**149**	177
Foreign exchange contracts - Euro forwards - sell *(millions of Euro)*	**92**	**91**	**86**	**85**	**81**	**262**	**697**	801
Foreign exchange contracts - Japanese yen forwards - purchase *(millions of yen)*	**—**	**—**	**84,800**	**—**	**—**	**—**	**84,800**	72,500
Interest rate contracts - short-term pay fixed rate *(millions of Canadian dollars)*	**8,698**	**538**	**30**	**26**	**25**	**39**	**9,356**	597
Interest rate contracts - long-term pay fixed rate *(millions of Canadian dollars)*	**5,496**	**1,766**	**589**	**—**	**—**	**—**	**7,851**	5,279
Equity contracts *(millions of Canadian dollars)*	**37**	**31**	**12**	**—**	**—**	**—**	**80**	67
Commodity contracts - natural gas *(billions of cubic feet)*	**52**	**25**	**15**	**1**	**—**	**—**	**93**	199
Commodity contracts - crude oil *(millions of barrels)*	**16**	**—**	**—**	**—**	**—**	**—**	**16**	12
Commodity contracts - power *(megawatt per hour (MW/H))*	**26**	**(25)**	**(44)**	**—**	**—**	**—**	**(14)** [1]	(43) [1]

1 Total is an average net purchase/(sell) of power.

Fair Value Derivatives

For foreign exchange derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative is included in Other income/(expense) or Interest expense in the Consolidated Statements of Earnings. The offsetting loss or gain on the hedged item attributable to the hedged risk is included in Other income/(expense) in the Consolidated Statements of Earnings. Any excluded components are included in the Consolidated Statements of Comprehensive Income.

Year ended December 31,	2022	2021
(millions of Canadian dollars)		
Unrealized gain on derivative	**262**	8
Unrealized loss on hedged item	**(254)**	(15)
Realized loss on derivative	**(110)**	(41)
Realized gain on hedged item	**85**	45

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:

	2022	2021	2020
(millions of Canadian dollars)			
Amount of unrealized gain/(loss) recognized in OCI			
Cash flow hedges			
Foreign exchange contracts	**3**	(29)	(1)
Interest rate contracts	**1,151**	252	(595)
Commodity contracts	**(53)**	(28)	2
Other contracts	**(4)**	1	(3)
Fair value hedges			
Foreign exchange contracts	**(35)**	(5)	5
Net investment hedges			
Foreign exchange contracts	**—**	—	13
	1,062	191	(579)
Amount of (gain)/loss reclassified from AOCI to earnings			
Foreign exchange contracts[1]	**13**	5	5
Interest rate contracts[2]	**186**	296	253
Commodity contracts[3]	**—**	1	—
Other contracts[3]	**4**	2	(2)
	203	304	256

1 Reported within Transportation and other services revenues and Other income/(expense) in the Consolidated Statements of Earnings.

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

3 Reported within Operating and administrative expense in the Consolidated Statements of Earnings.

We estimate that a gain of $67 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, 2022.

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,	**2022**	2021	2020
(millions of Canadian dollars)			
Foreign exchange contracts[1]	**(1,344)**	92	902
Interest rate contracts[2]	**10**	2	(25)
Commodity contracts[3]	**50**	71	(114)
Other contracts[4]	**4**	8	(7)
Total unrealized derivative fair value gain/(loss), net	**(1,280)**	173	756

1 For the respective annual periods, reported within Transportation and other services revenue (2022 - $238 million loss; 2021 - $98 million gain; 2020 - $533 million gain) and Other income/(expense) (2022 - $1,106 million loss; 2021 - $6 million loss; 2020 - $369 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 (2022 - $13 million gain; 2021 - $9 million gain; 2020 - $2 million loss), Commodity sales (2022 - $89 million gain; 2021 - $160 million gain; 2020 - $321 million loss), Commodity costs (2022 - $102 million loss; 2021 - $105 million loss; 2020 - $207 million gain) and Operating and administrative expense (2022 - $50 million gain; 2021 - $7 million gain; 2020 - $2 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. Our shelf prospectuses with securities regulators enable 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, 2022. As a result, all credit facilities are available to us and the banks are obligated to fund 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,	**2022**	2021
(millions of Canadian dollars)		
Canadian financial institutions	**644**	424
US financial institutions	**277**	130
European financial institutions	**334**	181
Asian financial institutions	**224**	30
Other[1]	**105**	122
	1,584	887

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

As at December 31, 2022, we did not provide any letters of credit 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, 2022 and December 31, 2021.

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 utility's large and diversified customer base and the ability to recover an estimate for expected credit losses 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 utilize a loss allowance matrix which contemplates historical credit losses by age of receivables, adjusted for any forward-looking information and management expectations to measure lifetime expected credit losses of receivables. 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 financial 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 financial instruments 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 financial instrument 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, US and Canadian treasury bills, investments in exchange-traded equity funds held by our captive insurance subsidiaries, as well as restricted long-term investments in Canadian equity securities that are held in trust in accordance with the CER's regulatory requirements under the LMCI.

Level 2

Level 2 includes financial instrument valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Financial instruments 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 financial instrument. Derivatives valued using Level 2 inputs include non-exchange traded derivatives such as over-the-counter foreign exchange forward and cross currency swap contracts, interest rate swaps, physical forward commodity contracts, as well as commodity swaps and options for which observable inputs can be obtained.

We have also categorized the fair value of our long-term debt, investments in debt securities held by our captive insurance subsidiaries, and restricted long-term investments in Canadian government bonds held in accordance with the CER's regulatory requirements under the LMCI as Level 2. The fair value of our long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenor. When possible, the fair value of our restricted long-term investments is based on quoted market prices for similar instruments and, if not available, based on broker quotes.

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, NGL and natural gas contracts, basis swaps, commodity swaps, and 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, 2022	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	**—**	**46**	**—**	**46**
Interest rate contracts	**—**	**660**	**—**	**660**
Commodity contracts	**65**	**90**	**147**	**302**
Other contracts	**—**	**7**	**—**	**7**
	65	**803**	**147**	**1,015**
Long-term derivative assets				
Foreign exchange contracts	**—**	**309**	**—**	**309**
Interest rate contracts	**—**	**254**	**—**	**254**
Commodity contracts	**—**	**17**	**44**	**61**
Other contracts	**—**	**3**	**—**	**3**
	—	**583**	**44**	**627**
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	**—**	**(566)**	**—**	**(566)**
Commodity contracts	**(60)**	**(77)**	**(195)**	**(332)**
	(60)	**(643)**	**(195)**	**(898)**
Long-term derivative liabilities				
Foreign exchange contracts	**—**	**(1,116)**	**—**	**(1,116)**
Interest rate contracts	**—**	**(4)**	**—**	**(4)**
Commodity contracts	**—**	**(38)**	**(132)**	**(170)**
	—	**(1,158)**	**(132)**	**(1,290)**
Total net financial asset/(liability)				
Foreign exchange contracts	**—**	**(1,327)**	**—**	**(1,327)**
Interest rate contracts	**—**	**910**	**—**	**910**
Commodity contracts	**5**	**(8)**	**(136)**	**(139)**
Other contracts	**—**	**10**	**—**	**10**
	5	**(415)**	**(136)**	**(546)**

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)
	(52)	(519)	(146)	(717)
Long-term derivative liabilities				
Foreign exchange contracts	—	(423)	—	(423)
Interest rate contracts	—	(24)	—	(24)
Commodity contracts	—	(19)	(65)	(84)
	—	(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)

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

December 31, 2022	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	**(35)**	**Forward gas price**	**4.57**	**34.56**	**6.25**	**\$/mmbtu[2]**
Crude	**(4)**	**Forward crude price**	**71.10**	**105.22**	**83.26**	**\$/barrel**
Power	**(71)**	**Forward power price**	**36.63**	**364.00**	**103.30**	**\$/MW/H**
Commodity contracts - physical[1]						
Natural gas	**(41)**	**Forward gas price**	**1.67**	**33.89**	**6.00**	**\$/mmbtu[2]**
Crude	**(2)**	**Forward crude price**	**64.43**	**116.60**	**86.25**	**\$/barrel**
Power	**17**	**Forward power price**	**30.49**	**183.88**	**72.48**	**\$/MW/H**
	(136)					

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. Changes in forward commodity prices could result in significantly different fair values for our Level 3 derivatives.

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,	**2022**	2021
(millions of Canadian dollars)		
Level 3 net derivative liability at beginning of period	**(108)**	(191)
Total gain/(loss)		
Included in earnings[1]	**6**	(39)
Included in OCI	**(54)**	(29)
Settlements	**20**	151
Level 3 net derivative liability at end of period	**(136)**	(108)

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

There were no transfers into or out of Level 3 as at December 31, 2022 or 2021.

NET INVESTMENT HEDGES

We currently have designated a portion of our US dollar-denominated debt as a hedge of our net investment in US dollar-denominated investments and subsidiaries.

During the years ended December 31, 2022 and 2021, we recognized an unrealized foreign exchange loss of $954 million and gain of $49 million, respectively, on the translation of US dollar-denominated debt, in OCI. No unrealized gains or losses on the change in fair value of our outstanding foreign exchange forward contracts were recognized in OCI during the years ended December 31, 2022 and 2021. No realized gains or losses associated with the settlement of foreign exchange forward contracts were recognized in OCI during the years ended December 31, 2022 and 2021. During the years ended December 31, 2022 and 2021, we recognized a realized loss of $21 million and nil, respectively, associated with the settlement of US dollar-denominated debt that had matured during the period, in OCI.

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 $102 million and $52 million as at December 31, 2022 and 2021, respectively.

As at December 31, 2022, the fair value of short- and long-term investments in equity funds and debt securities held by our captive insurance subsidiaries was $145 million and $488 million, respectively (2021 - $14 million and $290 million, respectively). These investments in equity funds and debt securities are recognized at fair value, classified as Level 1 and Level 2 in the fair value hierarchy, and are recorded in Accounts receivable and other and Long-term investments, respectively, in the Consolidated Statements of Financial Position. There were unrealized holding losses in equity funds and debt securities of $26 million for the year ended December 31, 2022 (2021 - losses of $12 million).

As at December 31, 2022 and 2021, our long-term debt had a carrying value of $79.3 billion and $74.4 billion, respectively, before debt issuance costs and a fair value of $73.5 billion and $82.0 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, 2022 and 2021, the non-current notes receivable had a carrying value of $752 million and $954 million, respectively, which also approximates their fair value.

The fair value of financial assets and liabilities other than derivative instruments, long-term investments, restricted long-term investments, long-term debt and non-current notes receivable described above approximate their carrying value due to the short period to maturity.

25. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Earnings before income taxes	**4,542**	7,729	4,190
Canadian federal statutory income tax rate	**15%**	15%	15%
Expected federal taxes at statutory rate	**681**	1,159	629
Increase/(decrease) resulting from:			
Provincial and state income taxes[1]	**108**	228	288
Foreign and other statutory rate differentials[2]	**295**	134	(53)
Effects of rate-regulated accounting[3]	**(122)**	(139)	(145)
Foreign allowable interest deductions	**—**	—	(4)
Part VI.1 tax, net of federal Part I deduction[4]	**76**	73	76
US Minimum Tax[5]	**107**	—	44
Non-taxable portion of gain on sale of investment[6]	**—**	(23)	—
Valuation allowance	**6**	5	(6)
Accounting impairment of non-deductible goodwill[7]	**370**	—	—
Noncontrolling interests[8]	**9**	(17)	(8)
Other[9]	**74**	(5)	(47)
Income tax expense	**1,604**	1,415	774
Effective income tax rate	**35.3%**	18.3%	18.5%

1 *The change in provincial and state income taxes from 2021 to 2022 reflects the decrease in earnings from Canadian operations and the effect of the reduction in the Pennsylvania corporate income tax rate in the US, partially offset by the increase in earnings from US operations before the non-deductible goodwill impairment relating to the Gas Transmission reporting unit in combination with state tax apportionment changes. Refer to* Note 16 - Goodwill.

2 *The change in foreign and other statutory rate differentials from 2021 to 2022 reflects the increase in earnings from US operations, before the goodwill impairment relating to the Gas Transmission reporting unit. Refer to* Note 16 - Goodwill.

3 *The amount in 2022 relates to the federal component of the tax impact relating to the 2022 variable consideration attributable to the Canadian Mainline. Refer to* Note 4 - Revenue.

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

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

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

7 *The amount in 2022 relates to the federal impact of the non-deductible goodwill impairment relating to the Gas Transmission reporting unit. Refer to* Note 16 - Goodwill.

8 *The amount in 2022 includes the federal tax impact of an impairment to Magic Valley attributable to noncontrolling interests. Refer to* Note 11 - Property, Plant and Equipment.

9 *The amount in 2022 includes the federal component of the tax impact relating to the 2021 variable consideration attributable to the Canadian Mainline. Refer to* Note 4 - Revenue.

COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Earnings before income taxes			
Canada	**583**	3,399	2,789
US	**2,865**	3,336	407
Other	**1,094**	994	994
	4,542	7,729	4,190
Current income taxes			
Canada	**360**	162	165
US	**201**	80	64
Other	**86**	82	98
	647	324	327
Deferred income taxes			
Canada	**(358)**	344	378
US	**1,309**	741	66
Other	**6**	6	3
	957	1,091	447
Income tax expense	**1,604**	1,415	774

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,	**2022**	2021
(millions of Canadian dollars)		
Deferred income tax liabilities		
Property, plant and equipment	**(9,096)**	(8,721)
Investments	**(7,099)**	(6,097)
Regulatory assets	**(1,291)**	(1,245)
Pension and OPEB plans	**(30)**	—
Other	**(46)**	(208)
Total deferred income tax liabilities	**(17,562)**	(16,271)
Deferred income tax assets		
Financial instruments	**456**	315
Pension and OPEB plans	**—**	110
Loss carryforwards	**2,259**	3,081
Other	**1,753**	1,648
Total deferred income tax assets	**4,468**	5,154
Less valuation allowance	**(215)**	(84)
Total deferred income tax assets, net	**4,253**	5,070
Net deferred income tax liabilities	**(13,309)**	(11,201)
Presented as follows:		
Total deferred income tax assets	**472**	488
Total deferred income tax liabilities	**(13,781)**	(11,689)
Net deferred income tax liabilities	**(13,309)**	(11,201)

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, 2022, we recognized the benefit of unused tax loss carryforwards of $2.1 billion (2021 - $1.9 billion) in Canada which expire in 2030 and beyond.

As at December 31, 2022, we recognized the benefit of unused tax loss carryforwards of $8.1 billion (2021 - $11.0 billion) in the US. Unused tax loss carryforwards of $0.2 billion (2021 - $3.5 billion) begin to expire in 2023, and unused tax loss carryforwards of $7.9 billion (2021 - $7.5 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 $8.0 billion and $4.3 billion for the periods ended December 31, 2022 and 2021, 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 applicable to 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 Québec). We are open to examination by Canadian tax authorities for the 2015 to 2022 tax years and by US tax authorities for the 2019 to 2022 tax years. We are currently under examination for income tax matters in Canada for the 2016 to 2019 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,	**2022**	2021
(millions of Canadian dollars)		
Unrecognized tax benefits at beginning of year	**76**	121
Gross increases for tax positions of current year	**—**	1
Gross decreases for tax positions of prior year	**(17)**	(26)
Change in translation of foreign currency	**1**	(1)
Lapses of statute of limitations	**(5)**	(19)
Unrecognized tax benefits at end of year	**55**	76

The unrecognized tax benefits as at December 31, 2022, 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, 2022 and 2021 were a $1 million expense and $5 million recovery, respectively. As at December 31, 2022 and 2021, interest and penalties of $13 million and $12 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 pension plans provide defined benefit and defined contribution pension benefits to our Canadian employees. The US pension 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,	**2022**	2021	**2022**	2021
(millions of Canadian dollars)				
Change in projected benefit obligation				
Projected benefit obligation at beginning of year	**4,600**	4,855	**1,184**	1,243
Service cost	**131**	139	**43**	44
Interest cost	**127**	101	**24**	17
Participant contributions	**29**	28	**—**	—
Actuarial gain[1]	**(1,069)**	(329)	**(201)**	(21)
Benefits paid	**(187)**	(194)	**(94)**	(84)
Foreign currency exchange rate changes	**—**	—	**77**	(11)
Other	**(1)**	—	**(4)**	(4)
Projected benefit obligation at end of year[2]	**3,630**	4,600	**1,029**	1,184
Change in plan assets				
Fair value of plan assets at beginning of year	**4,536**	4,077	**1,160**	1,062
Actual return/(loss) on plan assets	**(235)**	505	**(64)**	151
Employer contributions[3]	**91**	120	**4**	43
Participant contributions	**29**	28	**—**	—
Benefits paid	**(187)**	(194)	**(94)**	(84)
Foreign currency exchange rate changes	**—**	—	**78**	(8)
Other	**—**	—	**(4)**	(4)
Fair value of plan assets at end of year[4]	**4,234**	4,536	**1,080**	1,160
Overfunded/(underfunded) status at end of year	**604**	(64)	**51**	(24)
Presented as follows:				
Deferred amounts and other assets	**764**	250	**141**	98
Accounts payable and other	**(9)**	(9)	**(5)**	(4)
Other long-term liabilities	**(151)**	(305)	**(85)**	(118)
	604	(64)	**51**	(24)

1 Actuarial gains in 2022 and 2021 primarily due to increase in the discount rates used to measure the benefit obligations.

2 The accumulated benefit obligation for our Canadian pension plans was $3.4 billion and $4.3 billion as at December 31, 2022 and 2021, respectively. The accumulated benefit obligation for our US pension plans was $1.0 billion and $1.1 billion as at December 31, 2022 and 2021, respectively.

3 Lower employer contributions in 2022 compared to 2021 primarily due to more plans in an overfunded status.

4 Assets in the amount of $10 million (2021 - $13 million) and $58 million (2021 - $84 million), related to our Canadian and US 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,	**2022**	2021	**2022**	2021
(millions of Canadian dollars)				
Accumulated benefit obligation	**360**	440	**89**	115
Fair value of plan assets	**218**	247	**—**	—

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	**377**	1,272	**90**	121
Fair value of plan assets	**218**	1,020	**—**	—

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,	**2022**	2021	**2022**	2021
(millions of Canadian dollars)				
Net actuarial (gain)/loss	**(64)**	226	**40**	92
Prior service (credit)/cost	**—**	—	**1**	(1)
Total amount recognized in AOCI[1]	**(64)**	226	**41**	91

1 Excludes amounts related to CTA.

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,	**2022**	2021	2020	**2022**	2021	2020
(millions of Canadian dollars)						
Service cost	**131**	139	148	**43**	44	44
Interest cost[1]	**127**	101	128	**24**	17	31
Expected return on plan assets[1]	**(295)**	(252)	(260)	**(85)**	(73)	(88)
Amortization/settlement of net actuarial loss[1]	**8**	54	42	**—**	11	1
Amortization/curtailment of prior service credit[1]	**—**	—	—	**(2)**	—	(1)
Net periodic benefit (credit)/cost	**(29)**	42	58	**(20)**	(1)	(13)
Defined contribution benefit cost	**10**	7	6	**—**	—	—
Net pension (credit)/cost recognized in Earnings	**(19)**	49	64	**(20)**	(1)	(13)
Amount recognized in OCI:						
Amortization/settlement of net actuarial loss	**(2)**	(25)	(21)	**—**	(11)	(1)
Amortization/curtailment of prior service credit	**—**	—	—	**2**	—	1
Net actuarial (gain)/loss arising during the year	**(288)**	(291)	118	**(52)**	(99)	100
Total amount recognized in OCI	**(290)**	(316)	97	**(50)**	(110)	100
Total amount recognized in Comprehensive income	**(309)**	(267)	161	**(70)**	(111)	87

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		
	2022	2021	2020	**2022**	2021	2020
Projected benefit obligation						
Discount rate	**5.1 %**	3.2 %	2.6 %	**4.9 %**	2.6 %	2.2 %
Rate of salary increase	**2.9 %**	2.9 %	2.3 %	**2.8 %**	2.8 %	2.7 %
Cash balance interest credit rate	**N/A**	N/A	N/A	**4.3 %**	4.3 %	4.3 %
Net periodic benefit cost						
Discount rate	**3.2 %**	2.6 %	3.0 %	**2.6 %**	2.2 %	3.0 %
Rate of return on plan assets	**6.6 %**	6.2 %	6.8 %	**7.4 %**	7.3 %	7.9 %
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 %

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,	**2022**	2021	**2022**	2021
(millions of Canadian dollars)				
Change in accumulated postretirement benefit obligation				
Accumulated postretirement benefit obligation at beginning of year	**274**	321	**173**	254
Service cost	**4**	6	**1**	1
Interest cost	**7**	7	**3**	3
Participant contributions	**—**	—	**6**	8
Actuarial gain[1]	**(66)**	(51)	**(37)**	(69)
Benefits paid	**(8)**	(9)	**(21)**	(22)
Foreign currency exchange rate changes	**—**	—	**11**	(3)
Other	**—**	—	**—**	1
Accumulated postretirement benefit obligation at end of year	**211**	274	**136**	173
Change in plan assets				
Fair value of plan assets at beginning of year	**—**	—	**201**	188
Actual return/(loss) on plan assets	**—**	—	**(21)**	22
Employer contributions	**8**	9	**7**	6
Participant contributions	**—**	—	**6**	8
Benefits paid	**(8)**	(9)	**(21)**	(22)
Foreign currency exchange rate changes	**—**	—	**13**	(3)
Other	**—**	—	**—**	2
Fair value of plan assets at end of year	**—**	—	**185**	201
Overfunded/(underfunded) status at end of year	**(211)**	(274)	**49**	28
Presented as follows:				
Deferred amounts and other assets	**—**	—	**75**	71
Accounts payable and other	**(12)**	(12)	**—**	—
Other long-term liabilities	**(199)**	(262)	**(26)**	(43)
	(211)	(274)	**49**	28

1 Actuarial gains in 2022 and 2021 primarily due to increase in the discount rates 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,	**2022**	2021	**2022**	2021
(millions of Canadian dollars)				
Accumulated benefit obligation	**211**	274	**76**	94
Fair value of plan assets	**—**	—	**50**	51

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,	**2022**	2021	**2022**	2021
(millions of Canadian dollars)				
Net actuarial gain	**(101)**	(35)	**(102)**	(104)
Prior service credit	**(1)**	(1)	**(30)**	(37)
Total amount recognized in AOCI[1]	**(102)**	(36)	**(132)**	(141)

1 Excludes amounts related to CTA.

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,	**2022**	2021	2020	**2022**	2021	2020
(millions of Canadian dollars)						
Service cost	**4**	6	5	**1**	1	2
Interest cost[1]	**7**	7	8	**3**	3	7
Expected return on plan assets[1]	**—**	—	—	**(12)**	(10)	(12)
Amortization/settlement of net actuarial gain[1]	**(1)**	—	(1)	**(6)**	(1)	(1)
Amortization/curtailment of prior service credit[1]	**—**	—	—	**(7)**	(7)	(2)
Net periodic benefit (credit)/cost recognized in Earnings	**10**	13	12	**(21)**	(14)	(6)
Amount recognized in OCI:						
Amortization/settlement of net actuarial gain	**1**	—	1	**6**	1	1
Amortization/curtailment of prior service credit	**—**	—	—	**7**	7	2
Net actuarial (gain)/loss arising during the year	**(67)**	(50)	21	**(4)**	(80)	15
Prior service credit	**—**	—	—	**—**	—	(33)
Total amount recognized in OCI	**(66)**	(50)	22	**9**	(72)	(15)
Total amount recognized in Comprehensive income	**(56)**	(37)	34	**(12)**	(86)	(21)

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

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		
	2022	2021	2020	**2022**	2021	2020
Accumulated postretirement benefit obligation						
Discount rate	**5.3 %**	3.2 %	2.6 %	**4.9 %**	2.4 %	2.0 %
Net periodic benefit cost						
Discount rate	**3.2 %**	2.6 %	3.1 %	**2.4 %**	2.0 %	2.8 %
Rate of return on plan assets	**N/A**	N/A	N/A	**6.0 %**	6.0 %	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[1]	
	2022	2021	**2022**	2021
Health care cost trend rate assumed for next year	**4.0 %**	4.0 %	**4.7 %**	7.0 %
Rate to which the cost trend is assumed to decline (ultimate trend rate)	**4.0 %**	4.0 %	**3.3 %**	4.5 %
Year that the rate reaches the ultimate trend rate	**N/A**	N/A	**2021 - 2045**	2037

1 In addition, under the Enbridge Employee Services, Inc., Health Reimbursement Account Plan, health care costs will increase by 5.0% every three years.

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	December 31,		**Target**	December 31,	
Asset Category	**Allocation**	**2022**	2021	**Allocation**	**2022**	2021
Equity securities	**43.8 %**	**38.2 %**	46.7 %	**45.0 %**	**38.3 %**	52.5 %
Fixed income securities	**28.4 %**	**31.7 %**	29.8 %	**20.0 %**	**20.5 %**	18.4 %
Alternatives[1]	**27.8 %**	**30.1 %**	23.5 %	**35.0 %**	**41.2 %**	29.1 %

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, 2022								
Cash and cash equivalents	**272**	**—**	**—**	**272**	**13**	**—**	**—**	**13**
Equity securities								
Canada	**—**	**355**	**—**	**355**	**—**	**—**	**—**	**—**
Global	**—**	**1,263**	**—**	**1,263**	**—**	**414**	**—**	**414**
Fixed income securities								
Government	**201**	**435**	**—**	**636**	**—**	**87**	**—**	**87**
Corporate	**—**	**433**	**—**	**433**	**—**	**121**	**—**	**121**
Alternatives[4]	**—**	**—**	**1,291**	**1,291**	**—**	**—**	**445**	**445**
Forward currency contracts	**—**	**(16)**	**—**	**(16)**	**—**	**—**	**—**	**—**
Total pension plan assets at fair value	**473**	**2,470**	**1,291**	**4,234**	**13**	**622**	**445**	**1,080**
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

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,	**2022**	2021	**2022**	2021
(millions of Canadian dollars)				
Balance at beginning of year	**1,064**	912	**337**	289
Unrealized and realized gains	**155**	77	**78**	38
Purchases and settlements, net	**72**	75	**30**	10
Balance at end of year	**1,291**	1,064	**445**	337

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, 2022				
Cash and cash equivalents	**2**	**—**	**—**	**2**
Equity securities				
US	**—**	**34**	**—**	**34**
Global	**—**	**62**	**—**	**62**
Fixed income securities				
Government	**46**	**5**	**—**	**51**
Corporate	**—**	**8**	**—**	**8**
Alternatives[4]	**—**	**—**	**28**	**28**
Total OPEB plan assets at fair value	**48**	**109**	**28**	**185**
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

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,	**2022**	2021
(millions of Canadian dollars)		
Balance at beginning of year	**22**	22
Unrealized and realized gains	**4**	2
Purchases and settlements, net	**2**	(2)
Balance at end of year	**28**	22

EXPECTED BENEFIT PAYMENTS

Year ending December 31,	2023	2024	2025	2026	2027	2028-2032
(millions of Canadian dollars)						
Pension						
Canada	204	210	216	221	226	1,208
US	88	87	87	88	90	424
OPEB						
Canada	12	12	13	13	13	68
US	16	15	14	13	12	49

EXPECTED EMPLOYER CONTRIBUTIONS

In 2023, we expect to contribute approximately $29 million and $5 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 year ended December 31, 2022, pre-tax employer matching contribution costs were $30 million ($27 million in each of 2021 and 2020).

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 1 month to 24 years as at December 31, 2022.

For the years ended December 31, 2022, 2021 and 2020, we incurred operating lease expenses of $118 million, $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, 2022, 2021 and 2020, operating lease payments to settle lease liabilities were $123 million, $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, 2022	December 31, 2021
(millions of Canadian dollars, except lease term and discount rate)		
Operating leases[1]		
Operating lease right-of-use assets, net[2]	**680**	645
Operating lease liabilities - current[3]	**87**	92
Operating lease liabilities - long-term[3]	**677**	612
Total operating lease liabilities	**764**	704
Finance leases		
Finance lease right-of-use assets, net[4]	**62**	49
Finance lease liabilities - current[5]	**17**	13
Finance lease liabilities - long-term[3]	**39**	33
Total finance lease liabilities	**56**	46
Weighted average remaining lease term		
Operating leases	**12 years**	12 years
Finance leases	**5 years**	7 years
Weighted average discount rate		
Operating leases	**4.2 %**	4.1 %
Finance leases	**4.4 %**	3.8 %

1 *Affiliate ROU assets, current lease liabilities and long-term lease liabilities as at December 31, 2022 were $47 million (December 31, 2021 - $51 million), $5 million (December 31, 2021 - $5 million) and $43 million (December 31, 2021 - $47 million), respectively.*
2 *Operating lease ROU 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 ROU 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, 2022, our operating and finance lease liabilities are expected to mature as follows:

	Operating leases	**Finance leases**
(millions of Canadian dollars)		
2023	**109**	**19**
2024	**110**	**16**
2025	**104**	**8**
2026	**90**	**8**
2027	**82**	**1**
Thereafter	**489**	**10**
Total undiscounted lease payments	**984**	**62**
Less imputed interest	**(220)**	**(6)**
Total	**764**	**56**

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 29 years as at December 31, 2022.

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Operating lease income	**266**	263	265
Variable lease income	**321**	333	361
Total lease income[1]	**587**	596	626

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

As at December 31, 2022, our future lease payments to be received under operating lease contracts where we are the lessor are as follows:

	Operating leases
(millions of Canadian dollars)	
2023	**227**
2024	**215**
2025	**204**
2026	**198**
2027	**201**
Thereafter	**1,832**
Future lease payments	**2,877**

28. OTHER INCOME/(EXPENSE)

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Gain/(loss) on dispositions	**(12)**	319	(17)
Realized foreign currency gain/(loss)	**92**	126	(10)
Unrealized foreign currency gain/(loss)	**(1,094)**	160	191
Net defined pension and OPEB credit	**239**	150	148
Other	**186**	224	(74)
	(589)	979	238

29. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	**2022**	2021	2020
(millions of Canadian dollars)			
Accounts receivable and other	**(967)**	(1,228)	1,546
Accounts receivable from affiliates	**17**	(38)	8
Inventory	**(599)**	(118)	(254)
Deferred amounts and other assets	**1**	(195)	(586)
Accounts payable and other	**1,100**	87	(770)
Accounts payable to affiliates	**16**	52	1
Interest payable	**58**	43	31
Other long-term liabilities	**362**	(69)	117
	(12)	(1,466)	93

30. 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,	**2022**	2021	2020
(millions of Canadian dollars)			
Transportation and other revenues	**185**	237	219
Commodity sales	**51**	20	21
Operating and administrative[1]	**503**	380	338
Commodity costs[2]	**778**	790	518
Gas distribution costs	**136**	131	135

1 *During the years ended December 31, 2022, 2021 and 2020, we had Operating and administrative costs from the Seaway Crude Pipeline System of $495 million, $389 million and $342 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.*

2 *During the years ended December 31, 2022, 2021 and 2020, we had Commodity costs from Aux Sable Canada LP of $571 million, $447 million and $91 million, respectively.*

LONG-TERM NOTES RECEIVABLE FROM AFFILIATES

As at December 31, 2022, amounts receivable from affiliates include a series of loans totaling $752 million (2021 - $954 million), which require quarterly or semi-annual interest payments at annual interest rates ranging from 3% to 8%. Interest income recognized from these notes totaled $30 million, $39 million and $44 million for the years ended December 31, 2022, 2021 and 2020, respectively. The amounts receivable from affiliates are included in Deferred amounts and other assets in the Consolidated Statements of Financial position.

31. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

As at December 31, 2022, 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]	78,742	6,024	8,220	6,051	3,730	10,344	44,373
Purchase of services, pipe and other materials, including transportation[2]	10,661	3,553	1,513	1,070	1,001	767	2,757
Maintenance agreements[3]	536	53	53	53	53	55	269
Right-of-ways commitments	1,474	45	45	46	46	46	1,246
Total	91,413	9,675	9,831	7,220	4,830	11,212	48,645

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 capital and operating commitments. Consists primarily of firm capacity payments that provide us with uninterrupted firm access to natural gas and crude oil transportation and storage contracts; contractual obligations to purchase physical quantities of natural gas; and power commitments.*

3 *Consists primarily of maintenance service contracts for our wind and solar assets.*

ENVIRONMENTAL

We are subject to various Canadian and US federal, provincial/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 obligations at various sites where we operate. We manage this environmental risk through appropriate environmental policies, programs and practices to minimize any impact our operations may have on the environment. To the extent that we are unable to recover payment for environmental liabilities from insurance or other potentially responsible parties, we will be responsible for payment of costs arising from environmental incidents associated with 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.

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

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.

INSURANCE
We maintain a comprehensive insurance program for us, our operating subsidiaries and certain equity investments. This program includes insurance coverage in types and amounts and is subject to certain deductibles, terms, exclusions and conditions that are generally consistent with coverage considered customary for our industry, however insurance does not cover all events in all circumstances. We self-insure a significant portion of expected losses relating to certain insurance property and casualty risk exposures in the US and Canada through our wholly-owned captive insurance subsidiaries.

In the unlikely event multiple insurable incidents occur which exceed coverage limits within the same insurance period, the total insurance coverage will be allocated among entities on an equitable basis based on an insurance allocation agreement we have entered into with us and other subsidiaries. Insurance estimates include certain assumptions and management judgments regarding the frequency and severity of claims, claim development and settlement practices and the selection of estimated loss among estimates derived using different methods.

32. 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 in 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, 2022, 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.

33. QUARTERLY FINANCIAL DATA (UNAUDITED)

	Q1	Q2	Q3	Q4	Total
(unaudited; millions of Canadian dollars, except per share amounts)					
2022					
Operating revenues	**15,097**	**13,215**	**11,573**	**13,424**	**53,309**
Operating income/(loss)	**2,420**	**1,520**	**1,778**	**(540)**	**5,178**
Earnings/(loss)	**2,057**	**607**	**1,383**	**(1,109)**	**2,938**
Earnings/(loss) attributable to controlling interests	**2,029**	**595**	**1,362**	**(983)**	**3,003**
Earnings/(loss) attributable to common shareholders	**1,927**	**450**	**1,279**	**(1,067)**	**2,589**
Earnings/(loss) per common share					
Basic	**0.95**	**0.22**	**0.63**	**(0.53)**	**1.28**
Diluted	**0.95**	**0.22**	**0.63**	**(0.53)**	**1.28**
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

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, 2022, 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, 2022, 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, 2022.

The effectiveness of our internal control over financial reporting as at December 31, 2022 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, 2022.

Changes in Internal Control Over Financial Reporting
During the three months ended December 31, 2022, there has been no material change in our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

NORMAL COURSE ISSUER BID
On January 4, 2023, we announced that the TSX had approved our new NCIB to purchase, for cancellation, up to 27,938,163 of the outstanding common shares of Enbridge to an aggregate amount of up to $1.5 billion.

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 6, 2023 and continuing until January 5, 2024, when the NCIB expires, or such earlier date on which Enbridge has either acquired the maximum number of common shares allowable under the NCIB or otherwise decided not to make any further repurchases under the NCIB.

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, 2022. 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, 2022. 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, 2022. 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, 2022. 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, 2022. 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, 2022. 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		Certificate of Amendment, dated January 17, 2022 (incorporated by reference to Exhibit 3.1 to Enbridge's Current Report on Form 8-K filed January 20, 2022)
3.41		Certificate of Amendment, dated January September 15, 2022 (incorporated by reference to Exhibit 3.1 to Enbridge's Current Report on Form 8-K filed September 20, 2022)
3.42		Certificate of Amendment, dated January September 15, 2022 (incorporated by reference to Exhibit 3.2 to Enbridge's Current Report on Form 8-K filed September 20, 2022)
3.43		General By-Law No. 1 of Enbridge Inc. (incorporated by reference to Exhibit 3.40 to Enbridge's Form 10-K filed February 11, 2022)
3.44		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		Ninth Supplemental Indenture to the Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated September 20, 2022 (incorporated by reference to Exhibit 4.1 to Enbridge's Current Report on Form 8-K filed September 20, 2022)

4.11		Tenth Supplemental Indenture to the Indenture between Enbridge Inc. and Deutsche Bank Trust Company Americas, dated September 20, 2022 (incorporated by reference to Exhibit 4.2 to Enbridge's Current Report on Form 8-K filed September 20, 2022)
4.12		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).
4.13		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 Executive Employment Agreement (2022) with Enbridge Employee Services, Inc. (incorporated by reference to Exhibit 10.1 to Enbridge's Form 10-Q filed on July 29, 2022)
10.12	+	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)

10.13	+	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)
10.14		Form of Enbridge Inc. 2019 Long-Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Grant Unit Award Agreement (Share-settled) – Retention Award Version (incorporated by reference to Exhibit 99.1 to Enbridge's 8-K filed November 30, 2022)
10.15	+	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)
10.16	+	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)
10.17	+	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)
10.18	+	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)
10.19	+	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)
10.20	+	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)
10.21	+	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)
10.22	+	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)
10.23	+	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)
10.24	+	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)
10.25	+	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)
10.26	+	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)
10.27	+	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)
10.28	+	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)

10.29	+	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)
10.30	+	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)
10.31	+	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)
10.32	+	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)
10.33	+	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).
10.34	+	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)
10.35	+	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)
10.36	+	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)
10.37	+	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)
10.38	+	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)
10.39	+	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)
10.40	+	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)
10.41	+	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)
10.42	+*	Fourth Amendment to The Enbridge Supplemental Pension Plan for United States Employees (As Amended and Restated Effective January 1, 2005)
10.43	+*	Fifth Amendment to The Enbridge Supplemental Pension Plan for United States Employees (As Amended and Restated Effective January 1, 2005)
10.44	+	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)

10.45	+	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)
10.46	+	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)
10.47	+	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)
10.48	+	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)
10.49	+	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)
10.50	+	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)
10.51	+	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 10, 2023

By: **/s/ Gregory L. Ebel**
Gregory L. Ebel
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on February 10, 2023 by the following persons on behalf of the registrant and in the capacities indicated.

/s/ Gregory L. Ebel
Gregory L. Ebel
President, Chief Executive Officer and Director
(Principal Executive Officer)

/s/ Vern D. Yu
Vern D. Yu
Executive Vice President, Corporate Development, Chief Financial Officer and President, New Energy Technologies
(Principal Financial Officer)

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

/s/ Pamela L. Carter
Pamela L. Carter
Chair of the Board of Directors

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

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

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

/s/ Jason B. Few
Jason B. Few
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

/s/ Steven W. Williams
Steven W. Williams
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 3, 2023 at 1:30 p.m. MDT. 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

2023 Enbridge Inc. Common Share Dividends

	Q1	Q2	Q3	Q4
Dividend	$0.89	$ –[2]	$ –[2]	$ –[2]
Payment date	Mar 01	Jun 01	Sep 01	Dec 01
Record date[1]	Feb 15	May 15	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

(as of December 31, 2022)

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 1 – ENB.PR.V
Series B – ENB.PR.B	Series 3 – ENB.PR.Y
Series D – ENB.PR.D	Series 5 – ENB.PF.V
Series F – ENB.PR.F	Series 7 – ENB.PR.J
Series H – ENB.PR.H	Series 9 – ENB.PF.A
Series L – ENB.PF.U	Series 11 – ENB.PF.C
Series N – ENB.PR.N	Series 13 – ENB.PF.E
Series P – ENB.PR.P	Series 15 – ENB.PF.G
Series R – ENB.PR.T	Series 19 – ENB.PF.K

Forward-looking information

This Annual Report includes references to forward-looking information, including with regards to our corporate vision and strategy, the supply of and demand for energy, energy transition and lower-carbon energy, ESG goals, and growth opportunities and outlook. 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 (MD&A), included in this Annual Report and available on both sedar.com and sec.gov.

Non-GAAP and other financial measures

The MD&A included in this Annual Report makes reference to non-GAAP and other financial measures, including EBITDA. EBITDA is defined as earnings before interest, income taxes and 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 are not measures that have a standardized meaning prescribed by the accounting principles generally accepted 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 in our earnings news releases and on our website, sedar.com or sec.gov.

Enbridge is committed to reducing its impact on the environment in every way, including the production of this publication. This report was printed entirely on FSC® Certified paper containing post-consumer waste fiber.

FSC www.fsc.org RECYCLED Paper made from recycled material FSC® C015495