ENBRIDGE INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

December 31, 2023

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 2023 and 2022 items and year-over-year comparisons between 2023 and 2022. For discussion of 2021 items and year-over-year comparisons between 2022 and 2021, 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, 2022.

RECENT DEVELOPMENTS

MAINLINE TOLLING AGREEMENT

Enbridge Inc. (Enbridge) has reached an agreement on a negotiated settlement with shippers for tolls on its Mainline System. The Mainline Tolling Settlement (MTS) covers both the Canadian and US portions of the Mainline and would see the Mainline continuing to operate as a common carrier system available to all shippers on a monthly nomination basis. The MTS is subject to regulatory approval and the term is seven and a half years through the end of 2028, with revised interim tolls effective on July 1, 2023.

The MTS includes:

- an International Joint Toll (IJT), for heavy crude oil movements from Hardisty to Chicago, comprised of a Canadian Mainline Toll of $1.65 per barrel plus a Lakehead System Toll of US$2.57 per barrel, plus the applicable Line 3 Replacement (L3R) surcharge;
- toll escalation for operation, administration, and power costs tied to US consumer price and power indices;
- tolls that continue to be distance and commodity adjusted, and utilize a dual currency IJT; and
- a financial performance collar providing incentives for Enbridge to optimize throughput and cost, but also providing downside protection in the event of extreme supply or demand disruptions or unforeseen operating cost exposure. This performance collar is intended to ensure the Mainline earns 11% to 14.5% returns, on a deemed 50% equity capitalization, which is similar to the returns earned on average during the previous tolling agreement.

Approximately 70% of Mainline deliveries are tolled under this settlement, while approximately 30% of deliveries are tolled on a full path basis to markets downstream of the Mainline. The other continuing feature is that the Mainline toll flexes up or down US$0.035 per barrel for 50,000 barrel per day changes in throughput.

The expected financial outcome from this settlement is in line with previously reported financial results after taking into consideration the previously recognized provision, inflationary cost adjustments and increased volumes. Enbridge filed an application with the Canada Energy Regulator (CER) for approval of the MTS on December 15, 2023, with unanimous support from its Representative Stakeholder Group. The CER indicated in its process letter that no dissenting comments were received by January 19, 2024 and that it may decide on the application or it may establish further process steps.

On May 24, 2023, Enbridge filed an Offer of Settlement with the Federal Energy Regulatory Commission (FERC) for the Lakehead System (the Lakehead System Settlement). In addition to resolving litigation related to the Index portion of the Lakehead System rate, the Lakehead System Settlement also includes a depreciation truncation date of December 31, 2048 for the rate base applicable to the Index and Facilities Surcharge and agreement on the terms for future recovery through the Facilities Surcharge of costs related to two Line 5 projects: the Wisconsin Relocation Project and the Straits of Mackinac Tunnel. The Lakehead System Settlement was certified by the Settlement Judge on June 23, 2023 and was approved by the FERC Commissioners on November 27, 2023. Lakehead System tolls were revised effective December 1, 2023 to reflect the terms of the Lakehead System Settlement.

ACQUISITIONS

Acquisition of Renewable Natural Gas (RNG) Facilities

On January 2, 2024, through a wholly-owned US subsidiary, we acquired the first six Morrow Renewables operating landfill gas-to-RNG production facilities located in Texas and Arkansas for total consideration of $1.4 billion (US$1.1 billion), of which $0.5 billion (US$0.4 billion) was paid at close and $0.9 billion (US$0.7 billion) is payable within two years. The total consideration for all seven facilities is $1.6 billion (US$1.2 billion). Combined RNG production of the facilities is approximately 4.5 bcf per year. The acquired assets align with and advance our low-carbon strategy.

Fox Squirrel Solar

On November 15, 2023, we acquired a 50% interest in a newly formed partnership with EDF Renewables North America to participate in the initial phase of a solar power facility in Ohio. Cash consideration includes an upfront payment of $157 million (US$115 million) and subsequent capital commitments up to $398 million (US$291 million). Investments past the first phase are contingent on certain conditions being met. An additional payment of $164 million (US$123 million) was made at Phase 1 in-service in December 2023.

Hohe See and Albatros Offshore Wind Facilities

On November 3, 2023, we acquired an additional 24.45% interest in the Hohe See Offshore Wind Facilities and Albatros Offshore Wind Facilities (the Offshore Wind Facilities), through the acquisition of a 49% interest in Enbridge Renewable Infrastructure Investments S.à r.l (ERII), for $391 million (€267 million) of cash and assumed debt of $524 million (€358 million), bringing our interest in the Offshore Wind Facilities to 49.9%. The Hohe See Offshore Wind Facilities and Albatros Offshore Wind Facilities are located approximately 100 kilometers off the northern coast of Germany and came into service in 2019 and 2020, respectively.

Aitken Creek Gas Storage

On November 1, 2023, through a wholly-owned Canadian subsidiary, we acquired a 93.8% interest in Aitken Creek Gas Storage Facility and a 100% interest in Aitken Creek North Gas Storage Facility (collectively, Aitken Creek), located in BC, Canada, for $400 million, subject to other customary closing adjustments (the Aitken Creek Acquisition). Aitken Creek is the only underground natural gas storage facility in BC and connects to all major natural gas pipelines in western Canada. The Aitken Creek Acquisition enables us to continue to meet regional energy needs and to support increasing demand for liquefied natural gas (LNG) exports.

US Gas Utilities
On September 5, 2023, we announced that Enbridge had entered into three separate definitive agreements with Dominion Energy, Inc. to acquire The East Ohio Gas Company, Questar Gas Company and its related Wexpro companies, and Public Service Company of North Carolina for an aggregate purchase price of $19.1 billion (US$14.0 billion), comprised of $12.8 billion (US$9.4 billion) of cash consideration and $6.3 billion (US$4.6 billion) of assumed debt, subject to customary closing adjustments (together, the Acquisitions). If completed, the Acquisitions will create North America's largest natural gas utility platform delivering over 9 billion cubic feet (bcf) per day to approximately 7 million customers across multiple regulatory jurisdictions. The Acquisitions are expected to close in 2024, subject to the satisfaction of customary closing conditions including the receipt of certain regulatory approvals, which are not cross-conditional.

On September 8, 2023, we closed a public offering of 102,913,500 common shares at a price of $44.70 per share for gross proceeds of $4.6 billion which is intended to finance a portion of the aggregate cash consideration payable for the Acquisitions. Refer to *Financing Update* for further details on the debt issuances and credit facility obtained to support the Acquisitions.

Tres Palacios Holdings LLC
On April 3, 2023, we acquired Tres Palacios Holdings LLC (Tres Palacios) for $451 million (US$335 million) of cash. Tres Palacios is a natural gas storage facility located in the US Gulf Coast and its infrastructure serves Texas gas-fired power generation and LNG exports, as well as Mexico pipeline exports. Tres Palacios is comprised of three natural gas storage salt caverns with a total FERC-certificated working gas capacity of approximately 35 billion bcf and also owns an integrated 62-mile natural gas header pipeline system, with eleven inter- and intrastate natural gas pipeline connections.

ASSET MONETIZATION
Disposition of Alliance Pipeline and Aux Sable
On December 13, 2023, we announced that Enbridge has entered into a definitive agreement to sell our 50.0% interest in the Alliance Pipeline and our interest in Aux Sable (including 42.7% interest in Aux Sable Midstream LLC and Aux Sable Liquid Products L.P., and 50% interest in Aux Sable Canada LP) to Pembina Pipeline Corporation for $3.1 billion, including approximately $0.3 billion of non-recourse debt, subject to customary closing adjustments. Closing is expected to occur in the first half of 2024, subject to the receipt of regulatory approvals and satisfaction of customary closing conditions. The sales proceeds will fund a portion of the Acquisitions and be used for debt reduction.

GAS TRANSMISSION AND MIDSTREAM PROCEEDINGS
Texas Eastern Transmission
The Stipulation and Agreement for Texas Eastern Transmission, LP’s (Texas Eastern) consolidated 2021 rate cases was approved by the FERC on November 30, 2022, and became effective on January 1, 2023. Texas Eastern received FERC approval on April 3, 2023 to implement the settled rates and other settlement provisions.

Maritimes & Northeast Pipeline
The toll settlement agreement for the Canadian portion of the Maritimes & Northeast (M&N) Pipeline (M&N Canada) expired in December 2023. M&N Canada reached a toll settlement with shippers for the effective period from January 1, 2024 to December 31, 2025. On November 28, 2023, M&N Canada filed the 2024 - 2025 toll settlement agreement with the CER for review and approval. A CER decision is expected in the first quarter of 2024.

GAS DISTRIBUTION AND STORAGE RATE APPLICATIONS

Incentive Regulation Rate Application

In October 2022, Enbridge Gas Inc. (Enbridge Gas) filed its application with the Ontario Energy Board (OEB) to establish a 2024 through 2028 Incentive Regulation (IR) rate setting framework. The application initially sought approval in two phases to establish 2024 base rates (Phase 1) on a cost-of-service basis and to establish a price cap rate setting mechanism (Phase 2) to be used for the remainder of the IR term. A third phase (Phase 3) has been established with the OEB as part of the Phase 1 Partial Settlement Proposal (Settlement Proposal).

On August 17, 2023, the OEB approved the Settlement Proposal to support the determination of just and reasonable rates effective January 1, 2024. Items resolved in whole or in part include:

- additions to rate base up to and including 2022;
- interest rates on debt and return on equity;
- deferral and variance accounts;
- Indigenous engagement; and
- rate implementation approach for 2024.

On December 21, 2023, the OEB issued its Decision and Order on Phase 1 (Phase 1 Decision). The decision addressed three main areas: energy transition, Enbridge Gas Distribution Inc. and Union Gas Limited amalgamation and harmonization issues, and other issues. The Phase 1 Decision included the following key findings or orders:

- energy transition risk requires Enbridge Gas to carry out a risk assessment to consider further risk mitigation measures in three areas: system access and expansion capital spending, system renewal capital spending and depreciation policy;
- our 2024 capital plan must be reduced by $250 million with a focus on monitoring, repair and life extension of our assets and a further $50 million of capitalized indirect overhead costs must be expensed, escalating to $250 million per year during the IR term with an offsetting adjustment to revenues in each year;
- all new small volume customers wishing to connect to natural gas pay their full connection costs as an upfront charge rather than through rates over time effective January 1, 2025;
- approval of a harmonized depreciation methodology that reduced the level of depreciation sought and adjusted asset lives including extensions of service life for certain asset classes;
- an increase in equity thickness from 36% to 38% effective for 2024; and
- January 1, 2024 will be the effective date for 2024 rates.

The issues addressed in the Settlement Proposal and the Phase 1 Decision resulted in the following items not approved for future recovery, and the subsequent impairments recognized for the year ended December 31, 2023:

- a portion of undepreciated capital projects removed from 2024 rate base of $41 million;
- undepreciated integration capital costs removed from 2024 rate base of $84 million; and
- pre-2017 Union Gas Limited related pension balances of $156 million.

Enbridge Gas filed a Notice of Appeal in the Ontario Divisional Court on January 22, 2024 regarding four aspects of the Phase 1 Decision: small volume customer revenue horizon, the 2024 capital plan reduction, the extension of service life for certain asset classes and equity thickness. On January 29, 2024 Enbridge Gas also filed a Notice of Motion with the OEB requesting the OEB to review and vary five aspects of the Phase 1 Decision: small volume customer revenue horizon, the 2024 capital plan reduction, integration capital, depreciation and equity thickness. The outcome of these proceedings is uncertain.

The Phase 1 Decision results in interim rates, pending phases 2 and 3 of the proceeding, resolution of the Notice of Appeal, Notice of Motion and any possible legislative steps that could be undertaken by the Government of Ontario further to the Ontario Minister of Energy's December 22, 2023 news release. Phase 2 will establish and determine the incentive rate mechanism for the remainder of the rebasing term, and gas cost and unregulated storage cost allocation. Phase 3 will address cost allocation and the harmonization of rates and rate classes between legacy rate zones.

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 2023, the April 1, 2023 QRAM application was filed and approved by the OEB, which included an adjustment to the prior rate mitigation approved as part of the July 1, 2022 QRAM. The recovery of the outstanding PGVA balance from the extended recovery period approved as part of the July 1, 2022 QRAM will now be completed by March 31, 2024. In June, September and December 2023, the July 1, 2023, October 1, 2023, and January 1, 2024 QRAM applications, respectively, 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, 2023, Enbridge Gas' PGVA liability balance was $16 million.

FINANCING UPDATE
We completed long-term debt issuances totaling US$8.5 billion and $3.9 billion during the year ended December 31, 2023, including aggregate amounts of US$2.3 billion of 10-year sustainability-linked senior notes in March 2023 and $400 million of 10-year sustainability-linked medium-term notes in May 2023.

We increased our credit facilities in March 2023 by approximately $500 million. During our annual renewal process, we renewed and extended approximately $15.4 billion of our credit facilities with maturities ranging from 2024-2028.

In September 2023, we obtained commitments for a US$9.4 billion senior unsecured bridge term loan credit facility to support the Acquisitions. The commitment for this facility was subsequently reduced to nil as at December 31, 2023 as a result of the September 2023 $4.6 billion equity offering, the September 2023 subordinated long-term debt issuances, and the November 2023 senior notes long-term debt issuances.

In September 2023, we closed a public offering of 102,913,500 common shares at a price of $44.70 per share for gross proceeds of $4.6 billion which is intended to finance a portion of the aggregate cash consideration payable for the Acquisitions.

Our 2023 financing activities have provided significant liquidity that we expect will enable us to fund our current portfolio of capital projects and acquisitions 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, 2023, after adjusting for the impact of floating-to-fixed interest rate swap hedges, less than 5% of our total debt is exposed to floating rates. Refer to Part II. *Item 8. Financial Statements and Supplementary Data - Note 23 - Risk Management and Financial Instruments* for more information on our interest rate hedging program.

NORMAL COURSE ISSUER BID

On January 4, 2023, the Toronto Stock Exchange (TSX) approved our normal course issuer bid (NCIB), which commenced on January 6, 2023 and expired on January 5, 2024. Our NCIB permitted us 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 through the facilities of the TSX, the New York Stock Exchange and other designated exchanges and alternative trading systems.

FORWARD-LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this management's discussion and analysis (MD&A) 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), 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; the characteristics, anticipated benefits, financing and timing of our acquisitions of three US gas utilities (Gas Utilities) from Dominion Energy, Inc. (the Acquisitions); expected costs, benefits and in-service dates related to announced projects and projects under construction; expected capital expenditures; investable capacity and capital allocation priorities; 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, including the Acquisitions; expected benefits of transactions, including the Acquisitions; our ability to complete the Acquisitions and successfully integrate the Gas Utilities; 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 Distribution and Storage and Gas Transmission and Midstream 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; 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 and transactions; anticipated in-service dates; weather; the timing, terms and closing of acquisitions and dispositions, including the Acquisitions; the realization of anticipated benefits of transactions, including the Acquisitions; 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 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.

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 (including the 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; and the supply of, demand for and prices of commodities and other alternative energy, including but not limited to, those risks and uncertainties discussed in this MD&A 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 MD&A 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

This Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) 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.sedarplus.ca or www.sec.gov.

RESULTS OF OPERATIONS

Year ended December 31,	2023	2022	2021
(millions of Canadian dollars, except per share amounts)			
Segment earnings/(loss) before interest, income taxes and depreciation and amortization[1]			
Liquids Pipelines	**9,499**	8,364	7,897
Gas Transmission and Midstream	**4,264**	3,126	3,671
Gas Distribution and Storage	**1,592**	1,827	2,117
Renewable Power Generation	**149**	262	508
Energy Services	**(37)**	(417)	(313)
Eliminations and Other	**837**	(1,124)	356
Earnings before interest, income taxes and depreciation and amortization[1]	**16,304**	12,038	14,236
Depreciation and amortization	**(4,613)**	(4,317)	(3,852)
Interest expense	**(3,812)**	(3,179)	(2,655)
Income tax expense	**(1,821)**	(1,604)	(1,415)
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**133**	65	(125)
Preference share dividends	**(352)**	(414)	(373)
Earnings attributable to common shareholders	**5,839**	2,589	5,816
Earnings per common share attributable to common shareholders	**2.84**	1.28	2.87
Diluted earnings per common share attributable to common shareholders	**2.84**	1.28	2.87

1 Non-GAAP financial measures.

EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS

Year ended December 31, 2023 compared with year ended December 31, 2022

Earnings attributable to common shareholders increased by $3.2 billion due to certain infrequent or other non-operating factors, primarily explained by the following:

- the absence in 2023 of a goodwill impairment of $2.5 billion relating to our Gas Transmission reporting unit;
- a non-cash, net unrealized derivative fair value gain of $1,127 million ($856 million after-tax) in 2023, compared with a net unrealized loss of $1,246 million ($950 million after-tax) in 2022, reflecting changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange, interest rate, and commodity risks;
- the absence in 2023 of: 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 within the North Dakota System of our Bakken System, an impairment of $44 million ($34 million after-tax) for lease assets due to office relocation plans, and an asset impairment loss of $40 million ($30 million after-tax) relating to MacKay River line within our Alberta Regional Oil Sands System;
- a gain of $151 million ($129 million after-tax) and a deferred tax adjustment of $69 million were recognized as a result of Southern Lights Pipeline's (Southern Lights) discontinuation of regulatory accounting;
- the absence in 2023 of a transaction cost of $114 million in relation to our investment purchase in the Woodfibre LNG project;
- a deferred income tax recovery of $104 million related to a tax adjustment on asset impairments;
- a non-cash, net unrealized gain of $73 million ($55 million after-tax) in 2023, compared with a net unrealized loss of $27 million ($21 million after-tax) in 2022, 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;
- the receipt of a litigation claim settlement of $68 million ($52 million after-tax) in 2023; and
- a non-cash, net unrealized gain of $35 million ($33 million after-tax) in 2023, compared with a net unrealized loss of $25 million ($22 million after-tax) in 2022, reflecting changes in the mark-to-market value of equity fund investments held by our wholly-owned captive insurance subsidiaries.

The factors above were partially offset by:

- the absence in 2023 of a gain of $1,076 million ($732 million after-tax) on the closing of the joint venture merger transaction with Phillips 66 (P66) realigning our indirect economic interests in Gray Oak Pipeline LLC (Gray Oak) and DCP Midstream, LP (DCP);
- a realized loss of $638 million ($479 million after-tax) due to termination of foreign exchange hedges, as foreign exchange risks inherent within the Competitive Toll Settlement (CTS) framework are not present in the negotiated Mainline tolling agreement;
- an impairment loss of $261 million ($20 million after-tax and net of noncontrolling interest) to our Chapman Ranch wind facilities;
- an impairment of $281 million ($232 million after-tax) recognized to certain capital projects, capital costs and pension balances in the fourth quarter of 2023 as a result of the OEB's Phase 1 Decision on Enbridge Gas' application;
- a deferred tax adjustment of $120 million as a result of deregulation of parts of the Canadian Mainline including Line 9 and L3R;
- a provision adjustment and settlement of $124 million ($95 million after-tax) related to a litigation matter;
- the absence in 2023 of a gain of $118 million ($89 million after-tax) on Texas Eastern recorded to reflect a settlement with a transportation customer undergoing bankruptcy;
- an asset retirement loss of $86 million ($65 million after-tax) related to our Alberta Regional Oil Sands System;
- an impairment loss of $82 million ($63 million after-tax) to certain Offshore equity investments in our Gas Transmission and Midstream segment; and
- transaction costs of $31 million ($24 million after-tax) incurred as a result of the Acquisitions.

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, interest rate 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 $51 million increase in earnings attributable to common shareholders is primarily explained by the following significant business factors:

- higher contributions from the Mainline System in our Liquids Pipelines segment driven by increased volumes due to increased crude demand, net of a lower L3R surcharge and lower Mainline System tolls as a result of revised interim tolls effective July 1, 2023;
- higher contributions from our Liquids Pipelines segment due to increased ownership of the Gray Oak Pipeline and Cactus II Pipeline acquired in the second half of 2022 and the Enbridge Ingleside Energy Center (EIEC) due to higher demand;
- the recognition of revenues in our Gas Transmission and Midstream segment attributable to the Texas Eastern rate case settlement;
- higher distribution charges at our Gas Distribution and Storage segment resulting from increases in rates and customer base as well as higher demand in the contract market;
- higher contributions from our Energy Services segment primarily due to the expiration of transportation commitments and favorable margins due to less pronounced market structure backwardation; and
- the favorable effect of translating US dollar earnings at a higher average exchange rate in 2023, as compared to 2022; partially offset by
- a reduction in earnings from our Gas Transmission and Midstream segment primarily due to our decreased interest in DCP as a result of a joint venture merger transaction with P66 that closed in the third quarter of 2022;
- higher operating and administrative costs in our Gas Transmission and Midstream and Gas Distribution and Storage segments;
- lower commodity prices impacting the DCP and Aux Sable joint ventures in our Gas Transmission and Midstream segment;
- higher interest expense primarily due to higher interest rates and higher average principal; and
- higher depreciation and amortization expense as a result of several projects placed into service in the second half of 2022.

REVENUES

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

Transportation and other services revenues of $19.8 billion, $18.5 billion and $16.2 billion for the years ended December 31, 2023, 2022 and 2021, respectively, were earned from our crude oil and natural gas pipeline transportation businesses and also include power generation revenues from our portfolio of renewable and power generation assets. For our transportation assets operating under market-based arrangements, revenues are driven by volumes transported and the corresponding tolls for transportation services. For assets operating under take-or-pay contracts, revenues reflect the terms of the underlying contract for services or capacity. For rate-regulated assets, revenues are charged in accordance with tolls established by the regulator and, in most cost-of-service based arrangements, are reflective of our cost to provide the service plus a regulator-approved rate of return.

Gas distribution sales revenues of $4.8 billion, $5.7 billion and $4.0 billion for the years ended December 31, 2023, 2022 and 2021, 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 $19.0 billion, $29.2 billion and $26.9 billion for the years ended December 31, 2023, 2022 and 2021, respectively, were generated primarily through our Energy Services operations. Energy Services includes the purchase and sale of crude oil, natural gas, power and NGL to generate a margin, which is typically a small fraction of gross revenue. Sales revenue generated from these operations 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,	**2023**	2022	2021
(millions of Canadian dollars)			
Earnings before interest, income taxes and depreciation and amortization	**9,499**	8,364	7,897

Year ended December 31, 2023 compared with year ended December 31, 2022
EBITDA was positively impacted by $500 million due to certain infrequent or other non-operating factors, primarily explained by the following:

- a non-cash, net unrealized gain of $607 million in 2023, compared with a net unrealized loss of $183 million in 2022, reflecting net fair value gains and losses arising from changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange and commodity price risks;
- a gain of $151 million recognized as a result of Southern Lights' discontinuation of regulatory accounting;
- the absence in 2023 of: a total asset impairment loss of $183 million on the US and Canadian components of the interstate pipeline within the North Dakota System of our Bakken System, and an asset impairment loss of $40 million relating to MacKay River line within our Alberta Regional Oil Sands System, partially offset by an asset retirement loss in 2023 of $86 million related to our Alberta Regional Oil Sands System; and
- the receipt of a litigation claim settlement of $68 million in 2023; partially offset by
- a realized loss of $638 million due to termination of foreign exchange hedges, as foreign exchange risks inherent within the CTS framework are not present in the negotiated Mainline tolling agreement.

After taking into consideration the factors above, the remaining $635 million increase is primarily explained by the following significant business factors:

- higher Mainline System ex-Gretna average throughput of 3.1 million barrels per day (mmbpd) in 2023 as compared to 3.0 mmbpd in 2022, and higher Line 9 deliveries to eastern Canada driven by higher crude demand, net of a lower L3R surcharge and lower Mainline System tolls as a result of revised interim Mainline tolls effective July 1, 2023;
- higher contributions from the Gulf Coast and Mid-Continent System due primarily to increased ownership of Gray Oak Pipeline and Cactus II Pipeline acquired in the second half of 2022 and the EIEC due to higher demand; and
- the favorable effect of translating US dollar earnings at a higher average exchange rate in 2023, as compared to 2022; partially offset by
- higher power costs as a result of increased volumes and power prices.

GAS TRANSMISSION AND MIDSTREAM

Year ended December 31,	**2023**	2022	2021
(millions of Canadian dollars)			
Earnings before interest, income taxes and depreciation and amortization	**4,264**	3,126	3,671

Year ended December 31, 2023 compared with year ended December 31, 2022
EBITDA was positively impacted by $1.2 billion due to certain infrequent or other non-operating factors primarily explained by the following:

- the absence in 2023 of a goodwill impairment of $2.5 billion; partially offset by
- the absence in 2023 of: 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, and a gain of $118 million on Texas Eastern recorded for a customer bankruptcy settlement;
- a provision adjustment and settlement of $124 million related to a litigation matter; and
- an impairment loss of $82 million to certain Offshore equity investments.

After taking into consideration the factors above, we saw a $19 million decrease, primarily explained by the following significant business factors:

- a reduction in earnings from our investment in DCP as a result of our decreased interest due to the joint venture merger transaction with P66 that closed during the third quarter of 2022;
- higher operating and administrative costs;
- lower commodity prices impacting our DCP and Aux Sable joint ventures;
- lower AECO-Chicago basis differential impacting our investment in Alliance Pipeline, partially offset by
- the favorable effect of translating US dollar earnings at a higher average exchange rate in 2023, as compared to 2022;
- favorable contracting on our US Gas Transmission and Storage assets;
- the recognition of revenues attributable to the Texas Eastern rate case settlement effective for 2023; and
- contributions from the Tres Palacios acquisition in the second quarter of 2023 and Aitken Creek in the fourth quarter of 2023.

GAS DISTRIBUTION AND STORAGE

Year ended December 31,	**2023**	2022	2021
(millions of Canadian dollars)			
Earnings before interest, income taxes and depreciation and amortization	**1,592**	1,827	2,117

Year ended December 31, 2023 compared with year ended December 31, 2022
EBITDA was negatively impacted by $252 million due to an impairment of $281 million recognized to certain capital projects, capital costs and pension balances in the fourth quarter of 2023 as a result of the OEB's Phase 1 Decision.

After taking into consideration the factors above, the remaining $17 million increase is primarily explained by the following significant business factors:

- higher distribution charges resulting from increases in rates and customer base, as well as higher demand in the contract market; partially offset by
- when compared with the normal weather forecast embedded in rates, warmer than normal weather in 2023 negatively impacted 2023 EBITDA by approximately $86 million year over year; and
- higher operating and administrative costs primarily due to higher pension related costs.

RENEWABLE POWER GENERATION

Year ended December 31,	**2023**	2022	2021
(millions of Canadian dollars)			
Earnings before interest, income taxes and depreciation and amortization	**149**	262	508

Year ended December 31, 2023 compared with year ended December 31, 2022
EBITDA was negatively impacted by $122 million due to certain infrequent or non-operating factors, primarily explained by:

- an impairment loss of $261 million to Chapman Ranch wind facilities, partially offset by the absence in 2023 of an impairment loss of $227 million to Magic Valley; and
- a non-cash, net unrealized loss of $72 million in 2023, compared with a net unrealized gain of $8 million in 2022, reflecting changes in the mark-to-market value of derivative financial instruments used to manage commodity price risks.

After taking into consideration the negative factors above, the remaining $9 million increase is primarily explained by the following significant business factors:

- fees earned on certain wind and solar development contracts;
- higher contribution from the Hohe See and Albatros Offshore Wind Facilities as a result of the November 2023 acquisition of an additional 24.45% interest in these facilities; and
- contributions from the Saint-Nazaire Offshore Wind Project, which reached full operating capacity in December 2022; partially offset by
- lower energy pricing at European offshore wind facilities; and
- weaker wind resources at Canadian and US onshore wind facilities.

ENERGY SERVICES

Year ended December 31,	**2023**	2022	2021
(millions of Canadian dollars)			
Loss before interest, income taxes and depreciation and amortization	**(37)**	(417)	(313)

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, 2023 compared with year ended December 31, 2022
EBITDA was positively impacted by $117 million due to certain non-operating factors, primarily explained by a non-cash, net unrealized gain of $73 million in 2023, compared with a net unrealized loss of $27 million in 2022, 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 $263 million increase is primarily explained by the following significant business factors:

- expiration of certain less attractive transportation commitments;
- more favorable margins realized on facilities where we hold capacity obligations and storage opportunities as compared to 2022; and
- less pronounced market structure backwardation as compared to 2022.

ELIMINATIONS AND OTHER

Year ended December 31,	**2023**	2022	2021
(millions of Canadian dollars)			
Earnings/(loss) before interest, income taxes and depreciation and amortization	**837**	(1,124)	356

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, 2023 compared with year ended December 31, 2022
EBITDA was positively impacted by $1.9 billion due to certain infrequent or non-operating factors, primarily explained by:

- a non-cash, net unrealized gain of $623 million in 2023, compared with a net unrealized loss of $1,090 million in 2022, reflecting changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange risk;
- the absence in 2023 of: $114 million of transaction costs 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; and
- a non-cash, net unrealized gain of $35 million in 2023, compared with a net unrealized loss of $25 million in 2022, reflecting changes in the mark-to-market value of equity fund investments held by our wholly-owned captive insurance subsidiaries; partially offset by
- transaction costs of $31 million incurred as a result of the Acquisitions.

After taking into consideration the non-operating factors above, we saw a $18 million increase in EBITDA that is primarily explained by higher investment income from the pre-funding of the Acquisitions.

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.	Texas Eastern Venice Extension Project[3]	100%	US$477 million	US$170 million	Under construction	2023 - 2024
2.	Texas Eastern Modernization	100%	US$394 million	US$37 million	Pre-construction	2025 - 2026
3.	T-North Expansion	100%	$1.2 billion	$70 million	Pre-construction	2026
4.	Rio Bravo Pipeline[5]	100%	US$1.2 billion	US$66 million	Pre-construction	2026
5.	Woodfibre LNG[6]	30%	US$1.5 billion	US$310 million	Under construction	2027
6.	T-South Expansion[4]	100%	$4.0 billion	$67 million	Pre-construction	2028
RENEWABLE POWER GENERATION						
7.	Fécamp Offshore Wind[7]	17.9%	$692 million (€471 million)	$528 million (€362 million)	Under construction	1Q-2024
8.	Calvados Offshore Wind[8]	21.7%	$954 million (€645 million)	$307 million (€214 million)	Under construction	2025
9.	Fox Squirrel Solar	50%	US$406 million	US$152 million	Under construction	2023-2024

1 These amounts are estimates and are subject to upward or downward adjustment based on various factors. Where appropriate, the amounts reflect our share of joint venture projects.
2 Expenditures to date and status of the project are determined as at December 31, 2023.
3 Includes the $37 million Gator Express Project placed into service in August 2023. Total estimated capital cost consists of the reversal and expansion of Texas Eastern's Line 40 expected to be completed in 2024.
4 Capital cost estimates will be updated prior to filing the regulatory applications.
5 Rio Grande LNG has reached a final investment decision for three liquefaction trains. Current estimated capital cost is based on two liquefaction trains and an update to the estimated capital cost is expected to be provided in 2024.
6 Our equity contribution is approximately US$893 million, with the remainder financed through non-recourse project level debt. Capital cost estimates will be updated prior to the 60% engineering milestone, at which point Enbridge's preferred return will be set.
7 Our equity contribution is $103 million, with the remainder financed through non-recourse project level debt.
8 Our equity contribution is $181 million, 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 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. On January 8, 2024, we filed the regulatory application with the CER.

- **Rio Bravo Pipeline** – In July 2023, the Rio Grande LNG export facility, owned by NextDecade Corporation (NextDecade), reached a final investment decision. As a result, the construction on our previously announced Rio Bravo Pipeline project is anticipated to proceed after obtaining necessary regulatory approvals. The first phase of the Rio Bravo Pipeline is designed to transport 2.6 bcf/d of natural gas feedstock to NextDecade's Rio Grande LNG export facility in the Port of Brownsville, Texas. The project is expected to achieve commercial operations in 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 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 megawatts (MW). Project revenues are underpinned by a 20-year fixed price power purchase agreement (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.

- **Fox Squirrel Solar** – A fully contracted, ground-mounted solar facility in Ohio with expected installed capacity of approximately 577 MW. The initial phase successfully commenced operations in December 2023. We plan to invest in the following phases in 2024, assuming certain conditions are met. Project revenues are underpinned by a 20-year fixed price PPA.

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 and acquisitions 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 maintaining sufficient liquidity through the use 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 17 - Debt* and *Note 26 - Leases* for amounts outstanding at December 31, 2023, related to debt and leases.

Long-term contracts are contracts that we have signed for the purchase of services, pipe and other materials totaling $8.9 billion which are expected to be paid over the next five years. Remaining long-term contracts primarily consist 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, including reinstatement of our dividend reinvestment and share purchase plan or at-the-market equity issuances.

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$8.5 billion and $3.9 billion in 2023:

Entity	Issuance date	Type of issuance	Amount
(in millions of Canadian dollars, unless stated otherwise)			
Enbridge Inc.	March 2023	Sustainability-linked senior notes	US$2,300
Enbridge Inc.	March 2023	Senior notes	US$700
Enbridge Inc.	May 2023	Medium-term notes	$1,100
Enbridge Inc.	May 2023	Sustainability-linked medium-term notes	$400
Enbridge Inc.	September 2023	Fixed-to-fixed subordinated notes	US$2,000
Enbridge Inc.	September 2023	Fixed-to-fixed subordinated notes	$1,000
Enbridge Inc.	November 2023	Senior notes	US$3,500
Enbridge Gas Inc.	October 2023	Medium-term notes	$1,000
Enbridge Pipelines Inc.	August 2023	Medium-term notes	$350

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, 2023:

	Maturity[1]	Total Facilities	Draws[2]	Available
(millions of Canadian dollars)				
Enbridge Inc.	2024-2028	**8,876**	**3,177**	**5,699**
Enbridge (U.S.) Inc.	2025-2028	**8,373**	**670**	**7,703**
Enbridge Pipelines Inc.	2025	**2,000**	**449**	**1,551**
Enbridge Gas Inc.	2025	**2,500**	**400**	**2,100**
Total committed credit facilities		**21,749**	**4,696**	**17,053**

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.

In March 2023, Enbridge Gas increased its 364-day extendible credit facility from $2.0 billion to $2.5 billion and in July 21, 2023, the facility's maturity date was extended to July 2025, which includes a one-year term out provision from July 2024.

In July 2023, Enbridge Pipelines Inc. extended the maturity date of its 364-day extendible credit facility to July 2025, which includes a one-year term out provision from July 2024.

In July 2023, we renewed approximately $6.8 billion of our 364-day extendible credit facilities, extending the maturity dates to July 2025, which includes a one-year term out provision from July 2024. We also renewed approximately $7.6 billion of our five-year credit facilities, extending the maturity dates to July 2028. Further, we extended our three-year credit facilities, extending the maturity dates to July 2026.

In September 2023, we obtained commitments for a US$9.4 billion senior unsecured bridge term loan credit facility to support the Acquisitions. The commitment for this facility was subsequently reduced to nil as at December 31, 2023 as a result of the September 2023 $4.6 billion equity offering, the September 2023 subordinated long-term debt issuances, and the November 2023 senior notes long-term debt issuances.

In addition to the committed credit facilities noted above, we maintain $1.1 billion of uncommitted demand letter of credit facilities, of which $572 million was unutilized as at December 31, 2023. As at December 31, 2022, we had $1.3 billion of uncommitted demand letter of credit facilities, of which $689 million was unutilized.

As at December 31, 2023, our net available liquidity totaled $23.0 billion (2022 - $10.0 billion), consisting of available credit facilities of $17.1 billion (2022 - $9.1 billion) and unrestricted Cash and cash equivalents of $5.9 billion (2022 - $861 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, 2023, 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 2023, 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 $84 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, 2023 and 2022, we had a positive and negative working capital positions of $3.0 billion and $2.1 billion, respectively. In 2023, the major contributing factor to the positive working capital position was the increase in cash associated with pre-funding of the Acquisitions. In 2022, the major contributing factor to the negative working capital position was the current liabilities associated with our growth capital program.

SOURCES AND USES OF CASH

Year ended December 31,	**2023**	2022	2021
(millions of Canadian dollars)			
Operating activities	**14,201**	11,230	9,256
Investing activities	**(6,043)**	(5,270)	(10,657)
Financing activities	**(2,864)**	(5,428)	1,236
Effect of translation of foreign denominated cash and cash equivalents and restricted cash	**(216)**	55	(5)
Net change in cash and cash equivalents and restricted cash	**5,078**	587	(170)

Significant sources and uses of cash for the years ended December 31, 2023 and 2022 are summarized below:

Operating Activities
Typically, the primary factors impacting cash provided by operating activities year-over-year include changes in our operating assets and liabilities in the normal course due to various factors, including the impact of fluctuations in commodity prices and activity levels on working capital within our business segments, the timing of tax payments, as well as timing of cash receipts and payments generally. Refer to Part II. *Item 8. Financial Statements and Supplementary Data - Note 28. Changes in Operating Assets and Liabilities.* Cash provided by operating activities is also impacted by changes in earnings and certain infrequent or other non-operating factors, as discussed under *Results of Operations,* as well as Distributions from equity investments.

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. Cash used in investing activities is also impacted by acquisitions and dispositions as discussed under *Recent Developments,* and changes in contributions to, and distributions from, our equity investments.

A summary of additions to property, plant and equipment for the years ended December 31, 2023, 2022 and 2021 is set out below:

Year ended December 31,	**2023**	2022	2021
(millions of Canadian dollars)			
Liquids Pipelines	**1,158**	1,418	4,051
Gas Transmission and Midstream	**1,890**	1,647	2,353
Gas Distribution and Storage	**1,451**	1,499	1,343
Renewable Power Generation	**100**	50	16
Energy Services	**—**	—	1
Eliminations and Other	**55**	33	54
Total capital expenditures	**4,654**	4,647	7,818

2023
The increase in cash used in investing activities primarily resulted from the following factors:

- the absence in 2023 of the proceeds received from the completion of a joint venture merger transaction for DCP Midstream, LLC in August 2022; and
- higher cash outflows related to acquisitions in 2023 when compared to 2022.

The factors above were partially offset by higher distributions in 2023 mainly related to our investment in NEXUS Gas Transmission, LLC.

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 Inc. in December 2021; and
- increased investments held by our wholly-owned captive insurance subsidiaries.

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 used in financing activities is also impacted by changes in distributions to, and contributions from, noncontrolling interests.

2023
The decrease in cash used in financing activities primarily resulted from the following factors:

- higher long-term debt issuances in 2023 when compared to the same period in 2022;
- our public offering of common shares, which closed on September 8, 2023, resulting in the issuance of 102,913,500 common shares at a price of $44.70 per share for gross proceeds of $4.6 billion, which is intended to finance a portion of the aggregate cash consideration payable for the Acquisitions; and
- the absence in 2023 of the redemption of Preference Shares, Series 17 and Series J in the first and second quarters of 2022, respectively.

The factors above were partially offset by:

- higher net commercial paper and credit facility repayments in 2023 when compared to the same period in 2022;
- net repayments of short-term borrowings in 2023 when compared to net issuances in 2022;
- the absence in 2023 of proceeds received from the sale of a non-operating interest in seven pipelines from our Regional Oil Sands System in October 2022;
- higher long-term debt repayments in 2023 when compared to the same period in 2022; and
- increased common share dividend payments primarily due to the increase in our common share dividend rate and an increase in the number of common shares outstanding.

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; and
- the absence in 2022 of the redemption of Westcoast's preferred shares in the first quarter of 2021.

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 31 - 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 for our equity investments. For additional information on these commitments, please refer to Part II. *Item 8. Financial Statements and Supplementary Data - Note 30 - 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.

OUTSTANDING PREFERENCE SHARES

Characteristics of our outstanding preference shares are as follows:

(Canadian dollars unless otherwise stated)	Dividend Rate	Dividend[1]	Per Share Base Redemption Value[2]	Redemption and Conversion Option Date[2,3]	Right to Convert Into[3,4]
Preference Shares, Series A	5.50%	$1.37500	$25	—	—
Preference Shares, Series B	5.20%	$1.30052	$25	June 1, 2027	Series C
Preference Shares, Series D[5]	5.41%	$1.35300	$25	March 1, 2028	Series E
Preference Shares, Series F[6]	5.54%	$1.38452	$25	June 1, 2028	Series G
Preference Shares, Series G[7]	6.96%	$1.90704	$25	June 1, 2028	Series F
Preference Shares, Series H[8]	6.11%	$1.52800	$25	September 1, 2028	Series I
Preference Shares, Series I[9]	7.19%	$1.81004	$25	September 1, 2028	Series H
Preference Shares, Series L	5.86%	US$1.46448	US$25	September 1, 2027	Series M
Preference Shares, Series N	6.70%	$1.67400	$25	December 1, 2028	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[10]	6.70%	US$1.67592	US$25	June 1, 2028	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[11]	6.21%	$1.55300	$25	March 1, 2028	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. Preference Shares, Series G and I contain a feature where the dividend rate resets on a quarterly basis. 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 Per Share Base Redemption Value 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 Per Share Base Redemption Value.

4 With the exception of Preference Shares, Series A, after the Redemption and Conversion Option Date, 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 D was increased to $0.33825 from $0.27875 on March 1, 2023 due to reset of the annual dividend on March 1, 2023.

6 The quarterly dividend per share paid on Preference Shares, Series F was increased to $0.34613 from $0.29306 on June 1, 2023 due to reset of the annual dividend on June 1, 2023.

7 On June 1, 2023, 1,827,695 of the outstanding Preference Shares, Series F were converted into Preference Shares, Series G.

8 The quarterly dividend per share paid on Preference Shares, Series H was increased to $0.38200 from $0.27350 on September 1, 2023 due to reset of the annual dividend on September 1, 2023.

9 On September 1, 2023, 2,350,602 of the outstanding Preference Shares, Series H were converted into Preference Shares, Series I.

10 The quarterly dividend per share paid on Preference Shares, Series 1 was increased to US$0.41898 from US$0.37182 on June 1, 2023 due to reset of the annual dividend on June 1, 2023.

11 The quarterly dividend per share paid on Preference Shares, Series 19 was increased to $0.38825 from $0.30625 on March 1, 2023 due to reset of the annual dividend on March 1, 2023.

DIVIDENDS

We have paid common share dividends in every year since we became a publicly traded company in 1953. In November 2023, we announced a 3.1% increase in our quarterly dividend to $0.9150 per common share, or $3.66 annualized, effective with the dividend payable on March 1, 2024, thereby declaring a dividend increase for 29 straight years.

For the years ended December 31, 2023 and 2022, total dividends paid were $7.3 billion and $7.0 billion, respectively, all of which were paid in cash and reflected in Cash Flows from Financing Activities in the Consolidated Statements of Cash Flows.

On November 28, 2023, our Board of Directors declared the following quarterly dividends. All dividends are payable on March 1, 2024 to shareholders of record on February 15, 2024.

	Dividend per share
Common Shares[1]	$0.91500
Preference Shares, Series A	$0.34375
Preference Shares, Series B	$0.32513
Preference Shares, Series D	$0.33825
Preference Shares, Series F	$0.34613
Preference Shares, Series G[2]	$0.47676
Preference Shares, Series H	$0.38200
Preference Shares, Series I[3]	$0.45251
Preference Shares, Series L	US$0.36612
Preference Shares, Series N[4]	$0.41850
Preference Shares, Series P	$0.27369
Preference Shares, Series R	$0.25456
Preference Shares, Series 1	US$0.41898
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	$0.38825

1 *The quarterly dividend per common share was increased 3.1% to $0.9150 from $0.8875, effective March 1, 2024.*

2 *The quarterly dividend per share paid on Preference Shares, Series G was increased to $0.47676 from $0.47245 on December 1, 2023 due to reset on a quarterly basis.*

3 *The quarterly dividend per share paid on Preference Shares, Series I was increased to $0.45251 from $0.44814 on December 1, 2023 due to reset on a quarterly basis following the date of issuance.*

4 *The quarterly dividend per share paid on Preference Shares, Series N was increased to $0.41850 from $0.31788 on December 1, 2023 due to reset of the annual dividend on December 1, 2023.*

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, 2023, the aggregate outstanding principal amount of SEP notes was approximately US$3.2 billion.
2 As at December 31, 2023, 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 2024	3.950% Medium-term Notes due 2024
3.500% Senior Notes due 2024	2.440% Medium-term Notes due 2025
2.150% Senior Notes due 2024	3.200% Medium-term Notes due 2027
2.500% Senior Notes due 2025	5.700% Medium-term Notes due 2027
2.500% Senior Notes due 2025	6.100% Medium-term Notes due 2028
4.250% Senior Notes due 2026	4.900% Medium-term Notes due 2028
1.600% Senior Notes due 2026	2.990% Medium-term Notes due 2029
5.969% Senior Notes due 2026	7.220% Medium-term Notes due 2030
5.900% Senior Notes due 2026	7.200% Medium-term Notes due 2032
3.700% Senior Notes due 2027	6.100% Sustainability-Linked Medium-term Notes due 2032
6.000% Senior Notes due 2028	3.100% Sustainability-Linked Medium-term Notes due 2033
3.125% Senior Notes due 2029	5.360% Sustainability-Linked Medium-term Notes due 2033
6.200% Senior Notes due 2030	5.570% Medium-term Notes due 2035
2.500% Sustainability-Linked Senior Notes due 2033	5.750% Medium-term Notes due 2039
5.700% Sustainability-Linked Senior Notes due 2033	5.120% Medium-term Notes due 2040
4.500% Senior Notes due 2044	4.240% Medium-term Notes due 2042
5.500% Senior Notes due 2046	4.570% Medium-term Notes due 2044
4.000% Senior Notes due 2049	4.870% Medium-term Notes due 2044
3.400% Senior Notes due 2051	4.100% Medium-term Notes due 2051
6.700% Senior Notes due 2053	6.510% Medium-term Notes due 2052
	5.760% Medium-term Notes due 2053
	4.560% Medium-term Notes due 2064

1 As at December 31, 2023, the aggregate outstanding principal amount of the Enbridge US dollar denominated notes was approximately US$15.7 billion.
2 As at December 31, 2023, the aggregate outstanding principal amount of the Enbridge Canadian dollar denominated notes was approximately $11.0 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,	**2023**
(millions of Canadian dollars)	
Operating loss	**(149)**
Earnings	**4,273**
Earnings attributable to common shareholders	**3,921**

Summarized Combined Statements of Financial Position

December 31,	**2023**	2022
(millions of Canadian dollars)		
Cash and cash equivalents	**6,525**	425
Accounts receivable from affiliates	**3,440**	2,486
Short-term loans receivable from affiliates	**3,291**	5,232
Other current assets	**491**	969
Long-term loans receivable from affiliates	**45,702**	43,873
Other long-term assets	**3,303**	4,111
Accounts payable to affiliates	**2,264**	1,375
Short-term loans payable to affiliates	**807**	1,745
Trade payable and accrued liabilities	**743**	716
Other current liabilities	**7,256**	8,036
Long-term loans payable to affiliates	**35,556**	37,626
Other long-term liabilities	**52,096**	47,447

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 US 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 October 24 through November 1, 2022.

On May 9, 2023, the Band filed an Emergency Motion for Injunctive Relief asking the Court to require Enbridge to purge and shutdown Line 5 on the Reservation due to significant erosion at the Meander. Enbridge responded and a hearing was held on May 18, 2023 in front of Judge Conley who indicated that he did not find the Band had proven imminence but his final ruling on all issues would be provided soon.

On June 26, 2023, the Court issued its Final Order ruling that (1) Enbridge shall adopt and implement its 2022 Monitoring and Shutdown Plan with the Court's modifications by July 5, 2023; (2) Enbridge owes the Band $5,151,668 for past trespass on the 12 allotted parcels; (3) Enbridge must continue to pay money on a quarterly basis using the formula set in its Order as long as Line 5 operates in trespass on the 12 allotted parcels (approximately $400,000 per year); (4) Enbridge must cease operation of Line 5 on any parcel within the Band's tribal territory without a valid right of way by June 16, 2026 and thereafter arrange prompt, reasonable remediation at those sites; and (5) The Court declined to allow for the Relocation to be completed prior to having to cease operations. The Final Judgment was entered on June 29, 2023. Enbridge filed its Notice of Appeal on June 30, 2023 and the Band filed its Notice of Cross Appeal on July 27, 2023. On December 12, 2023, the 7th Circuit requested the US to file a brief in this appeal as amicus curiae to address the effect of the Agreement Between the US and Canada Concerning Transit Pipelines, 28 U.S.T. 7449 (1977), and any other issues that the US believes to be material. Briefing by the parties was complete on December 15, 2023. Oral argument is scheduled in February 2024, and we anticipate a decision in 2024.

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, Enbridge 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 followed 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 motion to remand the 2019 case, which the US District Court allowed on January 5, 2022. However, after full briefing, on August 18, 2022, Judge Neff denied the AG's motion to remand. On August 30, 2022, the AG filed a motion to certify the August 18 Order to pursue an appeal on the jurisdictional issue, which Enbridge opposed. On February 21, 2023, that motion was granted and shortly after, on March 2, 2023, the AG filed her Petition for Permission to Appeal in the 6th Circuit Court of Appeals (6th Circuit).

On July 21, 2023, the 6th Circuit granted the AG's Petition for Permission to appeal the US District Court's August 18 Order denying remand to state court. The 6th Circuit's briefing was completed by the end of 2023 and oral argument has been scheduled for March 2024. We anticipate a decision in 2024.

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.

On March 25, 2020, in response to amended complaints from the Tribes, the District Court found that the Army Corps' subsequent environmental review completed in August 2018 was also 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. On that day, the US Court of Appeals for the District of Columbia Circuit stayed the District Court's July 6 order to shut down and empty the pipeline.

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. The US Supreme Court subsequently 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 an injunction proceeding, the District Court could not order DAPL's operations to cease. While not an issue before, 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.

The Army Corps earlier indicated that it did not intend to exercise its authority to bar DAPL's continued operation, notwithstanding the absence of an easement.

On September 8, 2023, the Army Corps issued its draft EIS, which assesses the impacts of DAPL under five alternative scenarios: denying the easement removing the pipeline; denying the easement and leaving the pipeline in place; granting the easement with the prior conditions (which allow for the ongoing operation, maintenance and ultimate removal of the pipeline and its related facilities); granting the easement with some new safety conditions; and rerouting the pipeline. The Army Corps did not identify a preferred alternative. The public comment period that commenced on the issuance of the draft EIS closed on December 13, 2023. The pipeline will remain operational while the environmental review process continues.

GAS TRANSMISSION AND MIDSTREAM

Aux Sable

The previously reported claim filed against Aux Sable by a counterparty to an NGL supply agreement was settled and discontinued during the fourth quarter of 2023. A provision was recognized for this claim in the third quarter 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 POLICIES AND ESTIMATES

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

BUSINESS COMBINATIONS

We apply the provisions of Accounting Standards Codification 805 *Business Combinations* in accounting for our acquisitions. The acquired 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 identifiable 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 a corresponding offset to goodwill. Upon conclusion of the measurement period, or the final determination of values for assets acquired or liabilities assumed, whichever comes first, any subsequent adjustments are recorded to our Consolidated Statements of Earnings.

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 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 discounted cash flow technique. 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 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, 2023, we performed our annual goodwill impairment assessment which consisted of a qualitative assessment for the Liquids Pipelines, Gas Transmission, Gas Distribution and Storage, and Renewable Power Generation reporting units and did not identify impairment indicators. Due to an impairment recorded in 2022 for the Gas Transmission reporting unit and the OEB decision on Phase 1 for Enbridge Gas, we performed a quantitative assessment for the Gas Transmission and Gas Distribution and Storage reporting units as at December 1, 2023, which did not result in the recognition of an impairment charge for either reporting unit. Also, we did not identify any indicators of goodwill impairment during the remainder of 2023.

The Gas Transmission reporting unit remains at risk as the quantitative test performed resulted in the fair value exceeding carrying value by less than 10% and once the Alliance Pipeline and Aux Sable disposition closes in 2024, the fair value of the reporting unit will decrease.

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 that 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 its expected undiscounted cash flows, 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 qualitative or quantitative 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 using present value techniques. The determination of 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 parts of our businesses are subject to regulation by various authorities including, but not limited to, the CER, the FERC, the Alberta Energy Regulator, the BC Energy Regulator, the OEB and the Québec Régie de l'énergie. 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, amounts collected from customers in advance of costs being incurred, or 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 regulator. If there are changes in our assessment of the probability of recovery for a regulatory asset, we reduce its carrying amount to the balance that we expect to recover from customers in future periods through rates. If a regulator later excludes from allowable costs all or a part of costs that were capitalized as a regulatory asset, we reduce the carrying amount of the asset by the excluded amounts.

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. During the fourth quarter of 2023, Southern Lights Pipeline completed an open season to negotiate new transportation service agreements effective 2025. We do not expect to renew the agreements under a cost-of-service toll methodology, therefore Southern Lights Pipeline is no longer subject to rate-regulated accounting. As a result, the related regulatory liabilities, regulatory tax assets and associated regulatory deferred tax liabilities were derecognized.

As at December 31, 2023 and 2022, our regulatory assets totaled $5.7 billion and $6.5 billion, respectively, and regulatory liabilities totaled $3.8 billion.

DEPRECIATION
Depreciation of property, plant and equipment, our largest asset with a net book value at December 31, 2023 and 2022, of $104.6 billion and $104.5 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 consolidated financial statements for the year ended December 31, 2023 of a 0.5% change in key pension and other postretirement benefits (OPEB) obligation assumptions:

	Canada		United States	
	Obligation	Expense	Obligation	Expense
(millions of Canadian dollars)				
Pension				
Decrease in discount rate	297	12	52	3
Decrease in expected return on assets	—	21	—	5
Decrease in rate of salary increase	(60)	(5)	(5)	(1)
OPEB				
Decrease in discount rate	15	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 *Legal and Other Updates* and Part II. *Item 8. Financial Statements and Supplementary Data - Note 30. Commitments and Contingencies*. In addition, any unasserted claims that later may become evident could have a material impact on our financial results and certain subsidiaries and investments.

ASSET RETIREMENT OBLIGATIONS
Asset retirement obligations (ARO) associated with the retirement of long-lived assets are measured at fair value and recognized as Other current liabilities 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. The discount rates used to estimate the present value of expected future cash flows for the years ended December 31, 2023 and 2022 ranged from 1.5% 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 fair value of ARO 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 trusts 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*.