



ENBRIDGE INC.
CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2024

MANAGEMENT'S REPORT

TO THE SHAREHOLDERS OF ENBRIDGE INC.

Financial Reporting

Management of Enbridge Inc. (the Company) is responsible for the accompanying consolidated financial statements and all related financial information contained in the annual report, including Management's Discussion and Analysis. The consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States of America (US GAAP) and necessarily include amounts that reflect management's judgment and best estimates.

The Board of Directors (the Board) and its committees are responsible for all aspects related to governance of the Company. The Audit, Finance & Risk Committee (the AFRC) of the Board, composed of directors who are unrelated and independent, has a specific responsibility to oversee management's efforts to fulfil its responsibilities for financial reporting and internal controls related thereto. The AFRC meets with management, internal auditors and Independent Registered Public Accounting Firm auditors to review the consolidated financial statements and the internal controls as they relate to financial reporting. The AFRC reports its findings to the Board for its consideration in approving the consolidated financial statements for issuance to the shareholders. The internal auditors and Independent Registered Public Accounting Firm auditors have unrestricted access to the AFRC.

Internal Control over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting includes policies and procedures to facilitate the preparation of relevant, reliable and timely information, to prepare consolidated financial statements for external reporting purposes in accordance with US GAAP and to provide reasonable assurance that assets are safeguarded.

Management assessed the effectiveness of the Company's internal control over financial reporting as at December 31, 2024, based on the framework established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as at December 31, 2024.

During the year ended December 31, 2024, the Company acquired the East Ohio Gas Company, Questar Gas Company and its related Wexpro entities, and the Public Service Company of North Carolina. As permitted by the US Securities and Exchange Commission, the Company excluded these acquisitions from its evaluation of the effectiveness of the internal controls over financial reporting as at December 31, 2024 because the Company acquired them in a business combination during 2024. Total assets and total revenues of the East Ohio Gas Company, Questar Gas Company and its related Wexpro entities, and the Public Service Company of North Carolina combined represent approximately 11% and 4%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2024.

PricewaterhouseCoopers LLP, an Independent Registered Public Accounting Firm appointed by the shareholders of the Company, have conducted an audit of the consolidated financial statements of the Company and its internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States) and have issued an unqualified audit report, which is accompanying the consolidated financial statements.

/s/ Gregory L. Ebel

Gregory L. Ebel
President and Chief Executive Officer

/s/ Patrick R. Murray

Patrick R. Murray
Executive Vice President and Chief Financial Officer

February 14, 2025



Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Enbridge Inc.

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated statements of financial position of Enbridge Inc. and its subsidiaries (the Company) as of December 31, 2024 and 2023, and the related consolidated statements of earnings, of comprehensive income, of changes in equity and of cash flows for each of the three years in the period ended December 31, 2024, including the related notes (collectively referred to as the consolidated financial statements). We also have audited the Company's internal control over financial reporting as of December 31, 2024, based on criteria established in *Internal Control – Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2024 and 2023, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2024 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2024, based on criteria established in *Internal Control – Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

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

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

PricewaterhouseCoopers LLP

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"PwC" refers to PricewaterhouseCoopers LLP, an Ontario limited liability partnership.



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

As described in Management's Report on Internal Control over Financial Reporting, management has excluded The East Ohio Gas Company, Questar Gas Company and its related Wexpro entities, and Public Service Company of North Carolina, Incorporated from its assessment of internal control over financial reporting as of December 31, 2024 because they were acquired separately by the Company in business combinations during 2024. We have also excluded The East Ohio Gas Company, Questar Gas Company and its related Wexpro entities, and Public Service Company of North Carolina, Incorporated from our audit of internal control over financial reporting. The East Ohio Gas Company, Questar Gas Company and its related Wexpro entities, and Public Service Company of North Carolina, Incorporated are wholly-owned subsidiaries whose total assets and total revenues excluded from management's assessment and our audit of internal control over financial reporting collectively represent approximately 11% and 4%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2024.

Definition and Limitations of Internal Control over Financial Reporting

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

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



Critical Audit Matters

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

Qualitative goodwill impairment assessment for the Gas Transmission (GT) and Gas Distribution and Storage (GDS) reporting units

As described in Notes 2 and 15 to the consolidated financial statements, the Company's goodwill balance was \$36,600 million as at December 31, 2024 which includes goodwill balances of \$18,278 million and \$8,892 million related to the GT and GDS reporting units respectively. An annual goodwill impairment assessment is performed at the reporting unit level as of April 1 of each year, or more frequently if events or circumstances indicate that the carrying value of goodwill may be impaired. Management has the option to first assess qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment assessment. When performing a qualitative assessment, management determines the drivers of fair value for each reporting unit and evaluates whether those drivers have been positively or negatively affected by relevant events and circumstances since the last fair value assessment. Management's evaluation includes, but is not limited to, the assessment of macroeconomic trends (including the impact of changes in discount rates and rate base multiple), changes to regulatory environments, capital accessibility, operating income trends (including changes to projected cash flows from operations, expected future capital expenditures and forecasted rate base), and changes to industry conditions. Based on management's assessment of qualitative factors, if it is determined that 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. Management performed a qualitative goodwill impairment assessment as of April 1, 2024 and did not identify impairment indicators for the GT and GDS reporting units.

The principal considerations for our determination that performing procedures relating to the qualitative goodwill impairment assessment for the GT and GDS reporting units is a critical audit matter are the significant judgments required by management in assessing the drivers of fair value in the qualitative goodwill impairment assessment for the GT and GDS reporting units to determine whether further quantitative impairment testing is required. This led to a high degree of auditor judgment, effort and subjectivity in performing procedures related to management's assessment of drivers of fair value in the qualitative goodwill impairment assessment for the GT and GDS reporting units with respect to changes to projected cash flows from operations and expected future capital expenditures as well as the impact of changes in discount rate for the GT reporting unit and changes to rate base multiple and forecasted rate base for the GDS reporting unit. In addition, the audit effort involved the use of professionals with specialized skills and knowledge.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's qualitative goodwill impairment assessment. These



procedures also included, among others, evaluating the reasonableness of management's qualitative goodwill impairment assessment for the GT and GDS reporting units by assessing the reasonableness of changes to (i) projected cash flows from operations and expected future capital expenditures for the GT reporting unit and (ii) the forecasted rate base for the GDS reporting unit by considering the current and past performance of the GT and GDS reporting units, external industry data, and evidence obtained in other areas of the audit. Professionals with specialized skill and knowledge were used to assist in evaluating the reasonableness of management's qualitative goodwill impairment assessment for the GT and GDS reporting units, by assessing the reasonableness of the impact of changes in (i) discount rate for the GT reporting unit and (ii) the rate base multiple for the GDS reporting unit.

/s/PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Canada
February 14, 2025

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

ENBRIDGE INC.

CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	2024	2023	2022
<i>(millions of Canadian dollars, except per share amounts)</i>			
Operating revenues			
Commodity sales	27,018	18,981	29,150
Gas distribution sales	6,802	5,442	6,237
Transportation and other services	19,653	19,226	17,922
Total operating revenues <i>(Note 4)</i>	53,473	43,649	53,309
Operating expenses			
Commodity costs	26,556	18,526	28,942
Gas distribution costs	2,484	2,840	3,647
Operating and administrative	9,427	8,600	8,219
Depreciation and amortization	5,167	4,613	4,317
Impairment of long-lived assets	190	419	541
Impairment of goodwill	—	—	2,465
Total operating expenses	43,824	34,998	48,131
Operating income	9,649	8,651	5,178
Income from equity investments <i>(Note 13)</i>	2,304	1,816	2,056
Gain on disposition of equity investments <i>(Note 13)</i>	1,091	—	—
Gain on joint venture merger transaction <i>(Note 13)</i>	—	—	1,076
Other income/(expense) <i>(Note 27)</i>	(1,326)	1,224	(589)
Interest expense <i>(Note 17)</i>	(4,419)	(3,812)	(3,179)
Earnings before income taxes	7,299	7,879	4,542
Income tax expense <i>(Note 24)</i>	(1,668)	(1,821)	(1,604)
Earnings	5,631	6,058	2,938
(Earnings)/loss attributable to noncontrolling interests	(190)	133	65
Earnings attributable to controlling interests	5,441	6,191	3,003
Preference share dividends	(388)	(352)	(414)
Earnings attributable to common shareholders	5,053	5,839	2,589
Earnings per common share attributable to common shareholders <i>(Note 6)</i>	2.34	2.84	1.28
Diluted earnings per common share attributable to common shareholders <i>(Note 6)</i>	2.34	2.84	1.28

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

ENBRIDGE INC.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31, <i>(millions of Canadian dollars)</i>	2024	2023	2022
Earnings	5,631	6,058	2,938
Other comprehensive income/(loss), net of tax			
Change in unrealized gain on cash flow hedges	73	220	847
Change in unrealized gain/(loss) on net investment hedges	(1,305)	409	(971)
Other comprehensive income/(loss) from equity investees	(10)	6	(6)
Excluded components of fair value hedges	9	12	(35)
Reclassification to earnings of loss on cash flow hedges	23	14	143
Reclassification to earnings of pension and other postretirement benefits (OPEB) amounts	(16)	(18)	(10)
Reclassification to earnings of loss on equity investees	—	—	16
Actuarial gain/(loss) on pension and OPEB	248	(130)	312
Foreign currency translation adjustments	5,895	(1,728)	4,406
Other comprehensive income/(loss), net of tax	4,917	(1,215)	4,702
Comprehensive income	10,548	4,843	7,640
Comprehensive (income)/loss attributable to noncontrolling interests	(295)	131	(21)
Comprehensive income attributable to controlling interests	10,253	4,974	7,619
Preference share dividends	(388)	(352)	(414)
Comprehensive income attributable to common shareholders	9,865	4,622	7,205

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

ENBRIDGE INC.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

Year ended December 31,	2024	2023	2022
<i>(millions of Canadian dollars, except per share amounts)</i>			
Preference shares (Note 20)			
Balance at beginning of year	6,818	6,818	7,747
Redemption of preference shares	—	—	(929)
Balance at end of year	6,818	6,818	6,818
Common shares (Note 20)			
Balance at beginning of year	69,180	64,760	64,799
Shares issued, net of issue costs	2,489	4,485	—
Shares issued on exercise of stock options	39	3	53
Shares issued on vesting of restricted stock units (RSU), net of tax	30	12	—
Share repurchases at stated value	—	(80)	(88)
Other	—	—	(4)
Balance at end of year	71,738	69,180	64,760
Additional paid-in capital			
Balance at beginning of year	268	275	365
Stock-based compensation	98	71	36
Stock options exercised	(39)	(3)	(50)
Vested RSUs	(52)	(20)	—
Purchase of noncontrolling interests	—	(28)	(43)
Other	—	(27)	(33)
Balance at end of year	275	268	275
Deficit			
Balance at beginning of year	(17,115)	(15,486)	(10,989)
Earnings attributable to controlling interests	5,441	6,191	3,003
Preference share dividends	(388)	(352)	(414)
Common share dividends declared	(7,984)	(7,423)	(7,023)
Share repurchases in excess of stated value	—	(45)	(63)
Balance at end of year	(20,046)	(17,115)	(15,486)
Accumulated other comprehensive income/(loss) (Note 22)			
Balance at beginning of year	2,303	3,520	(1,096)
Other comprehensive income/(loss) attributable to common shareholders, net of tax	4,812	(1,217)	4,616
Balance at end of year	7,115	2,303	3,520
Total Enbridge Inc. shareholders' equity	65,900	61,454	59,887
Noncontrolling interests (Note 19)			
Balance at beginning of year	3,029	3,511	2,542
Earnings/(loss) attributable to noncontrolling interests	190	(133)	(65)
Other comprehensive income/(loss) attributable to noncontrolling interests, net of tax			
Change in unrealized gain/(loss) on cash flow hedges	9	35	(28)
Foreign currency translation adjustments	96	(33)	114
	105	2	86
Comprehensive income/(loss) attributable to noncontrolling interests	295	(131)	21
Distributions	(333)	(363)	(259)
Contributions	4	11	1,105
Purchase of noncontrolling interests	(2)	2	55
Other	—	(1)	47
Balance at end of year	2,993	3,029	3,511
Total equity	68,893	64,483	63,398
Dividends paid per common share	3.66	3.55	3.44

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

ENBRIDGE INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31, (millions of Canadian dollars)	2024	2023	2022
Operating activities			
Earnings	5,631	6,058	2,938
Adjustments to reconcile earnings to net cash provided by operating activities:			
Depreciation and amortization	5,167	4,613	4,317
Deferred income tax expense (Note 24)	719	1,420	957
Unrealized derivative fair value (gain)/loss, net (Note 23)	2,082	(1,180)	1,280
Income from equity investments (Note 13)	(2,304)	(1,816)	(2,056)
Distributions from equity investments	2,121	1,998	1,827
Impairment of long-lived assets	190	419	541
Impairment of goodwill (Note 15)	—	—	2,465
Gain on joint venture merger transaction (Note 13)	—	—	(1,076)
Gain on disposition of equity investment	(1,091)	—	—
Other	218	378	49
Changes in operating assets and liabilities (Note 28)	(133)	2,311	(12)
Net cash provided by operating activities	12,600	14,201	11,230
Investing activities			
Capital expenditures	(6,711)	(4,654)	(4,647)
Long-term, restricted and other investments	(3,416)	(1,276)	(1,041)
Distributions from equity investments in excess of cumulative earnings	785	1,151	763
Additions to intangible assets	(219)	(222)	(174)
Acquisitions	(13,472)	(954)	(828)
Proceeds from joint venture merger transaction (Note 13)	—	—	522
Proceeds from dispositions of equity investments	2,724	—	—
Net change in affiliate loans	2	(27)	135
Other	(56)	(61)	—
Net cash used in investing activities	(20,363)	(6,043)	(5,270)
Financing activities			
Net change in short-term borrowings	129	(1,596)	481
Net change in commercial paper and credit facility draws	6,549	(8,157)	(1,333)
Debenture and term note issues, net of issue costs	9,546	15,377	7,547
Debenture and term note repayments	(6,633)	(4,819)	(4,198)
Sale of noncontrolling interest in subsidiary (Note 8)	—	—	1,092
Contributions from noncontrolling interests	4	11	13
Distributions to noncontrolling interests	(333)	(363)	(259)
Common shares issued, net of issue costs	2,485	4,450	3
Common shares repurchased	—	(125)	(151)
Preference share dividends	(387)	(352)	(338)
Common share dividends	(7,875)	(7,276)	(6,968)
Redemption of preference shares	—	—	(1,003)
Net change in affiliate loan	99	71	—
Other	(40)	(85)	(314)
Net cash provided by/(used in) financing activities	3,544	(2,864)	(5,428)
Effect of translation of foreign denominated cash and cash equivalents and restricted cash	234	(216)	55
Net change in cash and cash equivalents and restricted cash	(3,985)	5,078	587
Cash and cash equivalents and restricted cash at beginning of year	5,985	907	320
Cash and cash equivalents and restricted cash at end of year ¹	2,000	5,985	907
Supplementary cash flow information			
Cash paid for income taxes	861	578	495
Cash paid for interest, net of amount capitalized	4,134	3,380	2,920
Property, plant and equipment and intangible assets non-cash accruals	1,251	813	937

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

1 As at December 31, 2024, long-term restricted cash of \$105 million (2023 and 2022 - nil) was included in Restricted long-term investments and cash in the Consolidated Statements of Financial Position.

ENBRIDGE INC.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	2024	2023
<i>(millions of Canadian dollars; number of shares in millions)</i>		
Assets		
Current assets		
Cash and cash equivalents	1,803	5,901
Restricted cash	92	84
Trade receivables and unbilled revenues	6,920	4,410
Other current assets <i>(Note 9)</i>	2,770	2,440
Accounts receivable from affiliates	90	85
Inventory <i>(Note 10)</i>	1,488	1,479
	13,163	14,399
Property, plant and equipment, net <i>(Note 11)</i>	131,104	104,641
Long-term investments <i>(Note 13)</i>	20,691	16,793
Restricted long-term investments and cash <i>(Note 23)</i>	998	717
Deferred amounts and other assets	11,034	8,041
Intangible assets, net <i>(Note 14)</i>	4,587	3,537
Goodwill <i>(Note 15)</i>	36,600	31,848
Deferred income taxes <i>(Note 24)</i>	796	341
Total assets	218,973	180,317
Liabilities and equity		
Current liabilities		
Short-term borrowings <i>(Note 17)</i>	529	400
Trade payables and accrued liabilities	7,060	4,308
Other current liabilities <i>(Note 16)</i>	7,241	5,659
Accounts payable to affiliates	22	26
Interest payable	1,231	958
Current portion of long-term debt <i>(Note 17)</i>	7,729	6,084
	23,812	17,435
Long-term debt <i>(Note 17)</i>	93,414	74,715
Other long-term liabilities	13,258	8,653
Deferred income taxes <i>(Note 24)</i>	19,596	15,031
	150,080	115,834
Commitments and contingencies <i>(Note 30)</i>		
Equity		
Share capital <i>(Note 20)</i>		
Preference shares	6,818	6,818
Common shares <i>(2,178 and 2,125 outstanding at December 31, 2024 and 2023, respectively)</i>	71,738	69,180
Additional paid-in capital	275	268
Deficit	(20,046)	(17,115)
Accumulated other comprehensive income <i>(Note 22)</i>	7,115	2,303
Total Enbridge Inc. shareholders' equity	65,900	61,454
Noncontrolling interests <i>(Note 19)</i>	2,993	3,029
	68,893	64,483
Total liabilities and equity	218,973	180,317

Variable Interest Entities (VIEs) *(Note 12)*

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

Approved by the Board of Directors:

/s/ Pamela L. Carter

Pamela L. Carter
Chair

/s/ Teresa S. Madden

Teresa S. Madden
Director

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

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1. BUSINESS OVERVIEW

The terms "we", "our", "us" and "Enbridge" as used in this report refer collectively to Enbridge Inc. and its subsidiaries unless the context suggests otherwise. These terms are used for convenience only and are not intended as a precise description of any separate legal entity within Enbridge.

Effective January 1, 2024, to better align how the chief operating decision maker (CODM) reviews operating performance and resource allocation across operating segments, we transferred our Canadian and United States (US) crude oil marketing businesses from the Energy Services segment to the Liquids Pipelines segment. As a result, the Energy Services segment ceased to exist and the remainder of the business, comprising natural gas and power marketing, is now reported in Eliminations and Other. Beginning in the first quarter of 2024, prior period comparable results for segmented information have been recast to reflect the change in reportable segments. This segment reporting change does not have an impact on our consolidated results.

Enbridge is a publicly traded energy transportation and distribution company. We conduct our business through four business segments: Liquids Pipelines, Gas Transmission, Gas Distribution and Storage, and Renewable Power Generation. These reporting segments are strategic business units established by senior management to facilitate the achievement of our long-term objectives, to aid in resource allocation decisions and to assess operational performance.

LIQUIDS PIPELINES

Liquids Pipelines consists of pipelines and terminals in Canada and the US that transport and export various grades of crude oil and other liquid hydrocarbons, including the Mainline System, Regional Oil Sands System, Gulf Coast and Mid-Continent, and Other. Effective January 1, 2024, our Canadian and US crude oil marketing businesses are included in this segment. These businesses provide energy marketing services to customers and undertake physical commodity marketing activity and logistical services to manage our volume commitments on various pipeline systems.

GAS TRANSMISSION

Gas Transmission consists of our investments in natural gas pipelines and gathering and processing facilities in Canada and the US, including US Gas Transmission, Canadian Gas Transmission, US Midstream, and Other. This segment also includes certain investments in renewable natural gas (RNG) facilities. On January 2, 2024, we acquired six Morrow Renewables operating landfill gas-to-RNG production facilities (Tomorrow RNG) located in Texas and Arkansas which are a component of Other within the Gas Transmission segment (*Note 8*). We also sold our interests in the Alliance Pipeline and Aux Sable (including a 42.7% interest in Aux Sable Midstream LLC and Aux Sable Liquid Products L.P., and a 50.0% interest in Aux Sable Canada LP), previously reported in the Gas Transmission segment, to Pembina Pipeline Corporation on April 1, 2024 (*Note 13*).

GAS DISTRIBUTION AND STORAGE

Gas Distribution and Storage consists of our rate-regulated natural gas utility operations in Canada and the US. Enbridge Gas Inc. (Enbridge Gas Ontario) serves residential, commercial and industrial customers across Ontario. In 2024, we acquired three US natural gas utilities, The East Ohio Gas Company (EOG), Questar Gas Company (Questar) and its related Wexpro companies (Wexpro), and Public Service Company of North Carolina, Incorporated (PSNC), which make up our US gas utilities (*Note 8*). This business segment also includes natural gas distribution activities in Québec.

RENEWABLE POWER GENERATION

Renewable Power Generation consists primarily of investments in wind and solar assets, as well as equity interests in geothermal power and power transmission assets. In North America, assets are primarily located in the provinces of Alberta, Ontario and Québec, and in the states of Colorado, Texas, Indiana, Ohio and West Virginia. We also hold interests in offshore wind facilities in operation, under construction and in active development in the United Kingdom, France and Germany. This segment also includes Tri Global Energy, LLC (TGE) which was acquired on September 27, 2022 (*Note 8*).

ELIMINATIONS AND OTHER

In addition to the segments described above, Eliminations and Other includes operating and administrative costs that are not allocated to business segments, the impact of foreign exchange hedge settlements and the activities of our wholly-owned captive insurance subsidiaries. The principal activity of our captive insurance subsidiaries is providing insurance and reinsurance coverage for certain insurable property and casualty risk exposures of our operating subsidiaries and certain equity investments. Eliminations and Other also includes new business development activities and corporate investments. Effective January 1, 2024, our natural gas and power marketing businesses are also included in Eliminations and Other.

Enbridge's CODM is the President and Chief Executive Officer. The CODM uses earnings before interest, income taxes and depreciation and amortization (EBITDA), disaggregated by line of business, to assess segment performance and to set targets predominantly in the annual and long-term budgeting and forecasting process. Budget-to-actual and actual-to-actual variances in EBITDA are considered when making decisions about the allocation of resources to the segments and to meet our strategic priorities. Refer to *Note 5 - Segmented Information* for a reconciliation of EBITDA to earnings before income taxes.

2. SIGNIFICANT ACCOUNTING POLICIES

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

BASIS OF PRESENTATION AND USE OF ESTIMATES

The preparation of financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities in the consolidated financial statements. Significant estimates and assumptions used in the preparation of the consolidated financial statements include, but are not limited to: variable consideration included in revenue (*Note 4*); carrying values of regulatory assets and liabilities (*Note 7*); purchase price allocations (*Note 8*); unbilled revenues; expected credit losses; depreciation rates and carrying value of property, plant and equipment (*Note 11*); amortization rates and carrying value of intangible assets (*Note 14*); measurement of goodwill (*Note 15*); fair value of asset retirement obligations (ARO) (*Note 18*); valuation of stock-based compensation (*Note 21*); fair value of financial instruments (*Note 23*); provisions for income taxes (*Note 24*); assumptions used to measure retirement benefits and OPEB (*Note 25*); commitments and contingencies (*Note 30*); and estimates of losses related to environmental remediation obligations (*Note 30*). Actual results could differ from these estimates.

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

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include our accounts and the accounts of our subsidiaries and VIEs for which we are the primary beneficiary. A VIE is a legal entity that does not have sufficient equity at risk to finance its activities without additional subordinated financial support or is structured such that equity investors lack the ability to make significant decisions relating to the entity's operations through voting rights or do not substantively participate in the gains and losses of the entity. Upon inception of a contractual agreement, we perform an assessment to determine whether the arrangement contains a variable interest in a legal entity and whether that legal entity is a VIE. The primary beneficiary has both the power to direct the activities of the VIE that most significantly impact the entity's economic performance and the obligation to absorb losses, or the right to receive benefits from, the VIE that could potentially be significant to the VIE. Where we conclude that we are the primary beneficiary of a VIE, we consolidate the accounts of that VIE. We assess all variable interests in the entity and use our judgment when determining if we are the primary beneficiary. Other qualitative factors that are considered include decision-making responsibilities, the VIE capital structure, risk and rewards sharing, contractual agreements with the VIE, voting rights and level of involvement of other parties. We assess the primary beneficiary determination for a VIE on an ongoing basis if there are changes in the facts and circumstances related to a VIE. If an entity is determined to not be a VIE, the voting interest entity model is applied, where an investor holding the majority voting rights consolidates the entity. The consolidated financial statements also include the accounts of any limited partnerships where we represent the general partner and, based on all facts and circumstances, control such limited partnerships, unless the limited partner has substantive participating rights or substantive kick-out rights. For certain investments where we retain an undivided interest in assets and liabilities, we record our proportionate share of assets, liabilities, revenues and expenses.

All intercompany accounts and transactions are eliminated upon consolidation. Ownership interests in subsidiaries represented by other parties that do not control the entity are presented in the consolidated financial statements as activities and balances attributable to noncontrolling interests. Investments and entities over which we exercise significant influence are accounted for using the equity method.

REGULATION

Certain of our businesses are subject to regulation by various authorities including, but not limited to, the Canada Energy Regulator (CER), the Federal Energy Regulatory Commission (FERC), the Alberta Energy Regulator, the British Columbia (BC) Energy Regulator, the Ontario Energy Board (OEB), the Québec Régie de l'énergie, the Public Utilities Commission of Ohio (Ohio Commission), the North Carolina Utilities Commission (North Carolina Commission), the Utah Public Service Commission (Utah Commission), the Wyoming Public Service Commission (Wyoming Commission), and the Idaho Public Utilities Commission (Idaho Commission). Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking, and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under US GAAP for non-rate-regulated entities.

Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates, amounts collected from customers in advance of costs being incurred, or to be paid to cover future abandonment costs 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. We believe that the recovery of our regulatory assets as at December 31, 2024 is probable over the periods described in *Note 7 - Regulatory Matters*.

During the fourth quarter of 2023, Southern Lights Pipeline completed an open season to negotiate new transportation service agreements. We did not renew the agreements under a cost-of-service toll methodology, therefore Southern Lights Pipeline was 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 in 2023.

We collect and set aside funds to cover future pipeline abandonment costs for all CER-regulated pipelines in accordance with the Land Matters Consultation Initiative (LMCI) to fund future pipeline decommissioning costs in the state of Minnesota and to satisfy retirement obligations as Wexpro properties are abandoned. The funds collected are held in trusts in accordance with applicable regulations. The funds collected from customers are reported within Operating revenues in the Consolidated Statements of Earnings and Restricted long-term investments and cash in the Consolidated Statements of Financial Position. Concurrently, for LMCI, we reflect the future abandonment cost as an increase to Operating and administrative expense in the Consolidated Statements of Earnings and Other long-term liabilities in the Consolidated Statements of Financial Position.

An allowance for funds used during construction (AFUDC) is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset. AFUDC includes both an interest component and, if approved by the regulator, a cost of equity component, which are both capitalized based on rates set out in a regulatory agreement. The corresponding impact on earnings is included in Interest expense for the interest component and Other income/(expense) for the equity component. In the absence of rate regulation, we would capitalize interest using a capitalization rate based on our cost of borrowing, whereas the capitalized equity component, the corresponding earnings during the construction phase and the subsequent depreciation relating to the equity component would not be recognized. The equity component of AFUDC is included as a non-cash reconciling item to earnings within Cash Flows from Operating Activities in the Consolidated Statements of Cash Flows.

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

With the approval of regulators, certain operations capitalize a portion of specified operating costs. These operations are authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation, a portion of such operating costs would be charged to earnings in the year incurred.

For certain regulated operations to which US GAAP guidance for phase-in plans applies, negotiated depreciation rates recovered in transportation tolls may be less than the depreciation expense calculated in accordance with US GAAP in early years of long-term contracts but recovered in future periods when tolls exceed depreciation. Depreciation expense on such assets is recorded in accordance with US GAAP and no regulatory asset is recorded.

REVENUE RECOGNITION

For businesses that are not rate-regulated, revenues are recorded when products have been delivered or services have been performed, the amount of revenue can be reliably measured and collectability is reasonably assured. Customer creditworthiness is assessed prior to agreement signing and throughout the contract duration. Certain revenues from our liquids and natural gas pipeline businesses are recognized under the terms of committed delivery contracts, rather than the cash tolls received.

Long-term take-or-pay contracts, under which shippers are obligated to pay fixed amounts ratably over the contract period regardless of volumes shipped, may contain make-up rights. Make-up rights are earned by shippers when minimum volume commitments are not utilized during the period but under certain circumstances can be used to offset overages in future periods, subject to expiry. We recognize revenues associated with make-up rights at the earlier of when the make-up volume is shipped, the make-up right expires, or when it is determined that the likelihood that the shipper will utilize the make-up right is remote. We also have long-term contracts where the revenue profile does not align with the cash receipt schedule, resulting in the recognition of deferred revenue.

Certain offshore pipeline transportation contracts require us to provide transportation services for the life of the underlying producing fields. Under these arrangements, shippers pay us a fixed monthly toll for a defined period of time which may be shorter than the estimated reserve life of the underlying producing fields, resulting in a contract period which extends past the period of cash collection. Fixed monthly toll revenues are recognized ratably over the committed volume made available to shippers throughout the contract period, regardless of when cash is received.

For the years ended December 31, 2024, 2023 and 2022, cash received net of revenue recognized for contracts under make-up rights and similar deferred revenue arrangements was \$97 million, \$210 million and \$238 million, respectively.

For rate-regulated businesses, revenues are recognized in a manner that is consistent with the underlying agreements as approved by the regulators. Natural gas utility revenues are generally recorded based on regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in our distribution franchise areas.

Certain of our US gas utilities have a revenue decoupling mechanism, referred to as a Customer Usage Tracker (CUT) or Conservation Enabling Tariff (CET), which allows for the collection of an allowed monthly revenue per customer and to promote energy conservation. Under the mechanism, non-gas revenues are decoupled from the temperature-adjusted usage per customer. The difference between actual revenue and the allowed monthly revenue per customer is recorded as a regulatory asset or liability and recovered from, or refunded to, customers through periodic rate adjustments.

Amounts deferred under the CUT or CET arise due to specific arrangements with the regulators rather than customers and represent alternative revenue programs. Revenue from alternative revenue programs is recorded within Operating revenues in the Consolidated Statements of Earnings in the month the related adjustments are deferred and is presented as Other revenues not from contracts with customers when disaggregated in *Note 4 - Revenue*.

Our crude oil, natural gas and power marketing businesses enter into commodity purchase and sale arrangements that are recorded on a gross basis as we are acting as the principal in the transactions.

No non-affiliated customer exceeded 10.0% of our third-party revenues for the years ended December 31, 2024, 2023 and 2022.

DERIVATIVE INSTRUMENTS AND HEDGING

Non-qualifying Derivatives

Non-qualifying derivative instruments are used primarily to mitigate foreign exchange, interest rate and commodity price earnings exposure. Non-qualifying derivatives are measured at fair value with changes in fair value recognized in earnings in Commodity sales, Transportation and other services revenues, Commodity costs, Operating and administrative expense, Other income/(expense) and Interest expense.

Derivatives in Qualifying Hedging Relationships

We use derivative financial instruments to manage our exposure to changes in commodity prices, foreign exchange rates and interest rates. Hedge accounting is optional and requires us to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. We present the earnings effects of hedging items with the hedged transaction. Derivatives in qualifying hedging relationships are categorized as cash flow hedges, fair value hedges or net investment hedges.

Cash Flow Hedges

We may use cash flow hedges to manage our exposure to changes in commodity prices, foreign exchange rates and interest rates. The change in the fair value of a cash flow hedging instrument is recorded in Other comprehensive income/(loss) (OCI) and is reclassified to earnings when the hedged item impacts earnings.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss at that date is deferred in OCI and recognized in earnings concurrently with the related transaction. If an anticipated hedged transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from derivative instruments for which hedge accounting has been discontinued are recognized in earnings in the period in which they occur.

Fair Value Hedges

We may use fair value hedges to hedge the fair value of debt instruments. The change in the fair value of the hedging instrument is recorded in earnings with changes in the fair value of the hedged risk of the asset or liability that is designated as part of the hedging relationship. If a fair value hedge is discontinued or ceases to be effective, the hedged risk of the asset or liability ceases to be remeasured at fair value and the cumulative fair value adjustment to the carrying value of the hedged item is recognized in earnings over the remaining life of the hedged item.

Net Investment Hedges

Gains and losses arising from the translation of our net investment in foreign operations from their functional currencies to Enbridge's Canadian dollar presentation currency are included in cumulative translation adjustments (CTA), a component of OCI. We currently have designated a portion of our US dollar-denominated debt, as well as a portfolio of foreign exchange forward contracts in prior periods, as a hedge of our net investment in US dollar-denominated investments and subsidiaries. As a result, the change in fair value of the foreign currency derivatives, as well as the translation of US dollar-denominated debt, are reflected in OCI. Amounts recognized previously in Accumulated other comprehensive income/(loss) (AOCI) are reclassified to earnings when there is a reduction of the hedged net investment resulting from the disposal of a foreign operation.

Classification of Derivatives

We recognize the fair value of derivative instruments in the Consolidated Statements of Financial Position as current and non-current assets or liabilities depending on the timing of settlements and the resulting cash flows associated with the instruments. Fair value amounts related to cash flows occurring beyond one year are classified as non-current.

Cash inflows and outflows related to derivative instruments are classified as Cash Flows from Operating and Financing Activities in the Consolidated Statements of Cash Flows.

Balance Sheet Offset

Assets and liabilities arising from derivative instruments may be offset in the Consolidated Statements of Financial Position when we have the legal right and intention to settle them on a net basis.

TRANSACTION COSTS

Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. We incur transaction costs primarily from the issuance of debt and account for these costs as a reduction to Long-term debt in the Consolidated Statements of Financial Position. These costs are amortized using the effective interest rate method over the term of the related debt instrument and are recorded in Interest expense.

EQUITY INVESTMENTS

Equity investments over which we exercise significant influence, but do not have controlling financial interests, are accounted for using the equity method. These investments are initially measured at cost and are adjusted for our proportionate share of undistributed equity earnings or loss. Our equity investments are increased for contributions made to, and decreased for distributions received from, the investee. To the extent an equity investee undertakes activities necessary to commence its planned principal operations, we capitalize interest costs associated with the investment during such period.

RESTRICTED LONG-TERM INVESTMENTS AND CASH

Long-term investments and cash that are restricted as to withdrawal or usage, for the purposes of funding pipeline abandonment in accordance with the CER's LMCI, to cover future pipeline decommissioning costs in the state of Minnesota, and to satisfy retirement obligations as Wexpro properties are abandoned, are presented as Restricted long-term investments and cash in the Consolidated Statements of Financial Position.

Cash and cash equivalents that are restricted as to withdrawal or usage for the purposes of the CER's LMCI or in accordance with specific commercial and debt arrangements are presented as Restricted cash in the Consolidated Statements of Financial Position.

OTHER INVESTMENTS

Generally, we classify equity investments in entities over which we do not exercise significant influence and that do not have readily determinable fair values as other investments measured using the fair value measurement alternative (FVMA). These investments are recorded at cost less impairment, if any, and adjusted for the impact of observable price changes occurring in orderly transactions for an identical or similar investment of the same issuer. Investments in equity securities measured using the FVMA are reviewed for impairment each reporting period and written down to their fair value if objective evidence of impairment is identified.

Equity investments with readily determinable fair values are measured at fair value through earnings. Dividends received from investments in equity securities are recognized in earnings when the right to receive payment is established. Investments in debt securities are classified as available-for-sale and measured at fair value through OCI.

NONCONTROLLING INTERESTS

Noncontrolling interests represent ownership interests attributable to third parties in certain consolidated subsidiaries. The portion of equity not owned by us in such entities is reflected as Noncontrolling interests within the equity section of the Consolidated Statements of Financial Position.

INCOME TAXES

Income taxes are accounted for using the liability method. Deferred income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Deferred income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. For our regulated operations, a deferred income tax liability or asset is recognized with a corresponding regulatory asset or liability, respectively, to the extent that taxes can be recovered through rates. Any interest and/or penalty incurred related to tax is reflected in Income tax expense.

FOREIGN CURRENCY TRANSACTIONS AND TRANSLATION

Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which Enbridge or a reporting subsidiary operates, referred to as the functional currency. Transactions denominated in foreign currencies are translated to the functional currency using the exchange rate prevailing at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency using the exchange rate in effect as at the balance sheet date. Exchange gains and losses resulting from the translation of monetary assets and liabilities are included in earnings in the period in which they arise.

Gains and losses arising from the translation of foreign operations' functional currencies to our Canadian dollar presentation currency are included in the CTA component of AOCI and are recognized in earnings upon sale of the foreign operation. Asset and liability accounts are translated at the exchange rates in effect as at the balance sheet date, while revenues and expenses are translated using monthly average exchange rates.

CASH AND CASH EQUIVALENTS

Cash and cash equivalents include short-term investments with a term to maturity of three months or less when purchased.

LOANS AND RECEIVABLES

Long-term notes receivable from affiliates are measured at amortized cost using the effective interest rate method, net of any impairment losses recognized. Trade receivables and unbilled revenues are measured at cost. Interest income is recognized in earnings as it is earned with the passage of time.

CURRENT EXPECTED CREDIT LOSSES

For accounts receivable, a loss allowance matrix is utilized to measure lifetime expected credit losses. The matrix contemplates historical credit losses by age of receivables, adjusted for any forward-looking information and management expectations. Other loan receivables and applicable off-balance sheet commitments utilize a discounted cash flow methodology which calculates the current expected credit losses based on historical default probability rates associated with the credit rating of the counterparty and the related term of the loan or commitment, adjusted for forward-looking information and management expectations. Trade receivables and unbilled revenues are presented net of allowance for expected credit losses of \$119 million and \$100 million as at December 31, 2024 and 2023, respectively.

NATURAL GAS IMBALANCES

The Consolidated Statements of Financial Position include balances as a result of differences in gas volumes received from, and delivered for, customers. As settlement of certain imbalances is in-kind, changes in the balances do not have an effect on our Consolidated Statements of Earnings or Consolidated Statements of Cash Flows. Most natural gas volumes owed to or by us are valued at natural gas market index prices as at the balance sheet dates.

INVENTORY

Inventory is comprised of natural gas held in storage by businesses in our Gas Distribution and Storage and Gas Transmission segments, crude oil and natural gas held by our crude oil and natural gas marketing businesses, and materials and supplies. Natural gas held in storage by our Gas Distribution and Storage businesses is recorded at the prices approved by the regulators in the determination of distribution rates. The actual price of gas purchased may differ from the regulator approved price. The difference between the approved price and the actual cost of gas purchased is deferred as a liability for future refund, or as an asset for collection, as approved by the regulators.

Commodity inventory held by our crude oil and natural gas marketing businesses is recorded at the lower of cost, as determined on a weighted average basis, or market value. Upon disposition, commodity inventory is recorded to Commodity costs in the Consolidated Statements of Earnings at the weighted average cost of inventory, including any adjustments recorded to reduce inventory to market value. Materials and supplies inventory is recorded at the lower of average cost or net realizable value.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is recorded at historical cost. Expenditures for construction, expansion, major renewals and betterments are capitalized. Maintenance and repair costs are expensed as incurred. Expenditures for project development are capitalized if they are expected to have future benefit. We capitalize interest incurred during construction for non-rate-regulated assets. For rate-regulated assets, AFUDC is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset.

Two primary methods of depreciation are utilized. For distinct assets, depreciation is generally provided on a straight-line basis over the estimated useful life of the asset commencing when it 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 generally not reflected in earnings but are booked as an adjustment to accumulated depreciation.

The successful efforts method of accounting is used for cost-of-service reserves developed and produced by Wexpro for gas utility affiliate, Questar. Cost-of-service reserves are properties for which the operations and return on investment are subject to the Wexpro Agreements. Under the successful efforts method, Wexpro capitalizes the costs of acquiring leaseholds, drilling development wells, drilling successful exploratory wells, and purchasing related support equipment and facilities. Geological and geophysical studies are expensed as incurred. Capitalized costs of development wells and leaseholds are amortized on a field-by-field basis using the unit-of-production method and the estimated proved developed or total proved natural gas and crude oil reserves.

LEASES

We recognize an arrangement as a lease when a customer has the right to obtain substantially all of the economic benefits from the use of an asset, as well as the right to direct the use of the asset. We recognize right-of-use (ROU) assets and the related lease liabilities in the Consolidated Statements of Financial Position for operating lease arrangements with a term of 12 months or longer. We do not separate non-lease components from the associated lease components of our lessee contracts and account for both components as a single lease component. We combine lease and non-lease components within a contract for operating lessor leases when certain conditions are met. ROU assets are assessed for impairment using the same approach applied for other long-lived assets.

Lease liabilities and ROU assets require the use of judgment and estimates which are applied in determining the term of a lease, appropriate discount rates, whether an arrangement contains a lease, whether there are any indicators of impairment for ROU assets and whether any ROU assets should be grouped with other long-lived assets for impairment testing. The lease term may include periods associated with options to extend or terminate the lease if it is reasonably certain the options will be exercised.

DEFERRED AMOUNTS AND OTHER ASSETS

Deferred amounts and other assets primarily consists of costs that regulatory authorities have permitted, or are expected to permit, to be recovered through future rates (*Note 7*), overfunded defined benefit pension and OPEB plan assets (*Note 25*), operating lease ROU assets (*Note 26*) and long-term gross derivative asset balances (*Note 23*).

INTANGIBLE ASSETS

Intangible assets consist primarily of certain software costs, customer relationships and biogas rights agreements. We capitalize costs incurred during the application development stage of internal use software projects. Customer relationships represent the underlying relationship from long-term agreements with customers that are capitalized upon acquisition. Biogas rights agreements are long-term gas supply agreements with landfill owners of our landfill gas-to-RNG production facilities that are capitalized upon acquisition. Intangible assets are generally amortized on a straight-line basis over their expected lives, commencing when the asset is available for use.

GOODWILL

Goodwill represents the excess of the purchase price over the fair value of net identifiable assets upon acquisition of a business. The carrying value of goodwill, which is not amortized, is assessed for impairment annually or more frequently if events or changes in circumstances arise that suggest the carrying value of goodwill may be impaired. We perform our annual review of the goodwill balance on April 1.

We perform our annual review for impairment at the reporting unit level, which is identified by assessing whether the components of our operating segments constitute businesses for which discrete information is available, whether segment management regularly reviews the operating results of those components, and whether the economic and regulatory characteristics are similar. Our reporting units are Liquids Pipelines, Gas Transmission, Gas Distribution and Storage, and Renewable Power Generation.

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 (including the impact of changes in discount rates and rate base multiple), changes to regulatory environments, capital accessibility, operating income trends (including changes to projected cash flows from operations, expected future capital expenditures and forecasted rate base), 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, 2024, 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. No indicators of goodwill impairment were identified during the remainder of 2024.

IMPAIRMENT

We review the carrying values of our long-lived assets as events or changes in circumstances warrant. If it is determined that the carrying value of an asset exceeds its expected undiscounted cash flows, we will calculate fair value based on the discounted cash flows and write the asset down to the extent that the carrying value exceeds the fair value.

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

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

PENSION AND OTHER POSTRETIREMENT BENEFITS

We sponsor defined benefit and defined contribution pension plans, as well as defined benefit OPEB plans.

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

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

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

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

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

Net periodic benefit cost is recognized in earnings and includes:

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

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

For defined contribution plans, our contributions are expensed when they occur.

STOCK-BASED COMPENSATION

Incentive stock options (ISO) granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value of the ISO granted as calculated by the Black-Scholes-Merton model and is recognized on a straight-line basis over the shorter of the vesting period or the period to early retirement eligibility, with a corresponding credit to Additional paid-in capital. Balances in Additional paid-in capital are transferred to Share capital when the options are exercised.

Performance stock units (PSU) and certain RSUs are cash-settled awards for which the related liability is remeasured each reporting period. PSUs vest at the completion of a three-year term and RSUs vest one-third annually from the grant date. During the vesting term, compensation expense is recorded based on the number of units outstanding and the current market price of Enbridge's common shares with an offset to Other current liabilities or Other long-term liabilities. The value of the PSUs is also dependent on our performance relative to targets set out under the plan. We also award share-settled RSUs to certain non-executive senior management employees which vest at the completion of a three-year term. Beginning in 2023, share-settled RSUs were also granted to non-executive employees, which vest either one-third annually from the grant date, or following a 12-month period. During the vesting term, compensation expense is recorded based on the number of units granted and the market price of Enbridge's common shares on the day immediately preceding the grant date, with an offset to Additional paid-in capital. There is no associated liability recorded for share-settled awards.

COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES

We expense or capitalize, as appropriate, expenditures for ongoing compliance with environmental regulations that relate to past or current operations. We expense costs incurred for remediation of existing environmental contamination caused by past operations that do not benefit future periods by preventing or eliminating future contamination. We record liabilities for environmental matters when assessments indicate that remediation efforts are probable and the costs can be reasonably estimated. Estimates of environmental liabilities are based on currently available facts, existing technology and presently enacted laws and regulations, taking into consideration the likely effects of inflation and other factors. These amounts also consider prior experience in remediating contaminated sites, other companies' clean-up experience and data released by government organizations. Our estimates are subject to revision in future periods based on actual costs or new information and are included in Other current liabilities and Other long-term liabilities in the Consolidated Statements of Financial Position at their undiscounted amounts. There is always a potential of incurring additional costs in connection with environmental liabilities due to variations in any or all of the categories described above, including modified or revised requirements from regulatory agencies, in addition to fines and penalties, as well as expenditures associated with litigation and settlement of claims. We evaluate recoveries from insurance coverage separately from the liability and, when recovery is probable, we record and report an asset separately from the associated liability in the Consolidated Statements of Financial Position.

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

3. CHANGES IN ACCOUNTING POLICIES

CHANGES IN ACCOUNTING POLICIES

There were no changes in accounting policies during the year ended December 31, 2024.

ADOPTION OF NEW ACCOUNTING STANDARDS

Segment Reporting

Effective January 1, 2024, with interim disclosure requirements effective after January 1, 2025, we adopted Accounting Standards Update (ASU) 2023-07 on a retrospective basis beginning on January 1, 2022. The new standard was issued in November 2023 to improve reportable segment disclosure requirements primarily through enhanced disclosures about significant segment expenses and to require in interim period financial statements all disclosures about a reportable segment's profit or loss and assets that are currently required annually. The ASU requires entities to disclose the title and position of the individual or the name of the group or committee identified as the CODM. The adoption of this ASU did not have a material impact on our consolidated financial statements.

FUTURE ACCOUNTING POLICY CHANGES

Income Tax Disclosures

ASU 2023-09 was issued in December 2023 to improve income tax disclosures by requiring specified categories in the annual rate reconciliation that meet quantitative thresholds and further disaggregation on income taxes paid by jurisdiction. ASU 2023-09 is effective January 1, 2025 and should be applied prospectively, with retrospective application being permitted. We are currently assessing the impact of the new standard on the presentation of *Note 24 - Income Taxes* to our consolidated financial statements.

Disaggregation of Income Statement Expenses

ASU 2024-03 was issued in November 2024 to improve financial reporting by requiring entities to disclose additional information about specific expense categories in the notes to financial statements at interim and annual reporting periods. The ASU requires entities to disclose 1) the amounts of (a) purchases of inventory, (b) employee compensation, (c) depreciation, (d) intangible asset amortization, (e) depreciation, depletion and amortization recognized as part of oil and gas producing activities, (f) expense reimbursements included in a relevant expense caption, and (g) selling expenses, and 2) a qualitative description of the amounts remaining in relevant expense captions that are not separately disaggregated quantitatively. ASU 2024-03 is effective January 1, 2027, with interim period disclosure requirements effective after January 1, 2028 and can be applied either prospectively or retrospectively. We are currently assessing the impact of the new standard on our annual disclosures for the year ending December 31, 2027 and on our interim disclosures beginning in 2028.

4. REVENUE

Change in Revenue Classification

To better align the classification of revenues resulting from our acquisitions of the US gas utilities (*Note 8*), we have made adjustments to Gas distribution sales and Transportation and other services revenues. Revenues generated from customers who procure their own gas but use our distribution system for delivery to the end use location have been reclassified to Gas distribution sales revenue from Transportation and other services revenue on the Consolidated Statements of Earnings and reclassified to Gas distribution sales from Transportation revenue in the Revenue from Contracts with Customers tables below. Our prior period comparable results have been recast to reflect the change in revenue classification. This change does not have an impact on our Total operating revenues.

REVENUE FROM CONTRACTS WITH CUSTOMERS

Major Products and Services

Year ended December 31, 2024	Liquids Pipelines	Gas Transmission	Gas Distribution and Storage	Renewable Power Generation	Eliminations and Other	Consolidated
<i>(millions of Canadian dollars)</i>						
Transportation revenue	11,958	5,279	284	—	—	17,521
Storage and other revenue	255	573	509	—	—	1,337
Gas distribution sales	—	—	6,734	—	—	6,734
Electricity and transmission revenue	—	—	—	189	—	189
Commodity sales	—	158	—	—	—	158
Total revenue from contracts with customers	12,213	6,010	7,527	189	—	25,939
Commodity sales	25,689	99	—	—	1,072	26,860
Other revenue ^{1,2}	281	70	4	319	—	674
Intersegment revenue	—	20	11	6	(37)	—
Total revenue	38,183	6,199	7,542	514	1,035	53,473

Year ended December 31, 2023	Liquids Pipelines	Gas Transmission	Gas Distribution and Storage	Renewable Power Generation	Eliminations and Other	Consolidated
<i>(millions of Canadian dollars)</i>						
Transportation revenue ³	11,875	5,302	212	—	—	17,389
Storage and other revenue	257	461	355	—	—	1,073
Gas distribution sales ³	—	—	5,461	—	—	5,461
Electricity and transmission revenue	—	—	—	259	—	259
Commodity sales	—	17	—	—	—	17
Total revenue from contracts with customers	12,132	5,780	6,028	259	—	24,199
Commodity sales	17,494	—	—	—	1,470	18,964
Other revenue ^{1,2}	257	72	(58)	215	—	486
Intersegment revenue	(1)	2	6	3	(10)	—
Total revenue	29,882	5,854	5,976	477	1,460	43,649

Year ended December 31, 2022	Liquids Pipelines	Gas Transmission	Gas Distribution and Storage	Renewable Power Generation	Eliminations and Other	Consolidated
<i>(millions of Canadian dollars)</i>						
Transportation revenue ³	11,283	5,012	198	—	—	16,493
Storage and other revenue	235	350	308	—	—	893
Gas gathering and processing revenue	—	22	—	—	—	22
Gas distribution sales ³	—	—	6,227	—	—	6,227
Electricity and transmission revenue	—	—	—	281	—	281
Total revenue from contracts with customers	11,518	5,384	6,733	281	—	23,916
Commodity sales	25,740	—	—	—	3,410	29,150
Other revenue ^{1,2}	(81)	39	(20)	305	—	243
Intersegment revenue	(3)	3	16	(4)	(12)	—
Total revenue	37,174	5,426	6,729	582	3,398	53,309

1 Includes realized and unrealized gains and losses from our hedging program which were a net gain of \$23 million and losses of \$97 million and \$431 million for the years ended December 31, 2024, 2023 and 2022, respectively.

2 Includes revenues from lease contracts. Refer to Note 26 - Leases.

3 These balances reflect a transfer from Transportation revenue to Gas distribution sales of \$602 million and \$584 million for the years ended December 31, 2023 and 2022, respectively.

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

Contract Balances

	Contract Receivables	Contract Assets	Contract Liabilities
<i>(millions of Canadian dollars)</i>			
Balance as at December 31, 2024	3,764	330	2,828
Balance as at December 31, 2023	2,802	400	2,591

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

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

Contract liabilities represent payments received for performance obligations which have not been fulfilled. Contract liabilities primarily relate to make-up rights and deferred revenue. Revenue recognized during the year ended December 31, 2024 included in contract liabilities at the beginning of the year is \$372 million. Increases in contract liabilities from cash received, net of amounts recognized as revenue during the year ended December 31, 2024, were \$532 million.

Performance Obligations

Segment	Nature of Performance Obligation
Liquids Pipelines	• Transportation and storage of crude oil and natural gas liquids (NGL)
Gas Transmission	• Transportation, storage, gathering, compression and treating of natural gas • Transportation of crude oil and NGL • Sale of renewable natural gas and its attached environmental attributes
Gas Distribution and Storage	• Supply and delivery of natural gas • Transportation of natural gas • Storage of natural gas
Renewable Power Generation	• Generation and transmission of electricity • Delivery of electricity from renewable energy generation facilities

There was no material revenue recognized during the year ended December 31, 2024 from performance obligations satisfied in previous periods.

Payment Terms

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

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

Revenue to be Recognized from Unfulfilled Performance Obligations

The following table presents our estimated revenue allocated to remaining performance obligations for contracted revenue that has not yet been recognized, that is expected to be recognized in the following periods:

	Total	1 year	2-5 years	Thereafter
<i>(billions of Canadian dollars)</i>				
Expected revenue	62.6	10.4	25.2	27.0

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

SIGNIFICANT JUDGMENTS MADE IN RECOGNIZING REVENUE

Long-Term Transportation Agreements

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

Variable Consideration

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

On March 4, 2024, the CER approved the negotiated Mainline tolling settlement. The new tolls are finalized and were in effect on an interim basis on July 1, 2023, and the overall agreement is retroactively effective as of July 1, 2021 through to the end of 2028.

Recognition and Measurement of Revenue

	Liquids Pipelines	Gas Transmission	Gas Distribution and Storage	Renewable Power Generation	Consolidated
Year ended December 31, 2024					
<i>(millions of Canadian dollars)</i>					
Revenue from products transferred at a point in time	—	158	137	—	295
Revenue from products and services transferred over time ¹	12,213	5,852	7,390	189	25,644
Total revenue from contracts with customers	12,213	6,010	7,527	189	25,939

	Liquids Pipelines	Gas Transmission	Gas Distribution and Storage	Renewable Power Generation	Consolidated
Year ended December 31, 2023					
<i>(millions of Canadian dollars)</i>					
Revenue from products transferred at a point in time	—	17	138	—	155
Revenue from products and services transferred over time ¹	12,132	5,763	5,890	259	24,044
Total revenue from contracts with customers	12,132	5,780	6,028	259	24,199

	Liquids Pipelines	Gas Transmission	Gas Distribution and Storage	Renewable Power Generation	Consolidated
Year ended December 31, 2022					
<i>(millions of Canadian dollars)</i>					
Revenue from products transferred at a point in time	—	—	127	—	127
Revenue from products and services transferred over time ¹	11,518	5,384	6,606	281	23,789
Total revenue from contracts with customers	11,518	5,384	6,733	281	23,916

¹ Revenue from crude oil and natural gas pipeline transportation, storage, natural gas gathering, compression and treating, natural gas distribution, natural gas storage services and electricity sales.

Performance Obligations Satisfied Over Time

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

Determination of Transaction Prices

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

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

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

5. SEGMENTED INFORMATION

Year ended December 31, 2024	Liquids Pipelines	Gas Transmission	Gas Distribution and Storage	Renewable Power Generation	Total Reportable Segments
<i>(millions of Canadian dollars)</i>					
Operating revenues ¹	38,183	6,199	7,542	514	52,438
Commodity and gas distribution costs	(25,283)	(130)	(2,501)	4	(27,910)
Operating and administrative	(4,495)	(2,322)	(2,276)	(304)	(9,397)
Impairment of long-lived assets	(2)	(162)	(3)	(23)	(190)
Income from equity investments	1,051	812	3	455	2,321
Gain on disposition of equity investments <i>(Note 13)</i>	—	1,063	—	28	1,091
Other income	77	196	104	59	436
Earnings before interest, income taxes and depreciation and amortization	9,531	5,656	2,869	733	18,789
Eliminations and Other					(1,904)
Depreciation and amortization					(5,167)
Interest expense <i>(Note 17)</i>					(4,419)
Earnings before income taxes					7,299

Year ended December 31, 2023	Liquids Pipelines	Gas Transmission	Gas Distribution and Storage	Renewable Power Generation	Total Reportable Segments
<i>(millions of Canadian dollars)</i>					
Operating revenues ¹	29,882	5,854	5,976	477	42,189
Commodity and gas distribution costs	(17,106)	(15)	(2,871)	(20)	(20,012)
Operating and administrative	(4,659)	(2,380)	(1,285)	(261)	(8,585)
Impairment of long-lived assets ²	145	—	(281)	(283)	(419)
Income from equity investments	1,007	688	2	140	1,837
Other income	114	117	51	96	378
Earnings before interest, income taxes and depreciation and amortization	9,383	4,264	1,592	149	15,388
Eliminations and Other					916
Depreciation and amortization					(4,613)
Interest expense <i>(Note 17)</i>					(3,812)
Earnings before income taxes					7,879

Year ended December 31, 2022	Liquids Pipelines	Gas Transmission	Gas Distribution and Storage	Renewable Power Generation	Total Reportable Segments
<i>(millions of Canadian dollars)</i>					
Operating revenues ¹	37,174	5,426	6,729	582	49,911
Commodity and gas distribution costs	(25,495)	—	(3,693)	(16)	(29,204)
Operating and administrative	(4,318)	(2,254)	(1,289)	(255)	(8,116)
Impairment of long-lived assets	(258)	—	—	(235)	(493)
Impairment of goodwill	—	(2,465)	—	—	(2,465)
Income from equity investments	785	1,133	1	141	2,060
Gain on joint venture merger transaction <i>(Note 13)</i>	—	1,076	—	—	1,076
Other income	53	210	79	45	387
Earnings before interest, income taxes and depreciation and amortization	7,941	3,126	1,827	262	13,156
Eliminations and Other					(1,118)
Depreciation and amortization					(4,317)
Interest expense <i>(Note 17)</i>					(3,179)
Earnings before income taxes					4,542

¹ Refer to Note 4 - Revenue for a reconciliation of segment Operating revenues to the Consolidated Statements of Earnings.

² The Liquids Pipelines segment includes the impact of a gain resulting from the derecognition of a net regulatory liability due to the discontinuance of regulatory accounting for our Southern Lights Pipeline (Note 7).

Capital Expenditures¹

Year ended December 31,	2024	2023	2022
<i>(millions of Canadian dollars)</i>			
Liquids Pipelines	1,157	1,158	1,418
Gas Transmission	2,571	1,944	1,690
Gas Distribution and Storage	2,386	1,451	1,499
Renewable Power Generation	661	100	50
Eliminations and Other	59	55	33
	6,834	4,708	4,690

¹ Includes the equity component of the AFUDC.

Property, Plant and Equipment

Year ended December 31,	2024	2023	2022
<i>(millions of Canadian dollars)</i>			
Liquids Pipelines	53,863	51,855	53,573
Gas Transmission	34,683	31,016	29,666
Gas Distribution and Storage	38,636	18,766	17,857
Renewable Power Generation	3,612	2,706	3,082
Eliminations and Other	310	298	282
	131,104	104,641	104,460

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

GEOGRAPHIC INFORMATION**Revenues¹**

Year ended December 31,	2024	2023	2022
<i>(millions of Canadian dollars)</i>			
Canada	22,001	23,781	27,498
US	31,472	19,868	25,811
	53,473	43,649	53,309

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

Property, Plant and Equipment¹

December 31,	2024	2023
<i>(millions of Canadian dollars)</i>		
Canada	48,873	48,570
US	82,231	56,071
	131,104	104,641

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

6. EARNINGS PER COMMON SHARE

BASIC

Earnings per common share is calculated by dividing earnings attributable to common shareholders by the weighted average number of common shares outstanding.

DILUTED

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

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

December 31, (number of shares in millions)	2024	2023	2022
Weighted average shares outstanding	2,155	2,056	2,025
Effect of dilutive options and RSUs	3	2	4
Diluted weighted average shares outstanding	2,158	2,058	2,029

For the years ended December 31, 2024, 2023 and 2022, 14.6 million, 19.3 million and 10.4 million, respectively, of anti-dilutive stock options with a weighted average exercise price of \$54.37, \$54.42 and \$56.49, respectively, were excluded from the diluted earnings per common share calculation.

7. REGULATORY MATTERS

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

Under the current authorized rate structure for certain operations, income tax costs are recovered in rates based on the current income tax payable and do not include accruals for deferred income tax. However, as income taxes become payable as a result of the reversal of temporary differences that created the deferred income taxes, it is expected that rates will be adjusted to recover these taxes. Since most of these temporary differences are related to property, plant and equipment costs, this recovery is expected to occur over the life of the related assets. In the absence of rate-regulated accounting, this regulatory tax asset and the related earnings impact would not be recorded.

LIQUIDS PIPELINES

Canadian Mainline

Canadian Mainline includes the Canadian portion of our Mainline system. The Mainline Tolling Settlement (MTS), governs the tolls paid for products shipped on its Mainline System, with the exception of Lines 8 and 9 which are tolled on a separate basis and was approved by the CER on March 4, 2024. The MTS has a seven-and-a-half year term through the end of 2028 and continues with the previous CTS framework with a Canadian Local Toll for all volumes shipped on the Canadian Mainline and an International Joint Tariff for all volumes shipped from western Canadian receipt points to delivery points on our Lakehead System. We have recognized a regulatory asset of \$2.0 billion as at December 31, 2024 (2023 - \$1.9 billion) to offset deferred income taxes, as a CER rate order governing flow-through income tax treatment permits future recovery. No other material regulatory assets or liabilities are recognized under the terms of the MTS.

Southern Lights Pipeline

In February 2024, we entered into fixed-toll agreements for a five-year term. As at December 31, 2023, since we did not expect to renew the agreements under a cost-of-service toll methodology, Southern Lights Pipeline was no longer subject to rate-regulated accounting. As a result, \$151 million of net regulatory liabilities, \$92 million of regulatory tax assets and \$23 million of regulatory deferred tax liabilities were derecognized in 2023.

GAS TRANSMISSION

British Columbia Pipeline and Maritimes & Northeast Canada

British Columbia (BC) Pipeline and Maritimes & Northeast Canada (M&N Canada) are regulated by the CER. Rates are approved by the CER through negotiated toll settlement agreements based on cost-of-service. Both our BC Pipeline and M&N Canada systems currently operate under the terms of their respective 2022-2026 and 2024-2025 settlement agreements, which stipulate an allowable return on equity (ROE) and the continuation and establishment of certain deferral and variance accounts. 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, which was approved on February 14, 2024, as filed.

US Gas Transmission

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

GAS DISTRIBUTION AND STORAGE

Enbridge Gas Ontario

Enbridge Gas Ontario's distribution rates, commencing in 2024, were set by the OEB under a five-year Incentive Regulation (IR) framework. The framework included the establishment of 2024 base rates on a cost-of-service basis, while rates for 2025 through 2028 will be established using a price cap mechanism. The price cap mechanism will establish new rates each year through an annual base rate adjustment to expense an incremental \$50 million of capitalized overheads as operating and maintenance costs; annual base rate escalation at inflation less a 0.28% productivity factor; annual updates for certain costs to be passed through to customers; and, where applicable, it will provide for the recovery of material unexpected events and discrete incremental capital investments beyond those that can be funded through base rates. The price cap mechanism includes the continuation and establishment of certain deferral and variance accounts, as well as an earnings sharing mechanism that requires Enbridge Gas Ontario to share equally with customers any earnings in excess of 100 basis points over the allowed ROE, and share 90% of earnings in excess of 300 basis points over the allowed ROE.

Enbridge Gas Ohio

Enbridge Gas Ohio is subject to the jurisdiction of the Ohio Commission with its natural gas sales and transportation and storage services being provided under rate schedules approved by the regulatory commission. Enbridge Gas Ohio uses a straight-fixed-variable rate design, where majority of operating costs are recovered through a monthly charge, as established in a 2008 rate case settlement.

In October 2023, Enbridge Gas Ohio filed for a non-fuel base rate increase of \$212 million projected to be effective January 2025. This base rate increase aims to recover investments in distribution infrastructure for the benefit of Ohio customers. The proposed rates would provide an ROE of 10.40% compared to the currently authorized 10.38%. Additionally, Enbridge Gas Ohio also requested approval for an alternative rate plan for the continuation and modification of the Pipeline Infrastructure Replacement (PIR) and the Capital Expenditure Program (CEP). On December 18, 2024, Enbridge Gas Ohio filed a Notice of Intent to Modify Filed Positions. The Notice of Intent indicated a willingness to accept a reduced annual revenue requirement increase (from \$212 million to \$60 million) and, if the reduced position were adopted, to forgo filing a new base rate case until October 31, 2027. The hearing began on January 13, 2025, and remains underway.

The PIR program aims to replace 25% of the pipeline system. In April 2022, the Ohio Commission extended the PIR program through 2026.

The CEP allows Enbridge Gas Ohio to defer depreciation expense, property tax expense and carrying costs at the debt rate of 6.5% on capital investments not covered by its PIR program. In September 2024, the Ohio Commission approved adjustments to CEP cost recovery rates for 2023 costs.

Enbridge Gas Utah, Enbridge Gas Wyoming and Enbridge Gas Idaho

Enbridge Gas Utah, Enbridge Gas Wyoming and Enbridge Gas Idaho are regulated by the Utah Commission, the Wyoming Commission, and the Idaho Commission. For rate oversight of Enbridge Gas Idaho's operations in a small area of southeastern Idaho, the Idaho Commission has contracted with Utah Commission. Both Utah and Wyoming Commissions allow for the recovery of gas costs through a balancing-account mechanism.

Enbridge Gas Utah, Enbridge Gas Wyoming and Enbridge Gas Idaho use several mechanisms to manage costs and promote efficiency. They recover gas costs through a balance-account mechanism that adjusts rates periodically to reflect changes in natural gas prices. The Infrastructure Replacement Program allows Enbridge Gas Utah, Enbridge Gas Wyoming, and Enbridge Gas Idaho to earn a return on capital expenditures for infrastructure replacement. The CET decouples non-gas revenues from customer usage, enabling the collection of allowed revenue per customer and encourages energy conservation. The Energy Efficiency Program promotes natural gas conservation through advertising, rebates, and home energy plans. These costs are recovered through periodic rate adjustments. The Utah Commission approved the construction of natural gas infrastructure to extend services to rural Utah, including 30 miles of intermediate high-pressure pipeline and up to 500 service lines. Recent approvals also include adjustments in the rural expansion rate tracker.

Enbridge Gas North Carolina

Enbridge Gas North Carolina is subject to regulation of rates and other aspects of its business by the North Carolina Commission. Base rates for Enbridge Gas North Carolina are designed primarily based on rate design methodology in which the majority of operating costs are recovered through volumetric charges. The North Carolina Commission authorized Enbridge Gas North Carolina to use a tracker mechanism to recover costs related to pipeline integrity and safety requirements that are not included in current base rates.

Enbridge Gas North Carolina uses several mechanisms to adjust rates and recover costs. CUT allows for rate adjustments based on changes in customer usage patterns. Rider D enables the recovery of gas purchases from customers, with rates periodically adjusted to reflect market price changes. Rider F facilitates the recovery of costs associated with energy efficiency measures and programs.

FINANCIAL STATEMENT EFFECTS

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

December 31, (millions of Canadian dollars)	2024	2023	Recovery/Refund Period Ends
Current regulatory assets			
Purchase gas variance	74	15	2025
Under-recovery of fuel costs	4	75	2025
Deferred projects costs ¹	90	—	2025
Other current regulatory assets	304	380	2025
Total current regulatory assets² (Note 9)	472	470	
Long-term regulatory assets			
Deferred income taxes ³	4,698	4,456	Various
Deferred projects costs ¹	1,045	—	Various
Long-term debt ⁴	318	348	2032-2046
Negative salvage ⁵	136	180	Various
Demand-side management costs	237	54	Various
Pension plan receivable ⁶	266	1	Various
Other long-term regulatory assets	447	198	Various
Total long-term regulatory assets²	7,147	5,237	
Total regulatory assets	7,619	5,707	
Current regulatory liabilities			
Purchase gas variance	292	31	2025
Regulatory liability related to US income taxes ⁷	44	—	2025
Other current regulatory liabilities	280	276	2025
Total current regulatory liabilities⁸ (Note 16)	616	307	
Long-term regulatory liabilities			
Future removal and site restoration reserves ⁹	2,964	1,693	Various
Regulatory liability related to US income taxes ⁷	2,021	854	Various
Pipeline future abandonment costs (Note 23)	826	745	Various
Pension plan payable ⁶	59	143	Various
Other long-term regulatory liabilities	242	86	Various
Total long-term regulatory liabilities⁸	6,112	3,521	
Total regulatory liabilities	6,728	3,828	

1 Represents the amounts anticipated to be collected from customers in East Ohio's service areas for rider projects, including CEP, PIR and costs related to the Pipeline Safety Management Program. The recovery periods for these expenditures vary according to the stipulations outlined in the respective riders. For Enbridge Gas North Carolina, these amounts relate to pipeline integrity management which represent operating costs incurred to comply with federal regulatory requirements related to natural gas pipelines and have been deferred pending future approval of rate recovery.

2 Current regulatory assets are included in Other current assets, while long-term regulatory assets are included in Deferred amounts and other assets.

3 Represents the regulatory offset to deferred income tax liabilities to the extent that it is expected to be included in future regulator-approved rates and recovered from customers. The recovery period depends on the timing of the reversal of temporary differences. In the absence of rate-regulated accounting, this regulatory balance and the related earnings impact would not be recorded. The balance as at December 31, 2024 is net of regulatory deferred tax write-offs.

4 Represents our regulatory offset to the fair value adjustment to debt acquired in our merger with Spectra Energy Corp. (Spectra Energy). The offset is viewed as a proxy for the regulatory asset that would be recorded in the event such debt was extinguished at an amount higher than the carrying value.

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

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

- 7 The regulatory liability related to US income taxes resulted from the US tax reform legislation dated December 22, 2017. These balances will be refunded to customers in accordance with the respective rate settlements approved by the FERC for our US Gas Transmission pipelines and by the respective state utility commission for each US Gas Distribution franchise.
- 8 Current regulatory liabilities are included in Other current liabilities, while long-term regulatory liabilities are included in Other long-term liabilities.
- 9 Future removal and site restoration reserves consists of amounts collected from customers, with the approval of the respective regulatory authorities, to fund future costs of removal and site restoration relating to property, plant and equipment. These costs are collected as part of the depreciation expense charged on property, plant and equipment that is reflected in rates. The settlement of this balance will occur over the long-term as costs are incurred. In the absence of rate-regulated accounting, depreciation rates would not include a charge for removal and site restoration and costs would be charged to earnings as incurred with recognition of revenue for amounts previously collected.

8. ACQUISITIONS AND DISPOSITION

BUSINESS COMBINATIONS

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

The fair values of regulatory assets and liabilities, which are subject to rate-setting and cost recovery mechanisms under ASC 980 *Regulated Operations*, are equal to their carrying values at acquisition. 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 at acquisition.

Public Service Company of North Carolina, Incorporated

On September 30, 2024, through a wholly-owned US subsidiary, we acquired all of the membership interests of Fall North Carolina Holdco LLC, which owns 100% of PSNC, for cash consideration of \$2.7 billion (US\$2.0 billion) (the PSNC Acquisition). PSNC is a public utility primarily engaged in the purchase, sale, transportation and distribution of natural gas to residential, commercial and industrial customers in North Carolina. PSNC operates under rates approved by the North Carolina Commission. Subsequent to its acquisition, PSNC conducts business as Enbridge Gas North Carolina.

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

	September 30, 2024 ¹
<i>(millions of Canadian dollars)</i>	
Fair value of net assets acquired:	
Current assets (a)	303
Property, plant and equipment (b)	4,147
Long-term assets (c)	189
Current liabilities	277
Long-term debt (d)	1,529
Other long-term liabilities (e)	653
Deferred income tax liabilities	365
Goodwill (f)	895
Purchase price:	
Cash	2,710

1 In the fourth quarter of 2024, immaterial adjustments were made to the PSNC Acquisition purchase price allocation.

- a) Current assets consist primarily of cash, trade and other accounts receivable, regulatory assets and inventory. The fair value of trade receivables from customers approximates their carrying value of \$70 million due to the short period to maturity. A provision of \$2 million for expected credit loss associated with accounts receivable has been recorded.

- b) PSNC's property, plant and equipment constitutes an integrated system of rate-regulated natural gas transmission, distribution and storage assets. For these rate-regulated assets, fair value was determined using a market participant perspective. Given the regulated nature of, and fixed return on the assets, the fair value of property, plant and equipment acquired is equal to its carrying value.
- c) Long-term assets consist primarily of \$114 million of regulatory assets expected to be recovered from customers in future periods through rates and equity interests in a liquefied natural gas (LNG) storage facility in North Carolina and in an intrastate natural gas pipeline.
- d) The fair value of long-term debt was determined based on the current underlying US Treasury interest rates on instruments of similar credit risk and tenor, as well as an implied credit spread based on current market conditions. We recorded a fair value adjustment to reduce long-term debt by \$156 million with no corresponding regulatory offset.
- e) Other long-term liabilities consist primarily of regulatory liabilities expected to be refunded to customers in future periods through rates.
- f) Goodwill is primarily attributable to the existing assembled assets and workforce of PSNC that cannot be duplicated at the same cost by a new entrant and the enhanced scale and geographic diversity of our regulated natural gas distribution business, which provides a platform for future growth and optimization with existing assets. The goodwill balance recognized has been assigned to our Gas Distribution and Storage segment and is not tax deductible.

Upon completion of the PSNC Acquisition, we began consolidating PSNC. For the period beginning September 30, 2024 through to December 31, 2024, PSNC generated \$284 million of operating revenues and \$50 million of earnings attributable to common shareholders.

Our supplemental pro forma consolidated financial information for the years ended December 31, 2024 and 2023, including the results of operations for PSNC as if the PSNC Acquisition had been completed on January 1, 2023, is as follows:

Year ended December 31, (unaudited; millions of Canadian dollars)	2024	2023
Operating revenues	54,116	44,614
Earnings attributable to common shareholders ¹	5,149	5,944

¹ Includes adjustment for pro forma interest expense on debt financing for the PSNC Acquisition of \$48 million (after-tax of \$37 million) for the year ended December 31, 2023.

Questar Gas Company

On May 31, 2024, through a wholly-owned US subsidiary, we acquired all of the membership interests of Fall West Holdco LLC which owns 100% of Questar and Wexpro for cash consideration of \$4.1 billion (US\$3.0 billion) (the Questar Acquisition). Questar is a public natural gas utility providing distribution, storage and transmission services to residential, commercial and industrial customers in Utah, southwestern Wyoming and southeastern Idaho. The Utah Commission, the Wyoming Commission and the Idaho Commission have granted Questar the necessary regulatory approvals to serve these areas. Wexpro develops and produces cost-of-service gas reserves for Questar and operates under agreements with the states of Utah and Wyoming. Subsequent to its acquisition, Questar conducts business as Enbridge Gas Utah, Enbridge Gas Wyoming and Enbridge Gas Idaho in those respective states.

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

	May 31, 2024 ¹
<i>(millions of Canadian dollars)</i>	
Fair value of net assets acquired:	
Current assets (a)	380
Property, plant and equipment (b)	6,013
Long-term assets (c)	163
Current liabilities	416
Long-term debt (d)	1,343
Other long-term liabilities (e)	919
Deferred income tax liabilities	527
Goodwill (f)	793
Purchase price:	
Cash	4,144

¹ In the fourth quarter of 2024, immaterial adjustments were made to the Questar Acquisition purchase price allocation.

- a) Current assets consist primarily of cash, trade and other accounts receivable and inventory. The fair value of trade receivables from customers approximates their carrying value of \$202 million due to the short period to maturity. A provision of \$9 million for expected credit loss associated with accounts receivable has been recorded.
- b) Questar's property, plant and equipment constitutes an integrated system of rate-regulated natural gas transmission, distribution and storage assets. Wexpro's property, plant and equipment consists of cost-of-service gas and oil properties developed and produced for Questar. For these rate-regulated assets, fair value was determined using a market participant perspective. Given the regulated nature of, and fixed return on the assets, the fair value of property, plant and equipment acquired is equal to its carrying value.
- c) Long-term assets consist primarily of funds collected from Questar by Wexpro and held in trust to fund future AROs, as well as regulatory assets expected to be recovered from customers in future periods through rates.
- d) The fair value of long-term debt was determined based on the current underlying US Treasury interest rates on instruments of similar credit risk and tenor, as well as an implied credit spread based on current market conditions. We recorded a fair value adjustment to reduce long-term debt by \$301 million with no corresponding regulatory offset.
- e) Other long-term liabilities consist primarily of regulatory liabilities, expected to be refunded to customers in future periods through rates, as well as ARO. The fair value of the ARO liability was determined using a discounted cash flow approach.

- f) Goodwill is primarily attributable to the existing assembled assets and workforce of Questar and Wexpro that cannot be duplicated at the same cost by a new entrant and the enhanced scale and geographic diversity of our regulated natural gas distribution business, which provides a platform for future growth and optimization with existing assets. The goodwill balance recognized has been assigned to our Gas Distribution and Storage segment and is not tax deductible.

Upon completion of the Questar Acquisition, we began consolidating Questar and Wexpro. For the period beginning May 31, 2024 through to December 31, 2024, Questar and Wexpro generated \$755 million of operating revenues and \$75 million of earnings attributable to common shareholders.

Our supplemental pro forma consolidated financial information for the years ended December 31, 2024 and 2023, including the results of operations for Questar and Wexpro as if the Questar Acquisition had been completed on January 1, 2023, is as follows:

Year ended December 31, (unaudited; millions of Canadian dollars)	2024	2023
Operating revenues	54,698	45,918
Earnings attributable to common shareholders ¹	5,193	6,005

¹ Includes adjustment for pro forma interest expense on debt financing for the Questar Acquisition of \$70 million (after-tax of \$53 million) for the year ended December 31, 2023.

The East Ohio Gas Company

On March 6, 2024, through a wholly-owned US subsidiary, we acquired all of the outstanding shares of capital stock of EOG for cash consideration of \$5.8 billion (US\$4.3 billion) (the EOG Acquisition). EOG is a public natural gas utility providing distribution, storage and transmission services to residential, commercial and industrial customers in Ohio and is regulated by the Ohio Commission. Subsequent to its acquisition, EOG conducts business as Enbridge Gas Ohio.

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

	March 6, 2024 ¹
(millions of Canadian dollars)	
Fair value of net assets acquired:	
Current assets (a)	493
Property, plant and equipment (b)	7,276
Long-term assets (c)	1,689
Current liabilities	551
Long-term debt (d)	2,612
Other long-term liabilities (e)	1,001
Deferred income tax liabilities	1,045
Goodwill (f)	1,603
Purchase price:	
Cash	5,852

¹ In the fourth quarter of 2024, immaterial adjustments were made to the EOG Acquisition purchase price allocation.

- a) Current assets consist primarily of trade and other accounts receivable, prepaid expenses, regulatory assets and inventory. The fair value of trade receivables from customers approximates their carrying value of \$379 million due to the short period to maturity. A provision of \$3 million for expected credit loss associated with accounts receivable has been recorded.

- b) EOG's property, plant and equipment constitutes an integrated system of rate-regulated natural gas transmission, gathering, distribution and storage assets. For these rate-regulated assets, fair value was determined using a market participant perspective. Given the regulated nature of, and fixed return on the assets, the fair value of property, plant and equipment acquired is equal to its carrying value.
- c) Long-term assets consist primarily of overfunded pension plan assets of \$367 million and \$1.2 billion of regulatory assets expected to be recovered from customers in future periods through rates.

Pension plan assets attributable to the workforce acquired from EOG were transferred in cash to an Enbridge-sponsored pension plan based on their fair value as at March 6, 2024. The fair value of plan assets was determined using unadjusted quoted market prices for identical investments.

- d) The fair value of long-term debt was determined based on the current underlying US Treasury interest rates on instruments of similar credit risk and tenor, as well as an implied credit spread based on current market conditions. We recorded a fair value adjustment to reduce long-term debt by \$478 million with no corresponding regulatory offset.
- e) Other long-term liabilities consist primarily of regulatory liabilities expected to be refunded to customers in future periods through rates.
- f) Goodwill is primarily attributable to the existing assembled assets and workforce of EOG that cannot be duplicated at the same cost by a new entrant and the enhanced scale and geographic diversity of our regulated natural gas distribution business, which provides a platform for future growth and optimization with existing assets. The goodwill balance recognized has been assigned to our Gas Distribution and Storage segment and is not tax deductible.

Upon completion of the EOG Acquisition, we began consolidating EOG. For the period beginning March 6, 2024 through to December 31, 2024, EOG generated \$1.2 billion of operating revenues and \$190 million of earnings attributable to common shareholders.

Our supplemental pro forma consolidated financial information for the years ended December 31, 2024 and 2023, including the results of operations for EOG as if the EOG Acquisition had been completed on January 1, 2023, is as follows:

Year ended December 31, (unaudited; millions of Canadian dollars)	2024	2023
Operating revenues	53,788	45,058
Earnings attributable to common shareholders ¹	5,130	5,961

¹ Includes adjustment for pro forma interest expense on debt financing for the EOG Acquisition of \$100 million (after-tax of \$77 million) for the year ended December 31, 2023.

The purchase price allocations for the PSNC Acquisition, Questar Acquisition and EOG Acquisition (together, the Acquisitions) were prepared on a preliminary basis and are subject to change as additional information becomes available concerning the fair values of the ARO and regulatory balances and their tax bases. Any adjustments to the purchase price allocations will be made as soon as practicable, but no later than one year from the date of each acquisition.

The Acquisitions further diversify, and are complementary to, our existing gas distribution operations.

Acquisition of RNG Facilities

On January 2, 2024, through a wholly-owned US subsidiary, we acquired six Morrow Renewables operating landfill gas-to-RNG production facilities (Tomorrow RNG) located in Texas and Arkansas for total consideration of \$1.3 billion (US\$1.0 billion), of which \$584 million (US\$439 million) was paid at close and an additional deferred consideration is payable within two years with a fair value of \$757 million (US\$568 million) (the RNG Facilities Acquisition). The acquired assets align with and advance our lower-carbon strategy.

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

	January 2, 2024
<i>(millions of Canadian dollars)</i>	
Fair value of net assets acquired:	
Current assets	31
Intangible assets (a)	925
Property, plant and equipment (b)	174
Current liabilities	5
Goodwill (c)	223
Purchase price:	
Cash	584
Deferred consideration (d):	
Current portion of long-term debt	550
Long-term debt	207
Other adjustments	7
	1,348

- a) Intangible assets consist of long-term gas supply agreements with the respective facility's landfill owner. Fair value was determined using an income-based approach, specifically the multi-period excess earnings method, by estimating the present value of the after-tax cash flows attributable to the gas rights. The intangible assets will be amortized on a straight-line basis over the term of the respective agreement, inclusive of extension options, which range from 13 to 42 years (approximately nine years to the next extension period on a weighted-average basis).
- b) Tomorrow RNG's property, plant and equipment constitutes specialized landfill gas plant and equipment which collects gas produced by waste decomposition, treats and compresses the gas to pipeline specifications. The direct method of replacement cost was used to determine the majority of the fair value of property, plant and equipment. Adjustments were then applied for estimated physical deterioration.
- c) Goodwill is primarily attributable to expected future returns from a portfolio of both operating and scalable RNG assets, furthering the diversity of our renewable projects portfolio and accelerating progress toward our energy transition goals. The goodwill balance recognized has been assigned to our Gas Transmission segment and is tax deductible over 15 years.

- d) We entered into six non-interest bearing promissory notes due to Morrow Renewables, the total value of which represents deferred payments of \$808 million (US\$606 million) due within two years. The first and second payments are due on January 2, 2025 and December 31, 2025, respectively. The \$757 million (US\$568 million) recognized in the purchase price represents the fair value of deferred consideration at the date of acquisition using the imputed interest rate method over the terms of the notes.

Upon completion of the RNG Facilities Acquisition, we began consolidating Tomorrow RNG. For the period beginning January 2, 2024 through to December 31, 2024, operating revenues and earnings attributable to common shareholders generated by Tomorrow RNG were immaterial. The impact to our supplemental pro forma consolidated operating revenues and earnings attributable to common shareholders for the years ended December 31, 2024 and 2023, as if the RNG Facilities Acquisition had been completed on January 1, 2023, was also immaterial.

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 (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 LNG exports.

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

	November 1, 2023
<i>(millions of Canadian dollars)</i>	
Fair value of net assets acquired:	
Current assets (a)	105
Property, plant and equipment (b)	466
Current liabilities	20
Long-term liabilities (c)	130
Goodwill (d)	46
Purchase price:	
Cash	397
Additional consideration (e)	70
	467

- a) Current assets consist primarily of inventory which is short-term in nature and represents natural gas held in storage. Fair value was determined using the market price of natural gas at the date of acquisition.
- b) Aitken Creek's property, plant and equipment constitutes an integrated system of cavern storage facilities, associated header pipeline, and land and right-of-ways. The depreciated replacement cost approach was adopted as the primary valuation methodology to determine the fair value of property, plant and equipment, excluding the reservoir storage asset. In determining replacement cost, both indirect costing using relevant inflation indices and direct costing using relevant market quotes were utilized. Adjustments were then applied for physical deterioration as well as functional and economic obsolescence.

Fair value of the reservoir storage asset was determined using a residual approach whereby the adjusted purchase price was allocated to the fair value of the net tangible assets, excluding the reservoir storage asset, with the remaining value allocated to the reservoir storage asset. The income approach was also utilized to corroborate that the cash flows attributable to the reservoir storage asset support the residual value.

- c) Long-term liabilities consist primarily of a deferred income tax liability arising from temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes at the date of acquisition.
- d) Goodwill is primarily attributable to the recognition of a deferred income tax liability. The goodwill balance recognized has been assigned to our Gas Transmission segment and is not tax deductible.
- e) The \$70 million of additional consideration recognized in the purchase price represents the fair value of derivative contracts and working gas as at March 31, 2023.

Upon completion of the Aitken Creek Acquisition, we began consolidating Aitken Creek. For the period beginning November 1, 2023 through to December 31, 2023, operating revenues and earnings attributable to common shareholders generated by Aitken Creek were immaterial. The impact to our supplemental pro forma consolidated operating revenues and earnings attributable to common shareholders for the years ended December 31, 2023 and 2022, as if the Aitken Creek Acquisition had been completed on January 1, 2022, was also immaterial.

Tri Global Energy, LLC

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

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

September 27,
2022

(millions of Canadian dollars)

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

- a) Intangible assets consist of compensation expected to be earned by TGE on existing development contracts once certain project development milestones are met. Fair value was determined using a discounted cash flow method which is an income-based approach to valuation that estimates the present value of future projected benefits from the contracts. The intangible assets will be amortized on a straight-line basis over an expected useful life of three and a half years.
- b) Long-term liabilities consist primarily of obligations payable to third parties which are contingent on milestones being met for certain projects. Fair value represents the present value of the future cash flow payments at the date of the TGE Acquisition.
- c) Goodwill is primarily attributable to expected future returns from new opportunities to develop wind and solar projects, as well as enhanced scale and operational diversity of our renewable projects portfolio. The goodwill balance recognized has been assigned to our Renewable Power Generation segment and is tax deductible over 15 years.
- d) We agreed to pay additional contingent consideration of up to \$72 million (US\$53 million) to TGE's former common unit holders if performance milestones were met on certain projects. The \$49 million (US\$36 million) of contingent consideration recognized in the purchase price represents the fair value of contingent consideration at the date of acquisition. The fair value was determined using an income-based approach.

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

ASSET ACQUISITION

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.

We allocated assets with a fair value of \$790 million (US\$588 million) to Property, plant and equipment, net, of which \$254 million (US\$189 million) relates to storage cavern right-of-use assets, and recorded the related lease liabilities of \$7 million (US\$5 million) and \$248 million (US\$184 million) to Current portion of long-term debt and Long-term debt, respectively, in the Consolidated Statements of Financial Position. The acquired assets are included in our Gas Transmission segment.

DISPOSITION

Athabasca Regional Oil Sands System

On October 5, 2022, we closed the sale of an 11.6% non-operating interest in seven pipelines in the Athabasca region of northern Alberta from our Regional Oil Sands System to Athabasca Indigenous Investments Limited Partnership (Aii), an entity representing 23 First Nation and Métis communities, for total consideration of approximately \$1.1 billion. No gain or loss was recognized on the sale and a noncontrolling interest was recorded in our Consolidated Statements of Financial Position beginning in 2022 to reflect the interest held by Aii (Note 19).

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

9. OTHER CURRENT ASSETS

December 31,	2024	2023
(millions of Canadian dollars)		
Derivative assets (Note 23)	557	623
Regulatory assets (Note 7)	472	470
Gas imbalances	517	209
Income taxes receivable	375	347
Other	849	791
	2,770	2,440

10. INVENTORY

December 31,	2024	2023
(millions of Canadian dollars)		
Natural gas	811	938
Crude oil	479	413
Other	198	128
	1,488	1,479

11. PROPERTY, PLANT AND EQUIPMENT

December 31, (millions of Canadian dollars)	Weighted Average Depreciation Rate	2024	2023
Pipelines	2.9%	73,633	66,698
Facilities and equipment	3.2%	43,439	37,634
Land and right-of-way ¹	2.8%	4,181	3,600
Gas mains, services and other	3.0%	26,925	15,346
Storage	2.6%	6,455	4,929
Wind turbines, solar panels and other	3.9%	4,798	4,511
Other	8.6%	3,987	1,652
Under construction	—%	5,648	2,829
Total property, plant and equipment ²		169,066	137,199
Total accumulated depreciation ²		(37,962)	(32,558)
Property, plant and equipment, net		131,104	104,641

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

² As at December 31, 2024, the cost and accumulated depreciation of leased assets accounted for as lessor operating leases was \$5.3 billion and \$2.3 billion, respectively (December 31, 2023 - \$5.1 billion and \$2.1 billion, respectively).

Depreciation expense for the years ended December 31, 2024, 2023 and 2022 was \$4.6 billion, \$4.0 billion and \$3.8 billion, respectively.

IMPAIRMENT

Chapman Ranch Wind Farm

Chapman Ranch Wind Farm (Chapman Ranch) is experiencing financial challenges associated with the original equipment integrity. As a result, we have recognized an impairment loss of \$251 million for the year ended December 31, 2023, which is included in Impairment of long-lived assets in the Consolidated Statements of Earnings and is part of our Renewable Power Generation segment.

Magic Valley Wind Farm

In 2022, Magic Valley Wind Farm (Magic Valley) had commercial challenges caused by electricity transmission congestion and a negative price differential arising from higher transmission costs resulting in a lower electricity sale price. As a result, we recognized an impairment loss of \$227 million for the year ended December 31, 2022, which is included in Impairment of long-lived assets in the Consolidated Statements of Earnings and is part of our Renewable Power Generation segment.

Bakken Pipeline System

For the year ended December 31, 2022, we recognized an impairment loss of \$183 million on the US and Canadian components of the interstate pipeline transportation system within the North Dakota System of our Bakken Pipeline System in connection with the expiration of certain long-term take-or-pay contracts in 2023. This loss is included in Impairment of long-lived assets in the Consolidated Statements of Earnings and is part of our Liquids Pipelines segment.

Impairment charges were based on the amount by which the carrying value of the assets exceeded fair value, determined using expected discounted future cash flows.

12. VARIABLE INTEREST ENTITIES

CONSOLIDATED VARIABLE INTEREST ENTITIES

Our consolidated VIEs consist of legal entities where we are the primary beneficiary. We are the primary beneficiary when our variable interest provides us with the power to direct the activities of the VIE that most significantly impact the entity's economic performance and the obligation to absorb losses, or the right to receive benefits from, the VIE that could potentially be significant to the VIE. We determine whether we are the primary beneficiary of a VIE by considering qualitative and quantitative factors, including, but not limited to: decision-making responsibilities, the VIE capital structure, risk and rewards sharing, contractual agreements with the VIE, voting rights and level of involvement of other parties.

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

December 31, (millions of Canadian dollars)	2024	2023
Assets		
Current assets		
Cash and cash equivalents	448	442
Restricted cash	11	9
Trade receivables and unbilled revenues	138	144
Other current assets	5	8
Accounts receivable from affiliates	13	5
Inventory	13	11
	628	619
Property, plant and equipment, net	6,934	7,105
Long-term investments	20	14
Restricted long-term investments and cash	141	106
Deferred amounts and other assets	145	148
Intangible assets, net	77	84
	7,945	8,076
Liabilities		
Current liabilities		
Trade payables and accrued liabilities	108	83
Other current liabilities	124	145
Accounts payable to affiliates	22	4
	254	232
Long-term debt	—	1
Other long-term liabilities	1,133	971
Deferred income taxes	6	5
	1,393	1,209
	6,552	6,867

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

UNCONSOLIDATED VARIABLE INTEREST ENTITIES

We also hold interests in unconsolidated VIEs where we are not the primary beneficiary as we do not have the power to direct the activities of the VIEs that most significantly impact the entity's economic performance. These interests include investments in limited partnerships that are assessed to be VIEs due to the limited partners not having substantive participating rights or kick-out rights. The power to direct the activities of a majority of these unconsolidated limited partnership VIEs is shared amongst the partners. Each partner has representatives that make up an executive committee that makes significant decisions for the VIE and none of the partners may make significant decisions unilaterally.

The carrying amount of these VIEs and our estimated maximum exposure to loss as at December 31, 2024 and 2023 are as follows:

	Carrying Amount of the VIE	Maximum Exposure to Loss
December 31, 2024		
<i>(millions of Canadian dollars)</i>		
Rampion Offshore Wind Limited ¹	387	490
Vector Pipeline ²	193	314
Woodfibre LNG Limited Partnership ³	1,275	3,153
Whistler Parent JV ⁴	1,102	1,425
Other ³	168	501
	3,125	5,883
December 31, 2023		
<i>(millions of Canadian dollars)</i>		
Aux Sable Liquid Products L.P. ⁵	105	130
Rampion Offshore Wind Limited ¹	391	452
Vector Pipeline ²	191	320
Woodfibre LNG Limited Partnership ³	778	2,854
Fox Squirrel Solar LLC ⁶	312	661
Other ³	132	230
	1,909	4,647

1 As at December 31, 2024 and 2023, our maximum exposure to loss includes parental guarantees that have been committed in project contracts in which we would be liable for in the event of default by the VIE and the carrying value of an affiliate dividend receivable of \$73 million and nil, respectively.

2 Includes Vector Pipeline Limited Partnership in Canada and Vector Pipeline L.P. in the US. As at December 31, 2024 and 2023, our maximum exposure to loss includes the carrying value of outstanding affiliate loans receivable of \$16 million and \$24 million, respectively, and our share of the VIE's available credit facility for \$105 million.

3 As at December 31, 2024 and 2023, our maximum exposure to loss includes parental guarantees and funding obligations that have been committed in connection with the projects for which we would be liable in the event of default by the VIE(s).

4 In May 2024, Enbridge formed a joint venture (the Whistler Parent JV) in which we hold a 19.0% interest. Refer to Note 13 - Long-Term Investments. As at December 31, 2024, our maximum exposure to loss includes funding obligations that have been committed in project contracts in which we would be liable for in the event of default by the VIE.

5 In April 2024, Enbridge sold its interest in Aux Sable Liquid Products L.P. Refer to Note 13 - Long-Term Investments. As at December 31, 2023, our maximum exposure to loss included a guarantee by us for our respective share of the VIE's borrowing on a bank credit facility.

6 In November 2023, Enbridge acquired a 50.0% interest in Fox Squirrel Solar LLC. Refer to Note 13 - Long-Term Investments. As at December 31, 2024, Fox Squirrel Solar LLC no longer met the requirements of a VIE as a result of a VIE reconsideration event. As at December 31, 2023, our maximum exposure to loss included parental guarantees that had been committed in project contracts in which we would be liable for in the event of default by the VIE.

We do not have an obligation to and did not provide any additional financial support to our unconsolidated VIEs during the years ended December 31, 2024 and 2023.

13. LONG-TERM INVESTMENTS

December 31, (millions of Canadian dollars)	Ownership Interest	2024	2023
EQUITY INVESTMENTS			
Liquids Pipelines			
Cactus II Pipeline LLC	30.0%	651	618
DCP Midstream, LLC (Class B Units) ¹	90.0%	1,554	1,486
Illinois Extension Pipeline Company, L.L.C.	65.0%	608	584
MarEn Bakken Company LLC ²	75.0%	2,296	1,819
Seaway Crude Holdings LLC	50.0%	2,820	2,661
Other	30.0% - 43.8%	96	84
Gas Transmission			
Alliance Pipeline ^{3,5}	50.0%	—	359
Aux Sable ^{4,5}	42.7% - 50.0%	—	229
DCP Midstream, LLC (Class A Units) ⁶	23.4%	480	367
Delaware Basin Residue, LLC ⁷	15.0%	319	—
Gulfstream Natural Gas System, L.L.C.	50.0%	1,316	1,224
NEXUS Gas Transmission, LLC	50.0%	1,301	1,220
Sabal Trail Transmission, LLC	50.0%	1,565	1,467
Southeast Supply Header, LLC	50.0%	355	80
Steckman Ridge, LP	50.0%	101	87
Vector Pipeline	60.0%	193	191
Whistler Parent JV ⁸	19.0%	1,102	—
Woodfibre LNG Limited Partnership	30.0%	1,275	777
Offshore - various joint ventures	22.0% - 74.3%	260	217
Other	21.3% - 45.0%	49	—
Gas Distribution and Storage			
Other	17.0% - 50.0%	67	22
Renewable Power Generation			
East-West Tie Limited Partnership	24.1%	106	132
EIH S.à r.l. ⁹	51.0%	89	52
Fox Squirrel Solar LLC	50.0%	783	312
Hohe See and Albatros Offshore Wind Facilities	49.9%	1,606	1,701
Rampion Offshore Wind Limited	24.9%	387	391
Other	16.4% - 50.0%	93	110
OTHER LONG-TERM INVESTMENTS			
Gas Transmission			
Ara Divert HoldCo, Inc.		116	106
Other		23	22
Gas Distribution and Storage			
Other		27	24
Renewable Power Generation			
Other		21	21
Eliminations and Other			
Other ¹⁰		1,032	430
		20,691	16,793

1 We own 90.0% of the Class B units of DCP Midstream, LLC. This class of units represents DCP Midstream, LLC's 65.0% interest in Gray Oak Pipeline, LLC (Gray Oak), resulting in a 58.5% interest in Gray Oak through DCP Midstream, LLC. On January 9, 2023, we acquired an additional 10.0% direct interest in Gray Oak for cash consideration of \$230 million (US\$172 million), bringing our effective interest to 68.5%.

2 MarEn Bakken Company LLC owns a 49.0% interest in Bakken Pipeline Investments LLC. Bakken Pipeline Investments LLC owns 75.0% of the Bakken Pipeline System, resulting in a 27.6% effective interest in the Bakken Pipeline System by us.

3 Includes Alliance Pipeline Limited Partnership in Canada and Alliance Pipeline L.P. in the US.

- 4 Includes Aux Sable Canada LP in Canada and Aux Sable Liquid Products L.P. and Aux Sable Midstream LLC in the US.
- 5 On April 1, 2024, we closed the sale of our 50.0% equity interest in the Alliance Pipeline and our interest in Aux Sable to Pembina Pipeline Corporation for \$3.1 billion, including \$0.3 billion of non-recourse debt.
- 6 We own 23.4% of the Class A units of DCP Midstream, LLC. These units represent DCP Midstream, LLC's 56.5% interest in DCP Midstream, LP (DCP), resulting in a 13.2% effective interest in DCP by us.
- 7 On October 31, 2024, we acquired an effective 15.0% interest in Delaware Basin Residue, LLC (DBR) for consideration of \$303 million (US\$220 million). DBR owns transportation and storage assets in West Texas, serving as the primary supply point for the Whistler Pipeline.
- 8 On May 29, 2024, we formed a joint venture with WhiteWater/I Squared Capital and MPLX LP. We hold a 19.0% interest in the joint venture, which owns a 100% interest in the Rio Bravo Pipeline project. Additionally, we have a 25.0% special interest in the Rio Bravo Pipeline project, resulting in a 39.3% effective interest in the Rio Bravo Pipeline project by us.
- 9 Owns a 50.0% interest in Éolien Maritime France SAS (EMF). Through our investment in EMF, we own equity interests in three French offshore wind projects, including effective interests in Saint-Nazaire (25.5%), Fécamp (17.9%) and Calvados (21.7%).
- 10 Consists of investments in exchange-traded funds and debt securities held by our wholly-owned captive insurance subsidiaries. Refer to Note 23 - Risk Management and Financial Instruments.

Equity investments include the unamortized excess of the purchase price over the underlying net book value of the investees' assets at the purchase date. As at December 31, 2024, this basis difference was \$3.7 billion (2023 - \$3.5 billion), of which \$1.7 billion (2023 - \$1.7 billion) was amortizable.

For the years ended December 31, 2024, 2023 and 2022, distributions received from equity investments were \$2.9 billion, \$3.1 billion and \$2.6 billion, respectively.

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

Year ended December 31, (millions of Canadian dollars)	2024	2023	2022
Operating revenues	20,657	22,586	30,026
Operating expenses	14,692	17,111	23,835
Earnings	5,177	4,818	5,123
Earnings attributable to Enbridge	2,304	1,816	2,056

December 31, (millions of Canadian dollars)	2024	2023
Current assets	8,611	5,842
Non-current assets	69,381	61,141
Current liabilities	7,240	6,194
Non-current liabilities	27,491	23,957
Noncontrolling interests	4,979	4,124

DISPOSITION

Disposition of Alliance Pipeline and Aux Sable Interests

On April 1, 2024, we closed the sale of our 50.0% interest in the Alliance Pipeline, our interest in Aux Sable and our interest in NRGreen Power Limited Partnership (NRGreen) to Pembina Pipeline Corporation for \$3.1 billion, including \$327 million of non-recourse debt. A gain on disposal of \$1.1 billion before tax, which is net of \$1.0 billion of the goodwill from our Gas Transmission segment allocated to the disposal group, is included in Gain on disposition of equity investments in the Consolidated Statements of Earnings for the year ended December 31, 2024. Our equity investments in the Alliance Pipeline and Aux Sable were previously included in our Gas Transmission segment. Our equity investment in NRGreen was previously included in our Renewable Power Generation segment.

OTHER EQUITY INVESTMENT TRANSACTIONS

Joint Venture with WhiteWater/I Squared and MPLX

On May 29, 2024, we formed a joint venture (the Whistler Parent JV) with WhiteWater/I Squared Capital (WhiteWater/I Squared) and MPLX LP (MPLX) that will develop, construct, own and operate natural gas pipeline and storage assets connecting Permian Basin natural gas supply to growing LNG and other US Gulf Coast demand. The Whistler Parent JV is owned by WhiteWater/I Squared (50.6%), MPLX (30.4%) and Enbridge (19.0%) and is accounted for as an equity method investment.

In connection with the formation of the Whistler Parent JV, we contributed our 100% interest in the Rio Bravo Pipeline project and \$487 million (US\$357 million) of cash to the Whistler Parent JV. In addition to our 19.0% equity interest in the Whistler Parent JV, we received a special equity interest in the Whistler Parent JV which provides for a 25.0% economic interest in the Rio Bravo Pipeline project. This interest is subject to certain redemption rights held by WhiteWater/I Squared and MPLX. After the closing on May 29, 2024, we accrued for our share of the post-closing mandatory capital expenditures of approximately US\$150 million for the Rio Bravo Pipeline project. Additional capital expenditures to complete the Rio Bravo Pipeline project will be proportionate to our economic interest.

The contribution of our interest in the Rio Bravo Pipeline project to the Whistler Parent JV in exchange for the equity interests discussed above represents a non-cash transaction in Cash Flows from Investing Activities and does not have an effect on our Consolidated Statements of Cash Flows. This component of the transaction resulted in a reduction of \$321 million (US\$235 million) to Property, plant and equipment, net and a corresponding increase to Long-term investments in the Consolidated Statements of Financial Position. The cash component of the transaction, as well as subsequent cash payments made for post-closing mandatory capital expenditures, have been reflected as contributions in Cash Flows from Investing Activities.

Fox Squirrel Solar LLC

On November 15, 2023, we acquired a 50.0% 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 included an upfront payment of \$157 million (US\$115 million) with subsequent capital contributions of \$591 million (US\$426 million), for all phases of construction, made at the project's in-service dates.

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 49.0% 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. Subsequent to the purchase, our interest in ERII is consolidated and our interest in the Offshore Wind Facilities will continue to be accounted for as an equity method investment included in the Renewable Power Generation segment.

DCP Midstream, LLC

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

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

14. INTANGIBLE ASSETS

December 31, 2024	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
<i>(millions of Canadian dollars)</i>				
Software	10.9%	2,109	(1,222)	887
Power purchase agreements	4.5%	58	(26)	32
Project agreement ¹	4.0%	173	(52)	121
Customer relationships	8.6%	2,856	(975)	1,881
Biogas rights agreements	3.4%	999	(34)	965
Other intangible assets	5.8%	665	(234)	431
Under development	—%	270	—	270
		7,130	(2,543)	4,587

December 31, 2023	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
<i>(millions of Canadian dollars)</i>				
Software	12.0%	1,921	(1,090)	831
Power purchase agreements	4.3%	58	(24)	34
Project agreement ¹	4.0%	158	(41)	117
Customer relationships	8.6%	2,636	(675)	1,961
Other intangible assets	8.2%	603	(185)	418
Under development	—%	176	—	176
		5,552	(2,015)	3,537

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

For the years ended December 31, 2024, 2023 and 2022, our amortization expense related to intangible assets totaled \$530 million, \$535 million and \$483 million, respectively. Our expected amortization expense associated with existing intangible assets for each of the years 2025 to 2029 is \$558 million.

15. GOODWILL

	Liquids Pipelines	Gas Transmission	Gas Distribution and Storage	Renewable Power Generation	Consolidated
<i>(millions of Canadian dollars)</i>					
Balance at January 1, 2023	8,549	18,106	5,397	388	32,440
Foreign exchange and other	(205)	(425)	—	(8)	(638)
Acquisition ³	—	46	—	—	46
Balance at December 31, 2023 ^{1,2}	8,344	17,727	5,397	380	31,848
Dispositions ⁴	—	(1,026)	—	—	(1,026)
Foreign exchange and other	672	1,354	204	34	2,264
Acquisitions ⁵	—	223	3,291	—	3,514
Balance at December 31, 2024 ^{1,2}	9,016	18,278	8,892	414	36,600

1 Gross goodwill as at December 31, 2024 and 2023 was \$40.7 billion and \$35.9 billion, respectively.

2 Accumulated impairment as at December 31, 2024 and 2023 was \$4.1 billion.

3 In 2023, we recorded \$46 million of goodwill related to the acquisition of Aitken Creek. Refer to Note 8 - Acquisitions and Disposition.

4 In 2024, we derecognized \$1.0 billion of goodwill related to the sale of our interests in the Alliance Pipeline and Aux Sable. Refer to Note 13 - Long-Term Investments.

5 In 2024, we recorded \$895 million of goodwill related to the PSNC Acquisition, \$793 million of goodwill related to the Questar Acquisition, \$1.6 billion of goodwill related to the EOG Acquisition, and \$223 million of goodwill related to the RNG Facilities Acquisition. Refer to Note 8 - Acquisitions and Disposition.

16. OTHER CURRENT LIABILITIES

December 31,	2024	2023
<i>(millions of Canadian dollars)</i>		
Dividends payable	2,088	1,975
Deferred credits	1,072	1,177
Derivative liabilities (Note 23)	1,335	738
Taxes payable	959	596
Regulatory liabilities (Note 7)	616	307
Federal carbon program liability	498	376
Asset retirement obligations (Note 18)	120	136
Other	553	354
	7,241	5,659

17. DEBT

December 31, (millions of Canadian dollars)	Weighted Average Interest Rate ⁸	Maturity	2024	2023
Enbridge Inc.				
US dollar senior notes	4.8%	2025 - 2054	19,703	14,636
Medium-term notes	4.5%	2025 - 2064	9,900	8,598
Sustainability-linked bonds	4.7%	2032 - 2033	7,146	6,751
Fixed-to-fixed subordinated term notes ¹	7.4%	2054 - 2084	9,372	7,156
Fixed-to-floating rate subordinated term notes ²	5.8%	2077 - 2078	6,139	5,828
Floating rate notes			—	791
Fixed-to-floating non-call notes			—	923
Commercial paper and credit facility draws	3.7%	2025 - 2029	5,843	3,177
Other ³			12	17
Enbridge (U.S.) Inc.				
Commercial paper and credit facility draws	4.8%	2026 - 2029	4,707	670
Other ³			276	263
Enbridge Energy Partners, L.P.				
Senior notes	6.5%	2025 - 2045	3,524	3,231
Enbridge Gas Inc.				
Medium-term notes	4.1%	2025 - 2053	9,970	10,185
Debentures	8.7%	2025	125	210
Commercial paper and credit facility draws	3.4%	2026	530	400
Other ³			1	2
Enbridge Pipelines (Southern Lights) L.L.C.				
Senior notes	4.0%	2040	736	791
Enbridge Pipelines Inc.				
Medium-term notes ⁴	4.2%	2025 - 2053	5,425	5,425
Debentures			—	200
Commercial paper and credit facility draws	3.8%	2026	509	449
Other ³			2	4
Enbridge Southern Lights LP				
Senior notes	4.0%	2040	183	214
Spectra Energy Capital, LLC				
Senior notes	7.1%	2032 - 2038	248	228
Algonquin Gas Transmission, LLC				
Senior notes	4.4%	2029 - 2034	1,222	1,121
East Tennessee Natural Gas, LLC				
Senior notes	5.7%	2034	662	251
Texas Eastern Transmission, LP				
Senior notes	4.7%	2028 - 2048	3,667	3,362
Spectra Energy Partners, LP				
Senior notes	4.2%	2025 - 2045	3,164	4,220
Blauracke GmbH				
Senior notes	2.1%	2032	471	521
The East Ohio Gas Company				
Senior notes	3.1%	2025 - 2052	3,308	—
Other ³			24	—
Questar Gas Company				
Senior notes	4.2%	2027 - 2052	2,028	—
Public Service Company of North Carolina, Incorporated				
Senior notes	5.0%	2026 - 2054	1,798	—
Enbridge Holdings (Tomorrow RNG), LLC				
Senior notes	4.9%	2025	817	—
Westcoast Energy Inc.				
Medium-term notes	5.4%	2025 - 2041	875	1,225
Debentures	8.1%	2025 - 2026	275	275
Fair value adjustment			(468)	514
Other ⁵			(522)	(439)
Total debt ⁶			101,672	81,199
Current maturities			(7,729)	(6,084)
Short-term borrowings ⁷			(529)	(400)
Long-term debt			93,414	74,715

- 1 For an initial five, 5.5, 9.75 or 10 years, the notes carry a fixed interest rate. Subsequently, during each reset period the interest rate will be reset to equal to the Five-Year US Treasury rate or Five-Year Government of Canada bond yield plus a margin. The notes would be converted automatically into Conversion Preference Shares in the event of bankruptcy and related events.
- 2 For an initial five or 10 years, the notes carry a fixed interest rate. Subsequently, the interest rate will be floating and set to equal to the Canadian Dollar Offered Rate or the Secured Overnight Financing Rate (SOFR) plus a margin. The notes would be converted automatically into Conversion Preference Shares in the event of bankruptcy and related events.
- 3 Primarily finance lease obligations.
- 4 Included in medium-term notes is \$100 million with a maturity date of 2112.
- 5 Primarily unamortized discounts, premiums and debt issuance costs.
- 6 2024 - \$40 billion, US\$43 billion and €316 million; 2023 - \$37 billion, US\$33 billion and €359 million. Totals exclude capital lease obligations, unamortized discounts, premiums and debt issuance costs and fair value adjustment.
- 7 Weighted average interest rates on outstanding commercial paper were 3.4% as at December 31, 2024 (2023 - 5.2%).
- 8 Calculated based on term notes, debentures, commercial paper and credit facility draws outstanding as at December 31, 2024.

As at December 31, 2024, all outstanding debt was unsecured.

CREDIT FACILITIES

The following table provides details of our committed credit facilities as at December 31, 2024:

	Maturity ¹	Total Facilities	Draws ²	Available
<i>(millions of Canadian dollars)</i>				
Enbridge Inc.	2025-2049	8,840	5,843	2,997
Enbridge (U.S.) Inc.	2026-2029	10,813	4,707	6,106
Enbridge Pipelines Inc.	2026	2,000	509	1,491
Enbridge Gas Inc.	2026	2,500	530	1,970
Total committed credit facilities		24,153	11,589	12,564

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 2024, we entered into a delayed-draw term loan facility in support of sustainable retrofit projects for large buildings using decarbonization solutions for \$200 million which matures in March 2049.

In June 2024, we entered into a five-year, non-revolving term loan facility of US\$250 million which matures in June 2029.

In July 2024, we renewed approximately \$8.8 billion of our 364-day extendible credit facilities, extending the maturity dates to July 2026, which includes a one-year term out provision from July 2025. We also renewed approximately \$7.8 billion of our five-year credit facilities, extending the maturity dates to July 2029. Further, we extended the maturity dates of our three-year credit facilities to July 2027.

In July 2024, Enbridge Gas Ontario extended the maturity date of its 364-day extendible credit facility to July 2026, which includes a one-year term out provision from July 2025.

In July 2024, Enbridge Pipelines Inc. extended the maturity date of its 364-day extendible credit facility to July 2026, which includes a one-year term out provision from July 2025.

In January 2024 and October 2024, we entered into new letters of credit facilities and increased our letter of credit facilities by \$146 million and \$200 million, respectively.

In addition to the committed credit facilities noted above, we maintain \$1.4 billion of uncommitted demand letter of credit facilities, of which \$931 million was unutilized as at December 31, 2024. As at December 31, 2023, we had \$1.1 billion of uncommitted demand letter of credit facilities, of which \$572 million was unutilized.

Our credit facilities carry a weighted average standby fee of 0.1% per annum on the unused portion and draws bear interest at market rates. Certain credit facilities serve as a back-stop to the commercial paper programs and we have the option to extend such facilities, which are currently scheduled to mature from 2025 to 2049.

As at December 31, 2024 and 2023, commercial paper and credit facility draws, net of short-term borrowings and non-revolving credit facilities that mature within one year, of \$10.3 billion and \$3.8 billion, respectively, were supported by the availability of long-term committed credit facilities and, therefore, have been classified as long-term debt.

ACQUISITIONS

As a result of the EOG Acquisition, RNG Facilities Acquisition, Questar Acquisition and PSNC Acquisition, our debt increased by US\$1.9 billion, US\$568 million, US\$1.0 billion, and US\$1.1 billion, respectively, on each acquisition date. Refer to *Note 8 - Acquisitions and Disposition* for further details.

LONG-TERM DEBT ISSUANCES

During the year ended December 31, 2024, we completed the following long-term debt issuances totaling US\$5.7 billion and \$1.8 billion:

Company	Issue Date		Principal Amount
<i>(millions of Canadian dollars, unless otherwise stated)</i>			
Enbridge Inc.			
	April 2024	5.25% senior notes due April 2027	US\$750
	April 2024	5.30% senior notes due April 2029	US\$750
	April 2024	5.63% senior notes due April 2034	US\$1,200
	April 2024	5.95% senior notes due April 2054	US\$800
	June 2024	7.38% fixed-to-fixed subordinated notes due March 2055 ¹	US\$500
	June 2024	7.20% fixed-to-fixed subordinated notes due June 2054 ²	US\$700
	August 2024	4.21% medium-term notes due February 2030	\$600
	August 2024	4.73% medium-term notes due August 2034	\$800
	August 2024	5.32% medium-term notes due August 2054	\$400
Algonquin Gas Transmission, LLC			
	July 2024	5.95% senior notes due July 2034	US\$350
East Tennessee Natural Gas, LLC			
	December 2024	5.72% senior notes due December 2034	US\$460
Questar Gas Company			
	December 2024	5.33% senior notes due December 2034	US\$200

¹ For the initial 5.5 years, the notes carry a fixed interest rate. On March 15, 2030, the interest rate will be reset to equal the Five-Year US Treasury rate plus a margin of 3.12%.

² For the initial 9.75 years, the notes carry a fixed interest rate. On June 27, 2034, the interest rate will be reset to equal the Five-Year US Treasury rate plus a margin of 2.97%.

LONG-TERM DEBT REPAYMENTS

During the year ended December 31, 2024, we completed the following long-term debt repayments totaling US\$3.9 billion, \$1.4 billion, and €43 million, respectively:

Company	Repayment Date		Principal Amount
<i>(millions of Canadian dollars, unless otherwise stated)</i>			
Enbridge Inc.			
	February 2024	Floating rate notes ¹	US\$600
	February 2024	2.15% senior notes	US\$400
	March 2024	5.97% senior notes ²	US\$700
	June 2024	3.50% senior notes	US\$500
	November 2024	3.95% medium-term notes	\$500
Enbridge Gas Inc.			
	August 2024	3.15% medium-term notes	\$215
	December 2024	9.85 % debentures	\$85
Enbridge Pipelines (Southern Lights) L.L.C.			
	June and December 2024	3.98% senior notes	US\$89
Enbridge Pipelines Inc.			
	February 2024	8.20% debentures	\$200
Enbridge Southern Lights LP			
	January, July and December 2024	4.01% senior notes	\$31
Westcoast Energy Inc.			
	September 2024	3.43% medium-term notes	\$350
Spectra Energy Partners, LP			
	March 2024	4.75% senior notes	US\$1,000
Blauracke GmbH			
	April and October 2024	2.10% senior notes	€43
Algonquin Gas Transmission, LLC			
	July 2024	3.51% senior notes	US\$350
Questar Gas Company			
	December 2024	2.98% senior notes	US\$40
East Tennessee Natural Gas, LLC			
	December 2024	3.10% senior notes	US\$190

¹ Notes carried an interest rate set to equal the SOFR plus a margin of 63 basis points.

² The notes carried an original maturity date in March 2026, and were callable in March 2024, which was one year after their issuance.

DEBT COVENANTS

Our credit facility agreements and term debt indentures include standard events of default and covenant provisions whereby accelerated repayment and/or termination of the agreements may result if we were to default on payment or violate certain covenants. As at December 31, 2024, we were in compliance with all debt covenants.

ANNUAL DEBT MATURITIES

As at December 31, 2024, we have commitments as detailed below:

	Total	Less than 1 year	2 years	3 years	4 years	5 years	Thereafter
<i>(millions of Canadian dollars)</i>							
Annual debt maturities ¹	101,819	7,724	7,379	4,704	3,056	13,578	65,378

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

INTEREST EXPENSE

Year ended December 31, (millions of Canadian dollars)	2024	2023	2022
Debtentures and term notes	4,123	3,439	2,910
Commercial paper and credit facility draws	439	519	388
Amortization of fair value adjustment	18	(45)	(45)
Capitalized interest	(161)	(101)	(74)
	4,419	3,812	3,179

18. ASSET RETIREMENT OBLIGATIONS

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

The discount rates used to estimate the present value of the expected future cash flows for the years ended December 31, 2024 and 2023 ranged from 1.5% to 9.0%.

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

December 31, (millions of Canadian dollars)	2024	2023
Obligations at beginning of year	493	488
Liabilities acquired	185	1
Liabilities incurred	3	—
Liabilities settled	(139)	(23)
Change in estimate and other	51	5
Foreign currency translation adjustment	40	(6)
Accretion expense	33	28
Obligations at end of year	666	493
Presented as follows:		
Other current liabilities (Note 16)	120	136
Other long-term liabilities	546	357
	666	493

19. NONCONTROLLING INTERESTS

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

December 31, (millions of Canadian dollars)	2024	2023
Algonquin Gas Transmission, LLC	414	384
Enbridge Athabasca Midstream Investor Limited Partnership	1,073	1,086
Maritimes & Northeast Pipeline, L.L.C.	606	559
Renewable energy assets	786	885
Maritimes & Northeast Pipeline Limited Partnership	109	111
Other	5	4
	2,993	3,029

20. SHARE CAPITAL

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

COMMON SHARES

	2024		2023		2022	
	Number of Shares	Amount	Number of Shares	Amount	Number of Shares	Amount
December 31, <i>(millions of Canadian dollars; number of shares in millions)</i>						
Balance at beginning of year	2,125	69,180	2,025	64,760	2,026	64,799
Shares issued, net of issue costs	51	2,489	103	4,485	—	—
Shares issued on exercise of stock options	1	39	—	3	2	53
Shares issued on vesting of RSUs, net of tax	1	30	—	12	—	—
Share repurchases at stated value ¹	—	—	(3)	(80)	(3)	(88)
Other	—	—	—	—	—	(4)
Balance at end of year	2,178	71,738	2,125	69,180	2,025	64,760

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

On May 15, 2024, we filed prospectus supplements in Canada and the US to establish an at-the-market equity issuance program (the ATM Program) that allowed us to issue and sell, at our discretion, up to \$2.75 billion (or the US dollar equivalent) of our common shares from treasury to the public from time to time at the market prices prevailing at the time of sale through the Toronto Stock Exchange, the New York Stock Exchange (NYSE) or any other marketplace in Canada or the US where the common shares may be traded.

During the period from May 15, 2024 to July 31, 2024, 51,298,629 common shares were issued and sold under the ATM Program at average prices of CAD\$48.72 and US\$35.77 per common share for aggregate gross proceeds of \$2.50 billion (\$2.48 billion, net of aggregate commissions paid of \$16.3 million and other issuance costs). On August 1, 2024, we terminated the ATM Program. Net proceeds from sales of common shares under the ATM Program were used to partially fund the Questar Acquisition and PSNC Acquisition and to pay related fees and expenses.

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 were also used to finance a portion of the aggregate cash consideration payable for the Acquisitions discussed in *Note 8 - Acquisitions and Disposition*.

PREFERENCE SHARES

December 31, (millions of Canadian dollars; number of shares in millions)	2024		2023		2022	
	Number of Shares	Amount	Number of Shares	Amount	Number of Shares	Amount
Preference Shares, Series A	5	125	5	125	5	125
Preference Shares, Series B	20	500	20	500	20	500
Preference Shares, Series D	18	450	18	450	18	450
Preference Shares, Series F	18	454	18	454	20	500
Preference Shares, Series G ¹	2	46	2	46	—	—
Preference Shares, Series H	12	291	12	291	14	350
Preference Shares, Series I ²	2	59	2	59	—	—
Preference Shares, Series L	16	411	16	411	16	411
Preference Shares, Series N	18	450	18	450	18	450
Preference Shares, Series P	16	400	16	400	16	400
Preference Shares, Series R	16	400	16	400	16	400
Preference Shares, Series 1	16	411	16	411	16	411
Preference Shares, Series 3	22	562	24	600	24	600
Preference Shares, Series 4 ³	2	38	—	—	—	—
Preference Shares, Series 5	8	206	8	206	8	206
Preference Shares, Series 7	10	250	10	250	10	250
Preference Shares, Series 9	11	275	11	275	11	275
Preference Shares, Series 11	20	500	20	500	20	500
Preference Shares, Series 13	14	350	14	350	14	350
Preference Shares, Series 15	11	275	11	275	11	275
Preference Shares, Series 19	20	500	20	500	20	500
Issuance costs		(135)		(135)		(135)
Balance at end of year		6,818		6,818		6,818

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

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

³ On September 1, 2024, 1,502,775 of the outstanding Preference Shares, Series 3 were converted into Preference Shares, Series 4.

Characteristics of our outstanding preference shares are as follows:

	Dividend Rate	Dividend ¹	Per Share Base Redemption Value ²	Redemption and Conversion Option Date ^{2,3}	Right to Convert Into ^{3,4}
<i>(Canadian dollars unless otherwise stated)</i>					
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	5.41%	\$1.35300	\$25	March 1, 2028	Series E
Preference Shares, Series F	5.54%	\$1.38452	\$25	June 1, 2028	Series G
Preference Shares, Series G ⁵	6.15%	\$1.51644	\$25	June 1, 2028	Series F
Preference Shares, Series H	6.11%	\$1.52800	\$25	September 1, 2028	Series I
Preference Shares, Series I ⁶	5.76%	\$1.42028	\$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 ⁷	5.92%	\$1.47952	\$25	March 1, 2029	Series Q
Preference Shares, Series R ⁸	6.31%	\$1.57852	\$25	June 1, 2029	Series S
Preference Shares, Series 1	6.70%	US\$1.67592	US\$25	June 1, 2028	Series 2
Preference Shares, Series 3 ⁹	5.29%	\$1.32200	\$25	September 1, 2029	Series 4
Preference Shares, Series 4 ¹⁰	6.02%	\$1.48440	\$25	September 1, 2029	Series 3
Preference Shares, Series 5 ¹¹	6.68%	US\$1.67076	US\$25	March 1, 2029	Series 6
Preference Shares, Series 7 ¹²	5.99%	\$1.49700	\$25	March 1, 2029	Series 8
Preference Shares, Series 9 ¹³	5.67%	\$1.41800	\$25	December 1, 2029	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	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, Series I and Series 4 contain a feature where the dividend rate resets on a quarterly basis. These Dividend Rates are presented in the table above on an annualized basis using the most recent quarterly dividend rate reset. 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 G was decreased to \$0.37911 from \$0.43014 on December 1, 2024 due to reset on a quarterly basis.

6 The quarterly dividend per share paid on Preference Shares, Series I was decreased to \$0.35507 from \$0.40589 on December 1, 2024 due to reset on a quarterly basis.

7 The quarterly dividend per share paid on Preference Shares, Series P was increased to \$0.36988 from \$0.27369 on March 1, 2024 due to reset of the annual dividend on March 1, 2024.

8 The quarterly dividend per share paid on Preference Shares, Series R was increased to \$0.39463 from \$0.25456 on June 1, 2024 due to reset of the annual dividend on June 1, 2024.

9 The quarterly dividend per share paid on Preference Shares, Series 3 was increased to \$0.33050 from \$0.23356 on September 1, 2024 due to reset of the annual dividend on September 1, 2024.

10 On September 1, 2024, 1,502,775 of the outstanding Preference Shares, Series 3 were converted into Preference Shares, Series 4. The quarterly dividend per share paid on Preference Shares, Series 4 was decreased to \$0.37110 from \$0.42206 on December 1, 2024 due to reset on a quarterly basis following the date of issuance.

11 The quarterly dividend per share paid on Preference Shares, Series 5 was increased to US\$0.41769 from US\$0.33596 on March 1, 2024 due to reset of the annual dividend on March 1, 2024.

12 The quarterly dividend per share paid on Preference Shares, Series 7 was increased to \$0.37425 from \$0.27806 on March 1, 2024 due to reset of the annual dividend on March 1, 2024.

13 The quarterly dividend per share paid on Preference Shares, Series 9 was increased to \$0.35450 from \$0.25606 on December 1, 2024 due to reset of the annual dividend on December 1, 2024.

SHAREHOLDER RIGHTS PLAN

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

21. STOCK OPTION AND STOCK UNIT PLANS

We maintain three primary vehicles under our long-term incentive plan (the Plan): ISOs, PSUs and RSUs. Total stock-based compensation expense recorded for the years ended December 31, 2024, 2023 and 2022 was \$186 million, \$154 million and \$260 million, respectively. The number of common shares authorized for share-settled awards under the Plan was 181 million as at December 31, 2024, 2023 and 2022.

INCENTIVE STOCK OPTIONS

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

December 31, 2024	Number	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (years)	Aggregate Intrinsic Value
<i>(number of options in thousands; weighted average exercise price in Canadian dollars; intrinsic value in millions of Canadian dollars)</i>				
Options outstanding at beginning of year	28,729	50.79		
Options granted	5,036	46.36		
Options exercised ¹	(7,328)	49.27		
Options cancelled or expired	(1,113)	51.78		
Options outstanding at end of year	25,324	50.31	5.7	70
Options vested at end of year ²	15,602	51.33	4.2	37

¹ The total intrinsic value of ISOs exercised during the years ended December 31, 2024, 2023 and 2022 was \$18 million, \$2 million and \$66 million, respectively, and cash received on exercise was \$1 million, nil and \$3 million, respectively.

² The total fair value of ISOs vested during the years ended December 31, 2024, 2023 and 2022 was \$17 million, \$20 million and \$21 million, respectively.

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

Year ended December 31,	2024	2023	2022
Fair value per option (Canadian dollars) ¹	4.07	6.05	5.07
Valuation assumptions			
Expected option term (years) ²	6	6	6
Expected volatility ³	21.1%	22.2%	21.9%
Expected dividend yield ⁴	8.1%	6.7%	6.5%
Risk-free interest rate ⁵	3.8%	3.5%	1.8%

1 Options granted to US employees are based on the NYSE prices. The option value and assumptions shown are based on a weighted average of the US and Canadian options. The fair value per option for the years ended December 31, 2024, 2023 and 2022 were \$3.53, \$5.38 and \$4.78, respectively, for Canadian employees and US\$3.58, US\$5.23 and US\$4.62, respectively, for US employees.

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

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

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

5 The risk-free interest rate is based on the Government of Canada's Canadian bond yields and the US Treasury bond yields at the grant date.

Compensation expense recorded for the years ended December 31, 2024, 2023 and 2022 for ISOs was \$19 million, \$18 million and \$15 million, respectively. As at December 31, 2024, unrecognized compensation expense related to non-vested ISOs was \$12 million. The expense is expected to be fully recognized over a weighted average period of approximately two years.

PERFORMANCE STOCK UNITS

PSUs are granted to certain key employees where cash awards are paid following a three-year performance cycle. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by Enbridge's weighted average share price for 20 days prior to the maturity of the grant and by a performance multiplier. The performance multiplier ranges from zero, if our performance fails to meet threshold performance levels, to a maximum of 2.0 if we perform within the highest range of the performance targets. The performance multiplier is derived through a calculation of our Total Shareholder Return percentile rank relative to a specified peer group of companies and our distributable cash flow per share, adjusted for unusual, infrequent or other non-operating factors, relative to targets established at the time of grant. Beginning with the 2023 grant, the performance multiplier also includes a greenhouse gas reduction component. To calculate the 2024 expense, a multiplier of 1.38 was used for 2024 PSU grants, 1.1 for 2023 PSU grants and 1.0 for 2022 PSU grants.

	Number	Weighted Average Remaining Contractual Life (years)	Aggregate Intrinsic Value
December 31, 2024			
(number of units in thousands; intrinsic value in millions of Canadian dollars)			
Units outstanding at beginning of year	3,180		
Units granted	1,444		
Units cancelled	(104)		
Units matured ¹	(1,355)		
Dividend reinvestment	237		
Units outstanding at end of year	3,402	1.6	244

1 The total amount paid during the years ended December 31, 2024, 2023 and 2022 for PSUs was \$65 million, \$123 million and \$90 million, respectively.

Compensation expense recorded for the years ended December 31, 2024, 2023 and 2022 for PSUs was \$75 million, \$59 million and \$169 million, respectively. As at December 31, 2024, unrecognized compensation expense related to non-vested PSUs was \$109 million. The expense is expected to be fully recognized over a weighted average period of approximately two years.

RESTRICTED STOCK UNITS

Employees may also be granted cash-settled or share-settled RSUs under the Plan. Share-settled awards granted to non-executive senior management employees vest following a three-year maturity period. Beginning in 2023, share-settled units were also granted to non-executive employees. These units vest either on each of the first, second and third anniversaries of the grant date, or following a 12-month period. Cash-settled RSUs are given to non-executive employees and are paid in equal installments on each of the first, second and third anniversaries of the grant date.

RSU holders receive cash or shares equal to Enbridge's weighted average share price for 20 days prior to the maturity of the grant multiplied by the number of units outstanding on the maturity date.

	Number	Weighted Average Grant Date Fair Value ²	Weighted Average Remaining Contractual Life (years)	Aggregate Intrinsic Value
December 31, 2024				
<i>(number of units in thousands; intrinsic value in millions of Canadian dollars)</i>				
Units outstanding at beginning of year	3,571	50.69		
Units granted	1,758	48.50		
Units cancelled	(112)	51.38		
Units matured ¹	(1,910)	49.99		
Dividend reinvestment	284	50.94		
Units outstanding at end of year	3,591	51.10	1.0	187

¹ The total amount paid during the years ended December 31, 2024, 2023 and 2022 for RSUs was \$40 million, \$56 million and \$32 million, respectively.

² Weighted average grant date fair value excludes cash-settled units.

Compensation expense recorded for the years ended December 31, 2024, 2023 and 2022 for RSUs was \$92 million, \$77 million and \$76 million, respectively. As at December 31, 2024, unrecognized compensation expense related to non-vested RSUs was \$67 million. The expense is expected to be fully recognized over a weighted average period of approximately one year.

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

Changes in AOCI attributable to our common shareholders for the years ended December 31, 2024, 2023 and 2022 are as follows:

	Cash Flow Hedges	Excluded Components of Fair Value Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Adjustment	Total
<i>(millions of Canadian dollars)</i>							
Balance as at January 1, 2024	320	(23)	(728)	2,653	11	70	2,303
Other comprehensive income/(loss) retained in AOCI	79	(42)	(1,305)	5,799	(9)	323	4,845
Other comprehensive (income)/loss reclassified to earnings							
Interest rate contracts ¹	31	—	—	—	—	—	31
Commodity contracts ²	(1)	—	—	—	—	—	(1)
Foreign exchange contracts ³	—	53	—	—	—	—	53
Amortization of pension and OPEB actuarial gain ⁴	—	—	—	—	—	(21)	(21)
	109	11	(1,305)	5,799	(9)	302	4,907
Tax impact							
Income tax on amounts retained in AOCI	(15)	10	—	—	(1)	(75)	(81)
Income tax on amounts reclassified to earnings	(7)	(12)	—	—	—	5	(14)
	(22)	(2)	—	—	(1)	(70)	(95)
Balance as at December 31, 2024	407	(14)	(2,033)	8,452	1	302	7,115

	Cash Flow Hedges	Excluded Components of Fair Value Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Adjustment	Total
<i>(millions of Canadian dollars)</i>							
Balance as at January 1, 2023	121	(35)	(1,137)	4,348	5	218	3,520
Other comprehensive income/(loss) retained in AOCI	232	62	409	(1,695)	6	(158)	(1,144)
Other comprehensive (income)/loss reclassified to earnings							
Interest rate contracts ¹	28	—	—	—	—	—	28
Foreign exchange contracts ³	—	(47)	—	—	—	—	(47)
Amortization of pension and OPEB actuarial gain ⁴	—	—	—	—	—	(24)	(24)
	260	15	409	(1,695)	6	(182)	(1,187)
Tax impact							
Income tax on amounts retained in AOCI	(47)	(14)	—	—	—	28	(33)
Income tax on amounts reclassified to earnings	(14)	11	—	—	—	6	3
	(61)	(3)	—	—	—	34	(30)
Balance as at December 31, 2023	320	(23)	(728)	2,653	11	70	2,303

	Cash Flow Hedges	Excluded Components of Fair Value Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Adjustment	Total
<i>(millions of Canadian dollars)</i>							
Balance as at January 1, 2022	(897)	—	(166)	56	(5)	(84)	(1,096)
Other comprehensive income/(loss) retained in AOCI	1,125	(35)	(971)	4,292	(6)	411	4,816
Other comprehensive (income)/loss reclassified to earnings							
Interest rate contracts ¹	186	—	—	—	—	—	186
Foreign exchange contracts ³	(4)	—	—	—	—	—	(4)
Other contracts ⁵	4	—	—	—	—	—	4
Amortization of pension and OPEB actuarial gain ⁴	—	—	—	—	—	(14)	(14)
Other	—	—	—	—	16	—	16
	1,311	(35)	(971)	4,292	10	397	5,004
Tax impact							
Income tax on amounts retained in AOCI	(250)	—	—	—	—	(99)	(349)
Income tax on amounts reclassified to earnings	(43)	—	—	—	—	4	(39)
	(293)	—	—	—	—	(95)	(388)
Balance as at December 31, 2022	121	(35)	(1,137)	4,348	5	218	3,520

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

2 Reported within Transportation and other services revenues in the Consolidated Statements of Earnings.

3 Reported within Interest expense and Other income/(expense) in the Consolidated Statements of Earnings.

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

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

23. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET RISK

Our earnings, cash flows and OCI are subject to movements in foreign exchange rates, interest rates, commodity prices and our share price (collectively, market risk). Formal risk management policies, processes and systems have been designed to mitigate these risks.

The following summarizes the types of market risks to which we are exposed and the risk management instruments used to mitigate them. We use a combination of qualifying and non-qualifying derivative instruments to manage the risks noted below.

Foreign Exchange Risk

We generate certain revenues, incur expenses and hold a number of investments and subsidiaries that are denominated in currencies other than Canadian dollars. As a result, our earnings, cash flows and OCI are exposed to fluctuations resulting from foreign exchange rate variability.

We employ financial derivative instruments to hedge foreign currency-denominated earnings exposure. A combination of qualifying and non-qualifying derivative instruments is used to hedge anticipated foreign currency-denominated revenues and expenses and to manage variability in cash flows. We hedge certain net investments in US dollar-denominated investments and subsidiaries using US dollar-denominated debt.

Interest Rate Risk

Our earnings, cash flows and OCI are exposed to short-term interest rate variability due to the regular repricing of our variable rate debt, primarily commercial paper. We have a policy of limiting our maximum floating rate debt to 30% of total debt outstanding. To ensure compliance with our policy, we monitor and adjust our debt portfolio mix of fixed and variable rate debt instruments in conjunction with the use of derivative instruments. We have implemented a program to partially mitigate the impact of short-term interest rate volatility on interest expense via the execution of floating-to-fixed interest rate swaps and costless collars. These swaps have an average fixed rate of 3.6%.

Our earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate term debt issuances. A combination of qualifying and non-qualifying forward starting interest rate swaps is used to hedge against the effect of future interest rate movements. We have established a program including some of our subsidiaries to partially mitigate our exposure to long-term interest rate variability on forecasted term debt issuances via execution of floating-to-fixed interest rate swaps with an average swap rate of 3.4%.

Commodity Price Risk

Our earnings, cash flows and OCI are exposed to changes in commodity prices as a result of our ownership interests in certain assets and investments, as well as through the activities of our energy marketing subsidiaries. These commodities include natural gas, crude oil, power and NGL. We employ financial and physical derivative instruments to fix a portion of the variable price exposures that arise from physical transactions involving these commodities. We use primarily non-qualifying derivative instruments to manage commodity price risk.

Equity Price Risk

Equity price risk is the risk of earnings fluctuations due to changes in our share price. We have exposure to our own common share price through the issuance of various forms of stock-based compensation, which affect earnings through the revaluation of outstanding units every period.

TOTAL DERIVATIVE INSTRUMENTS

We have a policy of entering into individual International Swaps and Derivatives Association, Inc. (ISDA) agreements, or other similar derivative agreements, with the majority of our derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit events and reduce our credit risk exposure on financial derivative asset positions in those circumstances.

The following table summarizes the Consolidated Statements of Financial Position location and carrying value of our derivative instruments, as well as the maximum potential settlement amounts, in the event of the specific circumstances described above.

	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Fair Value Hedges	Non- Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
December 31, 2024						
<i>(millions of Canadian dollars)</i>						
Other current assets						
Foreign exchange contracts	—	78	47	125	(29)	96
Interest rate contracts	44	—	23	67	(39)	28
Commodity contracts	2	—	360	362	(191)	171
Other contracts	—	—	3	3	—	3
	46	78	433	557	(259)	298
Deferred amounts and other assets						
Foreign exchange contracts	—	—	83	83	(71)	12
Interest rate contracts	9	—	137	146	(27)	119
Commodity contracts	—	—	197	197	(39)	158
	9	—	417	426	(137)	289
Other current liabilities						
Foreign exchange contracts	—	(73)	(731)	(804)	29	(775)
Interest rate contracts	(58)	—	(22)	(80)	39	(41)
Commodity contracts	—	—	(451)	(451)	191	(260)
	(58)	(73)	(1,204)	(1,335)	259	(1,076)
Other long-term liabilities						
Foreign exchange contracts	—	—	(1,579)	(1,579)	71	(1,508)
Interest rate contracts	—	—	(80)	(80)	27	(53)
Commodity contracts	(1)	—	(238)	(239)	39	(200)
	(1)	—	(1,897)	(1,898)	137	(1,761)
Total net derivative asset/(liability)						
Foreign exchange contracts	—	5	(2,180)	(2,175)	—	(2,175)
Interest rate contracts	(5)	—	58	53	—	53
Commodity contracts	1	—	(132)	(131)	—	(131)
Other contracts	—	—	3	3	—	3
	(4)	5	(2,251)	(2,250)	—	(2,250)

December 31, 2023	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Fair Value Hedges	Non- Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
<i>(millions of Canadian dollars)</i>						
Other current assets						
Foreign exchange contracts	—	41	98	139	(32)	107
Interest rate contracts	31	—	34	65	(32)	33
Commodity contracts	—	—	418	418	(270)	148
Other contracts	—	—	1	1	(1)	—
	31	41	551	623	(335)	288
Deferred amounts and other assets						
Foreign exchange contracts	—	16	319	335	(122)	213
Interest rate contracts	51	—	2	53	(21)	32
Commodity contracts	—	—	75	75	(41)	34
	51	16	396	463	(184)	279
Other current liabilities						
Foreign exchange contracts	—	(44)	(84)	(128)	32	(96)
Interest rate contracts	(183)	—	(3)	(186)	32	(154)
Commodity contracts	(11)	—	(412)	(423)	270	(153)
Other contracts	—	—	(1)	(1)	1	—
	(194)	(44)	(500)	(738)	335	(403)
Other long-term liabilities						
Foreign exchange contracts	—	(17)	(481)	(498)	122	(376)
Interest rate contracts	(3)	—	(85)	(88)	21	(67)
Commodity contracts	(7)	—	(159)	(166)	41	(125)
	(10)	(17)	(725)	(752)	184	(568)
Total net derivative liability						
Foreign exchange contracts	—	(4)	(148)	(152)	—	(152)
Interest rate contracts	(104)	—	(52)	(156)	—	(156)
Commodity contracts	(18)	—	(78)	(96)	—	(96)
Other contracts	—	—	—	—	—	—
	(122)	(4)	(278)	(404)	—	(404)

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

As at December 31,	2024						2023	
	2025	2026	2027	2028	2029	Thereafter	Total	Total
Foreign exchange contracts - US dollar forwards - purchase (millions of US dollars)	1,245	—	—	—	—	—	1,245	1,860
Foreign exchange contracts - US dollar forwards - sell (millions of US dollars)	6,406	5,627	4,811	3,522	1,248	—	21,614	24,747
Foreign exchange contracts - British pound (GBP) forwards - sell (millions of GBP)	30	28	32	—	—	—	90	120
Foreign exchange contracts - Euro forwards - sell (millions of Euro)	126	121	81	67	66	129	590	731
Foreign exchange contracts - Japanese yen forwards - purchase (millions of yen)	84,800	—	—	—	—	—	84,800	84,800
Interest rate contracts - short-term pay fixed rate (millions of Canadian dollars)	2,296	1,737	676	49	13	—	4,771	9,018
Interest rate contracts - short-term receive fixed rate (millions of Canadian dollars)	—	—	—	—	—	—	—	2,015
Interest rate contracts - long-term pay fixed rate (millions of Canadian dollars) ¹	4,531	753	—	—	—	—	5,284	5,162
Interest rate contracts - costless collar (millions of Canadian dollars)	1,938	268	104	6	—	—	2,316	1,139
Equity contracts (millions of Canadian dollars)	—	—	—	—	—	—	—	47
Commodity contracts - natural gas (billions of cubic feet) ²	154	79	37	11	5	2	288	86
Commodity contracts - crude oil (millions of barrels) ²	6	15	1	1	1	1	25	6
Commodity contracts - power (megawatt per hour (MW/H))	61	24	(31)	(49)	(30)	—	(5) ³	(22) ³

¹ Represents the notional amount of long-term debt issuances hedged.

² Represents the notional amount of net purchase/(sale).

³ Total is an average net purchase/(sale) of power.

Derivatives Designated as Fair Value Hedges

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

Year ended December 31, (millions of Canadian dollars)	2024	2023
Unrealized loss on derivative	(3)	(132)
Unrealized gain on hedged item	6	131
Realized gain/(loss) on derivative	26	(47)
Realized loss on hedged item	(79)	—

The Effect of Derivative Instruments on the Statements of Earnings and Comprehensive Income

The following table presents the effect of cash flow hedges and fair value hedges on our consolidated earnings and comprehensive income, before the effect of income taxes:

Year ended December 31, (millions of Canadian dollars)	2024	2023	2022
Amount of unrealized gain/(loss) recognized in OCI			
Cash flow hedges			
Foreign exchange contracts	—	—	3
Interest rate contracts	67	201	1,151
Commodity contracts	19	68	(53)
Other contracts	1	(2)	(4)
Fair value hedges			
Foreign exchange contracts	(42)	15	(35)
	45	282	1,062
Amount of (income)/loss reclassified from AOCI to earnings			
Foreign exchange contracts ¹	53	—	13
Interest rate contracts ²	31	28	186
Commodity contracts ³	(1)	—	—
Other contracts ⁴	—	—	4
	83	28	203

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

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

3 Reported within Transportation and other services revenues in the Consolidated Statements of Earnings.

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

We estimate that no amounts from AOCI related to open cash flow hedges will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the foreign exchange rates, interest rates and commodity prices in effect when derivative contracts that are currently outstanding mature. For all forecasted transactions, the maximum term over which we are hedging exposures to the variability of cash flows is two years as at December 31, 2024.

Non-Qualifying Derivatives

The following table presents the unrealized gains and losses associated with changes in the fair value of our non-qualifying derivatives:

Year ended December 31, (millions of Canadian dollars)	2024	2023	2022
Foreign exchange contracts ¹	(2,033)	1,292	(1,344)
Interest rate contracts ²	112	(63)	10
Commodity contracts ³	(163)	(41)	50
Other contracts ⁴	2	(8)	4
Total unrealized derivative fair value gain/(loss), net	(2,082)	1,180	(1,280)

1 For the respective years ended, reported within Transportation and other services revenues (2024 - nil ; 2023 - \$645 million gain; 2022 - \$238 million loss) and Other income/(expense) (2024 - \$2,033 million loss; 2023 - \$647 million gain; 2022 - \$1,106 million loss) in the Consolidated Statements of Earnings.

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

3 For the respective years ended, reported within Transportation and other services revenues (2024 - \$23 million loss; 2023 - \$35 million loss; 2022 - \$13 million gain), Commodity sales (2024 - \$92 million loss; 2023 - \$153 million gain; 2022 - \$89 million gain), Commodity costs (2024 - \$31 million loss; 2023 - \$94 million loss; 2022 - \$102 million loss) and Operating and administrative expense (2024 - \$17 million loss; 2023 - \$65 million loss; 2022 - \$50 million gain) in the Consolidated Statements of Earnings.

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

LIQUIDITY RISK

Liquidity risk is the risk that we will not be able to meet our financial obligations, including commitments and guarantees, as they become due. In order to mitigate this risk, we forecast cash requirements over a 12-month rolling time period to determine whether sufficient funds will be available. Our primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. Our shelf prospectuses with securities regulators enable ready access to either the Canadian or US public capital markets, subject to market conditions. In addition, we maintain sufficient liquidity through committed credit facilities with a diversified group of banks and institutions which, if necessary, enables us to fund all anticipated requirements for approximately one year without accessing the capital markets. We were in compliance with all the terms and conditions of our committed credit facility agreements and term debt indentures as at December 31, 2024. As a result, all credit facilities are available to us and the banks are obligated to fund us under the terms of the facilities. We also identify other potential sources of debt and equity funding alternatives, including reinstatement of our dividend reinvestment and share purchase plan or at-the-market equity issuances.

CREDIT RISK

Entering into derivative instruments may result in exposure to credit risk from the possibility that a counterparty will default on its contractual obligations. In order to mitigate this risk, we enter into risk management transactions primarily with institutions that possess strong investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated through the maintenance and monitoring of credit exposure limits, contractual requirements and netting arrangements. We also review counterparty credit exposure using external credit rating services and other analytical tools to manage credit risk.

We have credit concentrations and credit exposure, with respect to derivative instruments, in the following counterparty segments:

December 31, (millions of Canadian dollars)	2024	2023
Canadian financial institutions	344	457
US financial institutions	128	252
European financial institutions	116	107
Asian financial institutions	53	121
Other ¹	332	125
	973	1,062

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

As at December 31, 2024, we did not provide any letters of credit in lieu of providing cash collateral to our counterparties pursuant to the terms of the relevant ISDA agreements. We held no cash collateral on derivative asset exposures as at December 31, 2024 and 2023.

Gross derivative balances have been presented without the effects of collateral posted. Derivative assets are adjusted for non-performance risk of our counterparties using their credit default swap spread rates and are reflected at fair value. For derivative liabilities, our non-performance risk is considered in the valuation.

Credit risk also arises from trade and other long-term receivables, and is mitigated through credit exposure limits and contractual requirements, the assessment of counterparty credit ratings and netting arrangements. Within the Gas Distribution and Storage segment, credit risk is mitigated by the utility's large and diversified customer base and the ability to recover expected credit losses through the ratemaking process. We actively monitor the financial strength of large industrial customers and, in select cases, have obtained additional security to minimize the risk of default on receivables. Generally, we utilize a loss allowance matrix which contemplates historical credit losses by age of receivables, adjusted for any forward-looking information and management expectations to measure lifetime expected credit losses of receivables. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value.

FAIR VALUE MEASUREMENTS

Our financial assets and liabilities measured at fair value on a recurring basis include derivatives and other financial instruments. We also disclose the fair value of other financial instruments not measured at fair value. The fair value of financial instruments reflects our best estimates of market value based on generally accepted valuation techniques or models and is supported by observable market prices and rates. When such values are not available, we use discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value.

FAIR VALUE OF FINANCIAL INSTRUMENTS

We categorize our financial instruments measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement.

Level 1

Level 1 includes financial instruments measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a financial instrument is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis. Under the fair value hierarchy, cash and cash equivalents are classified as Level 1. Our Level 1 instruments consist primarily of exchange-traded derivatives used to mitigate the risk of crude oil price fluctuations, US and Canadian treasury bills, and investments in exchange-traded funds held by our captive insurance subsidiaries. We also hold restricted long-term investments in exchange-traded funds and common shares in trusts in accordance with the CER's regulatory requirements under the LMCI and to cover future pipeline decommissioning costs in the state of Minnesota.

Level 2

Level 2 includes financial instrument valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Financial instruments in this category are valued using models or other industry standard valuation techniques derived from observable market data. Such valuation techniques include inputs such as quoted forward prices, time value, volatility factors and broker quotes that can be observed or corroborated in the market for the entire duration of the financial instrument. Derivatives valued using Level 2 inputs include non-exchange traded derivatives such as over-the-counter foreign exchange forward and cross-currency swap contracts, interest rate swaps, physical forward commodity contracts, as well as commodity swaps and options for which observable inputs can be obtained.

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

Level 3

Level 3 includes derivative valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the derivative's fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available or have no binding broker quote to support Level 2 classification. We have developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on the extrapolation of observable future prices and rates. Derivatives valued using Level 3 inputs primarily include long-dated derivative power, NGL and natural gas contracts, basis swaps, commodity swaps, and power and energy swaps, physical forward commodity contracts, as well as options. We do not have any other financial instruments categorized in Level 3.

We use the most observable inputs available to estimate the fair value of our derivatives. When possible, we estimate the fair value of our derivatives based on quoted market prices. If quoted market prices are not available, we use estimates from third-party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, we use standard valuation techniques to calculate the estimated fair value. These methods include discounted cash flows for forwards and swaps and Black-Scholes-Merton pricing models for options. Depending on the type of derivative and nature of the underlying risk, we use observable market prices (interest, foreign exchange, commodity and share price) and volatility as primary inputs to these valuation techniques. Finally, we consider our own credit default swap spread, as well as the credit default swap spreads associated with our counterparties, in our estimation of fair value.

Fair Value of Derivatives

We have categorized our derivative assets and liabilities measured at fair value as follows:

				Total Gross Derivative Instruments
December 31, 2024	Level 1	Level 2	Level 3	
<i>(millions of Canadian dollars)</i>				
Financial assets				
Current derivative assets				
Foreign exchange contracts	—	125	—	125
Interest rate contracts	—	67	—	67
Commodity contracts	34	72	256	362
Other contracts	—	3	—	3
	34	267	256	557
Long-term derivative assets				
Foreign exchange contracts	—	83	—	83
Interest rate contracts	—	146	—	146
Commodity contracts	1	14	182	197
Other contracts	—	—	—	—
	1	243	182	426
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	—	(804)	—	(804)
Interest rate contracts	—	(80)	—	(80)
Commodity contracts	(52)	(116)	(283)	(451)
Other contracts	—	—	—	—
	(52)	(1,000)	(283)	(1,335)
Long-term derivative liabilities				
Foreign exchange contracts	—	(1,579)	—	(1,579)
Interest rate contracts	—	(80)	—	(80)
Commodity contracts	(1)	(31)	(207)	(239)
Other contracts	—	—	—	—
	(1)	(1,690)	(207)	(1,898)
Total net derivative asset/(liability)				
Foreign exchange contracts	—	(2,175)	—	(2,175)
Interest rate contracts	—	53	—	53
Commodity contracts	(18)	(61)	(52)	(131)
Other contracts	—	3	—	3
	(18)	(2,180)	(52)	(2,250)

December 31, 2023	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
<i>(millions of Canadian dollars)</i>				
Financial assets				
Current derivative assets				
Foreign exchange contracts	—	139	—	139
Interest rate contracts	—	65	—	65
Commodity contracts	142	103	173	418
Other contracts	—	1	—	1
	142	308	173	623
Long-term derivative assets				
Foreign exchange contracts	—	335	—	335
Interest rate contracts	—	53	—	53
Commodity contracts	—	24	51	75
	—	412	51	463
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	—	(128)	—	(128)
Interest rate contracts	—	(186)	—	(186)
Commodity contracts	(136)	(76)	(211)	(423)
Other contracts	—	(1)	—	(1)
	(136)	(391)	(211)	(738)
Long-term derivative liabilities				
Foreign exchange contracts	—	(498)	—	(498)
Interest rate contracts	—	(88)	—	(88)
Commodity contracts	—	(22)	(144)	(166)
	—	(608)	(144)	(752)
Total net derivative asset/(liability)				
Foreign exchange contracts	—	(152)	—	(152)
Interest rate contracts	—	(156)	—	(156)
Commodity contracts	6	29	(131)	(96)
Other contracts	—	—	—	—
	6	(279)	(131)	(404)

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

December 31, 2024	Fair Value	Unobservable Input	Minimum Price/ Volatility	Maximum Price/ Volatility	Weighted Average Price/Volatility	Unit of Measurement
<i>(fair value in millions of Canadian dollars)</i>						
Commodity contracts - financial ¹						
Natural gas	(5)	Forward gas price	3.73	9.85	4.12	\$/mmbtu ²
Crude	(13)	Forward crude price	73.54	104.42	97.44	\$/barrel
Power	(44)	Forward power price	31.17	229.29	68.51	\$/MW/H
Commodity contracts - physical ¹						
Natural gas	(80)	Forward gas price	1.40	22.57	4.12	\$/mmbtu ²
Crude	22	Forward crude price	77.31	118.28	99.76	\$/barrel
Power	(98)	Forward power price	12.94	211.42	70.30	\$/MW/H
Commodity options ³						
Natural gas	166	Forward gas price	2.44	7.09	4.44	\$/mmbtu ²
		Price volatility	3%	77%	50%	
	(52)					

¹ Financial and physical forward commodity contracts are valued using a market approach valuation technique.

² One million British thermal units (mmbtu).

³ Commodity options contracts are valued using an option model valuation technique.

If adjusted, the significant unobservable inputs disclosed in the table above would have a direct impact on the fair value of our Level 3 derivative instruments. The significant unobservable inputs used in the fair value measurement of Level 3 derivative instruments include forward commodity prices. Changes in forward commodity prices could result in significantly different fair values for our Level 3 derivatives.

Changes in the net fair value of derivative assets and liabilities classified as Level 3 in the fair value hierarchy were as follows:

Year ended December 31,	2024	2023
<i>(millions of Canadian dollars)</i>		
Level 3 net derivative liability at beginning of year	(131)	(136)
Total gain/(loss), unrealized		
Included in earnings ¹	(92)	(48)
Included in OCI	19	67
Included in regulatory assets/liabilities	130	—
Settlements	22	(14)
Level 3 net derivative liability at end of year	(52)	(131)

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

There were no transfers into or out of Level 3 as at December 31, 2024 or 2023.

Net Investment Hedges

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

During the years ended December 31, 2024 and 2023, we recognized unrealized foreign exchange losses of \$1,185 million and gains of \$645 million, respectively, on the translation of US dollar-denominated debt, in OCI. No unrealized gains or losses on the change in fair value of our outstanding foreign exchange forward contracts were recognized in OCI during the years ended December 31, 2024 and 2023. No realized gains or losses associated with the settlement of foreign exchange forward contracts were recognized in OCI during the years ended December 31, 2024 and 2023. During the years ended December 31, 2024 and 2023, we recognized realized losses of \$120 million and losses of \$236 million, respectively, associated with the settlement of US dollar-denominated debt that had matured during the period, in OCI.

Fair Value of Other Financial Instruments

Certain long-term investments in other entities with no actively quoted prices are classified as FVMA investments and are recorded at cost less impairment. The carrying value of FVMA investments totaled \$187 million and \$173 million as at December 31, 2024 and 2023, respectively.

We have wholly-owned captive insurance subsidiaries whose principal activity is providing insurance and reinsurance coverage for certain insurable property and casualty risk exposures of our operating subsidiaries and certain equity investments. As at December 31, 2024, the fair value of investments in equity funds and debt securities held by our captive insurance subsidiaries was \$114 million and \$1.1 billion, respectively (2023 - \$287 million and \$284 million, respectively). Our investments in debt securities had a cost basis of \$1.1 billion as at December 31, 2024 (2023 - \$279 million). These investments in equity funds and debt securities are recognized at fair value, classified as Level 1 and Level 2 in the fair value hierarchy, respectively, and are recorded in Other current assets and Long-term investments in the Consolidated Statements of Financial Position. There were unrealized holding losses of \$16 million for the year ended December 31, 2024 (2023 - gains of \$34 million).

As at December 31, 2024 and 2023, our long-term debt had a carrying value of \$101.6 billion and \$81.2 billion, respectively, before debt issuance costs and a fair value of \$98.9 billion and \$78.1 billion, respectively.

As at December 31, 2024 and 2023, we had investments with a fair value of \$998 million and \$717 million, respectively, included in Restricted long-term investments and cash in the Consolidated Statements of Financial Position which are classified as available-for-sale. These securities represent restricted funds held in trust for the purpose of funding pipeline abandonment in accordance with the CER's regulatory requirements, to cover future pipeline decommissioning costs in the state of Minnesota and to satisfy retirement obligations as Wexpro properties are abandoned.

We had restricted long-term investments and cash held in trust totaling \$491 million and \$263 million as at December 31, 2024 and 2023, respectively, which are classified as Level 1 in the fair value hierarchy. We also had restricted long-term investments held in trust totaling \$507 million (cost basis - \$540 million) and \$454 million (cost basis - \$486 million) as at December 31, 2024 and 2023, respectively, which are classified as Level 2 in the fair value hierarchy. There were unrealized holding gains of \$33 million and \$51 million on these investments for the years ended December 31, 2024 and 2023, respectively. Within Other long-term liabilities we had estimated future abandonment costs related to LMCI of \$826 million and \$745 million as at December 31, 2024 and 2023, respectively (*Note 7*).

The fair value of financial assets and liabilities other than derivative instruments, certain long-term investments in other entities, restricted long-term investments, investments held by our captive insurance subsidiaries and long-term debt described above approximate their carrying value due to the short period to maturity.

24. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31, (millions of Canadian dollars)	2024	2023	2022
Earnings before income taxes	7,299	7,879	4,542
Canadian federal statutory income tax rate	15%	15%	15%
Expected federal taxes at statutory rate	1,095	1,182	681
Increase/(decrease) resulting from:			
Provincial and state income taxes ¹	183	411	108
Foreign and other statutory rate differentials ²	340	187	295
Effects of rate-regulated accounting ^{3,4}	(192)	(106)	(122)
Write-off of regulatory deferrals ^{3,5}	4	115	—
Part VI.1 tax, net of federal Part I deduction ^{3,6}	73	66	76
US Minimum Tax	148	100	107
Non-taxable portion of gain on sale of investment ^{3,7}	(147)	—	—
Valuation allowance ³	(2)	(12)	6
Accounting impairment of non-deductible goodwill ^{3,8}	148	—	370
Noncontrolling interests ^{3,9}	(30)	19	9
Investment and production tax credits	(23)	(47)	—
Other ³	71	(94)	74
Income tax expense	1,668	1,821	1,604
Effective income tax rate	22.9%	23.1%	35.3%

1 The change in provincial and state income taxes from 2023 to 2024 reflects the decrease in earnings from Canadian operations partially offset by an increase in earnings from US operations before considering the non-deductible goodwill impairment to the Gas Transmission segment. Refer to Note 13 - Long-Term Investments.

2 The change in foreign and other statutory rate differentials from 2023 to 2024 reflects the increase in earnings from US operations before considering the non-deductible goodwill impairment to the Gas Transmission segment. Refer to Note 13 - Long-Term Investments.

3 The provincial and state tax component of these items is included in the Provincial and state income taxes above.

4 The amount in 2024 includes the effects of rate regulated accounting attributable to the Acquisitions. Refer to Note 8 - Acquisitions and Disposition.

5 The amount in 2023 includes the federal tax impact of the de-recognition of rate-regulated accounting for income tax relating to Southern Lights Canada and portions of the Canadian Mainline including Line 9 and L3R. Refer to Note 7 - Regulatory Matters.

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

7 The amount in 2024 represents the federal component of the non-taxable portion of the gain on sales relating to Alliance Pipeline and Aux Sable. Refer to Note 13 - Long-Term Investments.

8 The amounts relates to the federal impact of the non-deductible goodwill impairment to the Gas Transmissions segment. Refer to Note 13 - Long-Term Investments and Note 15 - Goodwill.

9 The amount in 2023 and 2022 includes the federal tax impact of impairments to Chapman Ranch and Magic Valley attributable to non-controlling interests in those respective years. Refer to Note 11 - Property, Plant and Equipment.

COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES

Year ended December 31, (millions of Canadian dollars)	2024	2023	2022
Earnings before income taxes			
Canada	1,035	2,233	583
US	5,231	4,620	2,865
Other	1,033	1,026	1,094
	7,299	7,879	4,542
Current income taxes			
Canada	248	100	360
US	578	191	201
Other	123	110	86
	949	401	647
Deferred income taxes			
Canada	(299)	456	(358)
US	1,013	974	1,309
Other	5	(10)	6
	719	1,420	957
Income tax expense	1,668	1,821	1,604

COMPONENTS OF DEFERRED INCOME TAXES

Deferred income tax assets and liabilities are recognized for the future tax consequences of differences between carrying amounts of assets and liabilities and their respective tax bases. Major components of deferred income tax assets and liabilities are as follows:

December 31, (millions of Canadian dollars)	2024	2023
Deferred income tax liabilities		
Property, plant and equipment	(11,368)	(9,202)
Investments	(9,043)	(7,765)
Regulatory assets	(1,940)	(1,338)
Other	(251)	(52)
Total deferred income tax liabilities	(22,602)	(18,357)
Deferred income tax assets		
Financial instruments	740	271
Loss carryforwards	1,272	1,745
Other	2,088	1,798
Total deferred income tax assets	4,100	3,814
Less valuation allowance	(298)	(147)
Total deferred income tax assets, net	3,802	3,667
Net deferred income tax liabilities, net	(18,800)	(14,690)
Presented as follows:		
Total deferred income tax assets	796	341
Total deferred income tax liabilities	(19,596)	(15,031)
Net deferred income tax liabilities, net	(18,800)	(14,690)

A valuation allowance has been established for certain loss and credit carryforwards, and outside basis temporary differences on investments that reduce deferred income tax assets to an amount that will more likely than not be realized.

As at both December 31, 2024 and 2023, we recognized the benefit of unused tax loss carryforwards of \$1.3 billion in Canada which expire in 2031 and beyond.

As at December 31, 2024, and 2023, we recognized the benefit of unused tax loss carryforwards of \$4.2 billion and \$6.4 billion, respectively, in the US with no expiration.

We have not provided for deferred income taxes on the difference between the carrying value of substantially all of our foreign subsidiaries and their corresponding tax basis as the earnings of those subsidiaries are intended to be permanently reinvested in their operations. As such, these investments are not anticipated to give rise to income taxes in the foreseeable future. The difference between the carrying values of the investments and their tax bases is largely a result of unremitted earnings and currency translation adjustments. The unremitted earnings and currency translation adjustment for which no deferred taxes have been recognized in respect of foreign subsidiaries were \$9.5 billion and \$6.6 billion for the periods ended December 31, 2024 and 2023, respectively. If such earnings are remitted, in the form of dividends or otherwise, we may be subject to income taxes and foreign withholding taxes. The determination of the amount of unrecognized deferred income tax liabilities applicable to such amounts is not practicable.

Enbridge and certain of our subsidiaries are subject to taxation in Canada, the US and other foreign jurisdictions. The material jurisdictions in which we are subject to potential examinations include the US (Federal) and Canada (Federal, Alberta and Québec). We are open to examination by Canadian tax authorities for the 2017 to 2024 tax years and by US tax authorities for the 2021 to 2024 tax years. We are currently under examination for income tax matters in Canada for the 2018 to 2021 tax years. We are not currently under examination for income tax matters in any other material jurisdiction where we are subject to income tax.

UNRECOGNIZED TAX BENEFITS

Year ended December 31, (millions of Canadian dollars)	2024	2023
Unrecognized tax benefits at beginning of year	45	55
Gross decreases for tax positions of prior year	(2)	(2)
Change in translation of foreign currency	4	(1)
Lapses of statute of limitations	(16)	(7)
Unrecognized tax benefits at end of year	31	45

The unrecognized tax benefits as at December 31, 2024, if recognized, would impact our effective income tax rate. We do not anticipate further adjustments to the unrecognized tax benefits during the next 12 months that would have a material impact on our consolidated financial statements.

We recognize accrued interest and penalties related to unrecognized tax benefits as a component of income taxes. Interest and penalties included in income taxes for the years ended December 31, 2024 and 2023 were \$8 million recovery and \$1 million expense, respectively. As at December 31, 2024 and 2023, interest and penalties of \$6 million and \$14 million, respectively, have been accrued.

25. PENSION AND OTHER POSTRETIREMENT BENEFITS

PENSION PLANS

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

Defined Benefit Pension Plan Benefits

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

Defined Contribution Pension Plan Benefits

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

Benefit Obligations, Plan Assets and Funded Status

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

December 31, (millions of Canadian dollars)	Canada		US	
	2024	2023	2024	2023
Change in projected benefit obligation				
Projected benefit obligation at beginning of year	4,092	3,630	1,036	1,029
Service cost	103	81	60	40
Interest cost	186	184	69	47
Participant contributions	32	31	—	—
Actuarial (gain)/loss ¹	—	359	(98)	31
Benefits paid	(210)	(193)	(100)	(76)
Transfer in	—	—	569	—
Foreign currency exchange rate changes	—	—	119	(29)
Other	—	—	(7)	(6)
Projected benefit obligation at end of year ²	4,203	4,092	1,648	1,036
Change in plan assets				
Fair value of plan assets at beginning of year	4,528	4,234	1,052	1,080
Actual return on plan assets	627	427	197	78
Employer contributions	23	27	5	5
Participant contributions	32	31	—	—
Benefits paid	(210)	(193)	(100)	(76)
Transfer in	—	—	900	—
Foreign currency exchange rate changes	—	—	146	(29)
Other	—	2	(6)	(6)
Fair value of plan assets at end of year ³	5,000	4,528	2,194	1,052
Overfunded status at end of year	797	436	546	16
Presented as follows:				
Deferred amounts and other assets	943	636	653	116
Other current liabilities	(10)	(8)	(6)	(5)
Other long-term liabilities	(136)	(192)	(101)	(95)
	797	436	546	16

¹ Primarily due to the increase in the discount rate and changes in benefit assumptions and member data used to measure the defined benefit obligations (2023 - primarily due to the decrease in the discount rates used to measure the benefit obligation).

² The accumulated benefit obligation for our Canadian pension plans was \$3.9 billion and \$3.8 billion as at December 31, 2024 and 2023, respectively. The accumulated benefit obligation for our US pension plans was \$1.6 billion and \$1.0 billion as at December 31, 2024 and 2023, respectively.

³ Assets in the amount of \$18 million (2023 - \$14 million) and \$80 million (2023 - \$62 million), related to our Canadian and US non-registered supplemental pension plan obligations, respectively, are held in grantor trusts and rabbi trusts that, in accordance with federal tax regulations, are not restricted from creditors. These assets are committed for the future settlement of benefit obligations included in the underfunded status as at the end of the year, however they are excluded from plan assets for accounting purposes.

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

December 31, (millions of Canadian dollars)	Canada		US	
	2024	2023	2024	2023
Accumulated benefit obligation	404	394	107	99
Fair value of plan assets	283	243	—	—

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

December 31, (millions of Canadian dollars)	Canada		US	
	2024	2023	2024	2023
Projected benefit obligation	428	416	107	99
Fair value of plan assets	283	243	—	—

Amount Recognized in Accumulated Other Comprehensive Income

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

December 31, (millions of Canadian dollars)	Canada		US	
	2024	2023	2024	2023
Net actuarial (gain)/loss	(122)	51	(42)	74
Prior service cost	—	—	5	1
Total amount recognized in AOCI ¹	(122)	51	(37)	75

¹ Excludes amounts related to CTA.

Net Periodic Benefit (Credit)/Cost and Other Amounts Recognized in Comprehensive Income

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

Year ended December 31, (millions of Canadian dollars)	Canada			US		
	2024	2023	2022	2024	2023	2022
Service cost ¹	103	81	131	60	40	43
Interest cost ²	186	184	127	69	47	24
Expected return on plan assets ²	(304)	(271)	(295)	(131)	(77)	(85)
Amortization/settlement of net actuarial (gain)/loss ²	4	—	8	7	(4)	—
Amortization/curtailment of prior service credit ²	—	—	—	(4)	—	(2)
Net periodic benefit (credit)/cost	(11)	(6)	(29)	1	6	(20)
Defined contribution benefit cost	12	12	10	—	—	—
Net pension (credit)/cost recognized in Earnings	1	6	(19)	1	6	(20)
Amount recognized in OCI:						
Amortization/settlement of net actuarial (gain)/loss	—	—	(2)	—	4	—
Amortization/curtailment of prior service credit	—	—	—	4	—	2
Net actuarial (gain)/loss arising during the year	(173)	115	(288)	(116)	30	(52)
Total amount recognized in OCI	(173)	115	(290)	(112)	34	(50)
Total amount recognized in Comprehensive income	(172)	121	(309)	(111)	40	(70)

¹ Reported within Operating and administrative in the Consolidated Statements of Earnings.

² Reported within Other income/(expense) in the Consolidated Statements of Earnings.

Actuarial Assumptions

The weighted average assumptions made in the measurement of the projected benefit obligation and net periodic benefit cost of our pension plans are as follows:

	Canada			US		
	2024	2023	2022	2024	2023	2022
Projected benefit obligation						
Discount rate	4.7%	4.6%	5.1%	5.5%	4.7%	4.9%
Rate of salary increase	3.0%	3.0%	2.9%	2.6%	2.6%	2.8%
Cash balance interest credit rate	N/A	N/A	N/A	4.0%	4.5%	4.3%
Net periodic benefit cost						
Discount rate	4.6%	5.3%	3.2%	4.8%	4.9%	2.6%
Rate of return on plan assets	6.8%	6.5%	6.6%	7.3%	7.4%	7.4%
Rate of salary increase	3.0%	2.9%	2.9%	2.8%	2.8%	2.8%
Cash balance interest credit rate	N/A	N/A	N/A	4.4%	4.3%	4.3%

OTHER POSTRETIREMENT BENEFIT PLANS

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

Benefit Obligations, Plan Assets and Funded Status

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

December 31, (millions of Canadian dollars)	Canada		US	
	2024	2023	2024	2023
Change in accumulated postretirement benefit obligation				
Accumulated postretirement benefit obligation at beginning of year	228	211	129	136
Service cost	3	3	3	1
Interest cost	10	11	7	6
Participant contributions	—	—	5	5
Actuarial (gain)/loss ¹	(21)	13	(9)	4
Benefits paid	(10)	(10)	(20)	(20)
Transfer in	—	—	46	—
Foreign currency exchange rate changes	—	—	16	(3)
Accumulated postretirement benefit obligation at end of year	210	228	177	129
Change in plan assets				
Fair value of plan assets at beginning of year	—	—	187	185
Actual return on plan assets	—	—	22	14
Employer contributions	10	10	7	7
Participant contributions	—	—	5	5
Benefits paid	(10)	(10)	(20)	(20)
Transfer in	—	—	55	—
Foreign currency exchange rate changes	—	—	20	(4)
Other	—	—	2	—
Fair value of plan assets at end of year	—	—	278	187
Overfunded/(underfunded) status at end of year	(210)	(228)	101	58
Presented as follows:				
Deferred amounts and other assets	—	—	113	73
Other current liabilities	(11)	(12)	—	—
Other long-term liabilities	(199)	(216)	(12)	(15)
	(210)	(228)	101	58

¹ Primarily due to the increase in the discount rate and changes in benefit assumptions and member data used to measure the defined benefit obligation (2023 - primarily due to decrease in the discount rate used to measure the benefit obligations).

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

December 31, (millions of Canadian dollars)	Canada		US	
	2024	2023	2024	2023
Accumulated benefit obligation	210	228	100	78
Fair value of plan assets	—	—	88	63

Amount Recognized in Accumulated Other Comprehensive Income

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

December 31, (millions of Canadian dollars)	Canada		US	
	2024	2023	2024	2023
Net actuarial gain	(99)	(82)	(103)	(96)
Prior service credit	—	(1)	(16)	(22)
Total amount recognized in AOCI ¹	(99)	(83)	(119)	(118)

¹ Excludes amounts related to CTA.

Net Periodic Benefit (Credit)/Cost and Other Amounts Recognized in Comprehensive Income

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

Year ended December 31, (millions of Canadian dollars)	Canada			US		
	2024	2023	2022	2024	2023	2022
Service cost ¹	3	3	4	3	1	1
Interest cost ²	10	11	7	7	6	3
Expected return on plan assets ²	—	—	—	(15)	(11)	(12)
Amortization/settlement of net actuarial gain ²	(5)	(6)	(1)	(5)	(6)	(6)
Amortization/curtailment of prior service credit ²	(1)	—	—	(6)	(8)	(7)
Net periodic benefit (credit)/cost recognized in Earnings	7	8	10	(16)	(18)	(21)
Amount recognized in OCI:						
Amortization/settlement of net actuarial gain	5	6	1	5	6	6
Amortization/curtailment of prior service credit	1	—	—	6	8	7
Net actuarial (gain)/loss arising during the year	(22)	13	(67)	(12)	—	(4)
Total amount recognized in OCI	(16)	19	(66)	(1)	14	9
Total amount recognized in Comprehensive income	(9)	27	(56)	(17)	(4)	(12)

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

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

The weighted average assumptions made in the measurement of the accumulated postretirement benefit obligation and net periodic benefit cost of our OPEB plans are as follows:

	Canada			US		
	2024	2023	2022	2024	2023	2022
Accumulated postretirement benefit obligation						
Discount rate	4.7%	4.6%	5.3%	5.3%	4.7%	4.9%
Net periodic benefit cost						
Discount rate	4.6%	5.3%	3.2%	5.5%	4.9%	2.4%
Rate of return on plan assets	N/A	N/A	N/A	6.7%	5.9%	6.0%

Assumed Health Care Cost Trend Rates

The assumed rates for the next year used to measure the expected cost of benefits are as follows:

	Canada		US ¹	
	2024	2023	2024	2023
Health care cost trend rate assumed for next year	4.0%	4.0%	3.2%	4.7%
Rate to which the cost trend is assumed to decline (ultimate trend rate)	4.0%	4.0%	3.7%	3.3%
Year that the rate reaches the ultimate trend rate	N/A	N/A	2023 - 2046	2022 - 2045

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

PLAN ASSETS

We manage the investment risk of our pension funds by setting a long-term asset mix policy for each plan after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plan; (iv) our operating environment and financial situation and our ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets.

The overall expected rate of return on plan assets is based on the asset allocation targets with estimates for returns based on long-term expectations.

The asset allocation targets and major categories of plan assets are as follows:

Asset Category	Canada			US		
	Target Allocation	December 31,		Target Allocation	December 31,	
		2024	2023		2024	2023
Equity securities	46.2%	39.1%	41.4%	43.4%	44.8%	39.5%
Fixed income securities	23.0%	31.6%	29.6%	23.2%	33.0%	19.4%
Alternatives ¹	30.8%	29.3%	29.0%	33.4%	22.2%	41.1%

1 Alternatives include investments in private debt, private equity, infrastructure and real estate funds. Fund values are based on the net asset value of the funds that invest directly in the aforementioned underlying investments. The values of the investments have been estimated using the capital accounts representing the plan's ownership interest in the funds.

Pension Plans

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

	Canada				US			
	Level 1 ¹	Level 2 ²	Level 3 ³	Total	Level 1 ¹	Level 2 ²	Level 3 ³	Total
<i>(millions of Canadian dollars)</i>								
December 31, 2024								
Cash and cash equivalents	201	—	—	201	57	—	—	57
Equity securities ⁴								
Canada	—	3	—	3	—	—	—	—
Global	134	1,817	—	1,951	27	954	—	981
Fixed income securities ⁴								
Government	—	543	—	543	—	194	—	194
Corporate	—	838	—	838	—	474	—	474
Alternatives ⁵	—	—	1,464	1,464	—	—	488	488
Total pension plan assets at fair value	335	3,201	1,464	5,000	84	1,622	488	2,194
December 31, 2023								
Cash and cash equivalents	227	—	—	227	8	—	—	8
Equity securities ⁴								
Canada	—	3	—	3	—	—	—	—
Global	—	1,871	—	1,871	—	416	—	416
Fixed income securities ⁴								
Government	—	446	—	446	—	46	—	46
Corporate	—	667	—	667	—	149	—	149
Alternatives ⁵	—	—	1,290	1,290	—	—	433	433
Forward currency contracts	—	24	—	24	—	—	—	—
Total pension plan assets at fair value	227	3,011	1,290	4,528	8	611	433	1,052

1 Level 1 assets include assets with quoted prices in active markets for identical assets.

2 Level 2 assets include assets with significant observable inputs.

3 Level 3 assets include assets with significant unobservable inputs.

4 Pension plan assets include \$77 million (2023 - \$61 million) of indirectly held related party equity and fixed income securities investments.

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

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

December 31,	Canada		US	
	2024	2023	2024	2023
<i>(millions of Canadian dollars)</i>				
Balance at beginning of year	1,290	1,291	433	445
Unrealized and realized gains/(losses)	104	(41)	63	(12)
Purchases and settlements, net	70	40	(8)	—
Balance at end of year	1,464	1,290	488	433

OPEB Plans

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

	Level 1 ¹	Level 2 ²	Level 3 ³	Total
<i>(millions of Canadian dollars)</i>				
December 31, 2024				
Cash and cash equivalents	4	—	—	4
Equity securities				
US	—	52	—	52
Global	—	93	—	93
Fixed income securities				
Government	71	6	—	77
Corporate	—	19	—	19
Alternatives ⁴	—	—	33	33
Total OPEB plan assets at fair value	75	170	33	278
December 31, 2023				
Cash and cash equivalents	3	—	—	3
Equity securities				
US	—	36	—	36
Global	—	62	—	62
Fixed income securities				
Government	42	3	—	45
Corporate	—	12	—	12
Alternatives ⁴	—	—	29	29
Total OPEB plan assets at fair value	45	113	29	187

1 Level 1 assets include assets with quoted prices in active markets for identical assets.

2 Level 2 assets include assets with significant observable inputs.

3 Level 3 assets include assets with significant unobservable inputs.

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

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

December 31,	2024	2023
<i>(millions of Canadian dollars)</i>		
Balance at beginning of year	29	28
Unrealized and realized gains	5	1
Purchases and settlements, net	(1)	—
Balance at end of year	33	29

EXPECTED BENEFIT PAYMENTS

Year ending December 31, <i>(millions of Canadian dollars)</i>	2025	2026	2027	2028	2029	2030-2034
Pension						
Canada	214	220	226	232	238	1,285
US	117	120	123	123	120	625
OPEB						
Canada	11	12	12	12	12	64
US	16	16	16	16	16	71

EXPECTED EMPLOYER CONTRIBUTIONS

In 2025, we expect to contribute approximately \$21 million and \$6 million to the Canadian and US pension plans, respectively, and \$11 million and \$6 million to the Canadian and US OPEB plans, respectively.

RETIREMENT SAVINGS PLANS

In addition to the pension and OPEB plans discussed above, we also have defined contribution employee savings plans available to US employees. Employees may receive a matching contribution where we match a certain percentage of before-tax employee contributions ranging from 3.0% to 7.0% of eligible pay per pay period. For the year ended December 31, 2024, pre-tax employer matching contribution costs were \$35 million (\$33 million in 2023 and \$30 million in 2022).

26. LEASES

LESSEE

We incur operating lease expenses related primarily to real estate, pipelines, storage and equipment. Our operating leases have remaining lease terms of 2 months to 41 years as at December 31, 2024.

For the years ended December 31, 2024, 2023 and 2022, we incurred operating lease expenses of \$132 million, \$131 million and \$118 million, respectively. Operating lease expenses are reported under Operating and administrative expense in the Consolidated Statements of Earnings.

For the years ended December 31, 2024, 2023 and 2022, operating lease payments to settle lease liabilities were \$128 million, \$129 million and \$123 million, respectively. Operating lease payments are reported under Operating activities in the Consolidated Statements of Cash Flows.

Supplemental Statements of Financial Position Information

	December 31, 2024	December 31, 2023
<i>(millions of Canadian dollars, except lease term and discount rate)</i>		
Operating leases¹		
Operating lease right-of-use assets, net ²	785	669
Operating lease liabilities - current ³	121	98
Operating lease liabilities - long-term ³	738	652
Total operating lease liabilities	859	750
Finance leases		
Finance lease right-of-use assets, net ⁴	294	287
Finance lease liabilities - current ⁵	16	19
Finance lease liabilities - long-term ⁵	300	264
Total finance lease liabilities	316	283
Weighted average remaining lease term		
Operating leases	14 years	12 years
Finance leases	31 years	31 years
Weighted average discount rate		
Operating leases	4.8%	4.5%
Finance leases	5.8%	5.7%

1 Affiliate ROU assets, current lease liabilities and long-term lease liabilities as at December 31, 2024 were \$42 million (December 31, 2023 - \$42 million), \$6 million (December 31, 2023 - \$5 million) and \$37 million (December 31, 2023 - \$38 million), respectively.

2 Operating lease ROU assets are reported under Deferred amounts and other assets in the Consolidated Statements of Financial Position.

3 Current operating lease liabilities and long-term operating lease liabilities are reported under Other current liabilities and Other long-term liabilities, respectively, in the Consolidated Statements of Financial Position.

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

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

As at December 31, 2024, our operating and finance lease liabilities are expected to mature as follows:

	Operating leases	Finance leases
<i>(millions of Canadian dollars)</i>		
2025	148	31
2026	134	30
2027	123	23
2028	97	23
2029	65	22
Thereafter	685	531
Total undiscounted lease payments	1,252	660
Less imputed interest	(393)	(344)
Total	859	316

LESSOR

We receive revenues from operating leases primarily related to natural gas and crude oil storage and processing facilities, and wind power generation assets. Our operating leases have remaining lease terms of 3 months to 27 years as at December 31, 2024.

Year ended December 31, (millions of Canadian dollars)	2024	2023	2022
Operating lease income	229	241	266
Variable lease income	321	299	321
Total lease income ¹	550	540	587

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

As at December 31, 2024, our future lease payments to be received under operating lease contracts where we are the lessor are as follows:

	Operating leases
(millions of Canadian dollars)	
2025	221
2026	202
2027	197
2028	198
2029	199
Thereafter	1,415
Future lease payments	2,432

27. OTHER INCOME/(EXPENSE)

Year ended December 31, (millions of Canadian dollars)	2024	2023	2022
Realized foreign currency gain/(loss)	121	(129)	92
Unrealized foreign currency gain/(loss)	(2,199)	821	(1,094)
Net defined pension and OPEB credit	188	135	239
Other	564	397	174
	(1,326)	1,224	(589)

28. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31, (millions of Canadian dollars)	2024	2023	2022
Trade receivables and unbilled revenues	(1,638)	1,125	(572)
Accounts receivable from affiliates	(23)	18	17
Inventory	177	763	(599)
Other current and non-current assets	(426)	1,301	(394)
Trade payables and accrued liabilities	1,383	(1,542)	585
Accounts payable to affiliates	(8)	(66)	16
Interest payable	157	199	58
Other current and long-term liabilities	245	513	877
	(133)	2,311	(12)

29. RELATED PARTY TRANSACTIONS

Related party transactions are conducted in the normal course of business and, unless otherwise noted, are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

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

Our transactions with significantly influenced investees are as follows:

Year ended December 31, (millions of Canadian dollars)	2024	2023	2022
Transportation and other revenues	181	169	185
Commodity sales	—	—	51
Operating and administrative ¹	637	625	503
Commodity costs ²	22	63	778
Gas distribution costs	147	140	136

¹ During the years ended December 31, 2024, 2023 and 2022, we had Operating and administrative costs from the Seaway Crude Pipeline System of \$650 million, \$632 million and \$495 million, respectively. These costs are a result of an operational contract where we utilize capacity on Seaway Crude Pipeline System assets for use in our Liquids Pipelines business.

² During the years ended December 31, 2024, 2023 and 2022, we had Commodity costs from Aux Sable Canada LP of nil, \$2 million and \$571 million, respectively.

30. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

As at December 31, 2024, we have commitments as detailed below:

	Total	Less than 1 year	2 years	3 years	4 years	5 years	Thereafter
(millions of Canadian dollars)							
Purchase of services, pipe and other materials, including transportation ¹	14,019	4,260	2,047	1,755	1,535	1,200	3,222
Maintenance agreements ²	452	57	56	57	36	36	210
Right-of-ways commitments ³	981	52	48	53	49	49	730
Total	15,452	4,369	2,151	1,865	1,620	1,285	4,162

¹ Includes capital and operating commitments. Consists primarily of firm capacity payments that provide us with uninterrupted firm access to natural gas and crude oil transportation and storage contracts; contractual obligations to purchase physical quantities of natural gas; and power commitments.

² Consists primarily of maintenance service contracts for our wind and solar assets.

³ Our right-of-way obligations primarily consist of non-lease agreements that existed at the time of adopting Topic 842 Leases, at which time we elected a practical expedient that allowed us to continue our historical treatment.

ENVIRONMENTAL

We are subject to various Canadian and US federal, provincial/state and local laws relating to the protection of the environment. These laws and regulations can change from time to time, imposing new obligations on us.

Environmental risk is inherent to liquid hydrocarbon and natural gas pipeline operations, and Enbridge and its affiliates are, at times, subject to environmental remediation obligations at various sites where we operate. We manage this environmental risk through appropriate environmental policies, programs and practices to minimize any impact our operations may have on the environment. To the extent that we are unable to recover payment for environmental liabilities from insurance or other potentially responsible parties, we will be responsible for payment of costs arising from environmental incidents associated with our operating activities.

OTHER LITIGATION

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

TAX MATTERS

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

INSURANCE

We maintain an insurance program for us, our subsidiaries and certain of our affiliates to mitigate a certain portion of our risks. However, not all potential risks arising from our operations are insurable, or are insured by us as a result of availability, high premiums and for various other reasons. We self-insure a significant portion of certain risks through our wholly-owned captive insurance subsidiaries, which require certain assumptions and management judgment regarding the frequency and severity of claims, claim development and settlement practices and the selection of estimated loss among estimates derived using different methods. Our insurance coverage is also subject to terms and conditions, exclusions and large deductibles or self-insured retentions which may reduce or eliminate coverage in certain circumstances.

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

In the unlikely event multiple insurable incidents occur which exceed coverage limits within the same insurance period, the total insurance coverage will be allocated among entities on an equitable basis based on an insurance allocation agreement we have entered into with us and other subsidiaries.

31. GUARANTEES

In the normal course of conducting business, we may enter into agreements which indemnify third parties and affiliates. We may also be a party to agreements with subsidiaries, jointly owned entities, unconsolidated entities such as equity method investees, or entities with other ownership arrangements that require us to provide financial and performance guarantees. Financial guarantees include stand-by letters of credit, debt guarantees, surety bonds and indemnifications. To varying degrees, these guarantees involve elements of performance and credit risk, which are not included in our Consolidated Statements of Financial Position. Performance guarantees require us to make payments to a third party if the guaranteed entity does not perform on its contractual obligations, such as debt agreements, purchase or sale agreements, and construction contracts and leases.

We typically enter into these arrangements to facilitate commercial transactions with third parties. Examples include indemnifying counterparties pursuant to sale agreements for assets or businesses in matters such as breaches of representations, warranties or covenants, loss or damages to property, environmental liabilities, and litigation and contingent liabilities. We may indemnify third parties for certain liabilities relating to environmental matters arising from operations prior to the purchase or transfer of certain assets and interests. Similarly, we may indemnify the purchaser of assets for certain tax liabilities incurred while we owned the assets, a misrepresentation related to taxes that result in a loss to the purchaser or other certain tax liabilities related to those assets.

The likelihood of having to perform under these guarantees and indemnifications is largely dependent upon future operations of various subsidiaries, investees and other third parties, or the occurrence of certain future events. We cannot reasonably estimate the total maximum potential amounts that could become payable to third parties and affiliates under such agreements described above; however, historically, we have not made any significant payments under guarantee or indemnification provisions. While these agreements may specify a maximum potential exposure, or a specified duration to the guarantee or indemnification obligation, there are circumstances where the amount and duration are unlimited. As at December 31, 2024, guarantees and indemnifications have not had, and are not reasonably likely to have, a material effect on our financial condition, changes in financial condition, earnings, liquidity, capital expenditures or capital resources.

32. QUARTERLY FINANCIAL DATA (UNAUDITED)

	Q1	Q2	Q3	Q4	Total
<i>(unaudited; millions of Canadian dollars, except per share amounts)</i>					
2024					
Operating revenues	11,038	11,336	14,882	16,217	53,473
Operating income	2,711	2,273	2,218	2,447	9,649
Earnings	1,565	2,001	1,447	618	5,631
Earnings attributable to controlling interests	1,512	1,943	1,391	595	5,441
Earnings attributable to common shareholders	1,419	1,848	1,293	493	5,053
Earnings per common share					
Basic	0.67	0.86	0.59	0.23	2.34
Diluted	0.67	0.86	0.59	0.23	2.34
2023					
Operating revenues	12,075	10,432	9,844	11,298	43,649
Operating income	2,662	2,350	1,794	1,845	8,651
Earnings	1,866	2,001	623	1,568	6,058
Earnings attributable to controlling interests	1,817	1,935	621	1,818	6,191
Earnings attributable to common shareholders	1,733	1,848	532	1,726	5,839
Earnings per common share					
Basic	0.86	0.91	0.26	0.81	2.84
Diluted	0.85	0.91	0.26	0.81	2.84