ENBRIDGE INC.

CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2021

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 AF&RC) 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 AF&RC 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 AF&RC 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 AF&RC.

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, 2021, based on the framework established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as at December 31, 2021.

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/ Al Monaco	**/s/ Vern D. Yu**
Al Monaco	Vern D. Yu
President & Chief Executive Officer	Executive Vice President & Chief Financial Officer

February 11, 2022

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors of Enbridge Inc.

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated statements of financial position of Enbridge Inc. and its subsidiaries (together, the Company) as of December 31, 2021 and 2020, and the related consolidated statements of earnings, comprehensive income, changes in equity and cash flows for each of the three years in the period ended December 31, 2021, including the related notes (collectively referred to as the consolidated financial statements). We also have audited the Company’s internal control over financial reporting as of December 31, 2021, based on criteria established in *Internal Control – Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2021, based on criteria established in *Internal Control – Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Company’s management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in 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
111-5th Avenue SW, Suite 3100, Calgary, Alberta, Canada T2P 5L3
T: +1 403 509 7500, F: +1 403 781 1825

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

Definition and Limitations of Internal Control over Financial Reporting

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

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

Critical Audit Matters

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

Goodwill impairment assessment
As described in Notes 2 and 16 to the consolidated financial statements, the Company's goodwill balance was $32,775 million at December 31, 2021. As disclosed by management, an annual goodwill impairment assessment is performed at the reporting unit level as of April 1 of each year, or more frequently if events or circumstances indicate that the carrying value of goodwill may be impaired. Management has the option to first assess qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment assessment. In making the qualitative assessment, management considers macroeconomic trends, changes to regulatory environments, capital accessibility, operating income trends, and changes to industry conditions. The quantitative goodwill impairment assessment involves determining the fair value of the Company's reporting units and comparing those values to the carrying value of each reporting unit, including goodwill. Fair value is estimated using a combination of discounted cash flow and earnings multiples techniques. The determination of fair value using the discounted cash flow technique requires the use of estimates and assumptions related to discount rates, projected operating income, terminal value growth rates, expected future capital expenditures and working capital levels. The determination of fair value using the earnings multiples technique requires assumptions to be made in relation to maintainable earnings and earnings multipliers for reporting units. In the current year, the quantitative goodwill impairment assessment was performed for the Gas Transmission and Midstream (Gas Transmission) reporting unit, while the qualitative goodwill impairment assessments were performed for the Liquids Pipelines and Gas Distribution and Storage reporting units.

The principal considerations for our determination that performing procedures relating to the goodwill impairment assessment is a critical audit matter are the significant judgment required by management when (i) developing the significant assumptions related to operating income trends used in the qualitative assessment for all reporting units outside of the Gas Transmission reporting unit, and (ii) developing such significant assumptions as discount rates, projected operating income, expected future capital expenditures and earnings multipliers used to estimate the fair value of the Gas Transmission reporting unit. This led to a high degree of auditor judgment, effort and subjectivity in performing procedures to evaluate the reasonableness of management's significant assumptions used in the qualitative assessment and the quantitative assessment of the Gas Transmission reporting unit. In addition, the audit effort involved the use of professionals with specialized skill and knowledge to assist in performing the procedures and evaluating the audit evidence obtained over the quantitative assessment.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's goodwill impairment assessment, including controls over (i) the development of significant assumptions related to operating income trends used in the qualitative assessment and (ii) the determination of the fair value estimate of the Gas Transmission reporting unit. These procedures also included, among others (i) evaluating the reasonableness of significant assumptions used by management in the qualitative assessment of the Company's reporting units, specifically those related to operating income trends and (ii) testing management's process for developing the fair value estimate of the Gas Transmission reporting unit. Testing management's process for developing the fair value estimate of the Gas Transmission reporting unit included evaluating the appropriateness of the discounted cash flow and the earnings multiples models; testing the completeness, accuracy, and relevance of underlying data used in the models; and evaluating the reasonableness of significant assumptions used by management in determining the fair value estimate including discount rates, projected operating income, expected future capital expenditures and earnings multipliers.

Assessing the reasonableness of projected operating income and its trends, and expected future capital expenditures, involved evaluating whether these significant assumptions were reasonable considering the current and past performance of the Company's reporting units, external industry data, and evidence obtained in other areas of the audit. Professionals with specialized skill and knowledge were used to assist in evaluating the appropriateness of management's discounted cash flow and earnings multiples models and evaluating the reasonableness of assumptions used in the models, specifically discount rates and earnings multipliers.

/s/PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Canada
February 11, 2022

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

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF EARNINGS

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

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

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

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

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

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

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

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

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

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

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

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

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

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

Approved by the Board of Directors:

/s/ Gregory L. Ebel
Gregory L. Ebel
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.

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

LIQUIDS PIPELINES

Liquids Pipelines consists of pipelines and terminals in Canada and the United States (US) that transport various grades of crude oil and other liquid hydrocarbons, including the Mainline System, Regional Oil Sands System, Gulf Coast and Mid-Continent, Southern Lights Pipeline, Express-Platte System, Bakken System, and Feeder Pipelines and Other. This segment also includes Moda Midstream Operating, LLC (Moda) which was acquired on October 12, 2021 *(Note 8)* and is a component of Gulf Coast and Mid-Continent.

GAS TRANSMISSION AND MIDSTREAM

Gas Transmission and Midstream consists of our investments in natural gas pipelines and gathering and processing facilities in Canada and the US, including US Gas Transmission, Canadian Gas Transmission, US Midstream and Other.

GAS DISTRIBUTION AND STORAGE

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

RENEWABLE POWER GENERATION

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

ENERGY SERVICES

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

ELIMINATIONS AND OTHER

In addition to the business segments noted above, Eliminations and Other includes operating and administrative costs that are not allocated to business segments as well as a foreign exchange hedging program. Eliminations and Other also includes new business development activities and corporate investments.

2. SIGNIFICANT ACCOUNTING POLICIES

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

BASIS OF PRESENTATION AND USE OF ESTIMATES
The preparation of financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities in the consolidated financial statements. Significant estimates and assumptions used in the preparation of the consolidated financial statements include, but are not limited to: variable consideration included in revenue *(Note 4);* carrying values of regulatory assets and liabilities *(Note 7)*; purchase price allocations *(Note 8)*; unbilled revenues; expected credit losses; depreciation rates and carrying value of property, plant and equipment *(Note 11)*; amortization rates and carrying value of intangible assets *(Note 15)*; measurement of goodwill *(Note 16)*; fair value of asset retirement obligations (ARO) *(Note 19)*; valuation of stock-based compensation *(Note 22)*; fair value of financial instruments *(Note 24)*; provisions for income taxes *(Note 25)*; assumptions used to measure retirement benefits and OPEB *(Note 26)*; commitments and contingencies *(Note 30)*; and estimates of losses related to environmental remediation obligations *(Note 30)*. Actual results could differ from these estimates.

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

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

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

REGULATION

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

Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates or expected to be paid to cover future abandonment costs in relation to the CER's Land Matters Consultation Initiative (LMCI). Regulatory assets are assessed for impairment if we identify an event indicative of possible impairment. The recognition of regulatory assets and liabilities is based on the actions, or expected future actions, of the regulator. To the extent that the regulator's actions differ from our expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded. In the absence of rate regulation, we would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned. A regulatory asset or liability is recognized in respect of deferred income taxes when it is expected the amounts will be recovered or settled through future regulator-approved rates. We believe that the recovery of our regulatory assets as at December 31, 2021 is probable over the periods described in *Note 7 - Regulatory Matters*.

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

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

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

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

REVENUE RECOGNITION

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

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

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

For the years ended December 31, 2021, 2020 and 2019, cash received net of revenue recognized for contracts under make-up rights and similar deferred revenue arrangements was $127 million, $292 million and $169 million, respectively.

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

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

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

DERIVATIVE INSTRUMENTS AND HEDGING

Non-qualifying Derivatives

Non-qualifying derivative instruments are used primarily to economically hedge foreign exchange, interest rate and commodity price earnings exposure. Non-qualifying derivatives are measured at fair value with changes in fair value recognized in earnings in Commodity sales, Transportation and other services revenue, Commodity costs, Operating and administrative expense, Net foreign currency gain/(loss) and Interest expense.

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

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

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

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

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

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

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

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

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

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

RESTRICTED LONG-TERM INVESTMENTS
Long-term investments that are restricted as to withdrawal or usage, for the purposes of the CER's LMCI, are presented as Restricted long-term investments in the Consolidated Statements of Financial Position.

OTHER INVESTMENTS
Generally, we classify equity investments in entities over which we do not exercise significant influence and that do not have readily determinable fair values as other investments measured using the fair value measurement alternative (FVMA). These investments are recorded at cost minus impairment, if any, plus or minus the impact of observable price changes occurring in orderly transactions for an identical or similar investment of the same issuer. Investments in equity securities measured using the FVMA are reviewed for impairment each reporting period and written down to their fair value if objective evidence of impairment is identified. Equity investments with readily determinable fair values are measured at fair value through earnings. Dividends received from investments in equity securities are recognized in earnings when the right to receive payment is established.

Investments in debt securities are classified as available-for-sale and measured at fair value through OCI.

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

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

FOREIGN CURRENCY TRANSACTIONS AND TRANSLATION

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

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

CASH AND CASH EQUIVALENTS

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

RESTRICTED CASH

Cash and cash equivalents that are restricted as to withdrawal or usage, in accordance with specific commercial arrangements, are presented as Restricted cash in the Consolidated Statements of Financial Position.

LOANS AND RECEIVABLES

Affiliate long-term notes receivable are measured at amortized cost using the effective interest rate method, net of any impairment losses recognized. Accounts receivable and other are measured at cost. Interest income is recognized in earnings as it is earned with the passage of time.

CURRENT EXPECTED CREDIT LOSSES

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

NATURAL GAS IMBALANCES

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

INVENTORY
Inventory is comprised of natural gas held in storage by Enbridge Gas, crude oil and natural gas held primarily by businesses in the Energy Services segment and materials and supplies. Natural gas held in storage by Enbridge Gas is recorded at the quarterly prices approved by the OEB in the determination of distribution rates. The actual price of gas purchased may differ from the OEB approved price. The difference between the approved price and the actual cost of gas purchased is deferred as a liability for future refund, or as an asset for collection as approved by the OEB. Other inventory is recorded at the lower of cost, as determined on a weighted average basis, or market value. Upon disposition, other commodities inventory is recorded to Commodity costs in the Consolidated Statements of Earnings at the weighted average cost of inventory, including any adjustments recorded to reduce inventory to market value. Materials and supplies inventory is recorded at the lower of average cost or net realizable value.

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

Two primary methods of depreciation are utilized. For distinct assets, depreciation is generally provided on a straight-line basis over the estimated useful lives of the assets commencing when the asset is placed in-service. For largely homogeneous groups of assets with comparable useful lives, the pool method of accounting for property, plant and equipment is followed whereby similar assets are grouped and depreciated as a pool. When group assets are retired or otherwise disposed of, gains and losses are generally not reflected in earnings but are booked as an adjustment to accumulated depreciation.

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

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

DEFERRED AMOUNTS AND OTHER ASSETS
Deferred amounts and other assets primarily consists of costs that regulatory authorities have permitted, or are expected to permit, to be recovered through future rates, including: deferred income taxes; the fair value adjustment to long-term debt; actual cost of removal of previously retired or decommissioned plant assets; and actuarial gains and losses arising from defined benefit pension plans.

INTANGIBLE ASSETS
Intangible assets consist primarily of certain software costs, customer relationships and emission allowances. We capitalize costs incurred during the application development stage of internal use software projects. Customer relationships represent the underlying relationship from long-term agreements with customers that are capitalized upon acquisition. Intangible assets are generally amortized on a straight-line basis over their expected lives, commencing when the asset is available for use, with the exception of emission allowances, which are not amortized as they will be used to satisfy compliance obligations as they come due.

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

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

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

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

The allocation of goodwill to held-for-sale and disposed businesses is based on the relative fair value of businesses included in the relevant reporting unit.

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

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

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

ASSET RETIREMENT OBLIGATIONS
ARO associated with the retirement of long-lived assets are measured at fair value and recognized as Accounts payable and other or Other long-term liabilities in the period in which they can be reasonably determined. Fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. ARO are added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. Our estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements. Currently, for the majority of our assets, it is not possible to make a reasonable estimate of ARO due to the indeterminate timing and scope of the asset retirements.

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

Defined benefit pension obligation and net periodic benefit cost are estimated using the projected unit credit method, which incorporates management's best estimates of future salary levels, other cost escalations, retirement ages of employees and other actuarial factors, including discount rates and mortality. The OPEB benefit obligation and net periodic benefit cost are estimated using the projected unit credit method, where benefits are attributed to years of service, taking into consideration projection of benefit costs.

We use mortality tables issued by the Society of Actuaries in the US (revised in 2021) and the Canadian Institute of Actuaries (revised in 2014) to measure the benefit obligations of our US pension plans (the US Plans) and our Canadian pension plans (the Canadian Plans), respectively.

We determine discount rates by reference to rates of high-quality long-term corporate bonds with maturities that approximate the timing of future payments we anticipate making under each of the respective plans.

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

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

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

Net periodic benefit cost is charged to earnings and includes:

- cost of benefits provided in exchange for employee services rendered during the year (current service cost);
- interest cost of plan obligations;
- expected return on plan assets (for funded pension and OPEB plans);
- amortization of prior service costs on a straight-line basis over the expected average remaining service period of the active employee group covered by the plans; and
- amortization of cumulative unrecognized net actuarial gains and losses in excess of 10% of the greater of the accrued benefit obligation or the fair value of plan assets, over the expected average remaining service life of the active employee group covered by the plans.

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

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

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

STOCK-BASED COMPENSATION

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

Performance Stock Units (PSU) and Restricted Stock Units (RSU) are cash settled awards for which the related liability is remeasured each reporting period. PSUs vest at the completion of a three-year term and RSUs vest one-third annually from the grant date. During the vesting term, compensation expense is recorded based on the number of units outstanding and the current market price of Enbridge's shares with an offset to Accounts payable and other or to Other long-term liabilities. The value of the PSUs is also dependent on our performance relative to performance targets set out under the plan.

COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES

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

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

3. CHANGES IN ACCOUNTING POLICIES

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

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

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

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

Accounting for Income Taxes
Effective January 1, 2021, we adopted ASU 2019-12 on a prospective basis. The new standard was issued in December 2019 with the intent of simplifying the accounting for income taxes. The accounting update removes certain exceptions to the general principles in ASC 740 *Income Taxes* as well as provides simplification by clarifying and amending existing guidance. The adoption of this ASU did not have a material impact on our consolidated financial statements.

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

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

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

Accounting for Convertible Instruments and Contracts in an Entity's Own Equity
ASU 2020-06 was issued in August 2020 to simplify accounting for certain financial instruments. The ASU eliminates the current models that require separation of beneficial conversion and cash conversion features from convertible instruments and simplifies the derivative scope exception guidance pertaining to equity classification of contracts in an entity's own equity. The ASU also introduces additional disclosures for convertible debt and freestanding instruments that are indexed to and settled in an entity's own equity. The ASU amends the diluted earnings per share guidance, including the requirement to use if-converted method for all convertible instruments and an update for instruments that can be settled in either cash or shares. ASU 2020-06 is effective January 1, 2022 and should be applied on a full or modified retrospective basis. The adoption of ASU 2020-06 is not expected to have a material impact on our consolidated financial statements.

4. REVENUE

REVENUE FROM CONTRACTS WITH CUSTOMERS
Major Products and Services

Year ended December 31, 2021	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Transportation revenue	**9,492**	**4,364**	**676**	**—**	**—**	**—**	**14,532**
Storage and other revenue	**147**	**255**	**246**	**—**	**—**	**—**	**648**
Gas gathering and processing revenue	**—**	**49**	**—**	**—**	**—**	**—**	**49**
Gas distribution revenue	**—**	**—**	**4,026**	**—**	**—**	**—**	**4,026**
Electricity and transmission revenue	**—**	**—**	**—**	**177**	**—**	**—**	**177**
Total revenue from contracts with customers	**9,639**	**4,668**	**4,948**	**177**	**—**	**—**	**19,432**
Commodity sales	**—**	**—**	**—**	**—**	**26,873**	**—**	**26,873**
Other revenue[1,2]	**375**	**42**	**13**	**336**	**—**	**—**	**766**
Intersegment revenue	**567**	**1**	**19**	**(1)**	**44**	**(630)**	**—**
Total revenue	**10,581**	**4,711**	**4,980**	**512**	**26,917**	**(630)**	**47,071**

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

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

1 *Includes mark-to-market gains from our hedging program for the year ended December 31, 2021 of $59 million, (2020 - $265 million, 2019 - $346 million).*
2 *Includes revenues from lease contracts. Refer to* Note 27 - Leases*.*

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

Contract Balances

	Contract Receivables	Contract Assets	Contract Liabilities
(millions of Canadian dollars)			
Balance as at December 31, 2021	**2,369**	**213**	**1,898**
Balance as at December 31, 2020	2,042	226	1,815

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

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

Contract liabilities represent payments received for performance obligations which have not been fulfilled. Contract liabilities primarily relate to make-up rights and deferred revenue. Revenue recognized during the year ended December 31, 2021 included in contract liabilities at the beginning of the period is $305 million. Increases in contract liabilities from cash received, net of amounts recognized as revenue during the year ended December 31, 2021 were $397 million.

Performance Obligations

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

There was no material revenue recognized in the year ended December 31, 2021 from performance obligations satisfied in previous periods.

Payment Terms

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

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

Revenue to be Recognized from Unfulfilled Performance Obligations

Total revenue from performance obligations expected to be fulfilled in future periods is $59.8 billion, of which $7.4 billion is expected to be recognized during the year ended December 31, 2022.

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

SIGNIFICANT JUDGMENTS MADE IN RECOGNIZING REVENUE

Long-Term Transportation Agreements

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

Variable Consideration

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

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

Recognition and Measurement of Revenue

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

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

Year ended December 31, 2019	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Consolidated
(millions of Canadian dollars)					
Revenue from products transferred at a point in time	—	4	65	—	69
Revenue from products and services transferred over time[1]	9,191	5,168	5,089	180	19,628
Total revenue from contracts with customers	9,191	5,172	5,154	180	19,697

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

Performance Obligations Satisfied Over Time

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

Determination of Transaction Prices

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

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

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

5. SEGMENTED INFORMATION

Segmented information for the years ended December 31, 2021, 2020 and 2019 is as follows:

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

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

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

1 Includes allowance for equity funds used during construction.

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

GEOGRAPHIC INFORMATION

Revenues[1]

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

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

Property, Plant and Equipment[1]

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

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

6. EARNINGS PER COMMON SHARE

BASIC

Earnings per common share is calculated by dividing earnings attributable to common shareholders by the weighted average number of common shares outstanding. The weighted average number of common shares outstanding has been reduced by our pro-rata weighted average interest in our own common shares of approximately 2 million as at December 31, 2021, 5 million as at December 31, 2020, and 6 million as at December 31, 2019, resulting from our reciprocal investment in Noverco. On December 30, 2021, we closed the sale of our non-operating minority ownership of Noverco. Refer to *Note 13 - Long-term Investments* for more information.

DILUTED

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

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

December 31,	**2021**	2020	2019
(number of shares in millions)			
Weighted average shares outstanding	**2,023**	2,020	2,017
Effect of dilutive options	**2**	1	3
Diluted weighted average shares outstanding	**2,025**	2,021	2,020

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

7. REGULATORY MATTERS

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

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

LIQUIDS PIPELINES

Canadian Mainline

Canadian Mainline includes the Canadian portion of our mainline system and is subject to regulation by the CER. Tolls, excluding Lines 8 and 9, are governed by the 10-year CTS which expired on June 30, 2021 *(Note 4).* The CTS established a Canadian Local Toll for all volumes shipped on the Canadian Mainline and an International Joint Tariff for all volumes shipped from western Canadian receipt points to delivery points on our Lakehead System. Under the CTS, we have recognized a regulatory asset of $2.1 billion as at December 31, 2021 (2020 - $1.9 billion) to offset deferred income taxes, as a CER rate order governing flow-through income tax treatment permits future recovery. No other material regulatory assets or liabilities are recognized under the terms of the CTS.

Southern Lights Pipeline

The US and Canadian portions of the Southern Lights Pipeline are regulated by the FERC and CER, respectively. Shippers on the Southern Lights Pipeline are subject to long-term transportation contracts under a cost-of-service toll methodology. Toll adjustments are filed annually with the regulators and provide for the recovery of allowable operating and debt financing costs, plus a pre-determined after-tax return on equity (ROE) of 10%.

GAS TRANSMISSION AND MIDSTREAM

British Columbia Pipeline and Maritimes & Northeast Canada

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

US Gas Transmission

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

GAS DISTRIBUTION AND STORAGE

Enbridge Gas

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

FINANCIAL STATEMENT EFFECTS

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

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

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

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

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

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

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

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

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

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

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

8. ACQUISITIONS AND DISPOSITIONS

ACQUISITION

Moda Midstream Operating, LLC

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

DISPOSITIONS

Line 10 Crude Oil Pipeline

In the first quarter of 2018, we satisfied the condition as set out in our agreements for the sale of our Line 10 crude oil pipeline (Line 10), which originates near Hamilton, Ontario and terminates at West Seneca, New York. Our subsidiaries, Enbridge Pipelines Inc. and Enbridge Energy Partners, L.P. (EEP), owned the Canadian and US portions of Line 10, respectively, and the related assets were included in our Liquids Pipelines segment. The transaction closed on June 1, 2020. No gain or loss on disposition was recorded.

Montana-Alberta Tie Line
In the fourth quarter of 2019, we committed to a plan to sell the Montana-Alberta Tie Line (MATL) transmission asset, a 345 kilometer transmission line from Great Falls, Montana to Lethbridge, Alberta. MATL was included in our Renewable Power Generation segment. The purchase and sale agreement was signed in January 2020.

Upon the reclassification and subsequent remeasurement of MATL assets as held for sale, a loss of $297 million was included within Impairment of long-lived assets in the Consolidated Statements of Earnings for the year ended December 31, 2019.

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

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

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

Canadian Natural Gas Gathering and Processing Businesses
On July 4, 2018, we entered into agreements to sell our Canadian natural gas gathering and processing businesses to Brookfield Infrastructure Partners L.P. and its institutional partners for a cash purchase price of approximately $4.3 billion, subject to customary closing adjustments. Separate agreements were entered into for those facilities currently governed by provincial regulations and those governed by federal regulations (collectively, Canadian Natural Gas Gathering and Processing Businesses assets); these assets were part of our Gas Transmission and Midstream segment.

On October 1, 2018, we closed the sale of the provincially regulated facilities. On December 31, 2019, we closed the sale of the federally regulated facilities for proceeds of approximately $1.7 billion. After closing adjustments, a loss on disposal of $268 million before tax was included in Other income/(expense) in the Consolidated Statements of Earnings for the year ended December 31, 2019. As these assets represented a portion of a reporting unit, we allocated a portion of the goodwill of the reporting unit to these assets using a relative fair value approach.

St. Lawrence Gas Company, Inc.
In August 2017, we entered into an agreement to sell the issued and outstanding shares of St. Lawrence Gas Company, Inc. (St. Lawrence Gas). St. Lawrence Gas assets were included in the Gas Distribution and Storage segment. On November 1, 2019, we closed the sale of St. Lawrence Gas for cash proceeds of approximately $72 million. After closing adjustments, a loss on disposal of $10 million was included in Other income/(expense) in the Consolidated Statements of Earnings for the year ended December 31, 2019.

Enbridge Gas New Brunswick
In December 2018, we entered into an agreement for the sale of Enbridge Gas New Brunswick Limited Partnership and Enbridge Gas New Brunswick Inc. (collectively, EGNB). EGNB assets were a part of our Gas Distribution and Storage segment. On October 1, 2019, we closed the sale of EGNB to Liberty Utilities (Canada) LP, a wholly-owned subsidiary of Algonquin Power and Utilities Corp., for cash proceeds of approximately $331 million. After closing adjustments, a loss on disposal of $3 million was included in Other income/(expense) in the Consolidated Statements of Earnings for the year ended December 31, 2019.

As EGNB assets represented a portion of a reporting unit, we allocated a portion of the goodwill of the reporting unit to these assets using a relative fair value approach. As such, allocated goodwill of $133 million was included in assets subsequently disposed.

9. ACCOUNTS RECEIVABLE AND OTHER

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

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

10. INVENTORY

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

11. PROPERTY, PLANT AND EQUIPMENT

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

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

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

IMPAIRMENT

Access Northeast Project

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

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

12. VARIABLE INTEREST ENTITIES

CONSOLIDATED VARIABLE INTEREST ENTITIES

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

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

December 31,	**2021**[1]	2020[1]
(millions of Canadian dollars)		
Assets		
Cash and cash equivalents	**247**	215
Restricted cash	**4**	1
Accounts receivable and other	**99**	65
Inventory	**9**	7
	359	288
Property, plant and equipment, net	**3,052**	3,201
Long-term investments	**16**	14
Restricted long-term investments	**101**	84
Deferred amounts and other assets	**2**	3
Intangible assets, net	**108**	115
	3,638	3,705
Liabilities		
Accounts payable and other	**84**	52
Other long-term liabilities	**182**	175
Deferred income taxes	**5**	5
	271	232
	3,367	3,473

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

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

UNCONSOLIDATED VARIABLE INTEREST ENTITIES

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

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

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

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

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

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

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

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

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

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

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

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

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

13. LONG-TERM INVESTMENTS

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

1 Owns 49% interest in Bakken Pipeline Investments L.L.C., which owns 75% of the Bakken Pipeline System resulting in a 27.6% effective interest in the Bakken Pipeline System.
2 Owns 65% interest in Gray Oak Pipeline, LLC resulting in a 22.8% effective interest in Gray Oak Pipeline, LLC.
3 Owns the Southern Access Extension Project.
4 In October 2021 we acquired an effective 20.0% interest in Cactus II Pipeline, LLC through the acquisition of Moda Midstream Operating, LLC. See Note 8 - Acquisitions and Dispositions for further discussion.
5 Includes Alliance Pipeline Limited Partnership in Canada and Alliance Pipeline L.P. in the US.
6 Includes Aux Sable Canada LP in Canada and Aux Sable Liquid Products LP and Aux Sable Midstream LLC in the US.

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

Equity investments include the unamortized excess of the purchase price over the underlying net book value of the investees' assets at the purchase date. As at December 31, 2021, this basis difference was $2.5 billion (2020 - $2.4 billion), of which $730 million (2020 - $657 million) was amortizable.

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

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

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

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

Noverco Inc.

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

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

IMPAIRMENT OF EQUITY INVESTMENTS

PennEast Pipeline Company, LLC

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

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

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

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

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

14. RESTRICTED LONG-TERM INVESTMENTS

Effective January 1, 2015, we began collecting and setting aside funds to cover future pipeline abandonment costs for all CER regulated pipelines as a result of the CER's regulatory requirements under LMCI. The funds collected are held in trusts in accordance with the CER decision. The funds collected from shippers are reported within Transportation and other services revenues on the Consolidated Statements of Earnings and Restricted long-term investments on the Consolidated Statements of Financial Position. Concurrently, we reflect the future abandonment cost as an increase to Operating and administrative expense on the Consolidated Statements of Earnings and Other long-term liabilities on the Consolidated Statements of Financial Position.

We routinely invest excess cash and various restricted balances in securities such as commercial paper, bankers acceptances, corporate debt securities, Canadian equity securities, treasury bills and money market securities in the US and Canada.

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

15. INTANGIBLE ASSETS

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

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

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

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

16. GOODWILL

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

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

17. ACCOUNTS PAYABLE AND OTHER

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

18. DEBT

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

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

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

CREDIT FACILITIES

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

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

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

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

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

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

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

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

Our credit facilities carry a weighted average standby fee of 0.1% per annum on the unused portion and draws bear interest at market rates. Certain credit facilities serve as a back-stop to the commercial paper programs and we have the option to extend such facilities, which are currently scheduled to mature from 2022 to 2026.

As at December 31, 2021 and 2020, commercial paper and credit facility draws, net of short-term borrowings and non-revolving credit facilities that mature within one year, of $11.3 billion and $9.9 billion, respectively, were supported by the availability of long-term committed credit facilities and, therefore, have been classified as long-term debt.

LONG-TERM DEBT ISSUANCES

During the year ended December 31, 2021, we completed the following long-term debt issuances totaling US$3.9 billion and $3.2 billion:

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

1 Notes carry an interest rate equal to the SOFR plus a margin of 40 basis points.

2 Issued through Texas Eastern Transmission, LP, a wholly-owned operating subsidiary of SEP.

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

LONG-TERM DEBT REPAYMENTS

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

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

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

INTEREST EXPENSE

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

19. ASSET RETIREMENT OBLIGATIONS

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

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

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

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

20. NONCONTROLLING INTERESTS

NONCONTROLLING INTERESTS

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

December 31,	**2021**	2020
(millions of Canadian dollars)		
Algonquin Gas Transmission, L.L.C	**377**	384
Maritimes & Northeast Pipeline, L.L.C	**546**	558
Renewable energy assets	**1,503**	1,646
Westcoast Energy Inc.[1]	**116**	408
	2,542	2,996

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

Westcoast Energy Inc. Preferred Shares Redemption

On March 20, 2019, Westcoast Energy Inc. (Westcoast) exercised its right to redeem all of its outstanding 5.5% Cumulative Redeemable First Preferred Shares, Series 7 (Series 7 Shares) and all of its outstanding 5.6% Cumulative Redeemable First Preferred Shares, Series 8 (Series 8 Shares) at a price of $25 per Series 7 Share and $25 per Series 8 Share, respectively, for a total payment of $300 million. In addition, payment of $4 million was made for all accrued and unpaid dividends. As a result, we recorded a $300 million decrease in Noncontrolling interests for the year ended December 31, 2019.

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

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

21. SHARE CAPITAL

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

COMMON SHARES

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

PREFERENCE SHARES

December 31,	**2021** Number of Shares	**2021** Amount	2020 Number of Shares	2020 Amount	2019 Number of Shares	2019 Amount
(millions of Canadian dollars; number of shares in millions)						
Preference Shares, Series A	**5**	**125**	5	125	5	125
Preference Shares, Series B	**18**	**457**	18	457	18	457
Preference Shares, Series C	**2**	**43**	2	43	2	43
Preference Shares, Series D	**18**	**450**	18	450	18	450
Preference Shares, Series F	**20**	**500**	20	500	20	500
Preference Shares, Series H	**14**	**350**	14	350	14	350
Preference Shares, Series J	**8**	**199**	8	199	8	199
Preference Shares, Series L	**16**	**411**	16	411	16	411
Preference Shares, Series N	**18**	**450**	18	450	18	450
Preference Shares, Series P	**16**	**400**	16	400	16	400
Preference Shares, Series R	**16**	**400**	16	400	16	400
Preference Shares, Series 1	**16**	**411**	16	411	16	411
Preference Shares, Series 3	**24**	**600**	24	600	24	600
Preference Shares, Series 5	**8**	**206**	8	206	8	206
Preference Shares, Series 7	**10**	**250**	10	250	10	250
Preference Shares, Series 9	**11**	**275**	11	275	11	275
Preference Shares, Series 11	**20**	**500**	20	500	20	500
Preference Shares, Series 13	**14**	**350**	14	350	14	350
Preference Shares, Series 15	**11**	**275**	11	275	11	275
Preference Shares, Series 17	**30**	**750**	30	750	30	750
Preference Shares, Series 19	**20**	**500**	20	500	20	500
Issuance costs		**(155)**		(155)		(155)
Balance at end of year		**7,747**		7,747		7,747

Characteristics of the preference shares are as follows:

(Canadian dollars unless otherwise stated)	Dividend Rate	Dividend[1]	Per Share Base Redemption Value[2]	Redemption and Conversion Option Date[2,3]	Right to Convert Into[3,4]
Preference Shares, Series A	5.50 %	$1.37500	$25	—	—
Preference Shares, Series B	3.42 %	$0.85360	$25	June 1, 2022	Series C
Preference Shares, Series C[5]	3-month treasury bill plus 2.40%	—	$25	June 1, 2022	Series B
Preference Shares, Series D	4.46 %	$1.11500	$25	March 1, 2023	Series E
Preference Shares, Series F	4.69 %	$1.17224	$25	June 1, 2023	Series G
Preference Shares, Series H	4.38 %	$1.09400	$25	September 1, 2023	Series I
Preference Shares, Series J	4.89 %	US$1.22160	US$25	June 1, 2022	Series K
Preference Shares, Series L	4.96 %	US$1.23972	US$25	September 1, 2022	Series M
Preference Shares, Series N	5.09 %	$1.27152	$25	December 1, 2023	Series O
Preference Shares, Series P	4.38 %	$1.09476	$25	March 1, 2024	Series Q
Preference Shares, Series R	4.07 %	$1.01825	$25	June 1, 2024	Series S
Preference Shares, Series 1	5.95 %	US$1.48728	US$25	June 1, 2023	Series 2
Preference Shares, Series 3	3.74 %	$0.93425	$25	September 1, 2024	Series 4
Preference Shares, Series 5	5.38 %	US$1.34383	US$25	March 1, 2024	Series 6
Preference Shares, Series 7	4.45 %	$1.11224	$25	March 1, 2024	Series 8
Preference Shares, Series 9	4.10 %	$1.02424	$25	December 1, 2024	Series 10
Preference Shares, Series 11	3.94 %	$0.98452	$25	March 1, 2025	Series 12
Preference Shares, Series 13	3.04 %	$0.76076	$25	June 1, 2025	Series 14
Preference Shares, Series 15	2.98 %	$0.74576	$25	September 1, 2025	Series 16
Preference Shares, Series 17	5.15 %	$1.28750	$25	March 1, 2022	Series 18
Preference Shares, Series 19	4.90 %	$1.22500	$25	March 1, 2023	Series 20

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

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

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

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

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

PREFERENCE SHARE REDEMPTION

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

SHAREHOLDER RIGHTS PLAN

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

22. STOCK OPTION AND STOCK UNIT PLANS

We maintain three long-term incentive compensation plans: the ISO Plan, the PSU Plan and the RSU Plan. Total stock-based compensation expense recorded for the years ended December 31, 2021, 2020 and 2019 was $157 million, $145 million and $117 million, respectively. Disclosure of activity and assumptions for material stock-based compensation plans are included below.

INCENTIVE STOCK OPTIONS

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

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

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

2 *The total fair value of ISOs exercised during the years ended December 31, 2021, 2020 and 2019 was $25 million, $30 million and $32 million, respectively.*

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

Year ended December 31,	2021	2020	2019
Fair value per option *(Canadian dollars)*[1]	**4.10**	4.01	4.37
Valuation assumptions			
Expected option term *(years)*[2]	**6**	6	5
Expected volatility[3]	**25.5 %**	18.3 %	19.9 %
Expected dividend yield[4]	**7.6 %**	5.9 %	6.1 %
Risk-free interest rate[5]	**0.7 %**	1.3 %	2.0 %

1 Options granted to US employees are based on NYSE prices. The option value and assumptions shown are based on a weighted average of the US and the Canadian options. The fair values per option for the years ended December 31, 2021, 2020 and 2019 were $3.91, $3.75 and $4.04, respectively, for Canadian employees and US$3.65, US$3.62 and US$4.09, respectively, for US employees.
2 The expected option term is six years based on historical exercise practice and five years for retirement eligible employees.
3 Expected volatility is determined with reference to historic daily share price volatility and consideration of the implied volatility observable in call option values near the grant date.
4 The expected dividend yield is the current annual dividend at the grant date divided by the current stock price.
5 The risk-free interest rate is based on the Government of Canada's Canadian Bond Yields and the US Treasury Bond Yields.

Compensation expense recorded for the years ended December 31, 2021, 2020 and 2019 for ISOs was $16 million, $24 million and $32 million, respectively. As at December 31, 2021, unrecognized compensation expense related to non-vested stock-based compensation arrangements granted under the ISO Plan was $11 million. The expense is expected to be fully recognized over a weighted average period of approximately two years.

PERFORMANCE STOCK UNITS

Under PSU awards for certain key employees, cash awards are paid following a three-year performance cycle. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by Enbridge's weighted average share price for 20 days prior to the maturity of the grant and by a performance multiplier. The performance multiplier ranges from zero, if our performance fails to meet threshold performance levels, to a maximum of two if we perform within the highest range of the performance targets. The performance multiplier is derived through a calculation of our Total Shareholder Return percentile rank, in each case relative to a specified peer group of companies and our distributable cash flow per share, adjusted for unusual, non-operating or non-recurring items, relative to targets established at the time of grant. To calculate the 2021 expense, a multiplier of 0.5 was used for 2021 PSU grants, 0.5 for 2020 PSU grants and 1.3 for the 2019 PSU grants.

December 31, 2021	Number	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value
(units in thousands; intrinsic value in millions of Canadian dollars)			
Units outstanding at beginning of year	**3,056**		
Units granted	**1,895**		
Units cancelled	**(76)**		
Units matured[1]	**(1,664)**		
Dividend reinvestment	**218**		
Units outstanding at end of year	**3,429**	**1.1**	**181**

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

Compensation expense recorded for the years ended December 31, 2021, 2020 and 2019 for PSUs was $56 million, $76 million and $40 million, respectively. As at December 31, 2021, unrecognized compensation expense related to non-vested PSUs was $31 million. The expense is expected to be fully recognized over a weighted average period of approximately two years.

RESTRICTED STOCK UNITS

Under RSU awards, cash awards are paid to certain of our employees vesting in equal installments on each of the first, second and third anniversaries of the grant date. Share settled awards are given to certain senior management employees following a three year maturity period. RSU holders receive cash or shares equal to our weighted average share price for 20 days prior to the maturity of the grant multiplied by the units outstanding on the maturity date.

December 31, 2021	Number	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value
(units in thousands; intrinsic value in millions of Canadian dollars)			
Units outstanding at beginning of year	**2,453**		
Units granted	**1,514**		
Units cancelled	**(75)**		
Units matured[1]	**(1,433)**		
Dividend reinvestment	**246**		
Units outstanding at end of year	**2,705**	**1.1**	**129**

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

Compensation expense recorded for the years ended December 31, 2021, 2020 and 2019 for RSUs was $85 million, $44 million and $41 million, respectively. As at December 31, 2021, unrecognized compensation expense related to non-vested RSUs was $62 million. The expense is expected to be fully recognized over a weighted average period of approximately two years.

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

Changes in AOCI attributable to our common shareholders for the years ended December 31, 2021, 2020 and 2019 are as follows:

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

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

	Cash Flow Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Adjustment	Total
(millions of Canadian dollars)						
Balance at January 1, 2019	(770)	(598)	4,323	34	(317)	2,672
Other comprehensive income/(loss) retained in AOCI	(599)	320	(2,927)	34	(124)	(3,296)
Other comprehensive (income)/loss reclassified to earnings						
Interest rate contracts[1]	157	—	—	—	—	157
Commodity contracts[2]	(1)	—	—	—	—	(1)
Foreign exchange contracts[3]	5	—	—	—	—	5
Other contracts[4]	(3)	—	—	—	—	(3)
Amortization of pension and OPEB actuarial loss and prior service costs[5]	—	—	—	—	17	17
	(441)	320	(2,927)	34	(107)	(3,121)
Tax impact						
Income tax on amounts retained in AOCI	169	(39)	—	6	28	164
Income tax on amounts reclassified to earnings	(31)	—	—	—	(4)	(35)
	138	(39)	—	6	24	129
Other	—	—	—	(7)	55	48
Balance at December 31, 2019	(1,073)	(317)	1,396	67	(345)	(272)

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

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

3 Reported within Transportation and other services revenue and Net foreign currency gain in the Consolidated Statements of Earnings.

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

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

24. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET RISK

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

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

Foreign Exchange Risk

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

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

Interest Rate Risk
Our earnings and cash flows are exposed to short-term interest rate variability due to the regular repricing of our variable rate debt, primarily commercial paper. We monitor our debt portfolio mix of fixed and variable rate debt instruments to manage a consolidated portfolio of floating rate debt within the Board of Directors approved policy limit of a maximum of 30% of floating rate debt as a percentage of total debt outstanding. We primarily use qualifying derivative instruments to manage interest rate risk. Pay fixed-receive floating interest rate swaps may be used to hedge against the effect of future interest rate movements. We have implemented a program to mitigate the impact of short-term interest rate volatility on interest expense via execution of floating to fixed interest rate swaps with an average swap rate of 3.9%.

We are exposed to changes in the fair value of fixed rate debt that arise as a result of changes in market interest rates. Pay floating-receive fixed interest rate swaps are used, when applicable, to hedge against future changes to the fair value of fixed rate debt which mitigates the impact of fluctuations in fair value via execution of fixed to floating interest rate swaps. As at December 31, 2021, we do not have any pay floating-receive fixed interest rate swaps outstanding.

Our earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate term debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. We have established a program including some of our subsidiaries to mitigate our exposure to long-term interest rate variability on select forecast term debt issuances via execution of floating to fixed interest rate swaps with an average swap rate of 2.0%.

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

Equity Price Risk
Equity price risk is the risk of earnings fluctuations due to changes in our share price. We have exposure to our own common share price through the issuance of various forms of stock-based compensation, which affect earnings through revaluation of the outstanding units every period. We use equity derivatives to manage the earnings volatility derived from one form of stock-based compensation, restricted share units. We use a combination of qualifying and non-qualifying derivative instruments to manage equity price risk.

TOTAL DERIVATIVE INSTRUMENTS
The following table summarizes the Consolidated Statements of Financial Position location and carrying value of our derivative instruments.

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

The following table summarizes the maximum potential settlement amounts in the event of these specific circumstances. All amounts are presented gross in the Consolidated Statements of Financial Position.

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

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

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

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

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

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

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

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

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

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

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

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

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

Fair Value Derivatives

For interest rate derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk is included in Interest expense in the Consolidated Statements of Earnings.

Year ended December 31,	**2021**	2020
(millions of Canadian dollars)		
Unrealized gain/(loss) on derivative	**8**	(116)
Unrealized gain/(loss) on hedged item	**(15)**	133
Realized loss on derivative	**(41)**	(12)
Realized gain on hedged item	**45**	—

Non-Qualifying Derivatives

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

Year ended December 31,	**2021**	2020	2019
(millions of Canadian dollars)			
Foreign exchange contracts[1]	**92**	902	1,626
Interest rate contracts[2]	**2**	(25)	178
Commodity contracts[3]	**71**	(114)	(62)
Other contracts[4]	**8**	(7)	9
Total unrealized derivative fair value gain/(loss), net	**173**	756	1,751

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

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

3 *For the respective annual periods, reported within Transportation and other services revenue (2021 - $9 million gain; 2020 - $2 million loss; 2019 - $26 million loss), Commodity sales (2021 - $160 million gain; 2020 - $321 million loss; 2019 - $544 million loss), Commodity costs (2021 - $105 million loss; 2020 - $207 million gain; 2019 - $459 million gain) and Operating and administrative expense (2021 - $7 million gain; 2020 - $2 million gain; 2019 - $49 million gain) in the Consolidated Statements of Earnings.*

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

LIQUIDITY RISK

Liquidity risk is the risk that we will not be able to meet our financial obligations, including commitments and guarantees, as they become due. In order to mitigate this risk, we forecast cash requirements over a 12-month rolling time period to determine whether sufficient funds will be available and maintain substantial capacity under our committed bank lines of credit to address any contingencies. Our primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. We also maintain current shelf prospectuses with securities regulators which enables ready access to either the Canadian or US public capital markets, subject to market conditions. In addition, we maintain sufficient liquidity through committed credit facilities with a diversified group of banks and institutions which, if necessary, enables us to fund all anticipated requirements for approximately one year without accessing the capital markets. We are in compliance with all the terms and conditions of our committed credit facility agreements and term debt indentures as at December 31, 2021. As a result, all credit facilities are available to us and the banks are obligated to fund and have been funding us under the terms of the facilities.

CREDIT RISK

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

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

December 31,	**2021**	2020
(millions of Canadian dollars)		
Canadian financial institutions	**424**	481
US financial institutions	**130**	99
European financial institutions	**181**	28
Asian financial institutions	**30**	167
Other[1]	**122**	97
	887	872

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

As at December 31, 2021, we provided letters of credit totaling nil in lieu of providing cash collateral to our counterparties pursuant to the terms of the relevant International Swaps and Derivatives Association agreements. We held no cash collateral on derivative asset exposures as at December 31, 2021 and December 31, 2020.

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

Credit risk also arises from trade and other long-term receivables, and is mitigated through credit exposure limits and contractual requirements, assessment of credit ratings and netting arrangements. Within Enbridge Gas, credit risk is mitigated by the utilities' large and diversified customer base and the ability to recover an estimate for doubtful accounts through the ratemaking process. We actively monitor the financial strength of large industrial customers and, in select cases, have obtained additional security to minimize the risk of default on receivables. Generally, we classify and provide for receivables older than 30 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value.

FAIR VALUE MEASUREMENTS

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

FAIR VALUE OF FINANCIAL INSTRUMENTS

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

Level 1

Level 1 includes derivatives measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a derivative is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis. Our Level 1 instruments consist primarily of exchange traded derivatives used to mitigate the risk of crude oil price fluctuations.

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

We have also categorized the fair value of our held to maturity preferred share investment and long-term debt as Level 2. The fair value of our held to maturity preferred share investment is primarily based on the yield of certain Government of Canada bonds. The fair value of our long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenor.

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

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

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

December 31, 2021	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	**—**	**259**	**—**	**259**
Interest rate contracts	**—**	**64**	**—**	**64**
Commodity contracts	**38**	**71**	**95**	**204**
Other contracts	**—**	**2**	**—**	**2**
	38	**396**	**95**	**529**
Long-term derivative assets				
Foreign exchange contracts	**—**	**240**	**—**	**240**
Interest rate contracts	**—**	**88**	**—**	**88**
Commodity contracts	**—**	**21**	**8**	**29**
Other contracts	**—**	**3**	**—**	**3**
	—	**352**	**8**	**360**
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	**—**	**(303)**	**—**	**(303)**
Interest rate contracts	**—**	**(150)**	**—**	**(150)**
Commodity contracts	**(52)**	**(66)**	**(146)**	**(264)**
Other contracts	**—**	**—**	**—**	**—**
	(52)	**(519)**	**(146)**	**(717)**
Long-term derivative liabilities				
Foreign exchange contracts	**—**	**(423)**	**—**	**(423)**
Interest rate contracts	**—**	**(24)**	**—**	**(24)**
Commodity contracts	**—**	**(19)**	**(65)**	**(84)**
Other contracts	**—**	**—**	**—**	**—**
	—	**(466)**	**(65)**	**(531)**
Total net financial asset/(liability)				
Foreign exchange contracts	**—**	**(227)**	**—**	**(227)**
Interest rate contracts	**—**	**(22)**	**—**	**(22)**
Commodity contracts	**(14)**	**7**	**(108)**	**(115)**
Other contracts	**—**	**5**	**—**	**5**
	(14)	**(237)**	**(108)**	**(359)**

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

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

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

1 Financial and physical forward commodity contracts are valued using a market approach valuation technique.
2 One million British thermal units (mmbtu).

If adjusted, the significant unobservable inputs disclosed in the table above would have a direct impact on the fair value of our Level 3 derivative instruments. The significant unobservable inputs used in the fair value measurement of Level 3 derivative instruments include forward commodity prices, and for option contracts, price volatility. Changes in forward commodity prices could result in significantly different fair values for our Level 3 derivatives. Changes in price volatility would change the value of the option contracts. Generally, a change in the estimate of forward commodity prices is unrelated to a change in the estimate of price volatility.

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

Year ended December 31,	**2021**	2020
(millions of Canadian dollars)		
Level 3 net derivative liability at beginning of period	**(191)**	(69)
Total gain/(loss)		
Included in earnings[1]	**(39)**	(123)
Included in OCI	**(29)**	2
Settlements	**151**	(1)
Level 3 net derivative liability at end of period	**(108)**	(191)

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

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

NET INVESTMENT HEDGES

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

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

FAIR VALUE OF OTHER FINANCIAL INSTRUMENTS

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

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

As at December 31, 2021 and 2020, our long-term debt had a carrying value of $74.4 billion and $66.1 billion, respectively, before debt issuance costs and a fair value of $82.0 billion and $75.1 billion, respectively. We also have non-current notes receivable carried at book value and recorded in Deferred amounts and other assets in the Consolidated Statements of Financial Position. As at December 31, 2021 and 2020, the non-current notes receivable had a carrying value of $1.0 billion and $1.1 billion, respectively, which also approximates their fair value.

The fair value of other financial assets and liabilities other than derivative instruments, other long-term investments, restricted long-term investments and long-term debt approximate their cost due to the short period to maturity.

25. INCOME TAXES

INCOME TAX RATE RECONCILIATION

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

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

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

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

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

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

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

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

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

9 The amount in 2019 relates to the federal component of changes in assertions regarding the manner of recovery of intercorporate investments such that deferred tax related to outside basis temporary differences was required to be recorded for MATL.

COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES

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

COMPONENTS OF DEFERRED INCOME TAXES

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

December 31,	**2021**	2020
(millions of Canadian dollars)		
Deferred income tax liabilities		
Property, plant and equipment	**(8,721)**	(7,786)
Investments	**(6,097)**	(4,649)
Regulatory assets	**(1,245)**	(1,156)
Other	**(208)**	(127)
Total deferred income tax liabilities	**(16,271)**	(13,718)
Deferred income tax assets		
Financial instruments	**315**	518
Pension and OPEB plans	**110**	251
Loss carryforwards	**3,081**	2,005
Other	**1,648**	1,461
Total deferred income tax assets	**5,154**	4,235
Less valuation allowance	**(84)**	(79)
Total deferred income tax assets, net	**5,070**	4,156
Net deferred income tax liabilities	**(11,201)**	(9,562)
Presented as follows:		
Total deferred income tax assets	**488**	770
Total deferred income tax liabilities	**(11,689)**	(10,332)
Net deferred income tax liabilities	**(11,201)**	(9,562)

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

As at December 31, 2021, we recognized the benefit of unused tax loss carryforwards of $1.9 billion (2020 - $2.6 billion) in Canada which expire in 2026 and beyond.

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

We have not provided for deferred income taxes on the difference between the carrying value of substantially all of our foreign subsidiaries and their corresponding tax basis as the earnings of those subsidiaries are intended to be permanently reinvested in their operations. As such, these investments are not anticipated to give rise to income taxes in the foreseeable future. The difference between the carrying values of the investments and their tax bases is largely a result of unremitted earnings and currency translation adjustments. The unremitted earnings and currency translation adjustment for which no deferred taxes have been recognized in respect of foreign subsidiaries were $4.3 billion and $5.5 billion for the periods December 31, 2021 and 2020, respectively. If such earnings are remitted, in the form of dividends or otherwise, we may be subject to income taxes and foreign withholding taxes. The determination of the amount of unrecognized deferred income tax liabilities on such amounts is not practicable.

Enbridge and certain of our subsidiaries are subject to taxation in Canada, the US and other foreign jurisdictions. The material jurisdictions in which we are subject to potential examinations include the US (Federal) and Canada (Federal, Alberta and Ontario). We are open to examination by Canadian tax authorities for the 2012 to 2021 tax years and by US tax authorities for the 2018 to 2021 tax years. We are currently under examination for income tax matters in Canada for the 2014 to 2018 tax years. We are not currently under examination for income tax matters in any other material jurisdiction where we are subject to income tax.

UNRECOGNIZED TAX BENEFITS

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

The unrecognized tax benefits as at December 31, 2021, if recognized, would impact our effective income tax rate. We do not anticipate further adjustments to the unrecognized tax benefits during the next 12 months that would have a material impact on our consolidated financial statements.

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

26. PENSION AND OTHER POSTRETIREMENT BENEFITS

PENSION PLANS

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

Defined Benefit Pension Plan Benefits

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

Defined Contribution Pension Plan Benefits

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

Benefit Obligations, Plan Assets and Funded Status

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

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

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

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

3 *Assets in the amount of $13 million (2020 - $11 million) and $84 million (2020 - $59 million), related to our Canadian and United States non-registered supplemental pension plan obligations, are held in grantor trusts and rabbi trusts that, in accordance with federal tax regulations, are not restricted from creditors. These assets are committed for the future settlement of benefit obligations included in the underfunded status as at the end of the year, however they are excluded from plan assets for accounting purposes.*

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

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

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

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

Amount Recognized in Accumulated Other Comprehensive Income

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

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

1 Excludes amounts related to cumulative translation adjustment.

Net Periodic Benefit Cost and Other Amounts Recognized in Comprehensive Income

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

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

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

Actuarial Assumptions

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

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

OTHER POSTRETIREMENT BENEFIT PLANS

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

Benefit Obligations, Plan Assets and Funded Status

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

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

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

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

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

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

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

1 Excludes amounts related to cumulative translation adjustment.

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

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

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

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

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

Assumed Health Care Cost Trend Rates
The assumed rates for the next year used to measure the expected cost of benefits are as follows:

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

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

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

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

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

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

Pension Plans

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

	Canada				US			
	Level 1[1]	Level 2[2]	Level 3[3]	Total	Level 1[1]	Level 2[2]	Level 3[3]	Total
(millions of Canadian dollars)								
December 31, 2021								
Cash and cash equivalents	**180**	**—**	**—**	**180**	**10**	**—**	**—**	**10**
Equity securities								
Canada	**198**	**228**	**—**	**426**	**—**	**—**	**—**	**—**
US	**1**	**—**	**—**	**1**	**—**	**—**	**—**	**—**
Global	**—**	**1,693**	**—**	**1,693**	**—**	**609**	**—**	**609**
Fixed income securities								
Government	**258**	**459**	**—**	**717**	**—**	**86**	**—**	**86**
Corporate	**—**	**453**	**—**	**453**	**—**	**118**	**—**	**118**
Alternatives[4]	**—**	**—**	**1,064**	**1,064**	**—**	**—**	**337**	**337**
Forward currency contracts	**—**	**2**	**—**	**2**	**—**	**—**	**—**	**—**
Total pension plan assets at fair value	**637**	**2,835**	**1,064**	**4,536**	**10**	**813**	**337**	**1,160**
December 31, 2020								
Cash and cash equivalents	213	—	—	213	5	—	—	5
Equity securities								
Canada	178	188	—	366	—	—	—	—
US	2	—	—	2	—	—	—	—
Global	—	1,556	—	1,556	—	590	—	590
Fixed income securities								
Government	207	378	—	585	—	75	—	75
Corporate	—	410	—	410	—	103	—	103
Alternatives[4]	—	—	912	912	—	—	289	289
Forward currency contracts	—	33	—	33	—	—	—	—
Total pension plan assets at fair value	600	2,565	912	4,077	5	768	289	1,062

1 Level 1 assets include assets with quoted prices in active markets for identical assets.
2 Level 2 assets include assets with significant observable inputs.
3 Level 3 assets include assets with significant unobservable inputs.
4 Alternatives include investments in private debt, private equity, infrastructure and real estate funds.

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

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

OPEB Plans

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

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

1 Level 1 assets include assets with quoted prices in active markets for identical assets.
2 Level 2 assets include assets with significant observable inputs.
3 Level 3 assets include assets with significant unobservable inputs.
4 Alternatives includes investments in private debt, private equity, infrastructure and real estate.

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

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

EXPECTED BENEFIT PAYMENTS

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

EXPECTED EMPLOYER CONTRIBUTIONS

In 2022, we expect to contribute approximately $110 million and $4 million to the Canadian and US pension plans, respectively, and $12 million and $6 million to the Canadian and US OPEB plans, respectively.

RETIREMENT SAVINGS PLANS

In addition to the pension and OPEB plans discussed above, we also have defined contribution employee savings plans available to US employees. Employees may participate in a matching contribution where we match a certain percentage of before-tax employee contributions of up to 6.0% of eligible pay per pay period. For the years ended December 31, 2021, 2020 and 2019, pre-tax employer matching contribution costs were $27 million each year, respectively.

27. LEASES

LESSEE

We incur operating lease expenses related primarily to real estate, pipelines, storage and equipment. Our operating leases have remaining lease terms of 5 months to 25 years as at December 31, 2021.

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

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

Supplemental Statements of Financial Position Information

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

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

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

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

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

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

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

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

LESSOR

We receive revenues from operating leases primarily related to natural gas and crude oil storage and processing facilities, rail cars, and wind power generation assets. Our operating leases have remaining lease terms of 1 month to 30 years as at December 31, 2021.

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

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

As at December 31, 2021, the following table sets out future lease payments to be received under operating lease contracts where we are the lessor:

	Operating leases
(millions of Canadian dollars)	
2022	**235**
2023	**215**
2024	**205**
2025	**196**
2026	**191**
Thereafter	**1,938**
Future lease payments	**2,980**

28. CHANGES IN OPERATING ASSETS AND LIABILITIES

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

29. RELATED PARTY TRANSACTIONS

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

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

Our transactions with significantly influenced investees are as follows:

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

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

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

LONG-TERM NOTES RECEIVABLE FROM AFFILIATES

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

30. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

As at December 31, 2021, we have commitments as detailed below:

	Total	Less than 1 year	2 years	3 years	4 years	5 years	Thereafter
(millions of Canadian dollars)							
Annual debt maturities[1]	73,809	6,164	7,910	4,559	4,357	11,007	39,812
Interest obligations[2]	36,044	2,531	2,389	2,229	2,073	1,925	24,897
Purchase of services, pipe and other materials, including transportation[3]	7,876	2,945	1,010	736	561	607	2,017
Maintenance agreements	346	41	20	20	21	21	223
Right-of-ways commitments	1,249	35	35	35	36	37	1,071
Total	119,324	11,716	11,364	7,579	7,048	13,597	68,020

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

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

3 Includes capital and operating commitments. Consists primarily of gas transportation and storage contracts, firm capacity payments and gas purchase commitments, transportation, service and product purchase obligations, and power commitments.

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

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

AUX SABLE
On October 14, 2016, an amended claim was filed against Aux Sable by a counterparty to an NGL supply agreement. On January 5, 2017, Aux Sable filed a Statement of Defence with respect to this claim.

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

While the final outcome of this action cannot be predicted with certainty, at this time management believes that the ultimate resolution of this action will not have a material impact on our consolidated financial position or results of operations.

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

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

31. GUARANTEES

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

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

The likelihood of having to perform under these guarantees and indemnifications is largely dependent upon future operations of various subsidiaries, investees and other third parties, or the occurrence of certain future events. We cannot reasonably estimate the total maximum potential amounts that could become payable to third parties and affiliates under such agreements described above; however, historically, we have not made any significant payments under guarantee or indemnification provisions. While these agreements may specify a maximum potential exposure, or a specified duration to the guarantee or indemnification obligation, there are circumstances where the amount and duration are unlimited. As at December 31, 2021 guarantees and indemnifications have not had, and are not reasonably likely to have, a material effect on our financial condition, changes in financial condition, earnings, liquidity, capital expenditures or capital resources.

32. QUARTERLY FINANCIAL DATA (UNAUDITED)

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

ENBRIDGE INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

December 31, 2021

INTRODUCTION

The following discussion and analysis of our financial condition and results of operations is based on and should be read in conjunction with "Forward-Looking Information" and "Non-GAAP and Other Financial Measures", Part I. *Item 1A. Risk Factors* and our consolidated financial statements and the accompanying notes included in Part II. *Item 8. Financial Statements and Supplementary Data* of this Annual Report on Form 10-K.

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

RECENT DEVELOPMENTS

ACQUISITION OF MODA MIDSTREAM OPERATING, LLC

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

NORMAL COURSE ISSUER BID

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

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

MAINLINE SYSTEM CONTRACTING

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

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

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

GAS TRANSMISSION AND MIDSTREAM RATE PROCEEDINGS

Texas Eastern Transmission

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

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

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

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

East Tennessee

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

Maritimes & Northeast Pipeline

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

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

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

GAS DISTRIBUTION AND STORAGE RATE APPLICATIONS

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

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

FINANCING UPDATE

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

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

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

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

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

ENERGY TRANSITION

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

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

ASSET MONETIZATION

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

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

FORWARD-LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this management's discussion and analysis (MD&A) to provide information about us and our subsidiaries and affiliates, including management’s assessment of our and our subsidiaries’ future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as ‘‘anticipate”, “believe”, “estimate”, “expect”, “forecast”, “intend”, “likely”, “plan”, “project”, “target” and similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information or statements included or incorporated by reference in this document include, but are not limited to, statements with respect to the following: our corporate vision and strategy, including strategic priorities and enablers; the COVID-19 pandemic and the duration and impact thereof; energy intensity and emissions reduction targets and related Environment, Social and Governance (ESG) matters; diversity and inclusion goals; expected supply of, demand for, and prices of crude oil, natural gas, natural gas liquids (NGLs), liquified natural gas and renewable energy; energy transition; anticipated utilization of our existing assets; expected earnings before interest, income taxes and depreciation and amortization (EBITDA); expected earnings/(loss); expected future cash flows and distributable cash flow; dividend growth and payout policy; financial strength and flexibility; expectations on sources of liquidity and sufficiency of financial resources; expected strategic priorities and performance of the Liquids Pipelines, Gas Transmission and Midstream, Gas Distribution and Storage, Renewable Power Generation and Energy Services businesses; expected costs related to announced projects and projects under construction and for maintenance; expected in-service dates for announced projects and projects under construction and for maintenance; expected capital expenditures, investment capacity and capital allocation priorities; expected equity funding requirements for our commercially secured growth program; expected future growth and expansion opportunities; expectations about our joint venture partners’ ability to complete and finance projects under construction; expected closing of acquisitions and dispositions and the timing thereof; expected benefits of transactions, including the realization of efficiencies, synergies and cost savings; expected future actions of regulators and courts; toll and rate cases discussions and filings, including Mainline System contracting; anticipated competition; United States Line 3 Replacement Program (US L3R Program), including anticipated in-service dates and capital costs; and Line 5 dual pipelines and related litigation and other matters.

Although we believe these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about the following: the COVID-19 pandemic and the duration and impact thereof; the expected supply of and demand for crude oil, natural gas, NGL and renewable energy; prices of crude oil, natural gas, NGLs and renewable energy; anticipated utilization of assets; exchange rates; inflation; interest rates; availability and price of labor and construction materials; operational reliability; customer and regulatory approvals; maintenance of support and regulatory approvals for our projects; anticipated in-service dates; weather; the timing and closing of acquisitions and dispositions; the realization of anticipated benefits and synergies of transactions; governmental legislation; litigation; estimated future dividends and impact of our dividend policy on our future cash flows; our credit ratings; capital project funding; hedging program; expected EBITDA; expected earnings/(loss); expected future cash flows; and expected distributable cash flow. Assumptions regarding the expected supply of and demand for crude oil, natural gas, NGLs and renewable energy, and the prices of these commodities, are material to and underlie all forward-looking statements, as they may impact current and future levels of demand for our services. Similarly, exchange rates, inflation, interest rates and the COVID-19 pandemic impact the economies and business environments in which we operate and may impact levels of demand for our services and cost of inputs, and are therefore inherent in all forward-looking statements. Due to the interdependencies and correlation of these macroeconomic factors, the impact of any one assumption on a forward-looking statement cannot be determined with certainty, particularly with respect to expected EBITDA, expected earnings/(loss), expected future cash flows, expected distributable cash flow or estimated future dividends. The most relevant assumptions associated with forward-looking statements regarding announced projects and projects under construction, including estimated completion dates and expected capital expenditures, include the following: the availability and price of labor and construction materials; the effects of inflation and foreign exchange rates on labor and material costs; the effects of interest rates on borrowing costs; the impact of weather, customer, government, court and regulatory approvals on construction and in-service schedules and cost recovery regimes; and the COVID-19 pandemic and the duration and impact thereof.

Our forward-looking statements are subject to risks and uncertainties pertaining to the successful execution of our strategic priorities, operating performance, legislative and regulatory parameters; litigation, including with respect to the Dakota Access Pipeline (DAPL) and the Line 5 dual pipelines; acquisitions, dispositions and other transactions and the realization of anticipated benefits therefrom; our dividend policy; project approval and support; renewals of rights-of-way; weather; economic and competitive conditions; public opinion; changes in tax laws and tax rates; exchange rates; interest rates; commodity prices; political decisions; the supply of, demand for and prices of commodities; and the COVID-19 pandemic, including but not limited to those risks and uncertainties discussed in this MD&A and in our other filings with Canadian and US securities regulators. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and our future course of action depends on management's assessment of all information available at the relevant time. Except to the extent required by applicable law, Enbridge assumes no obligation to publicly update or revise any forward-looking statement made in this MD&A or otherwise, whether as a result of new information, future events or otherwise. All forward-looking statements, whether written or oral, attributable to us or persons acting on our behalf, are expressly qualified in their entirety by these cautionary statements.

Non-GAAP and Other Financial Measures

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

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

RESULTS OF OPERATIONS

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

1 Non-GAAP financial measures.

EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS

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

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

- a non-cash, unrealized net gain of $53 million ($40 million after-tax) in 2021, compared with an unrealized net loss of $122 million ($92 million after-tax) in 2020 reflecting the revaluation of derivatives used to manage the profitability of transportation and storage transactions, as well as manage the exposure to movements in commodity prices;
- an impairment loss of $111 million ($83 million after-tax) in 2021 to our investment in the PennEast pipeline project after a decision by project partners to cease development, compared to a combined impairment loss of $615 million ($452 million after-tax) in 2020 to our investments in Southeast Supply Header (SESH) and Steckman Ridge, LP (Steckman);
- a gain of $303 million ($298 million after-tax) resulting from the sale of our investment in Noverco;
- employee severance, transition and transformation costs of $147 million ($112 million after-tax) in 2021, compared to $339 million ($256 million after-tax) in 2020 primarily related to our voluntary workforce reduction program offered in the second quarter of 2020;
- the absence in 2021 of a non-cash impairment to the carrying value of our investment in DCP Midstream, LLC (DCP Midstream) of $1.7 billion ($1.3 billion after-tax) and a $324 million loss ($244 million after-tax) resulting from our share of asset and goodwill impairments recognized by DCP Midstream, both recognized in 2020; and
- the absence in 2021 of a $159 million loss ($119 million after-tax) recorded in 2020 to reflect the Texas Eastern rate case settlement that re-established the Excess Accumulated Deferred Income Tax (EDIT) regulated liability that was previously eliminated in December 2018; partially offset by
- a non-cash, unrealized derivative fair value net gain of $197 million ($150 million after-tax) in 2021, compared with a net gain of $856 million ($646 million after-tax) in 2020, reflecting net fair value gains and losses arising from changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange risks.

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

After taking into consideration the factors above, the remaining $657 million increase in earnings attributable to common shareholders is primarily explained by the following significant business factors:

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

The business factors above were partially offset by the following:

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

REVENUES

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

Transportation and other services revenues of $16.2 billion, $16.2 billion and $16.6 billion for the years ended December 31, 2021, 2020 and 2019, respectively, were earned from our crude oil and natural gas pipeline transportation businesses and also include power generation revenues from our portfolio of renewable and power generation assets. For our transportation assets operating under market-based arrangements, revenues are driven by volumes transported and the corresponding tolls for transportation services. For assets operating under take-or-pay contracts, revenues reflect the terms of the underlying contract for services or capacity. For rate-regulated assets, revenues are charged in accordance with tolls established by the regulator and, in most cost-of-service based arrangements, are reflective of our cost to provide the service plus a regulator-approved rate of return.

Gas distribution sales revenues of $4.0 billion, $3.7 billion and $4.2 billion for the years ended December 31, 2021, 2020 and 2019, respectively, were recognized in a manner consistent with the underlying rate-setting mechanism mandated by the regulator. Revenues generated by the gas distribution businesses are primarily driven by volumes delivered, which vary with weather and customer composition and utilization, as well as regulator-approved rates. The cost of natural gas is passed through to customers through rates and does not ultimately impact earnings due to its flow-through nature.

Commodity sales revenues of $26.9 billion, $19.3 billion and $29.3 billion for the years ended December 31, 2021, 2020 and 2019, respectively, were generated primarily through our Energy Services operations. Energy Services includes the contemporaneous purchase and sale of crude oil, natural gas, power and Natural Gas Liquids (NGLs) to generate a margin, which is typically a small fraction of gross revenue. While sales revenue generated from these operations are impacted by commodity prices, net margins and earnings are relatively insensitive to commodity prices and reflect activity levels which are driven by differences in commodity prices between locations, grades and points in time, rather than on absolute prices. Any residual commodity margin risk is closely monitored and managed. Revenues from these operations depend on activity levels, which vary from year-to-year depending on market conditions and commodity prices.

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

BUSINESS SEGMENTS

LIQUIDS PIPELINES

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

1 Non-GAAP financial measure.

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

EBITDA was negatively impacted by $335 million due to certain unusual, infrequent or other non-operating factors, primarily explained by a non-cash, unrealized gain of $120 million in 2021 compared with an unrealized gain of $545 million in 2020 reflecting net fair value gains and losses arising from changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange risks.

The factor above was partially offset by the following:

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

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

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

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

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

GAS TRANSMISSION AND MIDSTREAM

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

1 Non-GAAP financial measure.

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

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

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

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

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

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

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

GAS DISTRIBUTION AND STORAGE

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

1 Non-GAAP financial measure.

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

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

- a gain of $303 million resulting from the sale of our investment in Noverco; and
- a non-cash, unrealized gain of $14 million in 2021, compared with a loss of $10 million in 2020, reflecting net fair value gains and losses arising from changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange risks.

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

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

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

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

RENEWABLE POWER GENERATION

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

1 Non-GAAP financial measure.

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

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

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

ENERGY SERVICES

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

1 Non-GAAP financial measure.

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

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

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

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

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

ELIMINATIONS AND OTHER

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

1 Non-GAAP financial measure.

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

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

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

- employee severance, transition and transformation costs of $87 million in 2021 compared with $279 million in 2020 primarily related to our voluntary workforce reduction program offered in the second quarter of 2020;
- the absence in 2021 of a non-cash loss of $74 million in 2020 relating to the recognition of a corporate guarantee obligation; and
- the absence in 2021 of a loss of $43 million in 2020 relating to the write-down of certain investments in emerging energy and other technologies; partially offset by
- a non-cash, unrealized gain of $55 million in 2021 compared with a gain of $318 million in 2020 reflecting net fair value gains and losses arising from the change in the mark-to-market value of derivative financial instruments used to manage foreign exchange risk.

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

GROWTH PROJECTS – COMMERCIALLY SECURED PROJECTS

The following table summarizes the status of our commercially secured projects, organized by business segment:

	Enbridge's Ownership Interest	Estimated Capital Cost[1]	Expenditures to Date[2]	Status[2]	Expected In-Service Date
(Canadian dollars, unless stated otherwise)					
LIQUIDS PIPELINES					
1. US Line 3 Replacement Program	100 %	US$4.0 billion	US$4.1 billion	Complete	In-service
2. Southern Access Expansion	100 %	US$0.5 billion	US$0.5 billion	Complete	In-service
3. Other - US	100 %	US$0.1 billion	US$0.1 billion	Complete	In-service
GAS TRANSMISSION AND MIDSTREAM					
4. T-South Reliability & Expansion Program	100 %	$1.0 billion	$0.9 billion	Complete	In-service
5. Spruce Ridge Project	100 %	$0.4 billion	$0.4 billion	Complete	In-service
6. Texas Eastern Modernization	100 %	US$0.4 billion	No significant expenditures to date	Pre-construction	2024 - 2026
7. Appalachia to Market II	100 %	US$0.1 billion	No significant expenditures to date	Pre-construction	2025
8. Other - US[3]	Various	US$0.6 billion	US$0.4 billion	Various stages	2021 - 2023
GAS DISTRIBUTION AND STORAGE					
9. System Enhancement Projects[4]	100 %	$0.4 billion	$0.1 billion	Various stages	2021 - 2023
10. Storage Enhancements	100 %	$0.1 billion	No significant expenditures to date	Under construction	2H - 2022
11. Natural Gas Expansion Program[5]	100 %	$0.1 billion	No significant expenditures to date	Pre-construction	2022 - 2027
RENEWABLE POWER GENERATION					
12. East-West Tie Line	25.0 %	$0.2 billion	$0.2 billion	Under construction	1H - 2022
13. Solar Self-Power Projects[6]	100 %	US$0.2 billion	No significant expenditures to date	Pre-construction	2022 - 2023
14. Saint-Nazaire France Offshore Wind Project[7]	25.5 %	$0.9 billion (€0.6 billion)	$0.5 billion (€0.3 billion)	Under construction	2H - 2022
15. Provence Grand Large Floating Offshore Wind Project[8]	25.0 %	$0.1 billion (€0.1 billion)	No significant expenditures to date	Pre-construction	2023
16. Fécamp Offshore Wind Project[9]	17.9 %	$0.7 billion (€0.5 billion)	$0.3 billion (€0.2 billion)	Under construction	2023
17. Calvados Offshore Wind Project[9]	21.7 %	$0.9 billion (€0.6 billion)	$0.1 billion (€0.1 billion)	Pre-construction	2024

1 *These amounts are estimates and are subject to upward or downward adjustment based on various factors. Where appropriate, the amounts reflect our share of joint venture projects.*

2 *Expenditures to date reflect total cumulative expenditures incurred from inception of the project up to December 31, 2021.*

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

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

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

LIQUIDS PIPELINES

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

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

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

GAS TRANSMISSION AND MIDSTREAM

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

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

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

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

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

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

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

GAS DISTRIBUTION AND STORAGE

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

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

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

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

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

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

RENEWABLE POWER GENERATION

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

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

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

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

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

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

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

OTHER ANNOUNCED PROJECTS UNDER DEVELOPMENT

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

LIQUIDS PIPELINES

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

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

GAS TRANSMISSION AND MIDSTREAM

- **Rio Bravo Pipeline** – the Rio Bravo Pipeline is designed to transport up to 4.5 billion cubic feet per day (bcf/d) of natural gas from the Agua Dulce supply area to NextDecade Corporation's (NextDecade) Rio Grande liquefied natural gas (LNG) export facility in the Port of Brownsville, Texas. We have executed a precedent agreement with NextDecade under which we will provide firm transportation capacity on the Rio Bravo Pipeline to NextDecade's Rio Grande LNG export facility for a term of at least 20 years. Construction of the pipeline will be subject to the Rio Grande LNG export facility reaching a final investment decision.

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

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

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

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

LIQUIDITY AND CAPITAL RESOURCES

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

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

Long-term contracts are contracts that we have signed for the purchase of services, pipe and other materials totaling $5.9 billion which are expected to be paid over the next five years. Long-term contracts also consists of the following purchase obligations: gas transportation and storage contracts, firm capacity payments and gas purchase commitments, transportation, service and product purchase obligations, and power commitments.

Our financing plan is regularly updated to reflect evolving capital requirements and financial market conditions and identifies a variety of potential sources of debt and equity funding alternatives. Our current financing plan does not include any issuances of additional common equity. On January 19, 2022, we closed a $750 million private placement offering of non-call 10-year fixed-to-fixed subordinated notes which mature on January 19, 2082. The net proceeds from the offering will be used to redeem the Preference Shares, Series 17 at par on March 1, 2022.

CAPITAL MARKET ACCESS

We ensure ready access to capital markets, subject to market conditions, through maintenance of shelf prospectuses that allow for issuance of long-term debt, equity and other forms of long-term capital when market conditions are attractive. In accordance with our funding plan, we completed the following long-term debt issuances totaling US$3.9 billion and $3.2 billion in 2021:

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

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

Credit Facilities, Ratings and Liquidity

To ensure ongoing liquidity and to mitigate the risk of capital market disruption, we maintain ready access to funds through committed bank credit facilities and actively manage our bank funding sources to optimize pricing and other terms. The following table provides details of our committed credit facilities at December 31, 2021:

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

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

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

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

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

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

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

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

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

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

There are no material restrictions on our cash. Total Restricted cash of $34 million, as reported on the Consolidated Statements of Financial Position, primarily includes cash collateral and future pipeline abandonment costs collected and held in trust. Cash and cash equivalents held by certain subsidiaries may not be readily accessible for alternative use by us.

Excluding current maturities of long-term debt, as at December 31, 2021 and 2020, we had a negative working capital position of $3.1 billion and $3.7 billion, respectively. In both periods, the major contributing factor to the negative working capital position was the current liabilities associated with our growth capital program.

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

SOURCES AND USES OF CASH

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

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

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

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

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

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

2021
The increase in cash used in investing activities primarily resulted from the following factors:

- Our acquisition of Moda on October 12, 2021 and higher capital expenditures related to the completion of the US L3R Program, partially offset by higher proceeds received from dispositions in 2021 compared with 2020 due to the sale of our interest in Noverco on December 30, 2021.

2020
The increase in cash used in investing activities primarily resulted from the following factors:

- Lower proceeds from asset dispositions in 2020 compared with 2019, primarily due to the sale of the federally regulated portion of our Canadian natural gas gathering and processing businesses assets on December 31, 2019.

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

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

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

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

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

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

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

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

Preference Share Issuances

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

	Gross Proceeds	Dividend Rate	Dividend[1]	Per Share Base Redemption Value[2]	Redemption and Conversion Option Date[2,3]	Right to Convert Into[3,4]
(Canadian dollars, unless otherwise stated)						
Series A	$125 million	5.50 %	$1.37500	$25	—	—
Series B	$457 million	3.42 %	$0.85360	$25	June 1, 2022	Series C
Series C[5]	$43 million	3-month treasury bill plus 2.40%	—	$25	June 1, 2022	Series B
Series D	$450 million	4.46 %	$1.11500	$25	March 1, 2023	Series E
Series F	$500 million	4.69 %	$1.17224	$25	June 1, 2023	Series G
Series H	$350 million	4.38 %	$1.09400	$25	September 1, 2023	Series I
Series J	US$200 million	4.89 %	US$1.22160	US$25	June 1, 2022	Series K
Series L	US$400 million	4.96 %	US$1.23972	US$25	September 1, 2022	Series M
Series N	$450 million	5.09 %	$1.27152	$25	December 1, 2023	Series O
Series P	$400 million	4.38 %	$1.09476	$25	March 1, 2024	Series Q
Series R	$400 million	4.07 %	$1.01825	$25	June 1, 2024	Series S
Series 1	US$400 million	5.95 %	US$1.48728	US$25	June 1, 2023	Series 2
Series 3	$600 million	3.74 %	$0.93425	$25	September 1, 2024	Series 4
Series 5	US$200 million	5.38 %	US$1.34383	US$25	March 1, 2024	Series 6
Series 7	$250 million	4.45 %	$1.11224	$25	March 1, 2024	Series 8
Series 9	$275 million	4.10 %	$1.02424	$25	December 1, 2024	Series 10
Series 11	$500 million	3.94 %	$0.98452	$25	March 1, 2025	Series 12
Series 13	$350 million	3.04 %	$0.76076	$25	June 1, 2025	Series 14
Series 15	$275 million	2.98 %	$0.74576	$25	September 1, 2025	Series 16
Series 17	$750 million	5.15 %	$1.28750	$25	March 1, 2022	Series 18
Series 19	$500 million	4.90 %	$1.22500	$25	March 1, 2023	Series 20

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

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

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

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

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

PREFERENCE SHARE REDEMPTION

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

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

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

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

	Dividend per share
Common Shares[1]	$0.86000
Preference Shares, Series A	$0.34375
Preference Shares, Series B	$0.21340
Preference Shares, Series C[2]	$0.15719
Preference Shares, Series D	$0.27875
Preference Shares, Series F	$0.29306
Preference Shares, Series H	$0.27350
Preference Shares, Series J	US$0.30540
Preference Shares, Series L	US$0.30993
Preference Shares, Series N	$0.31788
Preference Shares, Series P	$0.27369
Preference Shares, Series R	$0.25456
Preference Shares, Series 1	US$0.37182
Preference Shares, Series 3	$0.23356
Preference Shares, Series 5	US$0.33596
Preference Shares, Series 7	$0.27806
Preference Shares, Series 9	$0.25606
Preference Shares, Series 11	$0.24613
Preference Shares, Series 13	$0.19019
Preference Shares, Series 15	$0.18644
Preference Shares, Series 17	$0.32188
Preference Shares, Series 19	$0.30625

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

SUMMARIZED FINANCIAL INFORMATION

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

Consenting SEP notes and EEP notes under Guarantee

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

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

Enbridge Notes under Guarantees

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

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

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

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

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

Summarized Combined Statement of Earnings

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

Summarized Combined Statements of Financial Position

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

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

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

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

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

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

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

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

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

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

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

LEGAL AND OTHER UPDATES

LIQUIDS PIPELINES

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

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

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

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

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

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

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

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

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

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

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

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

OTHER LITIGATION

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

TAX MATTERS

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

CRITICAL ACCOUNTING ESTIMATES

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

Business Combinations

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

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

Goodwill Impairment

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

We perform our impairment assessment annually on April 1 at the reporting unit level. Reporting units are determined by assessing whether the components of our operating segments constitute businesses for which discrete information is available, whether segment management regularly reviews the operating results of those components and whether the economic and regulatory characteristics are similar.

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

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

Our most recent annual assessment of the goodwill balance was performed on April 1, 2021. As at April 1, 2021, our reporting units were equivalent to our reportable segments. We performed a quantitative goodwill impairment assessment for the Gas Transmission and Midstream reporting unit and qualitative assessments for the Liquids Pipelines and Gas Distribution and Storage reporting units. Our goodwill impairment assessments did not result in an impairment charge. Also, we did not identify any indicators of goodwill impairment during the remainder of 2021.

Asset Impairment
We evaluate the recoverability of our property, plant and equipment when events or circumstances such as economic obsolescence, business climate, legal or regulatory changes, or other factors indicate we may not recover the carrying amount of our assets. We continually monitor our businesses, the market and business environments to identify indicators that could suggest an asset may not be recoverable. If it is determined that the carrying value of an asset exceeds the undiscounted cash flows expected from the asset, we will assess the fair value of the asset. An impairment loss is recognized when the carrying amount of the asset exceeds its fair value.

With respect to equity method investments, we assess at each balance sheet date whether there is objective evidence that the investment is impaired by completing a quantitative or qualitative analysis of factors impacting the investment. If there is objective evidence of impairment, we determine whether the decline below carrying value is other than temporary. If the decline is determined to be other than temporary, an impairment charge is recorded in earnings with an offsetting reduction to the carrying value of the investment.

Asset fair value is determined by quoted market prices in active markets or present value techniques. The determination of the fair value using present value techniques requires the use of projections and assumptions regarding future cash flows and weighted average cost of capital. Any changes to these projections and assumptions could result in revisions to the evaluation of the recoverability of the asset and the recognition of an impairment loss in the Consolidated Statements of Earnings.

Assets Held for Sale

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

Regulatory Accounting

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

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

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

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

As at December 31, 2021 and 2020, our regulatory assets totaled $5.9 billion and $5.6 billion, respectively, and regulatory liabilities totaled $3.4 billion and $3.4 billion, respectively.

Depreciation
Depreciation of property, plant and equipment, our largest asset with a net book value at December 31, 2021 and 2020, of $100.1 billion and $94.6 billion, respectively, is charged in accordance with two primary methods. For distinct assets, depreciation is generally provided on a straight-line basis over the estimated useful lives of the assets commencing when the asset is placed in service. For largely homogeneous groups of assets with comparable useful lives, the pool method of accounting is followed whereby similar assets are grouped and depreciated as a pool. When group assets are retired or otherwise disposed of, gains and losses are not reflected in earnings but are booked as an adjustment to accumulated depreciation.

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

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

The following sensitivity analysis identifies the impact on the December 31, 2021 Consolidated Financial Statements of a 0.5% change in key pension and other postretirement benefit obligations (OPEB) assumptions:

	Canada		United States	
	Obligation	Expense	Obligation	Expense
(millions of Canadian dollars)				
Pension				
Decrease in discount rate	378	31	70	5
Decrease in expected return on assets	—	21	—	5
Decrease in rate of salary increase	(71)	(15)	(6)	(2)
OPEB				
Decrease in discount rate	21	1	8	—
Decrease in expected return on assets	N/A	N/A	—	1

Contingent Liabilities

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

Asset Retirement Obligations

Asset Retirement Obligations (ARO) associated with the retirement of long-lived assets are measured at fair value and recognized as Accounts payable and other or Other long-term liabilities in the period in which they can be reasonably determined. The fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. The discount rates used to estimate the present value of the expected future cash flows for the year ended December 31, 2021 ranged from 0.9% to 9.0% (2020 - 1.8% to 9.0%). ARO is added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. Our estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements. Currently, for the majority of our assets, there is insufficient data or information to reasonably determine the timing of settlement for estimating the fair value of the ARO. In these cases, the ARO cost is considered indeterminate for accounting purposes, as there is no data or information that can be derived from past practice, industry practice or the estimated economic life of the asset.

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

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

CHANGES IN ACCOUNTING POLICIES

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