Management's Report on Internal Control over Financial Reporting

The consolidated financial statements and Management's Discussion and Analysis (MD&A) included in this Annual Report are the responsibility of the management of TC Energy Corporation (TC Energy or the Company) and have been approved by the Board of Directors of the Company. The consolidated financial statements have been prepared by management in accordance with United States generally accepted accounting principles (GAAP) and include amounts that are based on estimates and judgments. The MD&A is based on the Company's financial results. It compares the Company's financial and operating performance in 2023 to that in 2022, and highlights significant changes between 2022 and 2021. The MD&A should be read in conjunction with the consolidated financial statements and accompanying notes. Financial information contained elsewhere in this Annual Report is consistent with the consolidated financial statements.

Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Company. Management has designed and maintains a system of internal control over financial reporting, including a program of internal audits to carry out its responsibility. Management believes these controls provide reasonable assurance that financial records are reliable and form a proper basis for the preparation of financial statements. The internal control over financial reporting includes management's communication to employees of policies that govern ethical business conduct.

Under the supervision and with the participation of the President and Chief Executive Officer and the Chief Financial Officer, management conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Management concluded, based on its evaluation, that internal control over financial reporting was effective as of December 31, 2023, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes.

The Board of Directors is responsible for reviewing and approving the consolidated financial statements and MD&A and ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board of Directors carries out these responsibilities primarily through the Audit Committee, which consists of independent, non-management directors. The Audit Committee meets with management at least four times a year and meets independently with internal and external auditors and as a group to review any significant accounting, internal control and auditing matters in accordance with the terms of the Charter of the Audit Committee, which is set out in the Annual Information Form. The Audit Committee's responsibilities include overseeing management's performance in carrying out its financial reporting responsibilities and reviewing the Annual Report, including the consolidated financial statements and MD&A, before these documents are submitted to the Board of Directors for approval. The internal and independent external auditors have access to the Audit Committee without the requirement to obtain prior management approval.

The Audit Committee approves the terms of engagement of the independent external auditors and reviews the annual audit plan, the Auditors' Report and the results of the audit. It also recommends to the Board of Directors the firm of external auditors to be appointed by the shareholders.

The shareholders have appointed KPMG LLP as independent external auditors to express an opinion as to whether the consolidated financial statements present fairly, in all material respects, the Company's consolidated financial position, results of operations and cash flows in accordance with GAAP. The reports of KPMG LLP outline the scope of its examinations and its opinions on the consolidated financial statements and the effectiveness of the Company's internal control over financial reporting.

François L. Poirier
President and
Chief Executive Officer

Joel E. Hunter
Executive Vice-President and
Chief Financial Officer

February 15, 2024

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors
TC Energy Corporation:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of TC Energy Corporation (the Company) as of December 31, 2023 and 2022, the related consolidated statements of income, comprehensive income, cash flows, and equity for each of the years in the three-year period ended December 31, 2023, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2023 and 2022, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2023, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2023, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 15, 2024 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the 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 audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits 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. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the Audit Committee and that: (1) relate to accounts or disclosures that are material to the consolidated financial statements; and (2) 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 matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Valuation of the equity investment in Coastal GasLink LP

As discussed in Notes 2 and 8 to the consolidated financial statements, the Company reviews equity method investments for impairment when an event or change in circumstances has a significant adverse effect on the investment's fair value. Where the Company concludes an investment's fair value is below its carrying value, the Company then determines whether the impairment is other-than-temporary, and if so, an impairment loss is recognized for the excess of the carrying value over the estimated fair value of the investment, not exceeding the carrying value of the investment.

With the expectation that additional equity contributions under the subordinated loan agreement between the Company and Coastal GasLink LP will be predominantly funded by TC Energy as a limited partner of Coastal GasLink LP, the Company completed valuation assessments during the first three quarters of 2023 and concluded that the fair value of its investment in Coastal GasLink LP was below its carrying value and that these were other-than-temporary impairments. As a result, a pre-tax impairment charge of $2,100 million was recognized during the nine months ended September 30, 2023. Fair value was estimated using a 40-year discounted cash flow model and incorporated assumptions related to capital cost estimates, discount rates, and long-term financing plans (collectively, the "key assumptions").

We identified the valuation of the equity investment in Coastal GasLink LP at September 30, 2023 as a critical audit matter. A high degree of auditor judgment was required to evaluate the key assumptions. Minor changes to the key assumptions could have had a significant effect on the Company's determination of the fair value of the investment. In addition, the audit effort associated with this estimate required specialized skills and knowledge.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls related to the critical audit matter. This included controls related to the Company's determination of the fair value of the investment and its evaluation of the key assumptions. We recalculated the capital cost estimates by comparing the project budget to the actual costs incurred to September 30, 2023. We also compared the amounts in the project budget to project status and milestone reporting provided to the partners of Coastal GasLink LP. We compared assumptions used in the long-term financing plans to publicly available data for comparable financing transactions and financing reports provided to the partners of Coastal GasLink LP. In addition, we involved a valuation professional with specialized skills and knowledge, who assisted in:

- evaluating the methodology used by management in the valuation by comparing it to methodologies used to value other development stage entities; and
- evaluating the discount rates used by management in the valuation by comparing them to discount rate ranges that were independently developed using publicly available market data for comparable entities.

Valuation of goodwill for the Columbia reporting unit

As discussed in Notes 2 and 15 to the consolidated financial statements, the goodwill balance as of December 31, 2023 for the Columbia reporting unit was $9,708 million. The Company assesses goodwill for impairment testing annually or more frequently if events or changes in circumstances indicate that the carrying value of a reporting unit, including goodwill, might be impaired. In respect of the Columbia reporting unit, the Company performed a quantitative goodwill impairment test on June 30, 2023 (the "June 30, 2023 impairment test") in conjunction with the process leading up to the sale of a 40 per cent equity interest in Columbia Gas Transmission, LLC (Columbia Gas) and Columbia Gulf Transmission, LLC (Columbia Gulf) (the "Transaction"). The quantitative goodwill impairment assessment involves determining the fair value of a reporting unit and comparing that value to the carrying value of the reporting unit, including goodwill. Fair value is estimated using a discounted cash flow model which requires the use of assumptions related to revenue and capital expenditure projections, the valuation multiple and the discount rate (collectively, the "key assumptions"). It was determined that the fair value of the Columbia reporting unit, inclusive of the Columbia Gas and Columbia Gulf business units, exceeded its carrying value, including goodwill, as of June 30, 2023. Although goodwill was not impaired, the estimated fair value in excess of the carrying value was less than 10 per cent.

We identified the valuation of goodwill for the Columbia reporting unit as a critical audit matter. A high degree of auditor judgment was required to evaluate the key assumptions. Minor changes to the key assumptions could have had a significant effect on the Company's determination of the fair value of the Columbia reporting unit. In addition, the audit effort associated with this estimate required specialized skills and knowledge.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls related to the critical audit matter. This included controls related to the Company's determination of the fair value of the Columbia reporting unit and its evaluation of the key assumptions. We compared the Company's historical revenue and capital expenditure projections used in the prior quantitative goodwill impairment test to 2023 actual results to assess the Company's ability to accurately forecast. We evaluated the Company's revenue and capital expenditure projections in the June 30, 2023 impairment test by comparing them to 2023 actual results and to assumptions used in industry publications related to North American and global energy consumption and production forecasts. We also inspected the executed agreements associated with the Transaction to assess whether the closing terms and economic value of the Transaction were consistent with the key assumptions and the fair value determined from the discounted cash flow model. In addition, we involved a valuation professional with specialized skills and knowledge, who assisted in:

- evaluating the Company's determination of a valuation multiple by comparing it to independently observed recent market transactions of comparable assets and publicly available market data for comparable entities
- evaluating the discount rate used by management in the valuation, by comparing it against a discount rate range that was independently developed using publicly available market data for comparable entities
- evaluating the Company's estimate of the fair value of the Columbia reporting unit by comparing the result of the Company's estimate to publicly available market data and valuation metrics for comparable entities.

Qualitative goodwill impairment indicators for the Columbia and ANR reporting units

As discussed in Notes 2 and 15 to the consolidated financial statements, the goodwill balance as of December 31, 2023 for the Columbia Pipeline Group, Inc. (Columbia) and the American Natural Resources (ANR) reporting units was $9,708 million and $2,570 million, respectively. The Company assesses goodwill for impairment testing annually or more frequently if events or changes in circumstances indicate that the carrying value of a reporting unit, including goodwill, might be impaired. The Company performed qualitative assessments to determine whether events or changes in circumstances indicate that the Columbia and ANR reporting units' goodwill might be impaired. These qualitative assessments were performed as of December 31, 2023.

We identified the evaluation of qualitative goodwill impairment indicators, or qualitative factors, for the Columbia and ANR reporting units as a critical audit matter. The assessment of the potential impact that these qualitative factors have on a reporting unit's fair value required the application of subjective auditor judgment. Qualitative factors include macroeconomic conditions, industry and market considerations, valuation multiples and discount rates, cost factors, historical and forecasted financial results and events specific to the reporting units, which required a higher degree of auditor judgment to evaluate. These qualitative factors could have had a significant effect on the Company's qualitative assessment and the potential for the need to perform a quantitative goodwill impairment test. In addition, the audit effort associated with this evaluation required specialized skills and knowledge.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls related to the Company's goodwill impairment assessment process, including controls related to the assessment of potential qualitative factors. We evaluated the Company's assessment of identified event-specific changes against our knowledge of event-specific changes obtained through other audit procedures. We evaluated information from analyst reports in the energy and utility industries, including global energy consumption forecasts and natural gas production forecasts, which were compared to geopolitical and market considerations used by the Company. We compared the current valuation multiples and discount rates, cost factors, historical and forecasted financial results of the reporting units, including the impact of newly approved growth projects, to assumptions used in the quantitative goodwill impairment tests performed in a previous period. In addition, we involved a valuation professional with specialized skills and knowledge, who assisted in:

- evaluating the Company's determination of the valuation multiples by comparing them to independently observed, recent market transactions of comparable assets and using publicly available market data for comparable entities
- evaluating the discount rates used by management in the assessment, by comparing them against a discount rate range that was independently developed using publicly available market data for comparable entities.

KPMG LLP

Chartered Professional Accountants
We have served as the Company's auditor since 1956.

Calgary, Canada
February 15, 2024

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors
TC Energy Corporation:

Opinion on Internal Control Over Financial Reporting

We have audited TC Energy Corporation's (the Company) internal control over financial reporting as of December 31, 2023, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2023, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2023 and 2022, the related consolidated statements of income, comprehensive income, cash flows, and equity for each of the years in the three-year period ended December 31, 2023, and the related notes (collectively, the consolidated financial statements), and our report dated February 15, 2024 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

The Company's management is responsible 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 included in the Company's Management's Discussion and Analysis. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the 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 audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. 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 audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) 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.

KPMG LLP

Chartered Professional Accountants
Calgary, Canada
February 15, 2024

Consolidated statement of income

year ended December 31 (millions of Canadian $, except per share amounts)	2023	2022	2021
Revenues (Note 6)			
Canadian Natural Gas Pipelines	**5,173**	4,764	4,519
U.S. Natural Gas Pipelines	**6,229**	5,933	5,233
Mexico Natural Gas Pipelines	**846**	688	605
Liquids Pipelines	**2,667**	2,668	2,306
Power and Energy Solutions	**1,019**	924	724
	15,934	14,977	13,387
Income (Loss) from Equity Investments (Note 12)	**1,377**	1,054	898
Impairment of Equity Investment (Notes 8 and 12)	**(2,100)**	(3,048)	—
Operating and Other Expenses			
Plant operating costs and other	**4,887**	4,932	4,098
Commodity purchases resold	**517**	534	87
Property taxes	**897**	848	774
Depreciation and amortization	**2,778**	2,584	2,522
Goodwill and asset impairment charges and other (Notes 7 and 15)	**(4)**	453	2,775
	9,075	9,351	10,256
Net Gain (Loss) on Sale of Assets	**—**	—	30
Financial Charges			
Interest expense (Note 21)	**3,263**	2,588	2,360
Allowance for funds used during construction	**(575)**	(369)	(267)
Foreign exchange (gains) losses, net (Note 23)	**(320)**	185	(10)
Interest income and other	**(242)**	(146)	(190)
	2,126	2,258	1,893
Income (Loss) before Income Taxes	**4,010**	1,374	2,166
Income Tax Expense (Recovery) (Note 20)			
Current	**931**	415	305
Deferred	**11**	174	(185)
	942	589	120
Net Income (Loss)	**3,068**	785	2,046
Net income (loss) attributable to non-controlling interests (Note 24)	**146**	37	91
Net Income (Loss) Attributable to Controlling Interests	**2,922**	748	1,955
Preferred share dividends	**93**	107	140
Net Income (Loss) Attributable to Common Shares	**2,829**	641	1,815
Net Income (Loss) per Common Share (Note 25)			
Basic	**$2.75**	$0.64	$1.87
Diluted	**$2.75**	$0.64	$1.86
Dividends Declared per Common Share	**$3.72**	$3.60	$3.48
Weighted Average Number of Common Shares (millions) (Note 25)			
Basic	**1,030**	995	973
Diluted	**1,030**	996	974

The accompanying Notes to the consolidated financial statements are an integral part of these statements.

Consolidated statement of comprehensive income

year ended December 31 (millions of Canadian $)	2023	2022	2021
Net Income (Loss)	**3,068**	785	2,046
Other Comprehensive Income (Loss), Net of Income Taxes			
Foreign currency translation gains and losses on net investment in foreign operations	**(1,141)**	1,494	(108)
Change in fair value of net investment hedges	**17**	(36)	(2)
Change in fair value of cash flow hedges	**—**	(39)	(10)
Reclassification to net income of (gains) losses on cash flow hedges	**74**	42	55
Unrealized actuarial gains (losses) on pension and other post-retirement benefit plans	**(11)**	63	158
Reclassification to net income of actuarial (gains) losses on pension and other post-retirement benefit plans	**—**	6	14
Other comprehensive income (loss) on equity investments	**(211)**	867	535
Other comprehensive income (loss) (Note 27)	**(1,272)**	2,397	642
Comprehensive Income (Loss)	**1,796**	3,182	2,688
Comprehensive income (loss) attributable to non-controlling interests	**(220)**	45	81
Comprehensive Income (Loss) Attributable to Controlling Interests	**2,016**	3,137	2,607
Preferred share dividends	**93**	107	140
Comprehensive Income (Loss) Attributable to Common Shares	**1,923**	3,030	2,467

The accompanying Notes to the consolidated financial statements are an integral part of these statements.

Consolidated statement of cash flows

year ended December 31 (millions of Canadian $)	2023	2022	2021
Cash Generated from Operations			
Net income (loss)	**3,068**	785	2,046
Depreciation and amortization	**2,778**	2,584	2,522
Goodwill and asset impairment charges and other (Notes 7 and 15)	**(4)**	453	2,775
Deferred income taxes (Note 20)	**11**	174	(185)
(Income) loss from equity investments (Note 12)	**(1,377)**	(1,054)	(898)
Impairment of equity investment (Notes 8 and 12)	**2,100**	3,048	—
Distributions received from operating activities of equity investments (Note 12)	**1,254**	1,025	975
Employee post-retirement benefits funding, net of expense (Note 28)	**(17)**	(29)	(5)
Net (gain) loss on sale of assets	**—**	—	(30)
Equity allowance for funds used during construction	**(367)**	(248)	(191)
Unrealized (gains) losses on financial instruments (Note 29)	**(342)**	135	194
Expected credit loss provision (Note 29)	**(83)**	163	—
Foreign exchange losses on loan receivable from affiliate (Note 13)	**—**	28	41
Other	**40**	(50)	(67)
(Increase) decrease in operating working capital (Note 30)	**207**	(639)	(287)
Net cash provided by operations	**7,268**	6,375	6,890
Investing Activities			
Capital expenditures (Note 5)	**(8,007)**	(6,678)	(5,924)
Capital projects in development (Note 5)	**(142)**	(49)	—
Contributions to equity investments (Notes 5, 8 and 12)	**(4,149)**	(3,433)	(1,210)
Acquisitions, net of cash acquired (Note 31)	**(307)**	—	—
Loans to affiliate (issued) repaid, net (Notes 8 and 13)	**250**	(11)	(239)
Keystone XL contractual recoveries (Note 7)	**10**	571	—
Proceeds from sales of assets, net of transaction costs	**33**	—	35
Other distributions from equity investments (Note 12)	**23**	2,632	73
Deferred amounts and other	**2**	(41)	(447)
Net cash (used in) provided by investing activities	**(12,287)**	(7,009)	(7,712)
Financing Activities			
Notes payable issued (repaid), net	**(6,299)**	766	1,003
Long-term debt issued, net of issue costs	**15,884**	2,508	10,730
Long-term debt repaid	**(3,772)**	(1,338)	(7,758)
Disposition of equity interest, net of transaction costs (Notes 24 and 31)	**5,328**	—	—
Junior subordinated notes issued, net of issue costs	**—**	1,008	495
Redeemable non-controlling interest repurchased (Note 7)	**—**	—	(633)
Dividends on common shares	**(2,787)**	(3,192)	(3,317)
Dividends on preferred shares	**(92)**	(106)	(141)
Distributions to non-controlling interests	**(124)**	(44)	(74)
Distributions on Class C Interests (Note 7)	**(49)**	(43)	(16)
Common shares issued, net of issue costs	**4**	1,905	148
Preferred shares redeemed (Note 26)	**—**	(1,000)	(500)
Gains (losses) on settlement of financial instruments	**—**	23	(10)
Acquisition of TC PipeLines, LP transaction costs (Note 24)	**—**	—	(15)
Net cash (used in) provided by financing activities	**8,093**	487	(88)
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**(16)**	94	53
Increase (Decrease) in Cash and Cash Equivalents	**3,058**	(53)	(857)
Cash and Cash Equivalents			
Beginning of year	**620**	673	1,530
Cash and Cash Equivalents			
End of year	**3,678**	620	673

The accompanying Notes to the consolidated financial statements are an integral part of these statements.

Consolidated balance sheet

at December 31 (millions of Canadian $)	2023	2022
ASSETS		
Current Assets		
Cash and cash equivalents	**3,678**	620
Accounts receivable	**4,209**	3,624
Inventories	**982**	936
Other current assets (Note 9)	**2,503**	2,152
	11,372	7,332
Plant, Property and Equipment (Note 10)	**80,569**	75,940
Net Investment in Leases (Note 11)	**2,263**	1,895
Equity Investments (Note 12)	**10,314**	9,535
Restricted Investments	**2,636**	2,108
Regulatory Assets (Note 14)	**2,330**	1,910
Goodwill (Note 15)	**12,532**	12,843
Other Long-Term Assets (Note 16)	**3,018**	2,785
	125,034	114,348
LIABILITIES		
Current Liabilities		
Notes payable (Note 17)	**—**	6,262
Accounts payable and other (Note 18)	**6,987**	7,149
Dividends payable	**979**	930
Accrued interest	**913**	668
Current portion of long-term debt (Note 21)	**2,938**	1,898
	11,817	16,907
Regulatory Liabilities (Note 14)	**4,806**	4,520
Other Long-Term Liabilities (Note 19)	**1,015**	1,017
Deferred Income Tax Liabilities (Note 20)	**8,125**	7,648
Long-Term Debt (Note 21)	**49,976**	39,645
Junior Subordinated Notes (Note 22)	**10,287**	10,495
	86,026	80,232
EQUITY		
Common shares, no par value (Note 25)	**30,002**	28,995
Issued and outstanding: December 31, 2023 – 1,037 million shares		
December 31, 2022 – 1,018 million shares		
Preferred shares (Note 26)	**2,499**	2,499
Additional paid-in capital	**—**	722
Retained earnings (Accumulated deficit)	**(2,997)**	819
Accumulated other comprehensive income (loss) (Note 27)	**49**	955
Controlling Interests	**29,553**	33,990
Non-controlling interests (Note 24)	**9,455**	126
	39,008	34,116
	125,034	114,348

Commitments, Contingencies and Guarantees (Note 32)

Variable Interest Entities (Note 33)

The accompanying Notes to the consolidated financial statements are an integral part of these statements.

On behalf of the Board:

François L. Poirier, Director

Una M. Power, Director

Consolidated statement of equity

year ended December 31 (millions of Canadian $)	2023	2022	2021
Common Shares (Note 25)			
Balance at beginning of year	**28,995**	26,716	24,488
Shares issued:			
Dividend reinvestment and share purchase plan	**1,003**	342	—
Exercise of stock options	**4**	183	165
Under public offering, net of issue costs	**—**	1,754	—
Acquisition of TC PipeLines, LP, net of transaction costs (Note 24)	**—**	—	2,063
Balance at end of year	**30,002**	28,995	26,716
Preferred Shares (Note 26)			
Balance at beginning of year	**2,499**	3,487	3,980
Redemption of shares	**—**	(988)	(493)
Balance at end of year	**2,499**	2,499	3,487
Additional Paid-In Capital			
Balance at beginning of year	**722**	729	2
Issuance of stock options, net of exercises	**9**	(7)	(6)
Disposition of equity interest, net of transaction costs (Note 24)	**(3,537)**	—	—
Reclassification of additional paid-in capital deficit to retained earnings (accumulated deficit)	**2,806**	—	—
Keystone XL project-level credit facility retirement and issuance of Class C Interests (Note 7)	**—**	—	737
Acquisition of TC PipeLines, LP (Note 24)	**—**	—	(398)
Repurchase of redeemable non-controlling interest (Note 7)	**—**	—	394
Balance at end of year	**—**	722	729
Retained Earnings (Accumulated Deficit)			
Balance at beginning of year	**819**	3,773	5,367
Net income (loss) attributable to controlling interests	**2,922**	748	1,955
Common share dividends	**(3,839)**	(3,595)	(3,409)
Preferred share dividends	**(93)**	(95)	(133)
Reclassification of additional paid-in capital deficit to retained earnings (accumulated deficit)	**(2,806)**	—	—
Redemption of preferred shares	**—**	(12)	(7)
Balance at end of year	**(2,997)**	819	3,773
Accumulated Other Comprehensive Income (Loss) (Note 27)			
Balance at beginning of year	**955**	(1,434)	(2,439)
Other comprehensive income (loss) attributable to controlling interests	**(379)**	2,389	652
Impact of non-controlling interest (Note 24)	**(527)**	—	—
Acquisition of TC PipeLines, LP (Note 24)	**—**	—	353
Balance at end of year	**49**	955	(1,434)
Equity Attributable to Controlling Interests	**29,553**	33,990	33,271
Equity Attributable to Non-Controlling Interests			
Balance at beginning of year	**126**	125	1,682
Disposition of equity interest (Note 24)	**9,451**	—	—
Non-controlling interests on acquisition of Texas Wind Farms (Note 24)	**222**	—	—
Net income (loss) attributable to non-controlling interests	**146**	37	90
Other comprehensive income (loss) attributable to non-controlling interests	**(366)**	8	(10)
Distributions declared to non-controlling interests	**(124)**	(44)	(74)
Acquisition of TC PipeLines, LP (Note 24)	**—**	—	(1,563)
Balance at end of year	**9,455**	126	125
Total Equity	**39,008**	34,116	33,396

The accompanying Notes to the consolidated financial statements are an integral part of these statements.

Notes to consolidated financial statements

1. DESCRIPTION OF TC ENERGY'S BUSINESS

TC Energy Corporation (TC Energy or the Company) is a leading North American energy infrastructure company which operates in five business segments: Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines, Mexico Natural Gas Pipelines, Liquids Pipelines and Power and Energy Solutions. These segments offer different products and services, including certain natural gas, crude oil and electricity marketing and storage services. The Company also has a Corporate segment, consisting of corporate and administrative functions that provide governance, financing and other support to the Company's business segments.

Canadian Natural Gas Pipelines

The Canadian Natural Gas Pipelines segment primarily consists of the Company's investments in 40,596 km (25,226 miles) of regulated natural gas pipelines currently in operation.

U.S. Natural Gas Pipelines

The U.S. Natural Gas Pipelines segment primarily consists of the Company's investments in 50,088 km (31,123 miles) of regulated natural gas pipelines, 532 Bcf of regulated natural gas storage facilities and other assets currently in operation.

Mexico Natural Gas Pipelines

The Mexico Natural Gas Pipelines segment primarily consists of the Company's investments in 2,895 km (1,798 miles) of regulated natural gas pipelines currently in operation.

Liquids Pipelines

The Liquids Pipelines segment primarily consists of the Company's investments in 4,865 km (3,024 miles) of crude oil pipeline systems currently in operation which connect Alberta and U.S. crude oil supplies to U.S. refining markets in Illinois, Oklahoma and Texas.

Power and Energy Solutions

The Power and Energy Solutions segment primarily consists of the Company's investments in approximately 4,600 MW of power generation facilities and 118 Bcf of non-regulated natural gas storage facilities. These assets are located in Alberta, Ontario, Québec, New Brunswick and Texas. In addition, TC Energy has physical and virtual power purchase agreements (PPAs) in Canada and the U.S. to buy and/or sell power from wind and solar facilities. These PPAs have the potential to be leases, derivatives or revenue arrangements depending on the contractual terms of the agreement.

2. ACCOUNTING POLICIES

The Company's consolidated financial statements have been prepared by management in accordance with U.S. generally accepted accounting principles. Amounts are stated in Canadian dollars unless otherwise indicated.

Basis of Presentation

These consolidated financial statements include the accounts of TC Energy and its subsidiaries. The Company consolidates variable interest entities (VIEs) for which it is considered to be the primary beneficiary as well as voting interest entities in which it has a controlling financial interest. To the extent there are interests owned by other parties, these interests are included in non-controlling interests. TC Energy uses the equity method of accounting for joint ventures in which the Company is able to exercise joint control and for investments in which the Company is able to exercise significant influence.

Certain prior year amounts have been reclassified to conform to current year presentation.

Use of Estimates and Judgments

In preparing these consolidated financial statements, TC Energy is required to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses since the determination of these items may be dependent on future events. The Company uses the most current information available and exercises careful judgment in making these estimates and assumptions.

Certain estimates and judgments have a material impact where the assumptions underlying these accounting estimates relate to matters that are highly uncertain at the time the estimate or judgment is made or are subjective. These estimates and judgments include, but are not limited to:

- fair value of TC Energy's equity investment in Coastal GasLink LP (Note 8)
- assessment of goodwill impairment indicators and fair value of reporting units that contain goodwill (Note 15)
- estimates and judgments used in measuring the fair value of Columbia Gas Transmission, LLC (Columbia Gas) and Columbia Gulf Transmission, LLC (Columbia Gulf) (Note 15).

Some of the estimates and judgments the Company has to make have a material impact on the consolidated financial statements, but do not involve significant subjectivity or uncertainty. These estimates and judgments include, but are not limited to:

- valuation of Keystone XL assets and Class C Interests (Note 7)
- recoverability and depreciation rates of plant, property and equipment (Note 10)
- allocation of consideration to lease and non-lease components in a contract that contains a lease (Note 11)
- assumptions used to measure the carrying amount of and expected credit losses on net investment in leases and certain contract assets (Notes 11 and 29)
- fair value of equity investments not otherwise noted above (Note 12)
- carrying value of regulatory assets and liabilities (Note 14)
- assumptions used to measure the environmental remediation liability from the Keystone pipeline rupture (Note 18)
- recognition of asset retirement obligations (Note 19)
- provisions for income taxes, including valuation allowances and releases as well as tax positions that may be reviewed as part of an audit by tax authorities (Note 20)
- assumptions used to measure retirement and other post-retirement benefit obligations (Note 28)
- fair value of financial instruments (Note 29)
- fair value of Fluvanna Wind Farm and Blue Cloud Wind Farm (Texas Wind Farms) assets (Note 31)
- commitments and provisions for contingencies and guarantees (Note 32).

TC Energy continues to assess the impact of climate change on the consolidated financial statements. There are ongoing developments in the ESG frameworks and regulatory initiatives that could further impact accounting estimates and judgments including, but not limited to, assessment of asset useful lives, goodwill valuation, impairment of plant, property and equipment, accrued environmental costs and asset retirement obligations. The impact of these changes is continuously assessed to ensure any changes in assumptions that would impact estimates listed above are adjusted on a timely basis.

Actual results could differ from these estimates.

Regulation

Certain Canadian, U.S. and Mexico natural gas pipeline and storage assets are regulated with respect to construction, operations and the determination of tolls. In Canada, regulated natural gas pipelines and liquids pipelines are subject to the authority of the Canada Energy Regulator (CER), the Alberta Energy Regulator or the B.C. Oil and Gas Commission. In the U.S., regulated interstate natural gas pipelines and liquids pipelines as well as regulated natural gas storage assets are subject to the authority of the Federal Energy Regulatory Commission (FERC). In Mexico, regulated natural gas pipelines are subject to the authority of the Energy Regulatory Commission (CRE). Rate-regulated accounting (RRA) standards may impact the timing of the recognition of certain revenues and expenses in TC Energy's rate-regulated businesses which may differ from that otherwise recognized in non-rate-regulated businesses to reflect the economic impact of the regulators' decisions regarding revenues and tolls. Regulatory assets represent costs that are expected to be recovered in customer rates in future periods and regulatory liabilities represent amounts that are expected to be returned to customers through future rate-setting processes. An operation qualifies for the use of RRA when it meets three criteria:

- a regulator must establish or approve the rates for the regulated services or activities
- the regulated rates must be designed to recover the cost of providing the services or products
- it is reasonable to assume that rates set at levels to recover the cost can be charged to and collected from customers because of the demand for services or products and the level of direct or indirect competition.

TC Energy's businesses that apply RRA currently include natural gas pipelines in Canada, U.S. and Mexico and regulated U.S. natural gas storage. RRA is not applicable to the Company's liquids pipelines as the regulators' decisions regarding operations and tolls on those systems generally do not have an impact on timing of recognition of revenues and expenses.

Revenue Recognition

The total consideration for services and products to which the Company expects to be entitled can include fixed and variable amounts. The Company has variable revenue that is subject to factors outside the Company's influence, such as market prices, actions of third parties and weather conditions. The Company considers this variable revenue to be "constrained" as it cannot be reliably estimated and, therefore, recognizes variable revenue when the service is provided.

Revenues from contracts with customers are recognized net of any commodity taxes collected from customers which are subsequently remitted to governmental authorities. The Company's contracts with customers include natural gas and liquids pipelines capacity arrangements and transportation contracts, power generation contracts, natural gas storage and other contracts.

Revenues from non-lease components associated with a lease arrangement are recognized systematically over the term of the contract.

The majority of income earned from marketing activities, as it relates to the purchase and sale of crude oil, natural gas and electricity, is recorded on a net basis in the month of delivery.

Canadian Natural Gas Pipelines

Capacity Arrangements and Transportation

Revenues from the Company's Canadian natural gas pipelines are generated from contractual arrangements for committed capacity and from the transportation of natural gas. Revenues earned from firm contracted capacity arrangements are recognized ratably over the term of the contract regardless of the amount of natural gas that is transported. Transportation revenues for interruptible or volumetric-based services are recognized when the service is performed.

Revenues from the Company's Canadian natural gas pipelines under federal jurisdiction are subject to regulatory decisions by the CER. The tolls charged on these pipelines are based on revenue requirements designed to recover the costs of providing natural gas capacity for transportation services, which includes a return of and on capital, as approved by the CER. The Company's Canadian natural gas pipelines are generally not subject to earnings volatility related to variances in revenues and costs. These variances, except as related to incentive arrangements, are generally subject to deferral treatment and are recovered or refunded in future tolls. Revenues recognized prior to a CER decision on rates for that period reflect the CER's last approved return on equity (ROE) assumptions. Adjustments to revenues are recorded when the CER decision is received. Canadian natural gas pipelines' revenues are invoiced and received on a monthly basis. The Company does not take ownership of the natural gas that it transports for customers.

Other

The Company is contracted to provide pipeline construction services to a partially-owned entity for a development fee. The development fee is considered variable consideration due to refund provisions in the contract. The Company recognizes its estimate of the most likely amount of the variable consideration to which it will be entitled. The development fee is recognized over time as the services are provided based on the input method using an estimate of activity level.

U.S. Natural Gas Pipelines

Capacity Arrangements and Transportation

Revenues from the Company's U.S. natural gas pipelines are generated from contractual arrangements for committed capacity and from the transportation of natural gas. Revenues earned from firm contracted capacity arrangements are generally recognized ratably over the term of the contract regardless of the amount of natural gas that is transported. Transportation revenues for interruptible or volumetric-based services are recognized when the service is performed.

The Company's U.S. natural gas pipelines are subject to FERC regulations and, as a result, a portion of revenues collected may be subject to refund if invoiced during an interim period when a rate proceeding is ongoing. Allowances for these potential refunds are recognized using management's best estimate based on the facts and circumstances of the proceeding. Any allowances that are recognized during the proceeding process are refunded or retained at the time a regulatory decision becomes final. U.S. natural gas pipelines' revenues are invoiced and received on a monthly basis. The Company does not take ownership of the natural gas that it transports for customers.

Natural Gas Storage and Other

Revenues from the Company's regulated U.S. natural gas storage services are generated mainly from firm committed capacity storage contracts. The performance obligation in these contracts is the reservation of a specified amount of capacity for storage including specifications with regard to the amount of natural gas that can be injected or withdrawn on a daily basis. Revenues are recognized ratably over the contract period for firm committed capacity regardless of the amount of natural gas that is stored, and when gas is injected or withdrawn for interruptible or volumetric-based services. Natural gas storage services revenues are invoiced and received on a monthly basis. The Company does not take ownership of the natural gas that it stores for customers.

The Company owns mineral rights associated with certain natural gas storage facilities. These mineral rights can be leased or contributed to producers of natural gas in return for a royalty interest which is recognized when natural gas and associated liquids are produced.

Mexico Natural Gas Pipelines

Capacity Arrangements and Transportation

Revenues from certain of the Company's Mexico natural gas pipelines are primarily collected based on CRE-approved negotiated firm capacity contracts and are generally recognized ratably over the term of the contract. Transportation revenues related to interruptible or volumetric-based services are recognized when the service is performed. Mexico natural gas pipelines' revenues are invoiced and received on a monthly basis. The Company does not take ownership of the natural gas that it transports for customers.

Other

The Company generates revenues from operating and maintenance services provided on certain leased pipelines. Revenues earned from these services are recognized ratably over the term of the contract.

Liquids Pipelines

Capacity Arrangements and Transportation

Revenues from the Company's liquids pipelines are generated mainly from providing customers with firm capacity arrangements to transport crude oil. The performance obligation in these contracts is the reservation of a specified amount of capacity together with the transportation of crude oil on a monthly basis. Revenues earned from these arrangements are recognized ratably over the term of the contract regardless of the amount of crude oil that is transported. Revenues for interruptible or volumetric-based services are recognized when the service is performed. Liquids pipelines' revenues are invoiced and received on a monthly basis. The Company does not take ownership of the crude oil that it transports for customers.

Power and Energy Solutions

Power

Revenues from the Company's Power and Energy Solutions business are primarily derived from long-term contractual commitments to provide power capacity to meet the demands of the market and from the sale of electricity to both centralized markets and to customers. Power generation revenues also include revenues from the sale of steam to customers. Revenues and capacity payments are recognized as the services are provided and as electricity and steam is delivered. Power generation revenues are invoiced and received on a monthly basis.

Natural Gas Storage and Other

Non-regulated natural gas storage contracts include park, loan and term storage arrangements. Revenues are recognized as the services are provided. Term storage revenues are invoiced and received on a monthly basis. Revenues from ancillary services are recognized as the service is provided. The Company does not take ownership of the natural gas that it stores for customers.

Cash and Cash Equivalents

The Company's Cash and cash equivalents consist of cash and highly liquid short-term investments with original maturities of three months or less and are recorded at cost, which approximates fair value.

Inventories

Inventories primarily consist of materials and supplies including spare parts and fuel, proprietary crude oil in transit, proprietary natural gas inventory in storage and emissions allowances and credits not held for compliance. The Company purchases certain emissions allowances and credits as part of bundled arrangements that also include the purchase of electricity for a fixed price. The cost allocated to emissions allowances and credits under such arrangements is based on observable market prices. Inventories are carried at the lower of cost and net realizable value.

Assets Held for Sale

The Company classifies assets as held for sale when management approves and commits to a formal plan to actively market a disposal group and expects the sale to close within the next 12 months. Upon classifying an asset as held for sale, the asset is recorded at the lower of its carrying amount or its estimated fair value, net of selling costs and any losses are recognized in net income. Gains related to the expected sale of these assets are not recognized until the transaction closes. Once an asset is classified as held for sale, depreciation expense is no longer recorded.

Plant, Property and Equipment

Natural Gas Pipelines

Plant, property and equipment for natural gas pipelines is carried at cost. Depreciation is calculated on a straight-line basis once the assets are ready for their intended use. Pipeline and compression equipment are depreciated at annual rates ranging from 0.75 per cent to 6.67 per cent and metering and other plant equipment are depreciated at various rates reflecting their estimated useful lives. The cost of major overhauls of equipment is capitalized and depreciated over the estimated service lives of the overhauls. The cost of regulated natural gas pipelines includes an allowance for funds used during construction (AFUDC) consisting of a debt component and an equity component based on the rate of return on rate base approved by regulators. AFUDC is reflected as an increase in the cost of the assets in Plant, property and equipment with a corresponding credit recognized in Allowance for funds used during construction in the Consolidated statement of income. The equity component of AFUDC is a non-cash expenditure. Interest is capitalized during construction of non-regulated natural gas pipelines.

Natural gas pipelines' linepack and natural gas storage base gas are valued at cost and are maintained to ensure adequate pressure exists to transport natural gas through pipelines and deliver natural gas held in storage. Linepack and base gas are not depreciated.

When rate-regulated natural gas pipelines retire plant, property and equipment from service, the original book cost is removed from the gross plant amount and recorded as a reduction to accumulated depreciation with no amount recorded to net income. Costs incurred to remove plant, property and equipment from service, net of any salvage proceeds, are also recorded in accumulated depreciation.

Other

The Company participates as a working interest partner in the development of certain Marcellus and Utica acreage. The working interest allows the Company to invest in drilling activities in addition to receiving a royalty interest in well production. The Company uses the successful efforts method of accounting for natural gas and crude oil resulting from its portion of drilling activities. Capitalized well costs are depleted based on the units of production method.

Liquids Pipelines

Plant, property and equipment for liquids pipelines is carried at cost. Depreciation is calculated on a straight-line basis once the assets are ready for their intended use. Pipeline and pumping equipment are depreciated at annual rates ranging from two per cent to 2.5 per cent and other plant and equipment are depreciated at various rates reflecting their estimated useful lives. The cost of these assets includes interest capitalized during construction. When liquids pipelines retire plant, property and equipment from service, the original book cost and related accumulated depreciation are derecognized and any gain or loss is recorded in net income.

Power and Energy Solutions

Plant, property and equipment for Power and Energy Solutions assets are recorded at cost and, once the assets are ready for their intended use, depreciated by major component on a straight-line basis over their estimated service lives at average annual rates ranging from two per cent to 20 per cent. Other equipment is depreciated at various rates reflecting their estimated useful lives. The cost of major overhauls of equipment is capitalized and depreciated over the estimated service lives of the overhauls. Interest is capitalized on facilities under construction. When these assets are retired from plant, property and equipment, the original book cost and related accumulated depreciation are derecognized and any gain or loss is recorded in net income.

Natural gas storage base gas, which is valued at original cost, represents gas volumes that are maintained to ensure adequate reservoir pressure exists to deliver gas held in storage. Base gas is not depreciated.

Corporate

Corporate plant, property and equipment is recorded at cost and depreciated on a straight-line basis over its estimated useful life at average annual rates ranging from four per cent to 20 per cent.

Capital Projects in Development

The Company capitalizes project costs once advancement of the project to construction stage is probable or costs are otherwise likely to be recoverable. The Company capitalizes interest costs for non-regulated projects in development and AFUDC for regulated projects in development. Capital projects in development are included in Other long-term assets on the Consolidated balance sheet. These represent larger projects that generally require regulatory or other approvals before physical construction can begin. Once approvals are received, projects are moved to plant, property and equipment under construction.

Leases

The Company determines if a contract contains a lease at inception of a contract by using judgment in assessing the following aspects: 1) the contract specifies an identified asset which is physically distinct or, if not physically distinct, represents substantially all of the capacity of the asset; 2) the contract provides the customer with the right to obtain substantially all of the economic benefits from the use of the asset and 3) the customer has the right to direct how and for what purpose the identified asset is used throughout the period of the contract.

If the contract is determined to contain a lease, further judgment is required to identify separate lease components of the arrangement by assessing whether the lessee can benefit from the right of use either on its own or together with other resources that are readily available to the lessee, as well as if the right of use is neither highly dependent on, nor highly interrelated, with the other rights to use the underlying assets in the contract.

The Company considers non-lease components as distinct elements of a contract that are not related to the use of the leased asset. A good or service that is provided to a customer is distinct if: 1) the customer can benefit from the good or service either on its own or together with other resources that are readily available to the customer and 2) the entity's promise to transfer the good or service to the customer is separately identifiable from other promises in the contract. The Company applies the practical expedient to not separate lease and non-lease components for all lessee contracts and facilities and liquids tank terminals for which the Company is the lessor in an operating lease.

Lessee Accounting Policy

Operating leases are recognized as right-of-use (ROU) assets and included in Plant, property and equipment while corresponding liabilities are included in Accounts payable and other and Other long-term liabilities on the Consolidated balance sheet.

Operating lease ROU assets and operating lease liabilities are recognized based on the present value of the future minimum lease payments over the lease term at the commencement date of the lease agreement. Lease terms may include options to extend or terminate the lease when it is reasonably certain that the Company will exercise that option. As the Company's lease contracts do not provide an implicit interest rate, the Company uses its incremental borrowing rate based on the information available at commencement date in determining the present value of future payments. Operating lease expense is recognized on a straight-line basis over the lease term and included in Plant operating costs and other in the Consolidated statement of income.

The Company applies the practical expedient to not recognize ROU assets or lease liabilities for leases that qualify for the short-term lease recognition exemption.

Lessor Accounting Policy

The Company provides transportation and other services on certain assets to customers according to long-term service agreements through sales-type and operating leases.

In a sales-type lease, the Company measures the total consideration within the contract at lease commencement. When a lease arrangement contains more than one lease and/or non-lease component, a portion of the contract consideration is allocated to each component based on the stand-alone selling price for each distinct service. The Company applies judgment to determine reasonable estimates of the expected future cost of satisfying the performance obligations of each service. The payments associated with lease components are apportioned between a reduction in the lease receivable and sales-type lease income.

At lease commencement, the Company recognizes a net investment in lease represented by the present value of both the future lease payments and the estimated residual value of the leased asset. The plant, property and equipment of the leased asset is derecognized, with related gains/losses, if any, recognized in the Consolidated statement of income. Sales-type lease income is determined using the rate implicit in the lease and is recorded in Revenues.

The Company is the lessor within certain other contracts, including PPAs, that are accounted for as operating leases. In an operating lease, the leased asset remains capitalized in Plant, property and equipment on the Consolidated balance sheet and is depreciated over its useful life, while lease payments are recognized as revenue over the term of the lease on a straight-line basis. Variable lease payments are recognized as income in the period in which they occur.

Impairment of Long-Lived Assets

The Company reviews long-lived assets such as plant, property and equipment and capital projects in development for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable. If the total of the estimated undiscounted future cash flows for an asset within plant, property and equipment, or the estimated selling price of any long-lived asset is less than the carrying value of an asset, an impairment loss is recognized for the excess of the carrying value over the estimated fair value of the asset.

Impairment of Equity Method Investments

The Company reviews equity method investments for impairment when an event or change in circumstances has a significant adverse effect on the investment's fair value. Where the Company concludes an investment's fair value is below its carrying value, the Company then determines whether the impairment is other-than-temporary, and if so, an impairment loss is recognized for the excess of the carrying value over the estimated fair value of the investment, not exceeding the carrying value of the investment.

Acquisitions and Goodwill

The Company accounts for business combinations using the acquisition method of accounting and, accordingly, the assets and liabilities of the acquired entities are primarily measured at their estimated fair values at the date of acquisition. The excess of the fair value of the consideration transferred over the estimated fair value of the net assets acquired is classified as goodwill. Goodwill is not amortized and is tested for impairment on an annual basis, or more frequently if events or changes in circumstances indicate that it might be impaired.

The annual review for goodwill impairment is performed at the reporting unit level which is one level below the Company's operating segments. The Company can initially assess qualitative factors to determine whether events or changes in circumstances indicate that goodwill might be impaired. The factors the Company considers include, but are not limited to, macroeconomic conditions, industry and market considerations, current valuation multiples and discount rates, cost factors, historical and forecasted financial results and events specific to that reporting unit.

If the Company concludes that it is not more likely than not that the fair value of the reporting unit is greater than its carrying value, the Company will then perform a quantitative goodwill impairment test. The Company can elect to proceed directly to the quantitative goodwill impairment test for any of its reporting units. If the quantitative goodwill impairment test is performed, the Company compares the fair value of the reporting unit to its carrying value, including its goodwill. If the carrying value of a reporting unit exceeds its fair value, goodwill impairment is measured at the amount by which the reporting unit's carrying value exceeds its fair value. The fair value of a reporting unit is determined by using a discounted cash flow analysis which requires the use of assumptions that may include, but are not limited to, revenue and capital expenditure projections, valuation multiples and discount rates. The Company has elected to allocate goodwill impairment charges first to goodwill that is non-deductible for income tax purposes, with any remaining charge allocated to tax-deductible goodwill.

When a portion of a reporting unit that constitutes a business is disposed, goodwill associated with that business is included in the carrying amount of the business in determining the gain or loss on disposal. The amount of goodwill disposed is determined based on the relative fair values of the business to be disposed and the portion of the reporting unit that will be retained. A goodwill impairment test will be completed for both the goodwill disposed and the portion of the goodwill that will be retained.

Non-Controlling Interests

Non-controlling interests (NCI) represent third-party ownership interests in certain consolidated subsidiaries of the Company.

Partial dispositions which result in a change in the Company's ownership interest, but do not result in a change in control, of a subsidiary that constitutes a business are accounted for as equity transactions. No gain or loss is recognized in earnings. At the time of partial disposition, NCI is recorded as the third-party's ownership interest in the Company's carrying value of the net assets of the subsidiary. Any difference between the amount by which the NCI is adjusted and the fair value of the consideration paid or received is recognized in additional-paid-in capital and/or retained earnings (accumulated deficit).

Loans and Receivables

Loans receivable from affiliates and accounts receivable are measured at amortized cost.

Impairment of Financial Assets

The Company reviews financial assets, inclusive of net investment in leases and certain contract assets, carried at amortized cost for impairment using the lifetime expected loss of the financial asset at initial recognition and throughout the life of the financial asset. An expected credit loss (ECL) is calculated using a model and methodology based on assumptions and judgment considering historical data, current counterparty information as well as reasonable and supportable forecasts of future economic conditions.

The ECL is recognized in Plant operating costs and other in the Consolidated statement of income, and is presented on the Consolidated balance sheet as a reduction to the carrying value of the related financial asset.

Restricted Investments

The Company has certain investments that are restricted as to their withdrawal and use. These restricted investments are classified as available for sale and are recorded at fair value on the Consolidated balance sheet.

As a result of the CER's Land Matters Consultation Initiative (LMCI), TC Energy is required to collect funds to cover estimated future pipeline abandonment costs for larger CER-regulated Canadian pipelines. Funds collected are placed in trusts that hold and invest the funds and are accounted for as restricted investments (LMCI restricted investments). LMCI restricted investments may only be used to fund the abandonment of the CER-regulated pipeline facilities, therefore, a corresponding regulatory liability is recorded on the Consolidated balance sheet. The Company also has other restricted investments that have been set aside to fund insurance claim losses to be paid by the Company's wholly-owned captive insurance subsidiary.

Income Taxes

The Company uses the asset and liability method of accounting for income taxes. This method requires the recognition of deferred income tax assets and liabilities for future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred income tax assets and liabilities are measured using enacted tax rates at the balance sheet date that are anticipated to apply to taxable income in the years in which temporary differences are expected to be reversed or settled. Changes to these balances are recognized in net income in the period in which they occur, except for changes in balances related to regulated natural gas pipelines which are deferred until they are refunded or recovered in tolls, as permitted by the regulator. Deferred income tax assets and liabilities are classified as non-current on the Consolidated balance sheet. The Company's exposure to uncertain tax positions is evaluated and a provision is made where it is more likely than not that this exposure will materialize.

Canadian income taxes are not provided for on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future.

Any interest and/or penalty incurred related to tax is reflected in income tax expense.

Asset Retirement Obligations

The Company recognizes the fair value of a liability for asset retirement obligations (ARO) in the period in which it is incurred, when a legal obligation exists and a reasonable estimate of fair value can be made. The fair value is added to the carrying amount of the associated asset and the liability is accreted through charges to Plant operating costs and other in the Consolidated statement of income.

In determining the fair value of ARO, the following assumptions are used:
- the expected retirement date
- the scope and cost of abandonment and reclamation activities that are required
- appropriate inflation and discount rates.

The Company's AROs are substantively related to its power generation facilities. The scope and timing of asset retirements related to the Company's natural gas and liquids pipelines and storage facilities are indeterminable because the Company intends to operate them as long as there is supply and demand. As a result, the Company has not recorded an amount for ARO related to these assets.

Environmental Liabilities and Emission Allowances and Credits

The Company records liabilities on an undiscounted basis for environmental remediation efforts that are likely to occur and where the cost can be reasonably estimated. These estimates, including associated legal costs, are based on available information using existing technology and enacted laws and regulations and are subject to revision in future periods based on actual costs incurred or new circumstances. TC Energy evaluates recoveries from insurers and other third parties separately from the liability and, when recovery is probable, it records an asset separately from the associated liability. These recoveries are presented, along with environmental remediation costs, on a net basis in Plant operating costs and other in the Consolidated statement of income. Variations in one or more of the categories described above could result in additional costs such as fines, penalties and/or expenditures associated with litigation and settlement of claims with respect to environmental liabilities.

Emission allowances or credits purchased for compliance are recorded on the Consolidated balance sheet at historical cost and derecognized when they are utilized or cancelled/retired by government agencies. Compliance costs are expensed when incurred. Allowances granted to or internally generated by TC Energy are not attributed a value for accounting purposes. When required, TC Energy accrues emission liabilities on the Consolidated balance sheet using the best estimate of the amount required to settle the compliance obligation. Allowances and credits not used for compliance are sold and any gain or loss is recorded in Revenues within the Power and Energy Solutions segment in the Consolidated statement of income. The Company records allowances and credits held for compliance in Other current assets and Other long-term assets on the Consolidated balance sheet. Allowances and credits not held for compliance are classified as Inventories on the Consolidated balance sheet.

Stock Options and Other Compensation Programs

TC Energy's Stock Option Plan permits options for the purchase of common shares to be awarded to certain employees, including officers. Stock options granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value as calculated using a binomial model and is recognized on a straight-line basis over the vesting period with an offset to Additional paid-in capital. Forfeitures are accounted for when they occur. Upon exercise of stock options, amounts originally recorded against Additional paid-in capital are reclassified to Common shares on the Consolidated balance sheet.

The Company has medium-term incentive plans under which payments are made to eligible employees. The expense related to these incentive plans is accounted for on an accrual basis. Under these plans, benefits vest when certain conditions are met, including the employees' continued employment during a specified period and achievement of specified corporate performance targets.

Employee Post-Retirement Benefits

The Company sponsors defined benefit pension plans (DB Plans), defined contribution plans (DC Plans), savings plans and other post-retirement benefit plans (OPEB Plans). Contributions made by the Company to the DC Plans and savings plans are expensed in the period in which contributions are made. The cost of the DB Plans and OPEB Plans received by employees is actuarially determined using the projected benefit method pro-rated based on service and management's best estimate of expected plan investment performance, salary escalation, retirement age of employees and expected health care costs.

The DB Plans' assets are measured at fair value at December 31 of each year. The expected return on the DB Plans' assets is determined using market-related values based on a five-year moving average value for all of the DB Plans' assets. Past service costs are amortized over the expected average remaining service life (EARSL) of the employees. Adjustments arising from plan amendments are amortized on a straight-line basis over the EARSL of employees active at the date of amendment. The Company recognizes the overfunded or underfunded status of its DB Plans as an asset or liability, respectively, on its Consolidated balance sheet and recognizes changes in that funded status through Other comprehensive income (loss) (OCI) in the year in which the change occurs. The excess of net actuarial gains or losses over 10 per cent of the greater of the benefit obligation and the market-related value of the DB Plans' assets, if any, is amortized out of Accumulated other comprehensive income (loss) (AOCI) and into net income over the EARSL of the active employees. When the restructuring of a benefit plan gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement.

For certain regulated operations, post-retirement benefit amounts are recoverable through tolls as benefits are funded. The Company records any unrecognized gains or losses or changes in actuarial assumptions related to these post-retirement benefit plans as either regulatory assets or liabilities. The regulatory assets or liabilities are amortized on a straight-line basis over the EARSL of active employees.

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 the Company or reporting subsidiary operates. This is referred to as the functional currency. Transactions denominated in foreign currencies are translated into 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 rate of exchange in effect at the balance sheet date whereas non-monetary assets and liabilities are translated at the historical rate of exchange in effect on the date of the transaction. Exchange gains and losses resulting from translation of monetary assets and liabilities are recorded in net income except for exchange gains and losses on any foreign currency debt related to Canadian regulated natural gas pipelines, which are deferred until they are refunded or recovered in tolls, as permitted by the CER.

Gains and losses arising from translation of foreign operations' functional currencies to the Company's Canadian dollar reporting currency are reflected in OCI until the operations are sold, at which time the gains and losses are reclassified to net income. Asset and liability accounts are translated at the rate of exchange in effect at the balance sheet date while revenues, expenses, gains and losses are translated at the exchange rate prevailing at the date of the transaction. The Company's U.S. dollar-denominated debt and certain derivative hedging instruments have been designated as a hedge of the net investment in foreign subsidiaries and, as a result, the unrealized foreign exchange gains and losses on the U.S. dollar-denominated debt and derivatives are also reflected in OCI.

Derivative Instruments and Hedging Activities

All derivative instruments are recorded on the Consolidated balance sheet at fair value, unless they qualify for and are designated under a normal purchase and normal sales exemption, or are considered to meet other permitted exemptions.

The Company applies hedge accounting to arrangements that qualify for and are designated for hedge accounting treatment. This includes fair value and cash flow hedges as well as hedges of foreign currency exposures of net investments in foreign operations. Hedge accounting is discontinued prospectively if the hedging relationship ceases to be effective or the hedging or hedged items cease to exist as a result of maturity, expiry, sale, termination, cancellation or exercise.

In a fair value hedging relationship, the carrying value of the hedged item is adjusted for changes in fair value attributable to the hedged risk and these changes are recognized in net income. Changes in the fair value of the hedged item, to the extent that the hedging relationship is effective, are offset by changes in the fair value of the hedging item, which are also recorded in net income. Changes in the fair value of foreign exchange and interest rate fair value hedges are recorded in Interest income and other and Interest expense, respectively. If hedge accounting is discontinued, the carrying value of the hedged item is no longer adjusted and the cumulative fair value adjustments to the carrying value of the hedged item are amortized to net income over the remaining term of the original hedging relationship.

In a cash flow hedging relationship, the change in the fair value of the hedging derivative is recognized in OCI. When hedge accounting is discontinued, the amounts recognized previously in AOCI are reclassified to Revenues, Interest expense and Interest income and other, as appropriate, during the periods when the variability in cash flows of the hedged item affects net income or as the original hedged item settles. Gains and losses on derivatives are reclassified immediately to net income from AOCI when the hedged item is sold or terminated early, or when it becomes probable that the anticipated transaction will not occur. Termination payments on interest rate derivatives are classified as a financing activity in the Consolidated statement of cash flows.

In hedging the foreign currency exposure of a net investment in a foreign operation, the foreign exchange gains and losses on the hedging instruments are recognized in OCI. The amounts recognized previously in AOCI are reclassified to net income in the event the Company reduces its net investment in a foreign operation.

In some cases, derivatives do not meet the specific criteria for hedge accounting treatment. In these instances, the changes in fair value are recorded in net income in the period of change.

Gains and losses arising from changes in the fair value of derivatives accounted for as part of RRA, including those that qualify for hedge accounting treatment, are refunded or recovered through the tolls charged by the Company. As a result, these gains and losses are deferred as regulatory assets or liabilities and are refunded to or collected from ratepayers in subsequent periods when the derivative settles.

Derivatives embedded in other financial instruments or contracts (host instrument) are recorded as separate derivatives. Embedded derivatives are measured at fair value if their economic characteristics are not clearly and closely related to those of the host instrument, their terms are the same as those of a stand-alone derivative and the total contract is not held for trading or accounted for at fair value. When changes in the fair value of embedded derivatives are measured separately, they are included in net income.

Long-Term Debt Transaction Costs and Issuance Costs

The Company records long-term debt transaction costs and issuance costs as a deduction from the carrying amount of the related debt liability and amortizes these costs using the effective interest method except those related to the Canadian natural gas regulated pipelines, which continue to be amortized on a straight-line basis in accordance with the provisions of regulatory tolling mechanisms.

Guarantees

Upon issuance, the Company records the fair value of certain guarantees entered into by the Company on behalf of a partially-owned entity or by partially-owned entities for which contingent payments may be made. The fair value of these guarantees is estimated by discounting the cash flows that would be incurred by the Company if letters of credit were used in place of the guarantees as appropriate in the circumstances. Guarantees are recorded as an increase to Equity investments or Plant, property and equipment and a corresponding liability is recorded in Other long-term liabilities. The release from the obligation is recognized either over the term of the guarantee or upon expiration or settlement of the guarantee.

Variable Interest Entities

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. The assessment of whether an entity is a VIE and, if so, whether the Company is the primary beneficiary, is completed at the inception of the entity or at a reconsideration event.

Consolidated VIEs

The Company's consolidated VIEs consist of legal entities where the Company has a variable interest and for which it is considered the primary beneficiary. As the primary beneficiary, the Company has the power, through voting or similar rights, to direct the activities of the VIE that most significantly impact economic performance including: purchasing or selling significant assets; maintenance and operations of assets; incurring additional indebtedness; or determining the strategic operating direction of the entity. In addition, the Company has the obligation to absorb losses or the right to receive benefits from the consolidated VIE that could potentially be significant to the VIE.

Non-Consolidated VIEs

The Company's non-consolidated VIEs consist of legal entities where the Company has a variable interest but is not the primary beneficiary as it does not have the power (either explicit or implicit), through voting or similar rights, to direct the activities that most significantly impact the economic performance of these VIEs or where this power is shared with third parties. The Company contributes capital to these VIEs and receives ownership interests that provide it with residual claims on assets after liabilities are paid. Non-consolidated VIEs are accounted for as equity investments.

The Company's maximum exposure to loss is the maximum loss that could potentially be recorded through net income in future periods as a result of the Company's variable interest in a VIE.

3. ACCOUNTING CHANGES

Future Accounting Changes

Income Taxes

In December 2023, the FASB issued new guidance to enhance the transparency and decision usefulness of income tax disclosures through improvements to the rate reconciliation and income taxes paid information. The guidance also includes certain other amendments to improve the effectiveness of income tax disclosures. This new guidance is effective for the annual period beginning January 1, 2025. The guidance is applied prospectively with retrospective application permitted. Early adoption is permitted for annual financial statements not yet issued. The Company does not expect this guidance to have a material impact on the Company's consolidated financial statements.

Segment Reporting

In November 2023, the FASB issued new guidance to improve disclosures about a public entity's reportable segments and address requests from investors for additional, more detailed information about a reportable segment's expenses. The guidance is effective for annual periods beginning January 1, 2024 and interim periods beginning January 1, 2025. Early adoption is permitted and the guidance is applied retrospectively. The Company is currently assessing the impact of the standard on the Company's consolidated financial statements.

Leases

In March 2023, the FASB issued new guidance that clarified the accounting for leasehold improvements associated with common control leases. The guidance requires all lessees to amortize leasehold improvements associated with common control leases over their useful life to the common control group and account for them as a transfer of assets between entities under common control at the end of the lease. Additional disclosures are required when the useful life of leasehold improvements to the common control group exceeds the related lease term. This new guidance is effective January 1, 2024 and can be applied either prospectively or retrospectively, with early application permitted. The Company will adopt the guidance on a prospective basis starting January 1, 2024, and it is not expected to have a material impact on the Company's consolidated financial statements.

4. SPINOFF OF LIQUIDS PIPELINES BUSINESS

On July 27, 2023, TC Energy announced plans to separate into two independent, investment-grade, publicly listed companies through the proposed spinoff of its Liquids Pipelines business (the spinoff Transaction) and on November 8, 2023 the Company communicated that the name of the new Liquids Pipelines business would be South Bow Corporation (South Bow). In addition to TC Energy shareholder and court approvals, the spinoff Transaction is subject to receipt of favourable tax rulings from Canadian and U.S. tax authorities, receipt of necessary regulatory approvals, and satisfaction of other customary closing conditions. TC Energy expects that the spinoff Transaction will be completed in the second half of 2024.

Under the spinoff Transaction, TC Energy shareholders will retain their current ownership in TC Energy’s common shares and receive a pro-rata allocation of common shares in South Bow. The determination of the number of common shares in South Bow to be distributed to TC Energy shareholders will be determined prior to the closing of the spinoff Transaction. The spinoff Transaction is expected to be tax free to TC Energy’s Canadian and U.S. shareholders.

For the year ended December 31, 2023, the Company incurred pre-tax Liquids Pipelines business separation costs of $40 million ($34 million after tax) with respect to the spinoff Transaction, which included internal costs related to separation activities, legal, tax, audit and other consulting fees recorded in Plant operating costs and other in the Consolidated statement of income.

5. SEGMENTED INFORMATION

year ended December 31, 2023 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Energy Solutions	Corporate[1]	Total
Revenues	5,173	6,229	846	2,667	1,019	—	15,934
Intersegment revenues	—	101	—	—	22	(123)[2]	—
	5,173	6,330	846	2,667	1,041	(123)	15,934
Income (loss) from equity investments	220	324	78	67	688	—	1,377
Impairment of equity investment	(2,100)	—	—	—	—	—	(2,100)
Plant operating costs and other	(1,756)	(1,660)	(39)	(836)	(603)	7[2]	(4,887)
Commodity purchases resold	—	(56)	—	(437)	(24)	—	(517)
Property taxes	(302)	(473)	—	(116)	(6)	—	(897)
Depreciation and amortization	(1,325)	(934)	(89)	(338)	(92)	—	(2,778)
Goodwill and asset impairment charges and other	—	—	—	4	—	—	4
Segmented Earnings (Losses)	(90)	3,531	796	1,011	1,004	(116)	6,136
Interest expense							(3,263)
Allowance for funds used during construction							575
Foreign exchange gains (losses), net							320
Interest income and other							242
Income (Loss) before Income Taxes							4,010
Income tax (expense) recovery							(942)
Net Income (Loss)							3,068
Net (income) loss attributable to non-controlling interests							(146)
Net Income (Loss) Attributable to Controlling Interests							2,922
Preferred share dividends							(93)
Net Income (Loss) Attributable to Common Shares							2,829
Capital Spending[3]							
Capital expenditures	2,953	2,536	2,292	49	144	33	8,007
Capital projects in development	—	—	—	—	142	—	142
Contributions to equity investments	3,231	124	—	—	794	—	4,149
	6,184	2,660	2,292	49	1,080	33	12,298

1 Includes intersegment eliminations.

2 The Company records intersegment sales at contracted rates. For segmented reporting, these transactions are included as Intersegment revenues in the segment providing the service and Plant operating costs and other in the segment receiving the service. These transactions are eliminated on consolidation. Intersegment profit is recognized when the product or service has been provided to third parties or otherwise realized.

3 Included in Investing activities in the Consolidated statement of cash flows.

year ended December 31, 2022 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Energy Solutions	Corporate [1]	Total
Revenues	4,764	5,933	688	2,668	924	—	14,977
Intersegment revenues	—	132	—	—	12	(144) [2]	—
	4,764	6,065	688	2,668	936	(144)	14,977
Income (loss) from equity investments	18	292	122	55	539	28 [3]	1,054
Impairment of Equity Investment	(3,048)	—	—	—	—	—	(3,048)
Plant operating costs and other	(1,679)	(1,856)	(221)	(756)	(544)	124 [2]	(4,932)
Commodity purchases resold	—	—	—	(512)	(22)	—	(534)
Property taxes	(297)	(426)	—	(121)	(4)	—	(848)
Depreciation and amortization	(1,198)	(887)	(98)	(329)	(72)	—	(2,584)
Goodwill and asset impairment charges and other	—	(571)	—	118	—	—	(453)
Segmented Earnings (Losses)	(1,440)	2,617	491	1,123	833	8	3,632
Interest expense							(2,588)
Allowance for funds used during construction							369
Foreign exchange gains (losses), net[3]							(185)
Interest income and other							146
Income (Loss) before Income Taxes							1,374
Income tax (expense) recovery							(589)
Net Income (Loss)							785
Net (income) loss attributable to non-controlling interests							(37)
Net Income (Loss) Attributable to Controlling Interests							748
Preferred share dividends							(107)
Net Income (Loss) Attributable to Common Shares							641
Capital Spending[4]							
Capital expenditures	3,274	2,137	1,027	106	93	41	6,678
Capital projects in development	—	—	—	—	49	—	49
Contributions to equity investments[5]	1,445	—	—	37	752	—	2,234
	4,719	2,137	1,027	143	894	41	8,961

1 Includes intersegment eliminations.

2 The Company records intersegment sales at contracted rates. For segmented reporting, these transactions are included as Intersegment revenues in the segment providing the service and Plant operating costs and other in the segment receiving the service. These transactions are eliminated on consolidation. Intersegment profit is recognized when the product or service has been provided to third parties or otherwise realized.

3 Income (loss) from equity investments includes the Company's proportionate share of Sur de Texas foreign exchange gains and losses on the peso-denominated loans from affiliates which are fully offset in Foreign exchange gains (losses), net by the corresponding foreign exchange losses and gains on the affiliate receivable balance until March 15, 2022, when it was fully repaid upon maturity. Refer to Note 13, Loans receivable from affiliates, for additional information.

4 Included in Investing activities in the Consolidated statement of cash flows.

5 Contributions to equity investments in the Corporate segment of $1.2 billion are offset by the equivalent amount in Other distributions from equity investments, although they are reported on a gross basis in the Company's Consolidated statement of cash flows. Refer to Note 13, Loans receivable from affiliates, for additional information.

year ended December 31, 2021 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Energy Solutions	Corporate [1]	Total
Revenues	4,519	5,233	605	2,306	724	—	13,387
Intersegment revenues	—	145	—	—	14	(159) [2]	—
	4,519	5,378	605	2,306	738	(159)	13,387
Income (loss) from equity investments	12	244	119	71	411	41 [3]	898
Plant operating costs and other	(1,567)	(1,393)	(55)	(700)	(455)	72 [2]	(4,098)
Commodity purchases resold	—	—	(3)	(84)	—	—	(87)
Property taxes	(289)	(367)	—	(113)	(5)	—	(774)
Depreciation and amortization	(1,226)	(791)	(109)	(318)	(78)	—	(2,522)
Goodwill and asset impairment charges and other	—	—	—	(2,775)	—	—	(2,775)
Net gain (loss) on sale of assets	—	—	—	13	17	—	30
Segmented Earnings (Losses)	1,449	3,071	557	(1,600)	628	(46)	4,059
Interest expense							(2,360)
Allowance for funds used during construction							267
Foreign exchange gains (losses), net[3]							10
Interest income and other							190
Income (Loss) before Income Taxes							2,166
Income tax (expense) recovery							(120)
Net Income (Loss)							2,046
Net (income) loss attributable to non-controlling interests							(91)
Net Income (Loss) Attributable to Controlling Interests							1,955
Preferred share dividends							(140)
Net Income (Loss) Attributable to Common Shares							1,815
Capital Spending[4]							
Capital expenditures	2,629	2,611	129	488	32	35	5,924
Contributions to equity investments	108	209	—	83	810	—	1,210
	2,737	2,820	129	571	842	35	7,134

1 Includes intersegment eliminations.

2 The Company records intersegment sales at contracted rates. For segmented reporting, these transactions are included as Intersegment revenues in the segment providing the service and Plant operating costs and other in the segment receiving the service. These transactions are eliminated on consolidation. Intersegment profit is recognized when the product or service has been provided to third parties or otherwise realized.

3 Income (loss) from equity investments includes the Company's proportionate share of Sur de Texas foreign exchange gains and losses on the peso-denominated loans from affiliates which are fully offset in Foreign exchange gains (losses), net by the corresponding foreign exchange losses and gains on the affiliate receivable balance. Refer to Note 13, Loans receivable from affiliates, for additional information.

4 Included in Investing activities in the Consolidated statement of cash flows.

at December 31 (millions of Canadian $)	2023	2022
Total Assets by Segment		
Canadian Natural Gas Pipelines	**29,782**	27,456
U.S. Natural Gas Pipelines	**50,499**	50,038
Mexico Natural Gas Pipelines	**12,003**	9,231
Liquids Pipelines	**15,490**	15,587
Power and Energy Solutions	**9,525**	8,272
Corporate	**7,735**	3,764
	125,034	114,348

Geographic Information

year ended December 31 (millions of Canadian $)	2023	2022	2021
Revenues			
Canada – domestic	**5,360**	4,942	4,603
Canada – export	**1,403**	1,322	1,226
United States	**8,325**	8,025	6,953
Mexico	**846**	688	605
	15,934	14,977	13,387

at December 31 (millions of Canadian $)	2023	2022
Plant, Property and Equipment		
Canada	**28,583**	27,232
United States	**44,609**	43,505
Mexico	**7,377**	5,203
	80,569	75,940

6. REVENUES

Disaggregation of Revenues

year ended December 31, 2023 (millions of Canadian $)	**Canadian Natural Gas Pipelines**	**U.S. Natural Gas Pipelines**	**Mexico Natural Gas Pipelines**	**Liquids Pipelines**	**Power and Energy Solutions**	**Total**
Revenues from contracts with customers						
Capacity arrangements and transportation	**5,141**	**5,107**	**442**	**2,115**	**—**	**12,805**
Power generation	**—**	**—**	**—**	**—**	**427**	**427**
Natural gas storage and other[1,2]	**32**	**874**	**125**	**3**	**363**	**1,397**
	5,173	**5,981**	**567**	**2,118**	**790**	**14,629**
Sales-type lease income[3]	**—**	**—**	**279**	**—**	**—**	**279**
Other revenues[4]	**—**	**248**	**—**	**549**	**229**	**1,026**
	5,173	**6,229**	**846**	**2,667**	**1,019**	**15,934**

1 Includes $31 million of fee revenues from an affiliate related to the development and construction of the Coastal GasLink pipeline project which is 35 per cent owned by TC Energy.
2 Includes $97 million of revenues generated from non-lease components for the provision of operating and maintenance services with respect to sales-type leases on the in-service TGNH pipelines. Refer to Note 11, Leases, for additional information.
3 Represents the sales-type lease income on the in-service TGNH pipelines. Refer to Note 11, Leases, for additional information.
4 Other revenues include income from the Company's operating lease arrangements, marketing activities and financial instruments. Refer to Note 11, Leases, and Note 29, Risk management and financial instruments, for additional information.

year ended December 31, 2022 (millions of Canadian $)	**Canadian Natural Gas Pipelines**	**U.S. Natural Gas Pipelines**	**Mexico Natural Gas Pipelines**	**Liquids Pipelines**	**Power and Energy Solutions**	**Total**
Revenues from contracts with customers						
Capacity arrangements and transportation	4,696	4,621	507	1,983	—	11,807
Power generation	—	—	—	—	490	490
Natural gas storage and other[1,2]	68	1,298	54	4	391	1,815
	4,764	5,919	561	1,987	881	14,112
Sales-type lease income[3]	—	—	127	—	—	127
Other revenues[4,5]	—	14	—	681	43	738
	4,764	5,933	688	2,668	924	14,977

1 Includes $68 million of fee revenues from an affiliate related to the development and construction of the Coastal GasLink pipeline project which is 35 per cent owned by TC Energy.
2 Includes $37 million of revenues generated from non-lease components for the provision of operating and maintenance services with respect to sales-type leases on the in-service TGNH pipelines. Refer to Note 11, Leases, for additional information.
3 Represents the sales-type lease income on the in-service TGNH pipelines. Refer to Note 11, Leases, for additional information.
4 Other revenues include income from the Company's operating lease arrangements, marketing activities and financial instruments. Refer to Note 11, Leases, and Note 29, Risk management and financial instruments, for additional information.
5 Other revenues from U.S. Natural Gas Pipelines include the amortization of the net regulatory liabilities resulting from H.R.1, the Tax Cuts and Jobs Act (U.S. Tax Reform). Refer to Note 14, Rate-regulated businesses, for additional information.

year ended December 31, 2021 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Energy Solutions	Total
Revenues from contracts with customers						
Capacity arrangements and transportation	4,432	4,139	576	2,025	—	11,172
Power generation	—	—	—	—	324	324
Natural gas storage and other[1]	87	1,057	29	5	278	1,456
	4,519	5,196	605	2,030	602	12,952
Other revenues[2,3]	—	37	—	276	122	435
	4,519	5,233	605	2,306	724	13,387

1 Includes $87 million of fee revenues from an affiliate related to the development and construction of the Coastal GasLink pipeline project which is 35 per cent owned by TC Energy.

2 Other revenues include income from the Company's operating lease arrangements, marketing activities and financial instruments. Refer to Note 11, Leases, and Note 29, Risk management and financial instruments, for additional information.

3 Other revenues from U.S. Natural Gas Pipelines include the amortization of the net regulatory liabilities resulting from U.S. Tax Reform. Refer to Note 14, Rate-regulated businesses, for additional information.

Contract Balances

at December 31 (millions of Canadian $)	2023	2022	Affected line item on the Consolidated balance sheet
Receivables from contracts with customers	**1,832**	1,907	Accounts receivable
Contract assets (Note 9)	**151**	155	Other current assets
Long-term contract assets (Note 16)	**457**	355	Other long-term assets
Contract liabilities[1] (Note 18)	**69**	62	Accounts payable and other
Long-term contract liabilities[1] (Note 19)	**12**	32	Other long-term liabilities

1 During the year ended December 31, 2023, $64 million (2022 – $51 million) of revenues were recognized that were included in contract liabilities and long-term contract liabilities at the beginning of the year.

Contract assets and long-term contract assets primarily relate to the Company’s right to revenues for services completed but not invoiced at the reporting date on long-term committed capacity natural gas pipelines contracts. The change in contract assets is primarily related to the transfer to Accounts receivable when these rights become unconditional and the customer is invoiced, as well as the recognition of additional revenues that remain to be invoiced. Contract liabilities and long-term contract liabilities primarily represent unearned revenue for contracted services. Under the terms of the consolidated Transportation Service Agreement (TSA), the contract liability relating to current and future in-service TGNH pipelines is netted against certain contract asset balances. The resulting net contract liability is settled against net investment in leases on the Consolidated balance sheet when the pipeline enters into service.

Future Revenues from Remaining Performance Obligations

As at December 31, 2023, future revenues from long-term pipeline capacity arrangements and transportation as well as natural gas storage and other contracts extending through 2055 are approximately $22.9 billion, of which approximately $4.9 billion is expected to be recognized in 2024.

A significant portion of the Company's revenues are considered constrained and therefore not included in the future revenue amounts above as the Company uses the following practical expedients:

- right to invoice practical expedient – applied to all U.S. and certain Mexico rate-regulated natural gas pipeline capacity arrangements and flow-through revenues
- variable consideration practical expedient – applied to the following variable revenues:
  - interruptible transportation service revenues as volumes cannot be estimated
  - liquids pipelines capacity revenues based on volumes transported
  - power generation revenues related to market prices that are subject to factors outside the Company's influence
- contracts for a duration of one year or less. In addition, future revenues from the Company's Canadian natural gas pipelines' regulated firm capacity contracts include fixed revenues only for the time periods that approved tolls under current rate settlements are in effect and certain. Future revenues exclude lease income from the Company's Mexico natural gas pipelines on projects that have not been placed into service.

7. KEYSTONE XL

Asset Impairment Charge and Other

Following the revocation of the Presidential Permit for the Keystone XL pipeline project on January 20, 2021, the Company terminated the Keystone XL pipeline project and evaluated the Keystone XL investment for impairment in 2021. As a result, the Company determined that the carrying amount of these assets within the Liquids Pipelines segment was no longer fully recoverable and recognized an asset impairment charge, net of expected contractual recoveries and other contractual and legal obligations related to termination activities, of $2,775 million ($2,134 million after tax) for the year ended December 31, 2021. The asset impairment charge was based on the excess of the carrying value of $3,301 million over the estimated fair value of $175 million.

year ended December 31, 2021 (millions of Canadian $)	**Estimated Fair Value of Plant, Property and Equipment**	**Asset impairment charge and other**	
		Pre tax	**After tax**
Asset impairment charge			
Plant and equipment	**175**	**412**	**312**
Related capital projects in development	**—**	**230**	**175**
Other capitalized costs	**—**	**2,158**	**1,642**
Capitalized interest	**—**	**326**	**248**
	175	**3,126**	**2,377**
Other			
Contractual recoveries	**n/a**	**(693)**	**(525)**
Contractual and legal obligations related to termination activities	**n/a**	**342**	**282**
	175	**2,775**	**2,134**

The estimated fair value of $175 million at December 31, 2021 related to plant and equipment was based on the price that was expected to be received from selling these assets in their current condition and is updated as required. The initial key assumptions used in the determination of selling price included an estimated two-year disposal period and current energy market demand. The valuation considered a variety of potential selling prices based on various markets that could be used to dispose of these assets and required the use of unobservable inputs. As a result, the fair value is classified in Level III of the fair value hierarchy.

In 2023, the Company received $10 million (2022 – $571 million) towards its contractual recoveries, resulting in a remaining balance of $117 million at December 31, 2023 (December 31, 2022 – $130 million).

In 2022, the Company revised its estimate of contractual and legal obligations related to termination activities based on a review of costs and commitments incurred, which resulted in a $54 million reduction to the asset impairment charge. No revision to the estimate was made in 2023. The Company paid $2 million in 2023 (2022 – $24 million; 2021 – $192 million) towards contractual and legal obligations related to termination activities. At December 31, 2023, the remaining balance accrued was $45 million (December 31, 2022 – $48 million).

In 2023, the Company sold plant and equipment with a carrying value of approximately $63 million (2022 – $25 million; 2021 – $16 million), resulting in a gain of $36 million (2022 – $64 million; 2021 – nil) recorded in Goodwill and asset impairment charges and other in the Consolidated statement of income.

As part of the Keystone XL impairment charge and other, the Company recorded a $14 million income tax recovery in 2023 (2022 – $96 million expense) in relation to the termination of the Keystone XL pipeline project.

Redeemable Non-Controlling Interest and Long-Term Debt

In March 2020, the Company announced that it would proceed with construction of the Keystone XL pipeline. As part of the funding plan, the Government of Alberta invested $1,033 million in the form of Class A Interests in the year ended December 31, 2020.

On January 4, 2021, the Company put in place a US$4.1 billion project-level credit facility to support construction of the Keystone XL pipeline, that was fully guaranteed by the Government of Alberta and non-recourse to the Company. On January 8, 2021, the Company exercised its call right with the Government of Alberta in accordance with contractual terms and paid $633 million (US$497 million) to repurchase the Government of Alberta Class A Interests in certain Keystone XL subsidiaries. This transaction was funded by draws on the project-level credit facility. For the year ended December 31, 2021, the Company made draws under the Keystone XL project-level credit facility totaling $1,028 million (US$849 million). Following the cancellation of the Keystone XL pipeline project, the Government of Alberta repaid the full outstanding balance in June 2021 in accordance with the terms of the guarantee, and the credit facility was subsequently terminated. Additionally, in June 2021, the Company repurchased the remaining Government of Alberta Class A Interests for a nominal amount, which was accounted for as an equity transaction and resulted in $394 million recognized in Additional paid-in capital. As part of this arrangement, TC Energy issued $91 million of Class C Interests in the Keystone XL subsidiaries which entitled the Government of Alberta to future liquidation proceeds from specified Keystone XL project assets. The entire $91 million was recorded (net of distributions) in Accounts payable and other on the Consolidated balance sheet. During 2023, it was determined that the Company would exceed the $91 million of Class C distributions and the Company increased the Class C Interests carrying value by $32 million with a corresponding amount recorded in Goodwill and asset impairment charges and other in the Consolidated statement of income. Termination of the project-level credit facility, net of the issuance of Class C Interests, resulted in $937 million ($737 million after tax) recorded to Additional paid-in capital in 2021. For the year ended December 31, 2023, the Company made Class C distributions to the Government of Alberta of $49 million (2022 – $43 million; 2021 – $16 million).

8. COASTAL GASLINK

Impairment of Equity Investment in Coastal GasLink LP

In July 2022, amended agreements were executed between Coastal GasLink LP, LNG Canada, TC Energy and its Coastal GasLink LP partners (collectively, the July 2022 agreements). These amendments revised the commercial terms between LNG Canada and Coastal GasLink LP, as well as funding provisions between the partners of Coastal GasLink LP.

With the expectation that additional equity contributions under a subordinated loan agreement between TC Energy and the Coastal GasLink LP partners will be predominantly funded by TC Energy as limited partner of Coastal GasLink LP, in accordance with the July 2022 agreements, the Company completed valuation assessments during the first three quarters of 2023 and concluded that, for each period an assessment was performed, the fair value of its investment in Coastal GasLink LP was below its carrying value and that these were other-than-temporary impairments. As a result, a pre-tax impairment charge of $2,100 million ($1,943 million after tax) was recognized during the year ended December 31, 2023 in Impairment of equity investment in the Consolidated statement of income in the Canadian Natural Gas Pipelines segment (2022 – $3,048 million; $2,643 million after tax). The carrying value of the investment in Coastal GasLink LP was $294 million at December 31, 2023 (2022 – nil), which reflects the balance of amounts, net of impairments, drawn on the subordinated loan to date at December 31, 2023 and other changes to TC Energy's equity investment. The impairment charge reflected the net impact of $2,020 million drawn on and a $250 million repayment of the subordinated loan for the nine months ended September 30, 2023, along with TC Energy's proportionate share of unrealized gains and losses on interest rate derivatives in Coastal GasLink LP and other changes to the equity investment. The cumulative pre-tax impairment charge recognized at December 31, 2023 is $5,148 million ($4,586 million after tax).

A deferred income tax recovery was recognized on the pre-tax impairment charge, net of certain unrealized tax losses not recognized. The impairment of the subordinated loan resulted in unrealized non-taxable capital losses that are not recognized. Refer to Note 20, Income taxes, for additional information.

At December 31, 2023, TC Energy expects to fund an additional $0.9 billion related to the capital cost estimates to complete the Coastal GasLink pipeline, which is consistent with the capital cost profile that was included in the September 30, 2023 impairment calculation. At December 31, 2023, there were no events or changes in circumstances since September 30, 2023 indicating a significant adverse impact on the estimated fair value of the Company's investment in Coastal GasLink LP.

The fair value of TC Energy's investment in Coastal GasLink LP at September 30, 2023 and December 31, 2022 was estimated using a 40-year discounted cash flow model and is classified as a Level III fair value measurement.

The discounted cash flow is most sensitive to assumptions related to the capital cost estimates for the Coastal GasLink pipeline of approximately $14.5 billion (2022 – $14.5 billion), discount rate and long-term financing plans.

Other assumptions included in the discounted cash flow model include contractually agreed upon terms and extension provisions in the TSAs between Coastal GasLink LP and the LNG Canada participants, potential expansion projects and estimated completion date.

Subordinated Loan Agreement

In 2021, TC Energy entered into a subordinated loan agreement with Coastal GasLink LP. This loan agreement was amended as part of the July 2022 agreements, and subsequent draws on this loan by Coastal GasLink LP will be provided through an interest-bearing loan, subject to a floating market-based interest rate to fund the capital cost to complete the Coastal GasLink pipeline. Committed capacity under the subordinated loan agreement between TC Energy and Coastal GasLink LP was $3.4 billion, with $2.5 billion drawn on the loan at December 31, 2023.

Any amounts outstanding on the loan will be repaid by Coastal GasLink LP to TC Energy once final project costs are known, which will be determined after the pipeline is placed into service. Coastal GasLink LP partners, including TC Energy, will contribute equity to Coastal GasLink LP to ultimately fund Coastal GasLink LP's repayment of this subordinated loan to TC Energy. The Company expects that these additional equity contributions will be predominantly funded by TC Energy. Amounts drawn on this loan subsequent to amended agreements executed in July 2022 are accounted for as in-substance equity contributions and are presented as Contributions to equity investments on the Company's Consolidated statement of cash flows. Interest and principal repayments on this loan, which are expected to be predominantly funded by TC Energy, will be accounted for as an equity investment distribution to the Company once received.

The table below reflects the changes in this loan receivable balance.

at December 31 (millions of Canadian $)	2023	2022
Outstanding balance at beginning of year	**250**	238
Issuances	**2,520**	112
Repayments	**(250)**	(100)
Outstanding balance at end of year	**2,520**	250
Impairment during the year	**(2,020)**	(250)
Carrying value at end of year	**500**	—

9. OTHER CURRENT ASSETS

at December 31 (millions of Canadian $)	2023	2022
Fair value of derivative contracts (Note 29)	**1,285**	614
Current portion of net investment in leases (Note 11)	**306**	291
Contract assets (Note 6)	**151**	155
Current portion of Keystone environmental provision recovery (Note 18)	**150**	410
Cash provided as collateral	**120**	106
Emissions credits	**94**	36
Prepaid expenses	**92**	118
Keystone XL contractual recoveries (Note 7)	**83**	86
Regulatory assets (Note 14)	**76**	67
Keystone XL assets held for sale	**58**	122
Other	**88**	147
	2,503	2,152

10. PLANT, PROPERTY AND EQUIPMENT

at December 31	2023			2022		
(millions of Canadian $)	Cost	Accumulated Depreciation	Net Book Value	Cost	Accumulated Depreciation	Net Book Value
Canadian Natural Gas Pipelines						
NGTL System						
Pipeline	**20,232**	**6,855**	**13,377**	18,119	6,285	11,834
Compression	**6,603**	**2,349**	**4,254**	6,265	2,224	4,041
Metering and other	**1,589**	**830**	**759**	1,518	769	749
	28,424	**10,034**	**18,390**	25,902	9,278	16,624
Under construction	**787**	**—**	**787**	1,552	—	1,552
	29,211	**10,034**	**19,177**	27,454	9,278	18,176
Canadian Mainline						
Pipeline	**10,729**	**7,996**	**2,733**	10,472	7,852	2,620
Compression	**4,437**	**3,354**	**1,083**	4,328	3,247	1,081
Metering and other	**729**	**308**	**421**	692	285	407
	15,895	**11,658**	**4,237**	15,492	11,384	4,108
Under construction	**147**	**—**	**147**	269	—	269
	16,042	**11,658**	**4,384**	15,761	11,384	4,377
Other Canadian Natural Gas Pipelines[1]						
Other	**2,846**	**1,682**	**1,164**	1,984	1,624	360
Under construction	**23**	**—**	**23**	455	—	455
	2,869	**1,682**	**1,187**	2,439	1,624	815
	48,122	**23,374**	**24,748**	45,654	22,286	23,368
U.S. Natural Gas Pipelines						
Columbia Gas						
Pipeline	**12,952**	**1,247**	**11,705**	12,471	1,069	11,402
Compression	**5,310**	**559**	**4,751**	5,190	495	4,695
Metering and other	**4,074**	**372**	**3,702**	4,026	346	3,680
	22,336	**2,178**	**20,158**	21,687	1,910	19,777
Under construction	**771**	**—**	**771**	659	—	659
	23,107	**2,178**	**20,929**	22,346	1,910	20,436
ANR						
Pipeline	**2,117**	**657**	**1,460**	2,066	641	1,425
Compression	**3,928**	**773**	**3,155**	3,785	734	3,051
Metering and other	**1,625**	**458**	**1,167**	1,666	440	1,226
	7,670	**1,888**	**5,782**	7,517	1,815	5,702
Under construction	**404**	**—**	**404**	328	—	328
	8,074	**1,888**	**6,186**	7,845	1,815	6,030

at December 31	2023			2022		
(millions of Canadian $)	Cost	Accumulated Depreciation	Net Book Value	Cost	Accumulated Depreciation	Net Book Value
Other U.S. Natural Gas Pipelines						
Columbia Gulf	**3,600**	**256**	**3,344**	3,511	224	3,287
GTN	**2,992**	**1,295**	**1,697**	2,964	1,239	1,725
Great Lakes	**2,359**	**1,401**	**958**	2,367	1,387	980
Other[2]	**2,071**	**800**	**1,271**	1,928	760	1,168
	11,022	**3,752**	**7,270**	10,770	3,610	7,160
Under construction	**584**	**—**	**584**	328	—	328
	11,606	**3,752**	**7,854**	11,098	3,610	7,488
	42,787	**7,818**	**34,969**	41,289	7,335	33,954
Mexico Natural Gas Pipelines[3]						
Pipeline	**2,280**	**387**	**1,893**	2,299	348	1,951
Compression	**370**	**79**	**291**	374	59	315
Metering and other	**482**	**123**	**359**	487	113	374
	3,132	**589**	**2,543**	3,160	520	2,640
Under construction	**4,823**	**—**	**4,823**	2,547	—	2,547
	7,955	**589**	**7,366**	5,707	520	5,187
Liquids Pipelines						
Keystone Pipeline System						
Pipeline	**9,569**	**2,212**	**7,357**	9,777	2,056	7,721
Pumping equipment	**1,096**	**312**	**784**	1,064	288	776
Tanks and other	**3,658**	**913**	**2,745**	3,723	859	2,864
	14,323	**3,437**	**10,886**	14,564	3,203	11,361
Under construction	**54**	**—**	**54**	96	—	96
	14,377	**3,437**	**10,940**	14,660	3,203	11,457
Intra-Alberta Pipelines	**203**	**25**	**178**	199	19	180
	14,580	**3,462**	**11,118**	14,859	3,222	11,637
Power and Energy Solutions						
Natural Gas Power Generation	**1,239**	**637**	**602**	1,260	642	618
Natural Gas Storage and Other	**845**	**256**	**589**	820	238	582
Renewable Power Generation	**581**	**19**	**562**	—	—	—
	2,665	**912**	**1,753**	2,080	880	1,200
Under construction	**153**	**—**	**153**	80	—	80
	2,818	**912**	**1,906**	2,160	880	1,280
Corporate	**909**	**447**	**462**	900	386	514
	117,171	**36,602**	**80,569**	110,569	34,629	75,940

1 Includes Foothills, Ventures LP and Great Lakes Canada.

2 Includes Portland, North Baja, Tuscarora, Crossroads and mineral rights business.

3 During the year ended December 31, 2023, the Company derecognized $407 million (2022 – $2,319 million) of Plant, property and equipment and recorded a corresponding asset for net investment in leases for the in-service TGNH pipelines. Refer to Note 11, Leases, for additional information.

11. LEASES

As a Lessee

The Company has operating leases for corporate offices, other various premises, equipment and land. Some leases have an option to renew for periods of one to 25 years, and some may include options to terminate the lease within one year or when certain conditions are met. Payments due under lease contracts include fixed payments plus, for many of the Company's leases, variable payments such as a proportionate share of the buildings' property taxes, insurance and common area maintenance. The Company subleases some of the leased premises.

Operating lease cost was as follows:

year ended December 31 (millions of Canadian $)	2023	2022
Operating lease cost[1]	**118**	106
Sublease income	**(4)**	(5)
Net operating lease cost	**114**	101

1 Includes short-term leases and variable lease costs.

Other information related to operating leases is noted in the following tables:

year ended December 31 (millions of Canadian $)	2023	2022
Cash paid for amounts included in the measurement of operating lease liabilities	**72**	67
ROU assets obtained in exchange for new operating lease liabilities	**84**	49

at December 31	2023	2022
Weighted average remaining lease term	**13 years**	8 years
Weighted average discount rate	**3.3%**	3.5%

Maturities of operating lease liabilities are as follows:

at December 31 (millions of Canadian $)	2023	2022
Less than one year	**72**	68
One to two years	**68**	65
Two to three years	**66**	62
Three to four years	**59**	60
Four to five years	**58**	54
More than five years	**225**	187
Total operating lease payments	**548**	496
Imputed interest	**(89)**	(63)
Operating lease liabilities	**459**	433

The amounts recognized on TC Energy's Consolidated balance sheet for its operating lease liabilities were as follows:

at December 31 (millions of Canadian $)	2023	2022
Accounts payable and other	**58**	54
Other long-term liabilities (Note 19)	**401**	379
	459	433

As at December 31, 2023, the carrying value of the ROU assets recorded under operating leases was $437 million (2022 – $415 million) and is included in Plant, property and equipment on the Consolidated balance sheet.

As a Lessor

Operating Leases

The Grandview and Bécancour power plants in the Power and Energy Solutions segment are accounted for as operating leases. The Company has long-term PPAs for the sale of power from these assets which expire between 2024 and 2026.

Some operating leases contain variable lease payments that are based on operating hours and the reimbursement of variable costs, and options to purchase the underlying asset at fair value or based on a formula considering the remaining fixed payments. Lessees have rights under some leases to terminate under certain circumstances.

The Company also leases liquids tanks which are accounted for as operating leases.

The fixed portion of the operating lease income recorded by the Company for the year ended December 31, 2023 was $116 million (2022 – $118 million; 2021 – $126 million).

Future lease payments to be received under operating leases are as follows:

at December 31 (millions of Canadian $)	2023	2022
Less than one year	**113**	113
One to two years	**94**	111
Two to three years	**70**	94
Three to four years	**—**	70
	277	388

The cost and accumulated depreciation for facilities accounted for as operating leases was $796 million and $370 million, respectively, at December 31, 2023 (2022 – $802 million and $360 million, respectively).

Sales-Type Leases

On August 4, 2022, TC Energy announced a strategic alliance with Mexico's state-owned electric utility, the Comisión Federal de Electricidad (CFE), for the development of new natural gas infrastructure in central and southeast Mexico. This alliance consolidates previous TSAs executed between TC Energy's Mexico-based subsidiary TGNH and the CFE in connection with the Company's natural gas pipeline assets in central Mexico (including the Tamazunchale, Villa de Reyes and Tula pipelines) under a single, U.S. dollar-denominated take-or-pay TSA that extends through 2055.

The consolidated TSA contains a lease with multiple lease and non-lease components. The lease components represent the capacity available to the CFE provided by the in-service pipelines which, at December 31, 2023, included the Tamazunchale pipeline, the north and lateral sections of the Villa de Reyes pipeline and the east section of the Tula pipeline. The non-lease components represent the Company's services with respect to operation and maintenance of the TGNH pipelines in service.

The consolidated TSA provides the CFE with substantially all of the economic benefits from the use of each identified in-service asset, therefore, the lease arrangements in the consolidated TSA are classified as sales-type leases.

The Company allocated a portion of the contract consideration to non-lease components for the provision of operating and maintenance services based on the stand-alone selling price using an expected cost plus margin approach. The remaining consideration was allocated to the lease components using the residual approach due to uncertainty surrounding the stand-alone selling price.

During 2023, the Company recognized an additional $407 million in net investment in leases (2022 – $2,319 million) to reflect sales type-leases placed into service. At the inception of the lease term, the Company applied judgment to determine that the fair value of the underlying assets approximated the carrying value and residual value of the lease based on the rate-regulated nature of the assets within the TGNH system.

The following table lists the components of the aggregate net investment in leases reflected on the Company's Consolidated balance sheet:

at December 31 (millions of Canadian $)	2023	2022
Net Investment in Leases		
Minimum lease payments	**9,627**	9,457
Unearned lease income	**(7,006)**	(7,132)
Lease receivable	**2,621**	2,325
Expected credit loss provision[1]	**(76)**	(150)
Present value of unguaranteed residual value	**24**	11
	2,569	2,186
Current portion included in Other current assets (Note 9)	**(306)**	(291)
	2,263	1,895

1 Includes nil (2022 – $1 million) of foreign currency translation losses.

Future lease payments to be received under the existing sales-type leases are as follows:

at December 31 (millions of Canadian $)	2023	2022
Less than one year	**305**	291
One to two years	**305**	291
Two to three years	**305**	291
Three to four years	**305**	291
Four to five years	**305**	291
More than five years	**8,102**	8,002
	9,627	9,457

Future lease payments will increase as assets associated with sales-type leases come into service.

For the year ended December 31, 2023, the Company recorded $279 million (2022 – $127 million) of sales-type lease income in Mexico Natural Gas Pipelines revenues.

For the year ended December 31, 2023, the Company recorded a $73 million ECL recovery (2022 – an expense of $149 million; 2021 – nil) in Plant operating costs and other relating to net investment in leases. Refer to Note 29, Risk management and financial instruments, for additional information.

12. EQUITY INVESTMENTS

(millions of Canadian $)	Ownership Interest at December 31, 2023	Income (Loss) from Equity Investments year ended December 31 2023	2022	2021	Equity Investments at December 31 2023	2022
Canadian Natural Gas Pipelines						
TQM[1]	50.0%	**17**	17	12	**166**	165
Coastal GasLink[1]	35.0%	**203**	1	—	**294**	—
U.S. Natural Gas Pipelines						
Northern Border	50.0%	**101**	92	80	**599**	516
Millennium	47.5%	**109**	103	91	**476**	500
Iroquois	50.0%	**98**	77	55	**227**	237
Other	Various	**16**	20	18	**120**	122
Mexico Natural Gas Pipelines						
Sur de Texas	60.0%	**78**	150	160	**1,078**	1,050
Liquids Pipelines						
Grand Rapids[1]	50.0%	**53**	54	54	**932**	964
Port Neches Link LLC[2,3]	74.9%	**13**	—	—	**124**	149
HoustonLink Pipeline[1]	50.0%	**1**	1	1	**18**	19
Northern Courier[1,4]	nil	**—**	—	16	**—**	—
Power and Energy Solutions						
Bruce Power[1]	48.3%	**690**	537	411	**6,242**	5,783
Other	Various	**(2)**	2	—	**38**	30
		1,377	1,054	898	**10,314**	9,535

1 Classified as a VIE. Refer to Note 33, Variable interest entities, for additional information.
2 Classified as a VIE in 2021.
3 In December 2023, TC Energy sold a 20.1 per cent equity interest in Port Neches Link LLC.
4 In November 2021, TC Energy sold its remaining 15 per cent equity interest in Northern Courier. Refer to Note 31, Acquisitions and dispositions, for additional information.

Coastal GasLink Incentive Payment

The Coastal GasLink project reached mechanical completion in November 2023 and was ready to deliver commissioning gas to the LNG Canada facility by the end of 2023. These milestones entitle Coastal GasLink LP to receive a $200 million incentive payment from LNG Canada. In accordance with the contractual terms between the Coastal GasLink LP partners, the amount accrues in full to TC Energy as the project developer and was settled through a cash distribution on February 12, 2024. The Company recognized the incentive payment as Income (loss) from equity investments in the Consolidated statement of income for the year ended December 31, 2023 and recorded a corresponding amount in Accounts receivable on the Consolidated balance sheet.

Impairment of Equity Investment

In the fourth quarter of 2022, the Company announced that a material increase in the Coastal GasLink pipeline project costs was expected. On February 1, 2023, Coastal GasLink LP announced an increase in the revised capital cost of the Coastal GasLink pipeline project. The increase in project costs and the Company's corresponding funding requirements were indicators that a decrease in the value of the Company's equity investment had occurred. As a result, the Company completed a valuation assessment and concluded that the fair value of TC Energy's investment was below its carrying value at December 31, 2022. The Company completed valuation assessments at each of the first three quarters of 2023 and concluded that an other-than-temporary impairment of its investment had occurred. This resulted in a pre-tax impairment charge of $2,100 million ($1,943 million after tax) and $3,048 million ($2,643 million after tax) recorded in the year ended December 31, 2023 and 2022, respectively. Refer to Note 8, Coastal GasLink, for additional information.

Distributions and Contributions

Distributions received from equity investments and contributions made to equity investments for the years ended December 31, 2023, 2022 and 2021 were as follows:

year ended December 31 (millions of Canadian $)	2023	2022	2021
Distributions			
Distributions received from operating activities of equity investments	**1,254**	1,025	975
Sur de Texas debt repayments[1,2]	**—**	2,404	73
Other[1]	**23**	228	—
	1,277	3,657	1,048
Contributions[1]			
Contributions to Coastal GasLink	**3,231**	1,414	92
Sur de Texas debt financing[2]	**—**	1,199	—
Contributions made to other equity investments	**918**	820	1,118
	4,149	3,433	1,210

1 Included in Investing activities in the Consolidated statement of cash flows.
2 Represents TC Energy's proportionate share of the Sur de Texas debt financing requirements and subsequent repayments. Refer to Note 13, Loans receivable from affiliates, for additional information.

Summarized Financial Information of Equity Investments

year ended December 31 (millions of Canadian $)	2023	2022	2021
Income			
Revenues	**6,425**	5,891	5,447
Operating and other expenses	**(3,450)**	(3,390)	(3,293)
Net income	**2,584**	2,147	1,859
Net income attributable to TC Energy	**1,377**	1,054	898

at December 31 (millions of Canadian $)	2023	2022
Balance Sheet		
Current assets	**3,526**	3,414
Non-current assets	**42,933**	37,713
Current liabilities	**(2,431)**	(2,856)
Non-current liabilities	**(21,895)**	(17,690)

At December 31, 2023, the cumulative carrying value of the Company's equity investments was $183 million (2022 – $299 million) lower than the cumulative underlying equity in the net assets primarily due to the impairment of the equity investment in Coastal GasLink LP, partially offset by fair value adjustments at the time of acquisition or partial disposition as well as interest capitalized during construction. Refer to Note 8, Coastal GasLink, for additional information.

13. LOANS RECEIVABLE FROM AFFILIATES

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

Coastal GasLink Pipeline Limited Partnership

TC Energy holds a 35 per cent equity interest in Coastal GasLink LP and has been contracted to develop and operate the Coastal GasLink pipeline.

Subordinated Demand Revolving Credit Facility

The Company has a subordinated demand revolving credit facility with Coastal GasLink LP to provide additional short-term liquidity and funding flexibility to the project. The facility bears interest at a floating market-based rate and has a capacity of $100 million (2022 – $100 million) with no outstanding balance at December 31, 2023 and 2022. This revolver was not impacted by the impairment charges recognized to date.

Subordinated Loan Agreement

In 2021, TC Energy entered into a subordinated loan agreement with Coastal GasLink LP, which was amended on July 28, 2022. At December 31, 2023, the total capacity committed by TC Energy under this subordinated loan agreement was $3.4 billion (2022 – $1.3 billion) with an outstanding balance of $2,520 million (2022 – $250 million). In the year ended December 31, 2023, $2,020 million (2022 – $250 million) was impaired. Refer to Note 8, Coastal GasLink, for additional information.

Sur de Texas

TC Energy holds a 60 per cent equity interest in a joint venture with IEnova to own the Sur de Texas pipeline, for which TC Energy is the operator. In 2017, TC Energy entered into a MXN$21.3 billion unsecured revolving credit facility with the joint venture, which bore interest at a floating rate and was fully repaid upon maturity on March 15, 2022 in the amount of $1.2 billion.

The Company's Consolidated statement of income reflects the related interest income and foreign exchange impact on this loan receivable until its repayment on March 15, 2022, which were fully offset upon consolidation with corresponding amounts included in TC Energy's proportionate share of Sur de Texas equity earnings as follows:

year ended December 31 (millions of Canadian $)	2023	2022	2021	Affected line item in the Consolidated statement of income
Interest income[1]	—	19	87	Interest income and other
Interest expense[2]	—	(19)	(87)	Income (loss) from equity investments
Foreign exchange losses[1]	—	(28)	(41)	Foreign exchange (gains) losses, net
Foreign exchange gains[1]	—	28	41	Income from equity investments

1 Included in the Corporate segment.
2 Included in the Mexico Natural Gas Pipelines segment.

On March 15, 2022, as part of refinancing activities with the Sur de Texas joint venture, the peso-denominated inter-affiliate loan discussed above was replaced with a new U.S. dollar-denominated inter-affiliate loan of an equivalent $1.2 billion (US$938 million) with a floating interest rate. On July 29, 2022, the Sur de Texas joint venture entered into an unsecured term loan agreement with third parties, the proceeds of which were used to fully repay the U.S. dollar-denominated inter-affiliate loan with TC Energy.

14. RATE-REGULATED BUSINESSES

TC Energy's businesses that apply RRA currently include almost all of the Canadian, U.S. and Mexico natural gas pipelines and certain U.S. natural gas storage operations. Rate-regulated businesses account for and report assets and liabilities consistent with the resulting economic impact of the regulators' established rates, provided the rates are designed to recover the costs of providing the regulated service and the competitive environment makes it probable that such rates can be charged and collected. Certain revenues and expenses subject to utility regulation or rate determination that would otherwise be reflected in the statement of income are deferred on the balance sheet and are expected to be recovered from or refunded to customers in future service rates.

Canadian Regulated Operations

The majority of TC Energy's Canadian natural gas pipelines are regulated by the CER under the Canadian Energy Regulator Act (CER Act). The Impact Assessment Agency of Canada continues to assess designated projects.

The CER regulates the construction and operation of facilities and the terms and conditions of services, including rates, for the Company's Canadian regulated natural gas transmission systems under federal jurisdiction.

TC Energy's Canadian natural gas transmission services are supplied under natural gas transportation tariffs that provide for cost recovery, including return of and on capital as approved by the CER. Rates charged for these services are typically set through a process that involves filing an application with the regulator wherein forecasted operating costs, including a return of and on capital, determine the revenue requirement for the upcoming year or multiple years. To the extent actual costs and revenues are more or less than forecasted costs and revenues, the regulator generally allows the difference to be deferred to a future period and recovered or refunded in rates at that time. Differences between actual and forecasted costs that the regulator does not allow to be deferred are included in the determination of net income in the year they occur. The Company's most significant regulated Canadian natural gas pipelines, based on total operated pipe length, are described below.

NGTL System

The NGTL System is operating under the 2020-2024 Revenue Requirement Settlement which includes an approved ROE of 10.1 per cent on 40 per cent deemed common equity. This settlement provides the NGTL System the opportunity to increase depreciation rates if tolls fall below specified levels and an incentive mechanism for certain operating costs where variances from projected amounts are shared with its customers.

Canadian Mainline

The Canadian Mainline currently operates under the terms of the 2015-2030 Tolls Application approved in 2014 (the 2014 Decision). In April 2020, the CER approved the six-year unanimous negotiated settlement (2021-2026 Mainline Settlement) effective January 1, 2021. Similar to the previous settlement, the 2021-2026 Mainline Settlement maintains a base equity return of 10.1 per cent on 40 per cent deemed common equity and includes an incentive to either achieve cost efficiencies and/or increase revenues on the pipeline with a beneficial sharing mechanism to both customers and TC Energy.

Toll stabilization is achieved using deferral accounts, including the toll-stabilization account and the short-term adjustment accounts (STAA), which capture the surplus or shortfall between system revenues and cost of service each year under the 2021-2026 Mainline Settlement. A portion of the STAA commenced amortization in 2023 according to the terms outlined in the 2021-2026 Mainline Settlement as predetermined thresholds per the settlement agreement were met. Similar to the STAA, the long-term adjustment account (LTAA) and bridging account were used to capture the surplus or shortfall between the Company's revenues and cost of service during the previous settlement and are amortized over the life of 2021-2026 Settlement and the 2014 Decision respectively.

U.S. Regulated Operations

TC Energy's U.S. regulated natural gas pipelines operate under the provisions of the Natural Gas Act of 1938 (NGA), the Natural Gas Policy Act of 1978 and the Energy Policy Act of 2005, and are subject to the jurisdiction of FERC. The NGA grants FERC authority over the construction, acquisition and operation of pipelines and related facilities, including the regulation of tariffs which incorporates maximum and minimum rates for services and allows U.S. regulated natural gas pipelines to discount or negotiate rates on a non-discriminatory basis. The Company's most significant regulated U.S. natural gas pipelines, based on effective ownership and total operated pipe length, are described below.

Columbia Gas

Columbia Gas' natural gas transportation and storage services are provided under a tariff at rates subject to FERC approval. Columbia Gas reached a settlement with its customers effective February 2021 and received FERC approval in February 2022. As part of the settlement, there is a moratorium on any further rate changes until April 1, 2025. Columbia Gas must file for new rates with an effective date no later than April 1, 2026. Previously accrued rate refund liabilities were refunded to customers, including interest, in second quarter 2022.

Additionally, Columbia Gas maintains a FERC-approved modernization program allowing for the cost recovery and return on additional investment up to US$1.2 billion over a four-year period through 2024 to modernize the Columbia Gas system, thereby improving system integrity and enhancing service reliability and flexibility.

ANR Pipeline

ANR Pipeline operated under rates established through a 2016 FERC-approved rate settlement until July 31, 2022. To meet terms of the 2016 settlement, in January 2022, ANR Pipeline filed a Section 4 Rate Case with FERC requesting an increase to maximum transportation rates. In December 2022 ANR Pipeline filed a Stipulation and Agreement of Settlement (2022 ANR Settlement) with FERC. The 2022 ANR Settlement reflects the agreement of ANR Pipeline, its customers and FERC staff to resolve all outstanding issues pertaining to the original rate case filing in January 2022 and was effective August 2022. The 2022 ANR Settlement received FERC approval on April 11, 2023. As part of the settlement, there is a moratorium on any further rate changes until November 1, 2025. ANR must file for new rates with an effective date no later than August 1, 2028. In second quarter 2023, previously accrued rate refund liabilities, including interest, were refunded to customers.

Columbia Gulf

Columbia Gulf operates under a settlement approved by FERC in December 2019 (2019 Columbia Gulf Settlement), which requires Columbia Gulf to file a general rate case under Section 4 of the NGA no later than January 31, 2027. The 2019 Columbia Gulf Settlement included a moratorium that expired in August 2022. In July 2023 Columbia Gulf, in advance of its obligation to file a general rate case from the 2019 Columbia Gulf Settlement, reached a settlement with its customers effective March 1, 2024 and received FERC approval in August 2023 (2023 Columbia Gulf Settlement). As part of the 2023 Columbia Gulf Settlement, there is a moratorium on any further rate changes through February 28, 2027 and Columbia Gulf must file for new rates no later than March 1, 2029.

Great Lakes

Great Lakes operates under a settlement approved by FERC in February 2018, which does not include a moratorium; however, Great Lakes was required to file for new rates no later than March 31, 2022.

In March 2022, Great Lakes filed a rate settlement (2022 Great Lakes Settlement) with FERC that satisfies the obligations from the 2017 settlement that Great Lakes file for rates to become effective no later than October 2022. The 2022 Great Lakes Settlement, approved by FERC in April 2022, maintains Great Lakes' existing maximum transportation rates through October 31, 2025. The 2022 Great Lakes Settlement contains a moratorium until October 31, 2025. Great Lakes will be required to file for new rates no later than April 30, 2025, with such new rates effective no later than November 1, 2025.

Tuscarora

Tuscarora operates under rates established as part of the FERC-approved rate settlement effective August 2019. Under the terms of this settlement, Tuscarora was required to file for new rates to be effective no later than February 1, 2023. Tuscarora filed a general NGA Section 4 Rate Case with FERC in July 2022, requesting an increase to its maximum rates effective February 1, 2023, subject to refund. On March 24, 2023, Tuscarora filed a Stipulation and Agreement of Settlement with FERC, which was approved on September 6, 2023.

Gas Transmission Northwest

Gas Transmission Northwest (GTN) operates under rates established as part of the FERC-approved rate settlement effective November 18, 2021 (2021 GTN Settlement). The 2021 GTN Settlement satisfies the obligations from the 2015 and 2018 rate settlements that GTN file for rates to become effective no later than January 1, 2022 and extends existing maximum transportation rates at their current levels. GTN's annual depreciation rates remain unchanged. The 2021 GTN Settlement contains a moratorium until December 31, 2023. Additionally, the 2021 GTN Settlement authorizes GTN to recover payments that it incurs in the states of Oregon and Washington for carbon/greenhouse gas-related taxes. GTN is required to file for new rates to become effective no later than April 1, 2024. Accordingly, GTN filed a general NGA Section 4 Rate Case with FERC on September 29, 2023, requesting an increase to GTN's maximum rates to become effective April 1, 2024, and subject to refund.

Mexico Regulated Operations

TC Energy's Mexico natural gas pipelines are regulated by CRE and operate in accordance with CRE-approved tariffs. The rates in effect on TC Energy's Mexico natural gas pipelines are in compliance with CRE economic regulations that provide for cost recovery, including a return of and on invested capital.

Regulatory Assets and Liabilities

at December 31 (millions of Canadian $)	Remaining Recovery/ Settlement Period (years)	2023	2022
Regulatory Assets			
Deferred income taxes[1]	n/a	**2,204**	1,817
Operating and debt-service regulatory assets[2]	1	**29**	2
Pensions and other post-retirement benefits[1,3]	n/a	**54**	28
Foreign exchange on long-term debt[1,4]	1-6	**11**	19
Other	n/a	**108**	111
		2,406	1,977
Less: Current portion included in Other current assets (Note 9)		**76**	67
		2,330	1,910
Regulatory Liabilities			
Pipeline abandonment trust balances[5]	n/a	**2,355**	2,014
Deferred income taxes – U.S. Tax Reform[6]	n/a	**1,137**	1,197
Canadian Mainline short-term adjustment and toll-stabilization accounts[7,8]	n/a	**437**	284
Canadian Mainline bridging amortization account[7]	7	**376**	429
Cost of removal[9]	n/a	**351**	337
Deferred income taxes[1]	n/a	**198**	181
Canadian Mainline long-term adjustment account[7,10]	3	**111**	149
ANR post-employment and retirement benefits other than pension[11]	n/a	**42**	43
Operating and debt-service regulatory liabilities[2]	1	**23**	50
Pensions and other post-retirement benefits[3]	n/a	**6**	10
Other	n/a	**54**	99
		5,090	4,793
Less: Current portion included in Accounts payable and other (Note 18)		**284**	273
		4,806	4,520

1 These regulatory assets and liabilities are underpinned by non-cash transactions or are recovered without an allowance for return as approved by the regulator. Accordingly, these regulatory assets or liabilities are not included in rate base and do not yield a return on investment during the recovery period.

2 Operating and debt-service regulatory assets and liabilities represent the accumulation of cost and revenue variances to be included in determination of rates in the following year.

3 These balances represent the regulatory offset to pension plan and other post-retirement benefit obligations to the extent the amounts are expected to be collected from or refunded to customers in future rates.

4 Foreign exchange on long-term debt of the NGTL System represents the variance resulting from revaluing foreign currency-denominated debt instruments to the current foreign exchange rate from the historical foreign exchange rate at the time of issue. Foreign exchange gains and losses realized when foreign debt matures or is redeemed early are expected to be recovered or refunded through the determination of future tolls.

5 This balance represents the amounts collected in tolls from customers and included in the LMCI restricted investments to fund future abandonment of the Company's CER-regulated pipeline facilities.

6 The U.S. corporate income tax rate was reduced from 35 per cent to 21 per cent in 2017 as a result of H.R.1, the Tax Cuts and Jobs Act (U.S. Tax Reform). This U.S. regulated operations balance, where applicable, represents established regulatory liabilities driven by 2018 FERC prescribed changes related to U.S. Tax Reform being amortized over varying terms that approximate the expected reversal of the underlying deferred tax liabilities that gave rise to the regulatory liabilities.

7 These regulatory accounts are used to capture revenue and cost variances plus toll-stabilization adjustments during the 2015-2030 settlement term.

8 Under the terms of the 2021-2026 Mainline Settlement, a portion of the STAA account commenced amortization in 2023 as predetermined thresholds were met, over the terms outlined per the settlement agreement.

9 This balance represents anticipated costs of removal that have been, and continue to be, included in depreciation rates and collected in the service rates of certain rate-regulated operations for future costs to be incurred.

10 Under the terms of the 2021-2026 Mainline Settlement, $223 million is amortized over the six-year settlement term.

11 This balance represents the amount ANR estimates it would be required to refund to its customers for post-retirement and post-employment benefit amounts collected through its FERC-approved rates that have not been used to pay benefits to its employees. Pursuant to a FERC-approved rate settlement, the $42 million (US$32 million) balance at December 31, 2023 is subject to resolution through future regulatory proceedings and, accordingly, a settlement period cannot be determined at this time.

15. GOODWILL

The Company's Goodwill balance on the Consolidated balance sheet is comprised of the following amounts:

at December 31	2023		2022	
(millions)	Canadian dollars	U.S. dollars	Canadian dollars	U.S. dollars
Columbia Pipeline Group, Inc.	**9,708**	**7,351**	9,948	7,351
ANR	**2,570**	**1,946**	2,634	1,946
Great Lakes	**161**	**122**	165	122
North Baja	**63**	**48**	65	48
Tuscarora	**30**	**23**	31	23
	12,532	**9,490**	12,843	9,490

Changes in Goodwill were as follows:

(millions of Canadian $)	U.S. Natural Gas Pipelines
Balance at January 1, 2022	12,582
Great Lakes impairment charge	(571)
Foreign exchange rate changes	832
Balance at December 31, 2022	12,843
Foreign exchange rate changes	**(311)**
Balance at December 31, 2023	**12,532**

As part of the annual goodwill impairment assessment at December 31, 2023, the Company evaluated qualitative factors impacting the fair value of the underlying reporting units for all reporting units other than for the Tuscarora and North Baja reporting units. It was determined that it was more likely than not that the fair value of these reporting units exceeded their carrying amounts, including goodwill.

Columbia

On October 4, 2023, as part of the asset divestiture program announced in 2022, the Company successfully completed the sale of a 40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf. In conjunction with the process leading up to the sale, the Company performed a quantitative goodwill impairment test at June 30, 2023.

The estimated fair value measurements used in the Company's goodwill impairment analysis are classified as Level III of the fair value hierarchy. In the determination of the fair value utilized in the quantitative goodwill impairment test for the Columbia reporting unit, the Company performed a discounted cash flow model analysis using projections of future cash flows and applied a risk-adjusted discount rate and value multiple which involved significant estimates and judgments. It was determined that the fair value of the Columbia reporting unit, inclusive of the Columbia Gas and Columbia Gulf business units, exceeded its carrying value, including goodwill. Although goodwill was not impaired, the estimated fair value in excess of the carrying value was less than 10 per cent. There is a risk that reductions in future cash flow forecasts and adverse changes in other key assumptions could result in a future impairment of a portion of the goodwill balance relating to Columbia.

The Company evaluated qualitative factors impacting the fair value of the Columbia reporting unit from June 30, 2023 to December 31, 2023 and determined that it was more likely than not that the fair value remains higher than the carrying amount, including goodwill.

North Baja and Tuscarora

The Company elected to proceed directly to a quantitative annual impairment test at December 31, 2023 for the $63 million of goodwill related to the North Baja reporting unit due to the passage of time from the previous quantitative test at December 31, 2018. The Company also elected to proceed directly to a quantitative annual impairment test for the $30 million of goodwill related to the Tuscarora reporting unit due to the passage of time from the previous quantitative test at December 31, 2018, and subsequent to the Tuscarora Section 4 rate case settlement in 2023. It was determined that the fair values of North Baja and Tuscarora exceeded their carrying values, including goodwill, at December 31, 2023.

Great Lakes

In March 2022, Great Lakes reached a pre-filing settlement with its customers and filed an unopposed rate case settlement with FERC by which Great Lakes and the settling parties agreed to maintain existing recourse rates through October 31, 2025. Management performed a quantitative impairment test which evaluated a range of assumptions through a discounted cash flow model analysis using a risk-adjusted discount rate. It was determined that the estimated fair value of the Great Lakes reporting unit no longer exceeded its carrying value, including goodwill, and that an impairment charge was necessary. As a result, the Company recorded a pre-tax goodwill impairment charge of $571 million ($531 million after tax) for the year ended December 31, 2022 within the U.S. Natural Gas Pipelines segment that is included in Goodwill and asset impairment charges and other in the Company's Consolidated statement of income. The remaining goodwill balance related to Great Lakes was US$122 million at December 31, 2022. There is a risk that continued reductions in future cash flow forecasts and adverse changes in other key assumptions could result in a future impairment of the goodwill balance relating to Great Lakes. The majority of the Great Lakes goodwill impairment charge was allocated to non-deductible goodwill and the income tax recovery of $40 million was attributable to the portion of the goodwill that was deductible for income tax purposes. The estimated fair value measurements used in the Company's goodwill impairment analysis is classified as Level III of the fair value hierarchy. In the determination of the fair value utilized in the quantitative goodwill impairment test for each reporting unit, the Company used its projections of future cash flows and applied a risk-adjusted discount rate which involved significant estimates and judgments.

Asset Divestiture Program

TC Energy is progressing the asset divestiture program announced in 2022, which may involve the divestiture of reporting units, or portions thereof. These divestitures could include assets that have associated goodwill. To the extent that a sale transaction indicates a value lower than previously estimated, goodwill could be impaired. In the event of a partial sale of such assets, the anticipated proceeds will be considered in management’s assessment of fair value of the retained interest and any associated goodwill. The Company will continue to evaluate incremental capital rotation opportunities.

16. OTHER LONG-TERM ASSETS

at December 31 (millions of Canadian $)	2023	2022
Deferred income tax assets (Note 20)	**1,332**	1,070
Employee post-retirement benefits (Note 28)	**518**	563
Long-term contract assets (Note 6)	**457**	355
Capital projects in development	**237**	99
Fair value of derivative contracts (Note 29)	**155**	91
Keystone XL contractual recoveries (Note 7)	**34**	44
Keystone environmental provision recovery (Note 18)	**33**	240
Other	**252**	323
	3,018	2,785

17. NOTES PAYABLE

at December 31	2023		2022	
(millions of Canadian $, unless otherwise noted)	Outstanding	Weighted Average Interest Rate per Annum	Outstanding	Weighted Average Interest Rate per Annum
Canada[1]	—	—	5,971	4.9%
Mexico (2023 – nil; 2022 – US$215)[2]	—	—	291	6.0%
	—		6,262	

1 At December 31, 2023, Notes payable consisted of Canadian dollar-denominated notes of nil (2022 – $2,810 million) and U.S. dollar-denominated notes of nil (2022 – US$2,336 million).
2 In January 2023, the Company's Mexico subsidiary fully repaid the outstanding balance and terminated its MXN$5.0 billion demand senior unsecured revolving credit facility.

On August 25, 2023, TransCanada PipeLines Limited (TCPL) fully repaid and retired its 364-day $1.5 billion senior unsecured term loan bearing interest at a floating rate entered into on November 22, 2022.

At December 31, 2022, Notes payable reflects short-term borrowings in Canada by TCPL and in Mexico by a wholly-owned Mexican subsidiary.

At December 31, 2023, total committed revolving and demand credit facilities were $11.6 billion (2022 – $12.9 billion). When drawn, interest on these lines of credit is charged at negotiated floating rates of Canadian and U.S. banks, and at other negotiated financial bases. These unsecured credit facilities included the following:

at December 31 (billions of Canadian $, unless otherwise noted)			2023		2022
Borrowers	Description	Matures	Total Facilities	Unused Capacity[1]	Total Facilities
Committed, syndicated, revolving, extendible, senior unsecured credit facilities[2]:					
TCPL	Supports commercial paper program and for general corporate purposes	December 2028	**3.0**	**3.0**	3.0
TCPL / TCPL USA	Supports commercial paper programs and for general corporate purposes of the borrowers, guaranteed by TCPL	December 2024	**US 2.5**	**US 2.5**	US 3.0
TCPL / TCPL USA	Supports commercial paper programs and for general corporate purposes of the borrowers, guaranteed by TCPL	December 2026	**US 2.5**	**US 2.5**	US 2.5
Demand senior unsecured revolving credit facilities[2]:					
TCPL / TCPL USA	Supports the issuance of letters of credit and provides additional liquidity; TCPL USA facility guaranteed by TCPL	Demand	**2.0** [3]	**1.0**	2.1 [3]
Mexico subsidiary	For Mexico general corporate purposes, guaranteed by TCPL	Demand	—	—	MXN 5.0 [3]

1 Unused capacity is net of commercial paper outstanding and facility draws.
2 Provisions of various trust indentures and credit arrangements with the Company's subsidiaries can restrict their ability to declare and pay dividends or make distributions under certain circumstances. If such restrictions apply, they may, in turn, have an impact on the Company's ability to declare and pay dividends on common and preferred shares. These trust indentures and credit arrangements also require the Company to comply with various affirmative and negative covenants and maintain certain financial ratios. At December 31, 2023, the Company was in compliance with all financial covenants.
3 Or the U.S. dollar equivalent.

For the year ended December 31, 2023, the cost to maintain the above facilities was $14 million (2022 – $14 million; 2021 – $17 million).

18. ACCOUNTS PAYABLE AND OTHER

at December 31 (millions of Canadian $)	2023	2022
Trade payables	**4,832**	4,330
Fair value of derivative contracts (Note 29)	**1,143**	871
Regulatory liabilities (Note 14)	**284**	273
Keystone environmental provision	**122**	650
Contract liabilities (Note 6)	**69**	62
Class C Interests (Note 7)	**19**	37
Coastal GasLink contractual contribution (Notes 8, 12 and 33)	**—**	537
Other	**518**	389
	6,987	7,149

Keystone Environmental Provision

In December 2022, a pipeline incident occurred in Washington County, Kansas on the Keystone Pipeline System. At December 31, 2022, the Company accrued an environmental liability of $650 million, before expected insurance recoveries and not including potential fines and penalties which continue to be indeterminable. At June 30, 2023, the cost estimate for the incident was adjusted to $794 million based on a review of costs and commitments incurred and, at December 31, 2023, remains unchanged. Amounts paid for the environmental remediation liability were $676 million at December 31, 2023 (December 31, 2022 – nil). The remaining balance reflected in Accounts payable and other and Other long-term liabilities on the Company's Consolidated balance sheet was $122 million and $9 million, respectively at December 31, 2023 (December 31, 2022 – $650 million and nil, respectively).

The expected recovery of the remaining estimated environmental remediation costs recorded in Other current assets and Other long-term assets were $150 million and $33 million, respectively at December 31, 2023 (December 31, 2022 – $410 million and $240 million, respectively). An additional $36 million was accrued during the year, which is expected to be recoverable from TC Energy's wholly-owned captive insurance subsidiary. This amount was recorded as an expense in Interest income and other in the Consolidated statement of income. During the year, the Company received $575 million (2022 – nil) from its insurance policies related to the costs for environmental remediation. Restoration activities are ongoing and expected to continue into 2024.

19. OTHER LONG-TERM LIABILITIES

at December 31 (millions of Canadian $)	2023	2022
Operating lease obligations (Note 11)	**401**	379
Fair value of derivative contracts (Note 29)	**106**	151
Employee post-retirement benefits (Note 28)	**97**	111
Asset retirement obligations	**64**	79
Long-term contract liabilities (Note 6)	**12**	32
Other	**335**	265
	1,015	1,017

20. INCOME TAXES

Geographic Components of Income before Income Taxes

year ended December 31 (millions of Canadian $)	2023	2022	2021
Canada	**(446)**	(2,154)	(292)
Foreign	**4,456**	3,528	2,458
Income before Income Taxes	**4,010**	1,374	2,166

Provision for Income Taxes

year ended December 31 (millions of Canadian $)	2023	2022	2021
Current			
Canada	**73**	43	29
Foreign	**858**	372	276
	931	415	305
Deferred			
Canada	**(39)**	(467)	(327)
Foreign	**50**	641	142
	11	174	(185)
Income Tax Expense	**942**	589	120

Reconciliation of Income Tax Expense

year ended December 31 (millions of Canadian $)	2023	2022	2021
Income before income taxes	**4,010**	1,374	2,166
Federal and provincial statutory tax rate	**23.0%**	23.0%	23.0%
Expected income tax expense	**922**	316	498
Income tax differential related to regulated operations	**(260)**	(174)	(139)
Foreign income tax rate differentials	**(174)**	(271)	(230)
Income from non-controlling interests and equity investments	**(56)**	(54)	(70)
Valuation allowance (release)	**197**	199	(8)
Non-taxable capital (gains) and losses	**196**	173	—
Mexico foreign exchange exposure	**132**	9	10
Impact of Mexico inflationary adjustments	**1**	24	32
Settlement of Mexico prior years' income tax assessments	**—**	196	—
U.S. minimum tax	**(14)**	96	—
Non-deductible goodwill impairment	**—**	91	—
Other	**(2)**	(16)	27
Income Tax Expense	**942**	589	120

Deferred Income Tax Assets and Liabilities

at December 31 (millions of Canadian $)	2023	2022
Deferred Income Tax Assets		
Tax loss and credit carryforwards	**1,833**	1,519
Regulatory and other deferred amounts	**569**	571
Unrealized foreign exchange losses on long-term debt	**206**	333
Other	**73**	193
	2,681	2,616
Less: Valuation allowance	**730**	640
	1,951	1,976
Deferred Income Tax Liabilities		
Difference in accounting and tax bases of plant, property and equipment	**6,816**	6,686
Equity investments	**1,115**	1,152
Taxes on future revenue requirement	**493**	397
Financial instruments	**160**	126
Other	**160**	193
	8,744	8,554
Net Deferred Income Tax Liabilities	**6,793**	6,578

The above deferred tax amounts have been classified on the Consolidated balance sheet as follows:

at December 31 (millions of Canadian $)	2023	2022
Deferred Income Tax Assets		
Other long-term assets (Note 16)	**1,332**	1,070
Deferred Income Tax Liabilities		
Deferred income tax liabilities	**8,125**	7,648
Net Deferred Income Tax Liabilities	**6,793**	6,578

At December 31, 2023, the Company has recognized the benefit of non-capital loss carryforwards of $6,593 million (2022 – $5,429 million) for federal and provincial purposes in Canada, which expire from 2030 to 2043. The Company has not yet recognized the benefit of capital loss carryforwards of $478 million (2022 – $251 million) for federal and provincial purposes in Canada which have no expiry date. The Company also has Ontario corporate minimum tax (CMT) credits of $140 million (2022 – $126 million), which expire from 2026 to 2043. As of December 31, 2023, the Company has not recognized the benefit of CMT credits of $22 million (2022 – $22 million).

At December 31, 2023, the Company has recognized the benefit of net operating loss carryforwards of US$47 million (2022 – US$69 million) in Mexico, which expire from 2024 to 2033.

TC Energy recorded an income tax valuation allowance of $730 million and $640 million against the deferred income tax asset balances at December 31, 2023 and 2022, respectively. The increase in the valuation allowance is primarily a result of the foreign exchange movement on unrecognized capital losses and the unrealized non-taxable capital losses on the Coastal GasLink equity investment. At December 31, 2023, the Company recorded a total of $358 million (2022 – $173 million) in valuation allowance as a result of the Coastal GasLink equity investment impairment that resulted in a portion of the impairment having unrealized non-taxable capital losses. These losses have not been recognized as of December 31, 2023. At each reporting date, the Company considers new evidence, both positive and negative, that could affect its view of the future realization of deferred tax assets. As at December 31, 2023, the Company determined there was sufficient positive evidence to conclude that it is more likely than not that the net deferred tax assets will be realized.

Unremitted Earnings of Foreign Investments

Income taxes have not been provided on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future. Deferred income tax liabilities would have increased at December 31, 2023 by approximately $1,629 million (2022 – $1,216 million) if there had been a provision for these taxes.

Income Tax Payments

Income tax payments of $836 million, net of refunds, were made in 2023 (2022 – payments, net of refunds, of $394 million; 2021 – payments, net of refunds, of $371 million).

Reconciliation of Unrecognized Tax Benefit

Below is the reconciliation of the annual changes in the total unrecognized tax benefit:

at December 31 (millions of Canadian $)	**2023**	**2022**	**2021**
Unrecognized tax benefit at beginning of year	**91**	80	52
Gross increases – tax positions in prior years	**9**	6	5
Gross decreases – tax positions in prior years	**(1)**	—	(1)
Gross increases – tax positions in current year	**16**	7	26
Lapse of statutes of limitations	**(30)**	(2)	(2)
Unrecognized Tax Benefit at End of Year	**85**	91	80

TC Energy's practice is to recognize interest and penalties related to income tax uncertainties in Income tax expense. Income tax expense for the year ended December 31, 2023 reflects $3 million interest expense (2022 – $6 million; 2021 – $1 million). At December 31, 2023, the Company had accrued $21 million in interest expense (2022 – $18 million; 2021 – $12 million). The Company incurred no penalties associated with income tax uncertainties related to income tax expense for the years ended December 31, 2023, 2022 and 2021 and no penalties were accrued as at December 31, 2023, 2022 and 2021.

Subject to the results of audit examinations by taxing authorities and other legislative amendments, TC Energy does not anticipate further adjustments to the unrecognized tax benefits during the next 12 months that would have a material impact on its financial statements.

TC Energy and its subsidiaries are subject to either Canadian federal and provincial income tax, U.S. federal, state and local income tax or the relevant income tax in other international jurisdictions. The Company has substantially concluded all Canadian federal and provincial income tax matters for the years through 2015. Substantially all material U.S. federal, state and local income tax matters have been concluded for years through 2015. Substantially all material Mexico income tax matters have been concluded for years through 2017.

Mexico Tax Audit

In 2019, the Mexican tax authority, the Tax Administration Services (SAT), completed an audit of the 2013 tax return of one of the Company's subsidiaries in Mexico. The audit resulted in a tax assessment that denied the deduction for all interest expense and an assessment of additional tax, penalties and financial charges totaling less than US$1 million. The Company disagreed with this assessment and commenced litigation to challenge it. In January 2022, TC Energy received the tax court's ruling on the 2013 tax return, which upheld the SAT assessment. From September 2021 to February 2022, the SAT issued assessments for tax years 2014 through 2017 which denied the deduction of all interest expense as well as assessed incremental withholding tax on the interest. These assessments totaled approximately US$490 million in income and withholding taxes, interest, penalties and other financial charges.

During 2022, TC Energy settled with the SAT on all of the above matters for the tax years 2013 through 2021 and recorded $196 million (US$153 million) of income tax expense, inclusive of withholding taxes, interest, penalties and other financial charges for the year ended December 31, 2022.

21. LONG-TERM DEBT

at December 31 (millions of Canadian $, unless otherwise noted)	Maturity Dates	2023 Outstanding	2023 Interest Rate[1]	2022 Outstanding	2022 Interest Rate[1]
TRANSCANADA PIPELINES LIMITED					
Medium Term Notes					
Canadian	2024 to 2052	**15,466**	**4.6%**	13,966	4.5%
Senior Unsecured Notes					
U.S. (2023 – US$16,167; 2022 – US$15,542)	2024 to 2049	**21,349**	**5.0%**	21,032	4.9%
		36,815		34,998	
NOVA GAS TRANSMISSION LTD.					
Debentures and Notes					
Canadian	2024	**100**	**9.9%**	100	9.9%
U.S. (2023 – nil; 2022 – US$200)		**—**	**—**	271	7.9%
Medium Term Notes					
Canadian	2025 to 2030	**504**	**7.4%**	504	7.4%
U.S. (2023 and 2022 – US$33)	2026	**43**	**7.5%**	44	7.5%
		647		919	
COLUMBIA PIPELINE GROUP, INC.					
Senior Unsecured Notes[2]					
U.S. (2023 – nil; 2022 – US$1,500)		**—**	**—**	2,030	4.9%
COLUMBIA PIPELINES OPERATING COMPANY LLC					
Senior Unsecured Notes[2]					
U.S. (2023 – US$6,100; 2022 – nil)	2025 to 2063	**8,055**	**6.1%**	—	—
COLUMBIA PIPELINES HOLDING COMPANY LLC					
Senior Unsecured Notes[2]					
U.S. (2023 – US$1,000; 2022 – nil)	2026 to 2028	**1,320**	**6.2%**	—	—
ANR PIPELINE COMPANY					
Senior Unsecured Notes					
U.S. (2023 and 2022 – US$1,172)	2024 to 2037	**1,548**	**4.1%**	1,587	4.1%
TC PIPELINES, LP					
Senior Unsecured Notes					
U.S. (2023 and 2022 – US$850)	2025 to 2027	**1,122**	**4.2%**	1,150	4.2%

at December 31		2023		2022	
(millions of Canadian $, unless otherwise noted)	Maturity Dates	Outstanding	Interest Rate[1]	Outstanding	Interest Rate[1]
GAS TRANSMISSION NORTHWEST LLC					
Senior Unsecured Notes					
U.S. (2023 – US$375; 2022 – US$325)	2030 to 2035	**495**	**4.4%**	440	4.3%
PORTLAND NATURAL GAS TRANSMISSION SYSTEM					
Senior Unsecured Notes					
U.S. (2023 and 2022 – US$250)	2030 to 2031	**330**	**2.8%**	338	2.8%
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP					
Senior Unsecured Notes					
U.S. (2023 – US$125; 2022 – US$146)	2028 to 2030	**165**	**7.6%**	198	7.6%
TUSCARORA GAS TRANSMISSION COMPANY					
Unsecured Term Loan					
U.S. (2023 – nil; 2022 – US$34)		**—**	**—**	46	6.5%
TC ENERGÍA MEXICANA, S. DE R.L. DE C.V.					
Senior Unsecured Term Loan					
U.S. (2023 – US$1,800; 2022 – nil)	2028	**2,377**	**7.7%**	—	—
Senior Unsecured Revolving Credit Facility					
U.S. (2023 – US$185; 2022 – nil)	2028	**244**	**7.7%**	—	—
		2,621		—	
		53,118		41,706	
Current portion of long-term debt		**(2,938)**		(1,898)	
Unamortized debt discount and issue costs		**(312)**		(239)	
Fair value adjustments[3]		**108**		76	
		49,976		39,645	

1 Interest rates are the effective interest rates except for those pertaining to long-term debt issued for the Company's Canadian regulated natural gas operations, in which case the weighted average interest rate is presented as approved by the regulators. The effective interest rate is calculated by discounting the expected future interest payments, adjusted for loan fees, premiums and discounts. Weighted average and effective interest rates are stated as at the respective outstanding dates.

2 On August 8, 2023, US$1.5 billion senior unsecured notes were assigned from Columbia Pipelines Group, Inc. to Columbia Pipelines Operating Company LLC in advance of the October 4, 2023 sale of a 40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf. Preceding this sale, US$5.6 billion of senior unsecured notes were issued. Refer to Note 24, Non-controlling interests, for additional information.

3 The fair value adjustments include $119 million (2022 – $140 million) related to the acquisition of Columbia Pipeline Group, Inc. These adjustments also include a decrease of $11 million (2022 – $64 million) related to hedged interest rate risk. Refer to Note 29, Risk management and financial instruments, for additional information.

Principal Repayments

At December 31, 2023, principal repayments for the next five years on the Company's long-term debt are approximately as follows:

(millions of Canadian $)	2024	2025	2026	2027	2028
Principal repayments on long-term debt	2,938	2,779	5,287	3,096	6,232

Long-Term Debt Issued

The Company issued long-term debt over the three years ended December 31, 2023 as follows:

(millions of Canadian $, unless otherwise noted)					
Company	**Issue Date**	**Type**	**Maturity Date**	**Amount**	**Interest Rate**
TRANSCANADA PIPELINES LIMITED					
	May 2023	Senior Unsecured Term Loan[1]	May 2026	US 1,024	Floating
	March 2023	Senior Unsecured Notes	March 2026[2]	US 850	6.20%
	March 2023	Senior Unsecured Notes	March 2026[2]	US 400	Floating
	March 2023	Medium Term Notes	July 2030	1,250	5.28%
	March 2023	Medium Term Notes	March 2026[2]	600	5.42%
	March 2023	Medium Term Notes	March 2026[2]	400	Floating
	May 2022	Medium Term Notes	May 2032	800	5.33%
	May 2022	Medium Term Notes	May 2026	400	4.35%
	May 2022	Medium Term Notes	May 2052	300	5.92%
	October 2021	Senior Unsecured Notes	October 2024	US 1,250	1.00%
	October 2021	Senior Unsecured Notes	October 2031	US 1,000	2.50%
	June 2021	Medium Term Notes	June 2024	750	Floating
	June 2021	Medium Term Notes	June 2031	500	2.97%
	June 2021	Medium Term Notes	September 2047	250	4.33% [3]
COLUMBIA PIPELINES OPERATING COMPANY LLC					
	August 2023	Senior Unsecured Notes	November 2033	US 1,500	6.04%
	August 2023	Senior Unsecured Notes	November 2053	US 1,250	6.54%
	August 2023	Senior Unsecured Notes	August 2030	US 750	5.93%
	August 2023	Senior Unsecured Notes	August 2043	US 600	6.50%
	August 2023	Senior Unsecured Notes	August 2063	US 500	6.71%
COLUMBIA PIPELINES HOLDING COMPANY LLC					
	August 2023	Senior Unsecured Notes	August 2028	US 700	6.04%
	August 2023	Senior Unsecured Notes	August 2026	US 300	6.06%
GAS TRANSMISSION NORTHWEST LLC					
	June 2023	Senior Unsecured Notes	June 2030	US 50	4.92%
TC ENERGÍA MEXICANA, S. DE R.L. DE C.V.					
	January 2023	Senior Unsecured Term Loan	January 2028	US 1,800	Floating
	January 2023	Senior Unsecured Revolving Credit Facility	January 2028	US 500	Floating
ANR PIPELINE COMPANY					
	May 2022	Senior Unsecured Notes	May 2032	US 300	3.43%
	May 2022	Senior Unsecured Notes	May 2034	US 200	3.58%
	May 2022	Senior Unsecured Notes	May 2037	US 200	3.73%
	May 2022	Senior Unsecured Notes	May 2029	US 100	3.26%
PORTLAND NATURAL GAS TRANSMISSION SYSTEM					
	October 2021	Senior Unsecured Notes	October 2031	US 125	2.68%

(millions of Canadian $, unless otherwise noted)					
Company	**Issue Date**	**Type**	**Maturity Date**	**Amount**	**Interest Rate**
TUSCARORA GAS TRANSMISSION COMPANY					
	August 2021	Unsecured Term Loan	August 2024	US 13	Floating
KEYSTONE XL SUBSIDIARIES[4]					
	Various	Project-Level Credit Facility	June 2021	US 849	Floating
COLUMBIA PIPELINE GROUP, INC.[5]					
	January 2021	Unsecured Term Loan	June 2022	US 4,040	Floating

1 This loan was fully repaid and retired in September 2023. Related unamortized debt issue costs of $3 million were included in Interest expense in the Consolidated statement of income.

2 Callable at par in March 2024 or at any time thereafter.

3 Reflects coupon rate on re-opening of a pre-existing Medium Term Notes (MTN) issue. The MTNs were issued at a premium to par, resulting in a re-issuance yield of 4.19 per cent.

4 In January 2021, the Company established a US$4.1 billion project-level credit facility to support the construction of the Keystone XL pipeline, which was fully guaranteed by the Government of Alberta and non-recourse to TC Energy. The availability of this credit facility was subsequently reduced to US$1.6 billion and all amounts outstanding were fully repaid by the Government of Alberta in June 2021. Refer to Note 7, Keystone XL, for additional information.

5 In December 2020, Columbia entered into a US$4.2 billion Unsecured Term Loan agreement. In January 2021, US$4.0 billion was drawn on the Unsecured Term Loan and the total availability under the loan agreement was reduced accordingly. The loan was fully repaid and retired in December 2021.

On January 9, 2024, Columbia Pipelines Holding Company LLC issued US$500 million senior unsecured notes due January 2034, bearing interest at a fixed rate of 5.68 per cent.

Long-Term Debt Retired/Repaid

The Company retired/repaid long-term debt over the three years ended December 31, 2023 as follows:

(millions of Canadian $, unless otherwise noted) Company	Retirement/ Repayment Date	Type	Amount	Interest Rate
TRANSCANADA PIPELINES LIMITED				
	October 2023	Senior Unsecured Notes	US 625	3.75%
	September 2023	Senior Unsecured Notes[1]	US 1,024	Floating
	July 2023	Medium Term Notes	750	3.69%
	December 2022	Medium Term Notes	25	9.95%
	August 2022	Senior Unsecured Notes	US 1,000	2.50%
	November 2021	Medium Term Notes	500	3.65%
	January 2021	Debentures	US 400	9.88%
TUSCARORA GAS TRANSMISSION COMPANY				
	November 2023	Unsecured Term Loan	US 32	Floating
NOVA GAS TRANSMISSION LTD.				
	April 2023	Debentures	US 200	7.88%
TC ENERGÍA MEXICANA, S. DE R.L. DE C.V.				
	Various	Senior Unsecured Revolving Credit Facility	US 315	Floating
COLUMBIA PIPELINE GROUP, INC.				
	December 2021	Unsecured Term Loan[2]	US 4,040	Floating
NORTH BAJA PIPELINE, LLC				
	December 2021	Unsecured Term Loan	US 50	Floating
TC PIPELINES, LP				
	November 2021	Unsecured Term Loan	US 450	Floating
	March 2021	Senior Unsecured Notes	US 350	4.65%
ANR PIPELINE COMPANY				
	November 2021	Senior Unsecured Notes	US 300	9.63%
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP				
	November 2021	Senior Unsecured Notes	US 10	9.09%
PORTLAND NATURAL GAS TRANSMISSION SYSTEM				
	October 2021	Unsecured Loan Facility	US 93	Floating
KEYSTONE XL SUBSIDIARIES[3]				
	June 2021	Project-Level Credit Facility	US 849	Floating

1 In May 2023, the Company entered into a US$1,024 million senior unsecured term loan and the full amount was drawn. The loan was fully repaid and retired in September 2023. Related unamortized debt issue costs of $3 million were included in Interest expense in the Consolidated statement of income.

2 In December 2020, Columbia entered into a US$4.2 billion Unsecured Term Loan agreement. In January 2021, US$4.0 billion was drawn on the Unsecured Term Loan and the total availability under the loan agreement was reduced accordingly. The loan was fully repaid and retired in December 2021. Related unamortized debt issue costs of $5 million were included in Interest expense in the Consolidated statement of income for the year ended December 31, 2021.

3 In June 2021, in accordance with the terms of the guarantee, the Government of Alberta repaid the US$849 million outstanding balance under the Keystone XL project-level credit facility bearing interest at a floating rate, subsequent to which it was terminated, resulting in no cash impact to TC Energy. Refer to Note 7, Keystone XL, for additional information.

In March 2021, the Company's subsidiary, TC PipeLines, LP, terminated its US$500 million Unsecured Loan Facility bearing interest at a floating rate on which no amount was outstanding.

Interest Expense

year ended December 31 (millions of Canadian $)	2023	2022	2021
Interest on long-term debt	**2,562**	1,883	1,841
Interest on junior subordinated notes	**617**	543	453
Interest on short-term debt	**165**	153	10
Capitalized interest	**(187)**	(27)	(22)
Amortization and other financial charges[1]	**106**	36	78
	3,263	2,588	2,360

1 Amortization and other financial charges include amortization of transaction costs and debt discounts calculated using the effective interest method and losses on derivatives used to manage the Company's exposure to changes in interest rates.

The Company made interest payments of $2,931 million in 2023 (2022 – $2,478 million; 2021 – $2,299 million) on long-term debt, junior subordinated notes and short-term debt, net of interest capitalized.

22. JUNIOR SUBORDINATED NOTES

at December 31		2023		2022	
(millions of Canadian $, unless otherwise noted)	Maturity Date	Outstanding	Effective Interest Rate[1]	Outstanding	Effective Interest Rate[1]
TRANSCANADA PIPELINES LIMITED					
US$1,000 issued 2007 at 6.35%[2]	2067	**1,320**	**6.5%**	1,353	6.2%
US$750 issued 2015 at 5.88%[3,4]	2075	**990**	**7.8%**	1,015	7.4%
US$1,200 issued 2016 at 6.13%[3,4]	2076	**1,585**	**8.3%**	1,624	8.0%
US$1,500 issued 2017 at 5.55%[3,4]	2077	**1,981**	**7.5%**	2,030	7.1%
$1,500 issued 2017 at 4.90%[3,4]	2077	**1,500**	**7.0%**	1,500	6.8%
US$1,100 issued 2019 at 5.75%[3,4]	2079	**1,453**	**8.0%**	1,488	7.6%
$500 issued 2021 at 4.45%[3,5]	2081	**500**	**5.7%**	500	5.7%
US$800 issued 2022 at 5.85%[3,5]	2082	**1,056**	**7.1%**	1,083	7.2%
		10,385		10,593	
Unamortized debt discount and issue costs		**(98)**		(98)	
		10,287		10,495	

1 The effective interest rate is calculated by discounting the expected future interest payments using the coupon rate and any estimated future rate resets, adjusted for issue costs and discounts.
2 Junior subordinated notes of US$1.0 billion were issued in 2007 at a fixed rate of 6.35 per cent and converted in 2017 to bear interest at a floating rate.
3 The Junior subordinated notes were issued to TransCanada Trust (the Trust), a financing trust subsidiary wholly-owned by TCPL. While the obligations of the Trust are fully and unconditionally guaranteed by TCPL on a subordinated basis, the Trust is not consolidated in TC Energy's financial statements since TCPL does not have a variable interest in the Trust and the only substantive assets of the Trust are junior subordinated notes of TCPL.
4 The coupon rate is initially a fixed interest rate for the first 10 years and converts to a floating rate thereafter.
5 The coupon rate is initially a fixed interest rate for the first 10 years and resets every five years thereafter.

The Junior subordinated notes are subordinated in right of payment to existing and future senior indebtedness or other obligations of TCPL.

In March 2022, TransCanada Trust (the Trust) issued US$800 million of Trust Notes – Series 2022-A to investors with a fixed interest rate of 5.60 per cent per annum for the first 10 years and resetting on the 10th anniversary and every five years thereafter. All of the proceeds of the issuance by the Trust were loaned to TCPL for US$800 million of junior subordinated notes of TCPL at an initial fixed rate of 5.85 per cent per annum, including a 0.25 per cent administration charge. The rate on the junior subordinated notes of TCPL will reset every five years commencing March 2032 until March 2052 to the then Five-Year Treasury Rate, as defined in the document governing the subordinated notes, plus 4.236 per cent per annum; from March 2052 until March 2082, the interest rate will reset every five years to the then Five-Year Treasury Rate plus 4.986 per cent per annum. The junior subordinated notes are callable at TCPL's option at any time from December 7, 2031 to March 7, 2032 and on each interest payment and reset date thereafter at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption.

In March 2021, the Trust issued $500 million of Trust Notes – Series 2021-A to investors with a fixed interest rate of 4.20 per cent per annum for the first 10 years and resetting on the 10th anniversary and every five years thereafter. All of the proceeds of the issuance by the Trust were loaned to TCPL for $500 million of junior subordinated notes of TCPL at an initial fixed rate of 4.45 per cent per annum, including a 0.25 per cent administration charge. The rate on the junior subordinated notes of TCPL will reset every five years commencing March 2031 until March 2051 to the then Five-Year Government of Canada Yield, as defined in the document governing the subordinated notes, plus 3.316 per cent per annum; from March 2051 until March 2081, the interest rate will reset every five years to the then Five-Year Government of Canada Yield plus 4.066 per cent per annum. The junior subordinated notes are callable at TCPL's option at any time from December 4, 2030 to March 4, 2031 and on each interest payment and reset date thereafter at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption.

Pursuant to the terms of the notes issued between the Trust and TCPL (the Trust Notes) and related agreements, in certain circumstances: 1) TCPL may issue deferral preferred shares to holders of the Trust Notes in lieu of interest; and 2) TC Energy and TCPL would be prohibited from declaring or paying dividends on or redeeming their outstanding preferred shares (or, if none are outstanding, their respective common shares) until all deferral preferred shares are redeemed by TCPL. The Trust Notes may also be automatically exchanged for preferred shares of TCPL upon certain kinds of bankruptcy and insolvency events. All of these preferred shares would rank equally with any other outstanding first preferred shares of TCPL.

23. FOREIGN EXCHANGE (GAINS) LOSSES, NET

year ended December 31			
(millions of Canadian $)	**2023**	**2022**	**2021**
Derivative instruments held for trading (Note 29)	**(401)**	151	(37)
Other	**81**	34	27
	(320)	185	(10)

24. NON-CONTROLLING INTERESTS

Disposition of Equity Interest

Columbia Gas and Columbia Gulf

On October 4, 2023, TC Energy completed the sale of a 40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf to Global Infrastructure Partners (GIP) for proceeds of $5.3 billion (US$3.9 billion). The Company continues to have a controlling interest in these companies and will remain the operator of the pipelines. TC Energy and GIP will each fund their proportionate share of annual maintenance, modernization and sanctioned growth capital expenditures through internally generated cash flows, debt financing within the Columbia entities, or from proportionate contributions from TC Energy and GIP.

The sale was accounted for as an equity transaction of which $9.5 billion (US$6.9 billion) was recorded as Non-controlling interests to reflect the 40 per cent change in the Company's ownership interest in Columbia Gulf and Columbia Gas. The difference between the non-controlling ownership interest recognized and the consideration received was recorded as a reduction to Additional paid-in capital of $3.5 billion (US$3.0 billion), net of tax and transaction costs.

Preceding the close of the equity sale, on August 8, 2023, Columbia Pipelines Operating Company LLC and Columbia Pipelines Holding Company LLC issued US$4.6 billion and US$1.0 billion of long-term, senior unsecured debt, respectively, with all proceeds paid to TC Energy. The net proceeds from the offerings and equity sale were used to repay existing intercompany and third-party debt. Refer to Note 21, Long-term debt, for additional information.

Acquisitions

Texas Wind Farms

On March 15, 2023 and June 14, 2023, TC Energy acquired 100 per cent of the Class B Membership Interests in Fluvanna Wind Farm (Fluvanna) and Blue Cloud Wind Farm (Blue Cloud), respectively. Each of these operating assets has a tax equity investor which owns 100 per cent of the Class A Membership Interests, to which a percentage of earnings, tax attributes and cash flows are allocated. The tax equity investors' interests were recorded as non-controlling interests at their aggregate estimated fair value of $222 million (US$167 million).

TC Energy has determined that the use of the Hypothetical Liquidation at Book Value (HLBV) method of allocating earnings between the Company and the tax equity investors is appropriate as the earnings, tax attributes and cash flows from Fluvanna and Blue Cloud are allocated to its Class A and Class B Membership Interest owners on a basis other than ownership percentages. Using the HLBV method, the Company's earnings from the projects is calculated based on how the projects would allocate and distribute cash if the net assets were sold at their carrying amounts on the reporting date under the provisions of the tax equity agreements.

TC Energy determined it has a controlling financial interest in both projects and has consolidated the acquired entities as voting interest entities. The tax equity investors' interests were recorded as Non-controlling interests at their estimated fair values of $106 million (US$80 million) for Fluvanna and $116 million (US$87 million) for Blue Cloud. These transactions are accounted for as asset acquisitions and therefore did not result in the recognition of goodwill.

TC PipeLines, LP

On March 3, 2021, the Company acquired all the outstanding common units of TC PipeLines, LP not beneficially owned by TC Energy or its affiliates in exchange for TC Energy common shares. Under this transaction, TC PipeLines, LP common unitholders received 0.70 TC Energy common shares for each issued and outstanding publicly-held TC PipeLines, LP common unit representing, in aggregate, 37,955,093 TC Energy common shares. As a result, TC PipeLines, LP became an indirect, wholly-owned subsidiary of TC Energy.

As the Company controlled TC PipeLines, LP, this acquisition was accounted for as an equity transaction with the following impact reflected on the Consolidated balance sheet:

(millions of Canadian $)	March 3, 2021
Common shares	**2,063**
Additional paid-in-capital	**(398)**
Accumulated other comprehensive income (loss)	**353**
Non-controlling interests	**(1,563)**
Deferred income tax liabilities	**(443)**
Other	**(12)**

Non-controlling interests

The Company's Net income (loss) attributable to non-controlling interests included in the Consolidated statement of income and Non-controlling interests included on the Consolidated balance sheet were as follows:

		Income (Loss) Attributable to Non-Controlling Interests			Non-Controlling Interests	
	Non-Controlling Interests Ownership at	year ended December 31			at December 31	
(millions of Canadian $)	December 31, 2023	2023	2022	2021	2023	2022
Columbia Gas and Columbia Gulf	40.0%	**143**	—	—	**9,167**	—
Portland Natural Gas Transmission System	38.3%	**41**	37	30	**106**	126
Texas Wind Farms	100% [1]	**(38)**	—	—	**182**	—
TC PipeLines, LP	nil [2]	**—**	—	60	**—**	—
Redeemable non-controlling interest (Note 7)	nil	**—**	—	1	**—**	—
		146	37	91	**9,455**	126

1 Non-controlling interests in the Texas Wind Farms comprises Class A Membership Interests.

2 Prior to the March 3, 2021 acquisition, the non-controlling interest in TC PipeLines, LP was 74.5 per cent.

25. COMMON SHARES

	Number of Shares (thousands)	Amount (millions of Canadian $)
Outstanding at January 1, 2021	940,064	24,488
Acquisition of TC PipeLines, LP, net of transaction costs (Note 24)	37,955	2,063
Exercise of options	2,797	165
Outstanding at December 31, 2021	980,816	26,716
Issued under public offering[1]	28,400	1,754
Dividend reinvestment and share purchase plan	5,916	342
Exercise of options	2,830	183
Outstanding at December 31, 2022	1,017,962	28,995
Dividend reinvestment and share purchase plan	**19,464**	**1,003**
Exercise of options	**62**	**4**
Outstanding at December 31, 2023	**1,037,488**	**30,002**

1 Net of underwriting commissions and deferred income taxes.

Common Shares Issued and Outstanding

The Company is authorized to issue an unlimited number of common shares without par value.

Common Shares Issued Under Public Offering

On August 10, 2022, TC Energy issued 28,400,000 common shares at a price of $63.50 each for total gross proceeds of approximately $1.8 billion.

Dividend Reinvestment and Share Purchase Plan

Under the Company's Dividend Reinvestment and Share Purchase Plan (DRP), eligible holders of common and preferred shares of TC Energy can reinvest their dividends and make optional cash payments to obtain additional TC Energy common shares. From August 31, 2022 to July 31, 2023, common shares were issued from treasury at a discount of two per cent to market prices over a specified period.

For the periods between January 1, 2021 and August 31, 2022 and after July 31, 2023, common shares purchased with reinvested cash dividends under TC Energy's DRP are acquired on the open market at 100 per cent of the weighted average purchase price.

Acquisition of TC PipeLines, LP

On March 3, 2021, TC Energy issued 37,955,093 common shares to acquire all the outstanding publicly-held common units of TC PipeLines, LP. Refer to Note 24, Non-controlling interests, for additional information.

Basic and Diluted Net Income (Loss) per Common Share

Net income (loss) per common share is calculated by dividing Net income (loss) attributable to common shares by the weighted average number of common shares outstanding. The weighted average number of shares for the diluted earnings per share calculation includes options exercisable under TC Energy's Stock Option Plan and, from August 31, 2022 to July 31, 2023, common shares issuable from treasury under the DRP.

Weighted Average Common Shares Outstanding (millions)	**2023**	**2022**	**2021**
Basic	**1,030**	995	973
Diluted	**1,030**	996	974

Stock Options

	Number of Options (thousands)	Weighted Average Exercise Prices	Weighted Average Remaining Contractual Life (years)
Options outstanding at January 1, 2023	**6,109**	**$63.86**	
Options granted	**1,933**	**$56.66**	
Options exercised	**(62)**	**$48.44**	
Options forfeited/expired	**(544)**	**$60.60**	
Options Outstanding at December 31, 2023	**7,436**	**$62.36**	**4.1**
Options Exercisable at December 31, 2023	**4,375**	**$64.47**	**3.0**

At December 31, 2023, an additional 2,267,871 common shares were reserved for future issuance from treasury under TC Energy's Stock Option Plan. The contractual life of options granted is seven years. Options may be exercised at a price determined at the time the option is awarded and vest equally on the anniversary date in each of the three years following the award. Forfeiture of stock options results from their expiration and, if not previously vested, upon resignation or termination of the option holder's employment.

The Company used a binomial model for determining the fair value of options granted and applied the following weighted average assumptions:

year ended December 31	2023	2022	2021
Weighted average fair value	**$7.88**	$8.24	$7.39
Expected life (years)[1]	**5.1**	5.4	5.4
Interest rate	**2.9%**	1.6%	0.5%
Volatility[2]	**24%**	22%	25%
Dividend yield	**6.3%**	5.5%	6.0%

1 Expected life is based on historical exercise activity.
2 Volatility is derived based on the average of both the historical and implied volatility of the Company's common shares.

The amount expensed for stock options, with a corresponding increase in Additional paid-in capital, was $9 million in 2023 (2022 – $10 million; 2021 – $12 million). At December 31, 2023, unrecognized compensation costs related to non-vested stock options were $12 million. The cost is expected to be fully recognized over a weighted average period of two years.

The following table summarizes additional stock option information:

year ended December 31 (millions of Canadian $, unless otherwise noted)	2023	2022	2021
Total intrinsic value of options exercised	**—**	33	28
Total fair value of options that have vested	**76**	89	110
Total options vested	**1.5 million**	1.6 million	1.9 million

As at December 31, 2023, the aggregate intrinsic values of the total options exercisable and the total options outstanding were nil.

Shareholder Rights Plan

TC Energy's Shareholder Rights Plan is designed to provide the Board of Directors (Board) with sufficient time to explore and develop alternatives for maximizing shareholder value in the event of a takeover offer for the Company and to encourage the fair treatment of shareholders in connection with any such offer. Attached to each common share is one right that, under certain circumstances, entitles certain holders to purchase an additional common share of the Company.

26. PREFERRED SHARES

at December 31, 2023	Number of Shares Outstanding	Current Yield	Annual Dividend Per Share[1,2]	Redemption Price Per Share	Redemption and Conversion Option Date	Right to Convert Into	Carrying Value December 31[3]		
							2023	2022	2021
	(thousands)						(millions of Canadian $)		
Cumulative First Preferred Shares									
Series 1	14,577	3.48%	$0.86975	$25.00	December 31, 2024	Series 2	**360**	360	360
Series 2	7,423	Floating [4]	Floating	$25.00	December 31, 2024	Series 1	**179**	179	179
Series 3	9,997	1.69%	$0.4235	$25.00	June 30, 2025	Series 4	**246**	246	246
Series 4	4,003	Floating [4]	Floating	$25.00	June 30, 2025	Series 3	**97**	97	97
Series 5	12,071	1.95% [5]	$0.48725	$25.00	January 30, 2026	Series 6	**294**	294	294
Series 6	1,929	Floating [4]	Floating	$25.00	January 30, 2026	Series 5	**48**	48	48
Series 7	24,000	3.90%	$0.97575	$25.00	April 30, 2024	Series 8	**589**	589	589
Series 9	18,000	3.76%	$0.9405	$25.00	October 30, 2024	Series 10	**442**	442	442
Series 11	10,000	3.35%	$0.83775	$25.00	November 28, 2025	Series 12	**244**	244	244
Series 15	—	—	—	—	—	—	**—**	—	988
							2,499	2,499	3,487

1 Each of the even-numbered series of preferred shares, if in existence, will be entitled to receive floating rate cumulative quarterly preferential dividends per share at an annualized rate equal to the 90-day Government of Canada Treasury bill rate (T-bill rate) plus 1.92 per cent (Series 2), 1.28 per cent (Series 4), 1.54 per cent (Series 6), 2.38 per cent (Series 8), 2.35 per cent (Series 10), or 2.96 per cent (Series 12). These rates reset quarterly with the then current T-Bill rate.

2 The odd-numbered series of preferred shares, if in existence, will be entitled to receive fixed rate cumulative quarterly preferential dividends, which will reset on the redemption and conversion option date and every fifth year thereafter, at an annualized rate equal to the then Five-Year Government of Canada bond yield plus 1.92 per cent (Series 1), 1.28 per cent (Series 3), 1.54 per cent (Series 5), 2.38 per cent (Series 7), 2.35 per cent (Series 9), or 2.96 per cent (Series 11).

3 Net of underwriting commissions and deferred income taxes.

4 The floating quarterly dividend rate for the Series 2 preferred shares is 6.96 per cent for the period starting December 29, 2023 to, but excluding, March 28, 2024. The floating quarterly dividend rate for the Series 4 preferred shares is 6.32 per cent for the period starting December 29, 2023 to, but excluding, March 28, 2024. The floating quarterly dividend rate for the Series 6 preferred shares is 6.69 per cent for the period starting October 30, 2023 to, but excluding, January 30, 2024. These rates will reset each quarter going forward.

5 The fixed rate dividend for Series 5 preferred shares decreased from 2.26 per cent to 1.95 per cent on January 30, 2021 and is due to reset on every fifth anniversary thereafter.

The holders of preferred shares are entitled to receive a fixed cumulative quarterly preferential dividend as and when declared by the Board with the exception of Series 2, Series 4 and Series 6 preferred shares. The holders of Series 2, Series 4 and Series 6 preferred shares are entitled to receive quarterly floating rate cumulative preferential dividends as and when declared by the Board. The holders will have the right, subject to certain conditions, to convert their first preferred shares of a specified series into first preferred shares of another specified series on the conversion option date and every fifth anniversary thereafter as indicated in the table above.

TC Energy may, at its option, redeem all or a portion of the outstanding preferred shares for the redemption price per share, plus all accrued and unpaid dividends on the applicable redemption option date and on every fifth anniversary thereafter. In addition, Series 2, Series 4 and Series 6 preferred shares are redeemable by TC Energy at any time other than on a designated date for $25.50 per share plus all accrued and unpaid dividends on such redemption date.

On May 31, 2022, TC Energy redeemed all 40,000,000 issued and outstanding Series 15 preferred shares at a redemption price of $25.00 per share and paid the final quarterly dividend of $0.30625 per Series 15 preferred share, for the period up to but excluding May 31, 2022. The Company used the proceeds from the March 2022 issuance of US$800 million of junior subordinated notes through the Trust to finance this preferred share redemption.

In May 2021, TC Energy redeemed all 20,000,000 issued and outstanding Series 13 preferred shares at a redemption price of $25.00 per share and paid the final quarterly dividend of $0.34375 per Series 13 preferred share for the period up to but excluding May 31, 2021. The Company used the proceeds from the March 2021 issuance of $500 million of junior subordinated notes through the Trust to finance this preferred share redemption.

In February 2021, 818,876 Series 5 preferred shares were converted, on a one-for-one basis, into Series 6 preferred shares and 175,208 Series 6 preferred shares were converted, on a one-for-one basis, into Series 5 preferred shares.

27. OTHER COMPREHENSIVE INCOME (LOSS) AND ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

Components of other comprehensive income (loss), including the portion attributable to non-controlling interests and related tax effects, were as follows:

year ended December 31, 2023 (millions of Canadian $)	**Before Tax Amount**	**Income Tax (Expense) Recovery**	**Net of Tax Amount**
Foreign currency translation gains and losses on net investment in foreign operations	**(1,148)**	**7**	**(1,141)**
Change in fair value of net investment hedges	**23**	**(6)**	**17**
Reclassification to net income of (gains) losses on cash flow hedges	**97**	**(23)**	**74**
Unrealized actuarial gains (losses) on pension and other post-retirement benefit plans	**(15)**	**4**	**(11)**
Other comprehensive income (loss) on equity investments	**(283)**	**72**	**(211)**
Other Comprehensive Income (Loss)	**(1,326)**	**54**	**(1,272)**

year ended December 31, 2022 (millions of Canadian $)	**Before Tax Amount**	**Income Tax (Expense) Recovery**	**Net of Tax Amount**
Foreign currency translation gains and losses on net investment in foreign operations	1,410	84	1,494
Change in fair value of net investment hedges	(48)	12	(36)
Change in fair value of cash flow hedges	(58)	19	(39)
Reclassification to net income of (gains) losses on cash flow hedges	63	(21)	42
Unrealized actuarial gains (losses) on pension and other post-retirement benefit plans	81	(18)	63
Reclassification to net income of actuarial (gains) losses on pension and other post-retirement benefit plans	9	(3)	6
Other comprehensive income (loss) on equity investments	1,156	(289)	867
Other Comprehensive Income (Loss)	2,613	(216)	2,397

year ended December 31, 2021 (millions of Canadian $)	**Before Tax Amount**	**Income Tax (Expense) Recovery**	**Net of Tax Amount**
Foreign currency translation gains and losses on net investment in foreign operations	(100)	(8)	(108)
Change in fair value of net investment hedges	(3)	1	(2)
Change in fair value of cash flow hedges	(13)	3	(10)
Reclassification to net income of (gains) losses on cash flow hedges	68	(13)	55
Unrealized actuarial gains (losses) on pension and other post-retirement benefit plans	208	(50)	158
Reclassification to net income of actuarial (gains) losses on pension and other post-retirement benefit plans	20	(6)	14
Other comprehensive income (loss) on equity investments	714	(179)	535
Other Comprehensive Income (Loss)	894	(252)	642

The changes in AOCI by component, net of tax, are as follows:

(millions of Canadian $)	Currency Translation Adjustments	Cash Flow Hedges	Pension and Other Post-Retirement Benefit Plan Adjustments	Equity Investments	Total
AOCI balance at January 1, 2021	(1,273)	(143)	(285)	(738)	(2,439)
Other comprehensive income (loss) before reclassifications[1]	(98)	(11)	158	506	555
Amounts reclassified from AOCI	—	55	14	28	97
Net current period other comprehensive income (loss)	(98)	44	172	534	652
Acquisition of TC PipeLines, LP[2]	362	(13)	—	4	353
AOCI balance at December 31, 2021	(1,009)	(112)	(113)	(200)	(1,434)
Other comprehensive income (loss) before reclassifications[1]	1,450	(39)	63	870	2,344
Amounts reclassified from AOCI	—	42	6	(3)	45
Net current period other comprehensive income (loss)	1,450	3	69	867	2,389
AOCI balance at December 31, 2022	441	(109)	(44)	667	955
Other comprehensive income (loss) before reclassifications[1]	**(231)**	**—**	**(11)**	**(195)**	**(437)**
Amounts reclassified from AOCI[3]	**—**	**74**	**—**	**(16)**	**58**
Net current period other comprehensive income (loss)	**(231)**	**74**	**(11)**	**(211)**	**(379)**
Impact of non-controlling interest[4]	**(527)**	**—**	**—**	**—**	**(527)**
AOCI balance at December 31, 2023	**(317)**	**(35)**	**(55)**	**456**	**49**

1 Other comprehensive income(loss) before reclassifications on currency translation adjustments, cash flow hedges and equity investments are net of non-controlling interest loss of $366 million (2022 – gains of $8 million; 2021 – losses of $12 million), nil (2022 – nil; 2021 – gains of $1 million), and nil (2022 – nil; 2021 – gains of $1 million), respectively.

2 Represents the AOCI attributable to non-controlling interests of TC PipeLines, LP which was reclassified to AOCI on the Consolidated balance sheet upon completion of the acquisition of all the outstanding publicly-held common units of TC PipeLines, LP on March 3, 2021. Refer to Note 24, Non-controlling interests, for additional information.

3 Losses related to cash flow hedges reported in AOCI and expected to be reclassified to net income in the next 12 months are estimated to be $4 million ($3 million, net of tax) at December 31, 2023. These estimates assume constant commodity prices, interest rates and foreign exchange rates over time; however, the amounts reclassified will vary based on the actual value of these factors at the date of settlement.

4 Represents the AOCI attributable to the 40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf upon its sale on October 4, 2023. Refer to Note 24, Non-controlling interests, for additional information.

Details about reclassifications out of AOCI into the Consolidated statement of income were as follows:

year ended December 31	Amounts Reclassified From AOCI			
(millions of Canadian $)	**2023**	**2022**	**2021**	**Affected Line Item in the Consolidated Statement of Income**[1]
Cash flow hedges				
Commodities	**(85)**	(47)	(22)	Revenues (Power and Energy Solutions)
Interest rate	**(12)**	(16)	(46)	Interest expense
	(97)	(63)	(68)	Total before tax
	23	21	13	Income tax (expense) recovery
	(74)	(42)	(55)	Net of tax
Pension and other post-retirement benefit plan adjustments				
Amortization of actuarial gains (losses)	**—**	(11)	(22)	Plant operating costs and other[2]
Settlement gain (loss)	**—**	2	2	Plant operating costs and other[2]
	—	(9)	(20)	Total before tax
	—	3	6	Income tax (expense) recovery
	—	(6)	(14)	Net of tax
Equity investments				
Equity income (loss)	**22**	4	(37)	Income (loss) from equity investments
	(6)	(1)	9	Income tax (expense) recovery
	16	3	(28)	Net of tax

1 Amounts in parentheses indicate expenses to the Consolidated statement of income.

2 These AOCI components are included in the computation of net benefit cost. Refer to Note 28, Employee post-retirement benefits, for additional information.

28. EMPLOYEE POST-RETIREMENT BENEFITS

The Company sponsors DB Plans for certain employees. Pension benefits provided under the DB Plans are generally based on years of service and highest average earnings over three to five consecutive years of employment. Effective January 1, 2019, there were certain amendments made to the Canadian DB Plan for new members. Subsequent to that date, and up until the Canadian DB Plan was closed to new entrants on January 1, 2024, benefits provided for these new members are based on years of service and highest average earnings over five consecutive years of employment. Upon commencement of retirement, pension benefits in the Canadian DB Plan increase annually by a portion of the increase in the Consumer Price Index for employees hired prior to January 1, 2019. In 2023, TC Energy announced a plan amendment to the Canadian OPEB Plan. This plan will be closed for any eligible active employees that do not retire by December 31, 2024. All active employees who no longer meet the eligibility for the OPEB Plan will be eligible for a new plan that provides an annual health spending account to retirees and their dependents from retirement to age 65.

The Company's U.S. DB Plan is closed to non-union new entrants and all non-union hires participate in the DC Plan. Net actuarial gains or losses are amortized out of AOCI over the EARSL of Plan participants, which was approximately nine years at December 31, 2023 (2022 – nine years; 2021 – 10 years).

The Company also provides its employees with savings plans in Canada and Mexico, DC Plans consisting of a 401(k) Plan in the U.S. and post-employment benefits other than pensions, including termination benefits and life insurance and medical benefits beyond those provided by government-sponsored plans. Net actuarial gains or losses for the plans are amortized out of AOCI over the EARSL of employees, which was approximately 12 years at December 31, 2023 (2022 – 12 years and 2021 – 11 years). In 2023, the Company expensed $64 million (2022 – $64 million and 2021 – $58 million) for the savings and DC Plans.

Total cash contributions by the Company for employee post-retirement benefits were as follows:

year ended December 31 (millions of Canadian $)	**2023**	**2022**	**2021**
DB Plans	**28**	78	105
Other post-retirement benefit plans	**9**	8	8
Savings and DC Plans	**64**	64	58
	101	150	171

Current Canadian pension legislation allows for partial funding of solvency requirements over a number of years through letters of credit in lieu of cash contributions, up to certain limits. Total letters of credit provided to the Canadian DB plan at December 31, 2023 was $244 million (2022 – $322 million; 2021 – $322 million).

The most recent actuarial valuation of the pension plans for funding purposes was as at January 1, 2023 and the next required valuation is at January 1, 2024.

In 2022, a settlement occurred for the U.S. DB Plan as a result of lump sum payments made during the year. The impact of the settlement was determined using actuarial assumptions consistent with those employed at December 31, 2022. The settlement gain decreased the U.S. DB Plan's unrealized actuarial gain by $2 million which was included in OCI, and was recorded in net benefit cost in 2022.

In mid-2021, the Company offered a one-time Voluntary Retirement Program (VRP) to eligible employees. Participants in the program retired by December 31, 2021 and received a transition payment along with existing retirement benefits. In 2021, the Company expensed $81 million mainly related to VRP transition payments which were included in Plant operating costs and other. In addition, $18 million was recorded in Revenues related to costs that are recoverable through regulatory and tolling structures on a flow-through basis.

As a result of employee participation in the VRP in 2021, a settlement and curtailment occurred for the U.S. DB Plan and a curtailment occurred in the U.S. OPEB Plan. The impact of these amounts was determined using actuarial assumptions consistent with those employed at December 31, 2021. The settlement gain decreased the U.S. DB Plan's unrealized actuarial gain by $2 million which was included in OCI, while the curtailment gain decreased the U.S. DB Plan's benefit obligation by $5 million, both of which were recorded in net benefit cost in 2021. The curtailment loss decreased the OPEB Plan's unrealized actuarial gain by $3 million which was included in OCI and increased the OPEB Plan obligation by $3 million, resulting in no adjustment to net benefit cost in 2021.

The Company's funded status was comprised of the following:

at December 31 (millions of Canadian $)	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
	2023	**2022**	**2023**	**2022**
Change in Benefit Obligation[1]				
Benefit obligation – beginning of year	**3,081**	4,027	**310**	419
Service cost	**93**	145	**3**	5
Interest cost	**158**	125	**16**	13
Employee contributions	**7**	6	**2**	2
Benefits paid	**(185)**	(324)	**(44)**	(24)
Actuarial (gain) loss	**219**	(949)	**2**	(120)
Foreign exchange rate changes	**(17)**	51	**(4)**	15
Benefit obligation – end of year	**3,356**	3,081	**285**	310
Change in Plan Assets				
Plan assets at fair value – beginning of year	**3,481**	4,145	**354**	431
Actual return on plan assets	**385**	(483)	**24**	(89)
Employer contributions[2]	**28**	78	**9**	8
Employee contributions	**7**	6	**2**	2
Benefits paid	**(185)**	(324)	**(23)**	(24)
Foreign exchange rate changes	**(19)**	59	**(8)**	26
Plan assets at fair value – end of year	**3,697**	3,481	**358**	354
Funded Status – Plan Surplus	**341**	400	**73**	44

1 The benefit obligation for the Company's pension benefit plans represents the projected benefit obligation. The benefit obligation for the Company's other post-retirement benefit plans represents the accumulated post-retirement benefit obligation.
2 The Company reduced letters of credit by $78 million in the Canadian DB Plan (2022 – nil) for funding purposes.

The actuarial loss realized on the defined benefit plan obligation is primarily attributable to a decrease in the weighted average discount rate from 5.15 per cent in 2022 to 4.75 per cent in 2023.

The actuarial loss realized on the OPEB Plan obligation is primarily due to a decrease in the weighted average discount rate from 5.45 per cent in 2022 to 5.10 per cent in 2023.

The amounts recognized on the Company's Consolidated balance sheet for its DB Plans and other post-retirement benefits plans were as follows:

at December 31 (millions of Canadian $)	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
	2023	**2022**	**2023**	**2022**
Other long-term assets (Note 16)	**341**	400	**177**	163
Accounts payable and other	**—**	—	**(7)**	(8)
Other long-term liabilities (Note 19)	**—**	—	**(97)**	(111)
	341	400	**73**	44

Included in the above benefit obligation and fair value of plan assets were the following amounts for plans that were not fully funded:

at December 31	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
(millions of Canadian $)	**2023**	2022	**2023**	2022
Projected benefit obligation[1]	**—**	—	**(104)**	(119)
Plan assets at fair value	**—**	—	**—**	—
Funded Status – Plan Deficit	**—**	—	**(104)**	(119)

1 The projected benefit obligation for the pension benefit plans differs from the accumulated benefit obligation in that it includes an assumption with respect to future compensation levels.

The funded status based on the accumulated benefit obligation for all DB Plans was as follows:

at December 31		
(millions of Canadian $)	**2023**	2022
Accumulated benefit obligation	**(3,090)**	(2,880)
Plan assets at fair value	**3,697**	3,481
Funded Status – Plan Surplus	**607**	601

The Company's DB Plans with respect to accumulated benefit obligations and the fair value of plan assets were fully funded as at December 31, 2023 and December 31, 2022.

The Company pension plans' weighted average asset allocations and target allocations by asset category were as follows:

at December 31	Percentage of Plan Assets		Target Allocations
	2023	2022	**2023**
Fixed income securities	**41%**	38%	**30% to 50%**
Equity securities	**44%**	44%	**30% to 55%**
Other investments	**15%**	18%	**10% to 25%**
	100%	100%	

Fixed income and equity securities include the Company's debt and common shares as follows:

at December 31			Percentage of Plan Assets	
(millions of Canadian $)	**2023**	2022	**2023**	2022
Fixed income securities	**7**	7	**0.2%**	0.2%
Equity securities	**2**	3	**0.1%**	0.1%

Pension plan assets are managed on a going concern basis, subject to legislative restrictions, and are diversified across asset classes to maximize returns at an acceptable level of risk. Asset mix strategies consider plan demographics and may include traditional equity and debt securities as well as alternative assets such as infrastructure, private equity, real estate and derivatives to diversify risk. Derivatives are not used for speculative purposes and may be used to hedge certain liabilities.

All investments are measured at fair value using market prices. Where the fair value cannot be readily determined by reference to generally available price quotations, the fair value is determined by considering the discounted cash flows on a risk-adjusted basis and by comparison to similar assets which are publicly traded. In Level I, the fair value of assets is determined by reference to quoted prices in active markets for identical assets that the Company has the ability to access at the measurement date. In Level II, the fair value of assets is determined using valuation techniques such as option pricing models and extrapolation using significant inputs which are observable directly or indirectly. In Level III, the fair value of assets is determined using a market approach based on inputs that are unobservable and significant to the overall fair value measurement.

The following table presents plan assets for DB Plans and OPEB Plans measured at fair value, which have been categorized into the three categories based on a fair value hierarchy. Refer to Note 29, Risk management and financial instruments, for additional information.

at December 31	Quoted Prices in Active Markets (Level I)		Significant Other Observable Inputs (Level II)		Significant Unobservable Inputs (Level III)		Total		Percentage of Total Portfolio	
(millions of Canadian $)	**2023**	2022	**2023**	2022	**2023**	2022	**2023**	2022	**2023**	2022
Asset Category										
Cash and Cash Equivalents	**68**	55	**1**	1	**—**	—	**69**	56	**2**	1
Equity Securities:										
Canadian	**121**	117	**—**	—	**—**	—	**121**	117	**3**	3
U.S.	**965**	897	**—**	—	**—**	—	**965**	897	**24**	24
International	**167**	172	**187**	172	**—**	—	**354**	344	**9**	9
Global	**—**	—	**74**	75	**—**	—	**74**	75	**2**	2
Emerging	**54**	50	**140**	127	**—**	—	**194**	177	**5**	5
Fixed Income Securities:										
Canadian Bonds:										
Federal	**—**	—	**266**	221	**—**	—	**266**	221	**7**	6
Provincial	**—**	—	**314**	249	**—**	—	**314**	249	**8**	6
Municipal	**—**	—	**16**	12	**—**	—	**16**	12	**—**	—
Corporate	**—**	—	**143**	108	**—**	—	**143**	108	**4**	3
U.S. Bonds:										
Federal	**185**	177	**240**	158	**—**	—	**425**	335	**10**	9
Municipal	**—**	—	**1**	1	**—**	—	**1**	1	**—**	—
Corporate	**312**	345	**74**	94	**—**	—	**386**	439	**10**	11
International:										
Government	**4**	5	**11**	6	**—**	—	**15**	11	**—**	—
Corporate	**—**	—	**83**	58	**—**	—	**83**	58	**2**	1
Mortgage backed	**43**	36	**17**	1	**—**	—	**60**	37	**1**	1
Net forward contracts	**—**	—	**(131)**	(78)	**—**	—	**(131)**	(78)	**(4)**	(2)
Other Investments:										
Real estate	**—**	—	**—**	—	**283**	336	**283**	336	**7**	9
Infrastructure	**—**	—	**—**	—	**269**	296	**269**	296	**7**	8
Private equity funds	**—**	—	**—**	—	**10**	—	**10**	—	**—**	—
Funds held on deposit	**138**	144	**—**	—	**—**	—	**138**	144	**3**	4
	2,057	1,998	**1,436**	1,205	**562**	632	**4,055**	3,835	**100**	100

The following table presents the net change in the Level III fair value category:

(millions of Canadian $, pre-tax)	
Balance at December 31, 2021	565
Purchases and sales	52
Realized and unrealized gains (losses)	15
Balance at December 31, 2022	632
Purchases and sales	**(76)**
Realized and unrealized gains (losses)	**6**
Balance at December 31, 2023	**562**

In 2024, the Company's expects to make funding contributions of $6 million for the other post-retirement benefit plans, approximately $70 million for the savings plans and DC Plans and no contributions for the DB Plans. The Company is not expecting to issue any additional letters of credit for the funding of solvency requirements to the Canadian DB plan in 2024.

The following are estimated future benefit payments, which reflect expected future service:

at December 31 (millions of Canadian $)	**Pension Benefits**	**Other Post-Retirement Benefits**
2024	204	23
2025	207	23
2026	211	23
2027	214	22
2028	216	22
2029 to 2033	1,127	104

The rate used to discount pension and other post-retirement benefit plan obligations was developed based on a yield curve of primarily corporate AA bond yields at December 31, 2023. This yield curve is used to develop spot rates that vary based on the duration of the obligations. The estimated future cash flows for the pension and other post-retirement benefit obligations were matched to the corresponding rates on the spot rate curve to derive a weighted average discount rate.

The significant weighted average actuarial assumptions adopted in measuring the Company's benefit obligations were as follows:

at December 31	**Pension Benefit Plans**		**Other Post-Retirement Benefit Plans**	
	2023	**2022**	**2023**	**2022**
Discount rate	**4.75%**	5.15%	**5.10%**	5.45%
Rate of compensation increase	**3.20%**	3.30%	**—**	—

The significant weighted average actuarial assumptions adopted in measuring the Company's net benefit plan costs were as follows:

year ended December 31	**Pension Benefit Plans**			**Other Post-Retirement Benefit Plans**		
	2023	**2022**	**2021**	**2023**	**2022**	**2021**
Discount rate	**5.15%**	3.05%	2.70%	**5.45%**	3.10%	2.80%
Expected long-term rate of return on plan assets	**6.45%**	6.10%	6.15%	**4.50%**	3.25%	3.00%
Rate of compensation increase	**3.25%**	3.00%	2.60%	**—**	—	—

The overall expected long-term rate of return on plan assets is based on historical and projected rates of return for the portfolio in aggregate and for each asset class in the portfolio. Assumed projected rates of return are selected after analyzing historical experience and estimating future levels and volatility of returns. Asset class benchmark returns and asset mix are also considered in determining the overall expected rate of return. The discount rate is based on market interest rates of high-quality bonds that match the timing and benefits expected to be paid under each plan.

A 5.95 per cent weighted-average annual rate of increase in the per capita cost of covered health care benefits was assumed for 2024 measurement purposes. The rate was assumed to decrease gradually to 4.80 per cent by 2030 and remain at this level thereafter.

The net benefit cost recognized for the Company's pension benefit plans and other post-retirement benefit plans was as follows:

year ended December 31	**Pension Benefit Plans**			**Other Post-Retirement Benefit Plans**		
(millions of Canadian $)	**2023**	**2022**	**2021**	**2023**	**2022**	**2021**
Service cost[1]	**93**	145	171	**3**	5	6
Other components of net benefit cost[1]						
Interest cost	**158**	125	119	**16**	13	12
Expected return on plan assets	**(234)**	(239)	(234)	**(16)**	(14)	(13)
Amortization of actuarial loss	**—**	10	23	**—**	1	2
Amortization of regulatory asset	**—**	12	27	**—**	1	2
Curtailment gain	**—**	—	(5)	**—**	—	—
Settlement gain – AOCI	**—**	(2)	(2)	**—**	—	—
	(76)	(94)	(72)	**—**	1	3
Net Benefit Cost Recognized	**17**	51	99	**3**	6	9

1 Service cost and other components of net benefit cost are included in Plant operating costs and other in the Consolidated statement of income.

Pre-tax amounts recognized in AOCI were as follows:

at December 31	**2023**		**2022**		**2021**	
(millions of Canadian $)	**Pension Benefits**	**Other Post-Retirement Benefits**	**Pension Benefits**	**Other Post-Retirement Benefits**	**Pension Benefits**	**Other Post-Retirement Benefits**
Net loss	**71**	**6**	38	24	147	5

Pre-tax amounts recognized in OCI were as follows:

year ended December 31	**2023**		**2022**		**2021**	
(millions of Canadian $)	**Pension Benefits**	**Other Post-Retirement Benefits**	**Pension Benefits**	**Other Post-Retirement Benefits**	**Pension Benefits**	**Other Post-Retirement Benefits**
Amortization of net gain (loss) from AOCI to net income	**—**	**—**	(10)	(1)	(23)	(2)
Curtailment	**—**	**—**	—	—	—	3
Settlement	**—**	**—**	2	—	2	—
Funded status adjustment	**33**	**(18)**	(101)	20	(190)	(18)
	33	**(18)**	(109)	19	(211)	(17)

29. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

Risk Management Overview

TC Energy has exposure to various financial risks and has strategies, policies and limits in place to manage the impact of these risks on its earnings, cash flows and, ultimately, shareholder value.

Risk management strategies, policies and limits are designed to ensure TC Energy's risks and related exposures are in line with the Company's business objectives and risk tolerance. TC Energy's risks are managed within limits that are established by the Company's Board, implemented by senior management and monitored by the Company's risk management, internal audit and business segment groups. The Board's Audit Committee oversees how management monitors compliance with risk management policies and procedures and oversees management's review of the adequacy of the risk management framework.

Market Risk

The Company constructs and invests in energy infrastructure projects, purchases and sells commodities, issues short- and long-term debt, including amounts in foreign currencies and invests in foreign operations. Certain of these activities expose the Company to market risk from changes in commodity prices, foreign exchange rates and interest rates, which may affect the Company's earnings, cash flows and the value of its financial assets and liabilities. The Company assesses contracts used to manage market risk to determine whether all, or a portion, meets the definition of a derivative.

Derivative contracts the Company uses to assist in managing exposure to market risk may include the following:
- forwards and futures contracts – agreements to purchase or sell a specific financial instrument or commodity at a specified price and date in the future
- swaps – agreements between two parties to exchange streams of payments over time according to specified terms
- options – agreements that convey the right, but not the obligation of the purchaser to buy or sell a specific amount of a financial instrument or commodity at a fixed price, either at a fixed date or at any time within a specified period.

Commodity price risk

The following strategies may be used to manage the Company's exposure to market risk resulting from commodity price risk management activities in the Company's non-regulated businesses:
- in the Company's natural gas marketing business, TC Energy enters into natural gas transportation and storage contracts as well as natural gas purchase and sale agreements. The Company manages exposure on these contracts using financial instruments and hedging activities to offset market price volatility
- in the Company's liquids marketing business, TC Energy enters into pipeline and storage terminal capacity contracts as well as crude oil purchase and sale agreements. The Company fixes a portion of the exposure on these contracts by entering into financial instruments to manage variable price fluctuations that arise from physical liquids transactions
- in the Company's power businesses, TC Energy manages the exposure to fluctuating commodity prices through long-term contracts and hedging activities including selling and purchasing electricity and natural gas in forward markets
- in the Company's non-regulated natural gas storage business, TC Energy's exposure to seasonal natural gas price spreads is managed with a portfolio of third-party storage capacity contracts and through offsetting purchases and sales of natural gas in forward markets to lock in future positive margins.

Lower natural gas, crude oil and electricity prices could lead to reduced investment in the development, expansion and production of these commodities. A reduction in the demand for these commodities could negatively impact opportunities to expand the Company's asset base and/or re-contract with TC Energy's shippers and customers as contractual agreements expire.

The physical and transition risks related to climate change could impact commodity prices and fossil fuel supply and demand dynamics which could affect the Company's financial performance. TC Energy evaluates the financial resilience of the Company’s asset portfolio against a range of future pricing and supply and demand outcomes as part of the Company’s strategic planning process. TC Energy’s exposure to climate change-related transition risks and resulting policy changes is managed through the Company’s business model, which is based on a long-term, low-risk strategy whereby the majority of TC Energy’s earnings are underpinned by regulated cost-of-service arrangements and/or long-term contracts. The Company factors physical and transition risks into capital planning, financial risk management and operational activities and is working towards reducing the GHG emissions intensity of existing operations.

Interest rate risk

TC Energy utilizes short- and long-term debt to finance its operations which exposes the Company to interest rate risk. TC Energy typically pays fixed rates of interest on its long-term debt and floating rates on short-term debt including its commercial paper programs and amounts drawn on its credit facilities. A small portion of TC Energy's long-term debt bears interest at floating rates. In addition, the Company is exposed to interest rate risk on financial instruments and contractual obligations containing variable interest rate components. The Company actively manages its interest rate risk using interest rate derivatives.

Foreign exchange risk

Certain of TC Energy's businesses generate all or most of their earnings in U.S. dollars and, since the Company reports its financial results in Canadian dollars, changes in the value of the U.S. dollar against the Canadian dollar can affect its net income. As the Company's U.S. dollar-denominated operations continue to grow, this exposure increases. A portion of this risk is offset by interest expense on U.S. dollar-denominated debt. The balance of the exposure is actively managed on a rolling basis up to three years in advance using foreign exchange derivatives; however, the natural exposure beyond that period remains.

A portion of the Company's Mexico Natural Gas Pipelines monetary assets and liabilities are peso-denominated, while TC Energy's Mexico operations' financial results are denominated in U.S. dollars. These peso-denominated balances are revalued to U.S. dollars and, as a result, changes in the value of the Mexican peso against the U.S. dollar can affect the Company's net income. In addition, foreign exchange gains or losses calculated for Mexico income tax purposes on the revaluation of U.S. dollar-denominated monetary assets and liabilities result in a peso-denominated income tax exposure for these entities, leading to fluctuations in Income from equity investments and Income tax expense. These exposures are actively managed using foreign exchange derivatives, although some unhedged exposure remains.

Net investment in foreign operations

The Company hedges a portion of its net investment in foreign operations (on an after-tax basis) with U.S. dollar-denominated debt, cross-currency interest rate swaps and foreign exchange options as appropriate.

The fair values and notional amounts for the derivatives designated as a net investment hedge were as follows:

at December 31	2023		2022	
(millions of Canadian $, unless otherwise noted)	Fair Value[1,2]	Notional Amount	Fair Value[1,2]	Notional Amount
U.S. dollar foreign exchange options (maturing 2024)	**8**	**US 1,000**	(22)	US 3,600
U.S. dollar cross-currency interest rate swaps (maturing 2024 to 2025)[3]	**2**	**US 200**	(5)	US 300
	10	**US 1,200**	(27)	US 3,900

1 Fair value equals carrying value.
2 No amounts have been excluded from the assessment of hedge effectiveness.
3 In 2023, Net income (loss) includes net realized gains of less than $1 million (2022 – gains of $1 million) related to the interest component of cross-currency swap settlements which are reported within Interest expense.

The notional amounts and fair value of U.S. dollar-denominated debt designated as a net investment hedge were as follows:

at December 31 (millions of Canadian $, unless otherwise noted)	2023	2022
Notional amount	**27,800 (US 21,100)**	32,500 (US 24,000)
Fair value	**26,600 (US 20,200)**	30,800 (US 22,700)

Counterparty Credit Risk

TC Energy's exposure to counterparty credit risk includes its cash and cash equivalents, accounts receivable and certain contractual recoveries, available-for-sale assets, the fair value of derivative assets, net investment in leases and certain contract assets in Mexico.

At times, the Company's counterparties may endure financial challenges resulting from commodity price and market volatility, economic instability and political or regulatory changes. In addition to actively monitoring these situations, there are a number of factors that reduce TC Energy's counterparty credit risk exposure in the event of default, including:

- contractual rights and remedies together with the utilization of contractually-based financial assurances
- current regulatory frameworks governing certain TC Energy operations
- the competitive position of the Company's assets and the demand for the Company's services
- potential recovery of unpaid amounts through bankruptcy and similar proceedings.

The Company reviews financial assets carried at amortized cost for impairment using the lifetime expected loss of the financial asset at initial recognition and throughout the life of the financial asset. TC Energy uses historical credit loss and recovery data, adjusted for management's judgment regarding current economic and credit conditions, along with reasonable and supportable forecasts to determine any impairment, which is recognized in Plant operating costs and other.

The Company’s net investment in leases and certain contract assets are financial assets subject to ECL. TC Energy’s methodology for assessing the ECL regarding these financial assets includes consideration of the probability of default (the probability that the customer will default on its obligation), the loss given default (the economic loss as a proportion of the financial asset balance in the event of a default) and the exposure at default (the financial asset balance at the time of a hypothetical default) with one-year forward-looking information that includes assumptions for future macroeconomic conditions under three probability-weighted future scenarios.

The macroeconomic factors considered most relevant to the Company's net investment in leases and contract assets include Mexico's GDP, Mexico's government debt to GDP and Mexico's inflation. The ECL amount is updated at each reporting date to reflect changes in assumptions and forecasts for future economic conditions.

For the year ended December 31, 2023, the Company recorded a $73 million ECL recovery (2022 – an expense of $149 million; 2021 – nil) with respect to the net investment in leases associated with the in-service TGNH pipelines and a $10 million ECL recovery (2022 – $14 million expense; 2021 – nil) for contract assets related to certain other Mexico natural gas pipelines.

Other than the ECL provision noted above, the Company had no significant credit losses at December 31, 2023 and 2022. At December 31, 2023 and 2022, there were no significant credit risk concentrations and no significant amounts past due or impaired.

TC Energy has significant credit and performance exposure to financial institutions that hold cash deposits and provide committed credit lines and letters of credit that help manage the Company's exposure to counterparties and provide liquidity in commodity, foreign exchange and interest rate derivative markets. TC Energy's portfolio of financial sector exposure consists primarily of highly-rated investment grade, systemically important financial institutions.

Non-Derivative Financial Instruments

Fair value of non-derivative financial instruments

Available-for-sale assets are recorded at fair value which is calculated using quoted market prices where available. Certain non-derivative financial instruments included in Cash and cash equivalents, Accounts receivable, Other current assets, Restricted investments, Net investment in leases, Other long-term assets, Notes payable, Accounts payable and other, Dividends payable, Accrued interest and Other long-term liabilities have carrying amounts that approximate their fair value due to the nature of the item or the short time to maturity. Each of these instruments are classified in Level II of the fair value hierarchy, except for the Company's LMCI equity securities which are classified in Level I of the fair value hierarchy.

Credit risk has been taken into consideration when calculating the fair value of non-derivative financial instruments.

Balance sheet presentation of non-derivative financial instruments

The following table details the fair value of non-derivative financial instruments, excluding those where carrying amounts approximate fair value, and would be classified in Level II of the fair value hierarchy:

at December 31	2023		2022	
(millions of Canadian $)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion (Note 21)[1,2]	**(52,914)**	**(52,815)**	(41,543)	(39,505)
Junior subordinated notes (Note 22)	**(10,287)**	**(9,217)**	(10,495)	(9,415)
	(63,201)	**(62,032)**	(52,038)	(48,920)

1 Long-term debt is recorded at amortized cost, except for US$2.0 billion (2022 – US$1.6 billion) that is attributed to hedged risk and recorded at fair value.

2 Net income (loss) for 2023 included unrealized losses of $53 million (2022 – unrealized gains of $64 million) for fair value adjustments attributable to the hedged interest rate risk associated with interest rate swap fair value hedging relationships on US$2.0 billion of long-term debt at December 31, 2023 (2022 – US$1.6 billion). There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

Available-for-sale assets summary

The following tables summarize additional information about the Company's restricted investments that were classified as available-for-sale assets:

at December 31	2023		2022	
(millions of Canadian $)	LMCI Restricted Investments	Other Restricted Investments[1]	LMCI Restricted Investments	Other Restricted Investments[1]
Fair value of fixed income securities[2,3]				
Maturing within 1 year	**1**	**35**	—	54
Maturing within 1-5 years	**8**	**291**	—	106
Maturing within 5-10 years	**1,340**	**—**	1,153	—
Maturing after 10 years	**102**	**—**	77	—
Fair value of equity securities[2,4]	**883**	**—**	749	—
	2,334	**326**	1,979	160

1 Other restricted investments have been set aside to fund insurance claim losses to be paid by the Company's wholly-owned captive insurance subsidiary.

2 Available-for-sale assets are recorded at fair value and included in Other current assets and Restricted investments on the Company's Consolidated balance sheet.

3 Classified in Level II of the fair value hierarchy.

4 Classified in Level I of the fair value hierarchy.

year ended December 31	2023		2022		2021	
(millions of Canadian $)	LMCI Restricted Investments[1]	Other Restricted Investments[2]	LMCI Restricted Investments[1]	Other Restricted Investments[2]	LMCI Restricted Investments[1]	Other Restricted Investments[2]
Net unrealized gains (losses)	**190**	**13**	(244)	(7)	45	(2)
Net realized gains (losses)[3]	**(34)**	**—**	(32)	—	3	—

1 Unrealized and realized gains (losses) arising from changes in the fair value of LMCI restricted investments impact the subsequent amounts to be collected through tolls to cover future pipeline abandonment costs. As a result, the Company records these gains and losses as regulatory liabilities or regulatory assets.

2 Unrealized and realized gains (losses) on other restricted investments are included in Interest income and other in the Company's Consolidated statement of income.

3 Realized gains (losses) on the sale of LMCI restricted investments are determined using the average cost basis.

Derivative Instruments

Fair value of derivative instruments

The fair value of foreign exchange and interest rate derivatives has been calculated using the income approach which uses year-end market rates and applies a discounted cash flow valuation model. The fair value of commodity derivatives has been calculated using quoted market prices where available. In the absence of quoted market prices, third-party broker quotes or other valuation techniques have been used. The fair value of options has been calculated using the Black-Scholes pricing model. Credit risk has been taken into consideration when calculating the fair value of derivative instruments. Unrealized gains and losses on derivative instruments are not necessarily representative of the amounts that will be realized on settlement.

In some cases, even though the derivatives are considered to be effective economic hedges, they do not meet the specific criteria for hedge accounting treatment or are not designated as a hedge and are accounted for at fair value with changes in fair value recorded in net income in the period of change. This may expose the Company to increased variability in reported earnings because the fair value of the derivative instruments can fluctuate significantly from period to period.

The recognition of gains and losses on derivatives for Canadian natural gas regulated pipeline exposures is determined through the regulatory process. Gains and losses arising from changes in the fair value of derivatives accounted for as part of RRA, including those that qualify for hedge accounting treatment, are expected to be refunded or recovered through the tolls charged by the Company. As a result, these gains and losses are deferred as regulatory assets or regulatory liabilities and are refunded to or collected from the rate payers in subsequent years when the derivative settles.

Balance sheet presentation of derivative instruments

The balance sheet classification of the fair value of derivative instruments was as follows:

at December 31, 2023 (millions of Canadian $)	Cash Flow Hedges	Fair Value Hedges	Net Investment Hedges	Held for Trading	Total Fair Value of Derivative Instruments[1]
Other current assets (Note 9)					
Commodities[2]	9	—	—	1,195	1,204
Foreign exchange	—	—	10	71	81
	9	—	10	1,266	1,285
Other long-term assets (Note 16)					
Commodities[2]	3	—	—	86	89
Foreign exchange	—	—	—	30	30
Interest rate	—	36	—	—	36
	3	36	—	116	155
Total Derivative Assets	12	36	10	1,382	1,440
Accounts payable and other (Note 18)					
Commodities[2]	(1)	—	—	(1,110)	(1,111)
Foreign exchange	—	—	—	(14)	(14)
Interest rate	—	(18)	—	—	(18)
	(1)	(18)	—	(1,124)	(1,143)
Other long-term liabilities (Note 19)					
Commodities[2]	—	—	—	(75)	(75)
Foreign exchange	—	—	—	(2)	(2)
Interest rate	—	(29)	—	—	(29)
	—	(29)	—	(77)	(106)
Total Derivative Liabilities	(1)	(47)	—	(1,201)	(1,249)
Total Derivatives	11	(11)	10	181	191

1 Fair value equals carrying value.
2 Includes purchases and sales of power, natural gas and liquids.

The balance sheet classification of the fair value of derivative instruments was as follows:

at December 31, 2022 (millions of Canadian $)	Cash Flow Hedges	Fair Value Hedges	Net Investment Hedges	Held for Trading	Total Fair Value of Derivative Instruments[1]
Other current assets (Note 9)					
Commodities[2]	—	—	—	597	597
Foreign exchange	—	—	6	11	17
	—	—	6	608	614
Other long-term assets (Note 16)					
Commodities[2]	—	—	—	62	62
Foreign exchange	—	—	2	15	17
Interest rate	—	12	—	—	12
	—	12	2	77	91
Total Derivative Assets	—	12	8	685	705
Accounts payable and other (Note 18)					
Commodities[2]	(72)	—	—	(584)	(656)
Foreign exchange	—	—	(31)	(158)	(189)
Interest rate	—	(26)	—	—	(26)
	(72)	(26)	(31)	(742)	(871)
Other long-term liabilities (Note 19)					
Commodities[2]	(2)	—	—	(75)	(77)
Foreign exchange	—	—	(4)	(20)	(24)
Interest rate	—	(50)	—	—	(50)
	(2)	(50)	(4)	(95)	(151)
Total Derivative Liabilities	(74)	(76)	(35)	(837)	(1,022)
Total Derivatives	(74)	(64)	(27)	(152)	(317)

1 Fair value equals carrying value.
2 Includes purchases and sales of power, natural gas and liquids.

The majority of derivative instruments held for trading have been entered into for risk management purposes and all are subject to the Company's risk management strategies, policies and limits. These include derivatives that have not been designated as hedges or do not qualify for hedge accounting treatment but have been entered into as economic hedges to manage the Company's exposures to market risk.

Derivatives in fair value hedging relationships

The following table details amounts recorded on the Consolidated balance sheet in relation to cumulative adjustments for fair value hedges included in the carrying amount of the hedged liabilities:

at December 31	Carrying Amount		Fair Value Hedging Adjustments[1]	
(millions of Canadian $)	2023	2022	2023	2022
Long-term debt	**(2,630)**	(2,101)	**11**	64

1 At December 31, 2023 and 2022, adjustments for discontinued hedging relationships included in these balances were nil.

Notional and maturity summary

The maturity and notional amount or quantity outstanding related to the Company's derivative instruments excluding hedges of the net investment in foreign operations was as follows:

at December 31, 2023	Power	Natural Gas	Liquids	Foreign Exchange	Interest Rate
Net sales (purchases)[1,2]	**9,209**	**50**	**(7)**	**—**	**—**
Millions of U.S. dollars	**—**	**—**	**—**	**4,978**	**2,000**
Millions of Mexican pesos	**—**	**—**	**—**	**20,000**	**—**
Maturity dates	**2024-2044**	**2024-2029**	**2024**	**2024-2026**	**2030-2034**

1 Volumes for power, natural gas and liquids derivatives are in GWh, Bcf and MMBbls, respectively.
2 In 2023, the Company entered into contracts to sell 50 MW of power commencing in 2025 with terms ranging from 15 to 20 years and provided from specified renewable sources in the Province of Alberta.

at December 31, 2022	Power	Natural Gas	Liquids	Foreign Exchange	Interest Rate
Net sales (purchases)[1]	673	(96)	11	—	—
Millions of U.S. dollars	—	—	—	5,997	1,600
Millions of Mexican pesos	—	—	—	9,747	—
Maturity dates	2023-2026	2023-2027	2023-2024	2023-2026	2030-2032

1 Volumes for power, natural gas and liquids derivatives are in GWh, Bcf and MMBbls, respectively.

Unrealized and Realized Gains (Losses) on Derivative Instruments

The following summary does not include hedges of the net investment in foreign operations:

year ended December 31 (millions of Canadian $)	2023	2022	2021
Derivative Instruments Held for Trading[1]			
Unrealized gains (losses) in the year			
Commodities	**96**	14	9
Foreign exchange (Note 23)	**246**	(149)	(203)
Realized gains (losses) in the year			
Commodities	**811**	759	287
Foreign exchange (Note 23)	**155**	(2)	240
Derivative Instruments in Hedging Relationships[2]			
Realized gains (losses) in the year			
Commodities	**(2)**	(73)	(44)
Interest rate	**(43)**	(3)	(32)

1 Realized and unrealized gains (losses) on held-for-trading derivative instruments used to purchase and sell commodities are included on a net basis in Revenues. Realized and unrealized gains (losses) on foreign exchange held-for-trading derivative instruments are included on a net basis in Foreign exchange (gains) losses, net.
2 In 2023, there were no gains or losses included in Net Income (loss) relating to discontinued cash flow hedges where it was probable that the anticipated transaction would not occur (2022 – nil; 2021 – realized loss of $10 million).

Derivatives in cash flow hedging relationships

The components of OCI (Note 27) related to the change in fair value of derivatives in cash flow hedging relationships before tax and including the portion attributable to non-controlling interests were as follows:

year ended December 31 (millions of Canadian $, pre-tax)	2023	2022	2021
Gains (losses) in fair value of derivative instruments recognized in OCI[1]			
Commodities	**—**	(94)	(35)
Interest rate	**—**	36	22
	—	(58)	(13)

1 No amounts have been excluded from the assessment of hedge effectiveness.

Effect of fair value and cash flow hedging relationships

The following table details amounts presented in the Consolidated statement of income in which the effects of fair value or cash flow hedging relationships were recorded:

year ended December 31 (millions of Canadian $)	2023	2022	2021
Fair Value Hedges			
Interest rate contracts[1]			
Hedged items	**(98)**	(30)	—
Derivatives designated as hedging instruments	**(43)**	(1)	—
Cash Flow Hedges			
Reclassification of gains (losses) on derivative instruments from AOCI to Net income (loss)[2,3]			
Commodity contracts[4]	**(85)**	(47)	(22)
Interest rate contracts[1]	**(12)**	(16)	(46)

1 Presented within Interest expense in the Consolidated statement of income.
2 Refer to Note 27, Other comprehensive income (loss) and accumulated other comprehensive income (loss), for the components of OCI related to derivatives in cash flow hedging relationships including the portion attributable to non-controlling interests.
3 There are no amounts recognized in earnings that were excluded from effectiveness testing.
4 Presented within Revenues (Power and Energy Solutions) in the Consolidated statement of income.

Offsetting of derivative instruments

The Company enters into derivative contracts with the right to offset in the normal course of business as well as in the event of default. TC Energy has no master netting agreements; however, similar contracts are entered into containing rights to offset.

The Company has elected to present the fair value of derivative instruments with the right to offset on a gross basis on the Consolidated balance sheet.

The following tables show the impact on the presentation of the fair value of derivative instrument assets and liabilities had the Company elected to present these contracts on a net basis:

at December 31, 2023 (millions of Canadian $)	Gross Derivative Instruments	Amounts Available for Offset[1]	Net Amounts
Derivative Instrument Assets			
Commodities	**1,293**	**(1,099)**	**194**
Foreign exchange	**111**	**(16)**	**95**
Interest rate	**36**	**(5)**	**31**
	1,440	**(1,120)**	**320**
Derivative Instrument Liabilities			
Commodities	**(1,186)**	**1,099**	**(87)**
Foreign exchange	**(16)**	**16**	**—**
Interest rate	**(47)**	**5**	**(42)**
	(1,249)	**1,120**	**(129)**

1 Amounts available for offset do not include cash collateral pledged or received.

at December 31, 2022 (millions of Canadian $)	Gross Derivative Instruments	Amounts Available for Offset[1]	Net Amounts
Derivative Instrument Assets			
Commodities	659	(591)	68
Foreign exchange	34	(33)	1
Interest rate	12	(4)	8
	705	(628)	77
Derivative Instrument Liabilities			
Commodities	(733)	591	(142)
Foreign exchange	(213)	33	(180)
Interest rate	(76)	4	(72)
	(1,022)	628	(394)

1 Amounts available for offset do not include cash collateral pledged or received.

With respect to the derivative instruments presented above, the Company provided cash collateral of $149 million and letters of credit of $83 million at December 31, 2023 (2022 – $138 million and $68 million, respectively) to its counterparties. At December 31, 2023, the Company held less than $1 million in cash collateral and $15 million in letters of credit (2022 – less than $1 million and $10 million, respectively) from counterparties on asset exposures.

Credit-risk-related contingent features of derivative instruments

Derivative contracts entered into to manage market risk often contain financial assurance provisions that allow parties to the contracts to manage credit risk. These provisions may require collateral to be provided if a credit-risk-related contingent event occurs, such as a downgrade in the Company's credit rating to non-investment grade. The Company may also need to provide collateral if the fair value of its derivative financial instruments exceeds pre-defined exposure limits.

Based on contracts in place and market prices at December 31, 2023, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $3 million (2022 – $19 million), for which the Company has provided no collateral in the normal course of business. If the credit-risk-related contingent features in these agreements were triggered on December 31, 2023, the Company would have been required to provide collateral equal to the fair value of the related derivative instruments discussed above. Collateral may also need to be provided should the fair value of derivative instruments exceed pre-defined contractual exposure limit thresholds. The Company has sufficient liquidity in the form of cash and undrawn committed revolving credit facilities to meet these contingent obligations should they arise.

Fair Value Hierarchy

The Company's financial assets and liabilities recorded at fair value have been categorized into three categories based on a fair value hierarchy.

Levels	How Fair Value Has Been Determined
Level I	Quoted prices in active markets for identical assets and liabilities that the Company has the ability to access at the measurement date. An active market is a market in which frequency and volume of transactions provides pricing information on an ongoing basis.
Level II	This category includes interest rate and foreign exchange derivative assets and liabilities where fair value is determined using the income approach and commodity derivatives where fair value is determined using the market approach. Inputs include published exchange rates, interest rates, interest rate swap curves, yield curves and broker quotes from external data service providers.
Level III	This category includes long-dated commodity transactions in certain markets where liquidity is low. The Company uses the most observable inputs available or alternatively long-term broker quotes or negotiated commodity prices that have been contracted for under similar terms in determining an appropriate estimate of these transactions. Where appropriate, these long-dated prices are discounted to reflect the expected pricing from the applicable markets. There is uncertainty caused by using unobservable market data which may not accurately reflect possible future changes in fair value.

The fair value of the Company's derivative assets and liabilities measured on a recurring basis, including both current and non-current portions, were categorized as follows:

at December 31, 2023 (millions of Canadian $)	Quoted Prices in Active Markets (Level I)	Significant Other Observable Inputs (Level II)[1]	Significant Unobservable Inputs (Level III)[1]	Total
Derivative Instrument Assets				
Commodities	**1,054**	**229**	**10**	**1,293**
Foreign exchange	**—**	**111**	**—**	**111**
Interest rate	**—**	**36**	**—**	**36**
Derivative Instrument Liabilities				
Commodities	**(1,002)**	**(163)**	**(21)**	**(1,186)**
Foreign exchange	**—**	**(16)**	**—**	**(16)**
Interest rate	**—**	**(47)**	**—**	**(47)**
	52	**150**	**(11)**	**191**

1 There were no transfers from Level II to Level III for the year ended December 31, 2023.

In 2023, the Company entered into contracts to sell 50 MW of power commencing in 2025 with terms ranging from 15 to 20 years and provided from specified renewable sources in the Province of Alberta. The fair value of these contracts is classified in Level III of the fair value hierarchy and is based on the assumption that the contract volumes will be sourced approximately 80 per cent from wind generation, 10 per cent from solar generation and 10 per cent from the market.

at December 31, 2022 (millions of Canadian $)	Quoted Prices in Active Markets (Level I)	Significant Other Observable Inputs (Level II)[1]	Significant Unobservable Inputs (Level III)[1]	Total
Derivative Instrument Assets				
Commodities	515	142	2	659
Foreign exchange	—	34	—	34
Interest rate	—	12	—	12
Derivative Instrument Liabilities				
Commodities	(478)	(242)	(13)	(733)
Foreign exchange	—	(213)	—	(213)
Interest rate	—	(76)	—	(76)
	37	(343)	(11)	(317)

1 There were no transfers from Level II to Level III for the year ended December 31, 2022.

The following table presents the net change in fair value of derivative assets and liabilities classified in Level III of the fair value hierarchy:

(millions of Canadian $, pre-tax)	2023	2022
Balance at beginning of year	**(11)**	(6)
Net gains (losses) included in Net income (loss)	**(2)**	(10)
Net gains (losses) included in OCI	**—**	(3)
Transfers out of Level III	**2**	7
Settlements	**—**	1
Balance at End of Year[1]	**(11)**	(11)

1 Revenues include unrealized losses of $2 million attributed to derivatives in the Level III category that were still held at December 31, 2023 (2022 – unrealized losses of $10 million).

30. CHANGES IN OPERATING WORKING CAPITAL

year ended December 31 (millions of Canadian $)	2023	2022	2021
(Increase) decrease in Accounts receivable	**(394)**	(575)	(925)
(Increase) decrease in Inventories	**(56)**	(190)	(93)
(Increase) decrease in Other current assets	**618**	118	(141)
Increase (decrease) in Accounts payable and other	**(206)**	(83)	890
Increase (decrease) in Accrued interest	**245**	91	(18)
(Increase) Decrease in Operating Working Capital	**207**	(639)	(287)

31. ACQUISITIONS AND DISPOSITIONS

U.S. Natural Gas Pipelines

Disposition of Equity Interest

On October 4, 2023, the Company completed the sale of a 40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf for $5.3 billion (US$3.9 billion). The sale was accounted for as an equity transaction of which $9.5 billion (US$6.9 billion) was recorded as Non-controlling interests to reflect the 40 per cent change in the Company's ownership interest in Columbia Gulf and Columbia Gas. The difference between the non-controlling ownership interest recognized and the consideration received was recorded as a reduction to Additional paid-in capital of $3.5 billion (US$3.0 billion), net of tax and transaction costs.

Liquids Pipelines

Northern Courier

In November 2021, TC Energy completed the sale of its remaining 15 per cent equity interest in Northern Courier to a third party for gross proceeds of approximately $35 million resulting in a pre-tax gain of $13 million ($19 million after tax). The pre-tax gain was included in Net gain(loss) on sale of assets in the Consolidated statement of income.

Power and Energy Solutions

Texas Wind Farms

On March 15, 2023, TC Energy closed the acquisition of 100 per cent of the Class B Membership Interests in the 155 MW Fluvanna Wind Farm located in Scurry County, Texas for US$99 million, before post-closing adjustments. On June 14, 2023, the Company closed the acquisition of 100 per cent of the Class B Membership Interests in the 148 MW Blue Cloud Wind Farm located in Bailey County, Texas for US$125 million, before post-closing adjustments. The Fluvanna and Blue Cloud assets have tax equity investors that own 100 per cent of the Class A Membership Interests, to which a percentage of earnings, tax attributes and cash flows are allocated.

32. COMMITMENTS, CONTINGENCIES AND GUARANTEES

Commitments

TC Energy and its affiliates have long-term natural gas transportation and natural gas purchase arrangements as well as other purchase obligations, all of which are transacted at market prices and in the normal course of business. Purchases under these contracts in 2023 were $397 million (2022 – $362 million; 2021 – $239 million).

The Company has entered into PPAs with solar and wind-power generating facilities ranging from 2024 to 2038 that require the purchase of generated energy and associated environmental attributes. At December 31, 2023, the total planned capacity secured under the PPAs is approximately 800 MW with the generation subject to operating availability and capacity factors. These PPAs do not meet the definition of a lease or derivative. Future payments and their timing cannot be reasonably estimated as they are dependent on when certain underlying facilities are placed into service and the amount of energy generated. Certain of these purchase commitments have offsetting sale PPAs for all or a portion of the related output from the facility.

Capital expenditure commitments include obligations related to the construction of growth projects and are based on the projects proceeding as planned. Changes to these projects, including cancellation, would reduce or possibly eliminate these commitments as a result of cost mitigation efforts. At December 31, 2023, TC Energy had approximately $2.1 billion of capital expenditure commitments, primarily consisting of:

- $0.3 billion for its U.S. natural gas pipelines, primarily related to construction costs associated with ANR and other pipeline projects
- $1.3 billion for its Mexico natural gas pipelines related to construction of the Southeast Gateway pipeline.

Contingencies

TC Energy is subject to laws and regulations governing environmental quality and pollution control. At December 31, 2023, the Company had accrued approximately $19 million (2022 – $20 million) related to operating facilities, which represents the present value of the estimated future amount it expects to spend to remediate the sites. However, additional liabilities may be incurred as assessments take place and remediation efforts continue.

TC Energy and its subsidiaries are subject to various legal proceedings, arbitrations and actions arising in the normal course of business. The amounts involved in such proceedings are not reasonably estimable as the final outcome of such legal proceedings cannot be predicted with certainty. The Company assesses all legal matters on an ongoing basis, including those of its equity investments, to determine if they meet the requirements for disclosure or accrual of a contingent loss. With the potential exception of the matters discussed below, for which the claims are material and there is a reasonable possibility of loss, but have not been assessed as probable and a reasonable estimate of loss cannot be made, it is the opinion of management that the ultimate resolution of such proceedings and actions will not have a material impact on the Company's consolidated financial position or results of operations.

Coastal GasLink LP

Coastal GasLink LP is in dispute with a number of contractors related to construction of the Coastal GasLink pipeline. Material legal matters pertaining to Coastal GasLink are summarized as follows:

SA Energy Group

Coastal GasLink LP is in arbitration with SA Energy Group (SAEG), which is one of the prime construction contractors on the Coastal GasLink pipeline. While still engaged as prime contractor, SAEG filed a request to arbitrate in February 2022, seeking damages for incremental costs resulting from alleged project delays. In order to mitigate cost, schedule and environmental risk while the project was in active construction, Coastal GasLink LP advanced without prejudice payments to SAEG which Coastal GasLink LP now seeks to recover via set off. By agreement among the parties, the scope of the arbitration is limited to damages for project work completed prior to December 29, 2022. In November 2023, SAEG filed materials purporting to seek damages in excess of $1.1 billion. Coastal GasLink LP continues to dispute the merits of SAEG's claims and to assert its right to set off. Arbitration is scheduled to proceed in late 2024. At December 31, 2023, the final outcome of this matter cannot be reasonably estimated.

Pacific Atlantic Pipeline Construction Ltd.

Coastal GasLink LP is in arbitration with one of its previous prime contractors, Pacific Atlantic Pipeline Construction Ltd. (PAPC). Coastal GasLink LP terminated its contract with PAPC for cause, due to the failure of PAPC to complete work as scheduled and made a demand on the parental guarantee for payment of the guaranteed obligations. Following Coastal GasLink LP's demand on the guarantee, in August 2022, PAPC initiated arbitration. As of November 2023, PAPC purports to seek at least $428 million in damages for wrongful termination for cause, termination damages and payments alleged to be outstanding. Coastal GasLink LP disputes the merits of PAPC's claims and has counterclaimed against PAPC and its parent company and guarantor, Bonatti S.p.A., citing delays and failures by PAPC to perform and manage work in accordance with the terms of its contract. Coastal GasLink LP estimates its damages to be $1.2 billion. Arbitration is scheduled to proceed in late 2024. At December 31, 2023, the final outcome of this matter cannot be reasonably estimated.

Separately, Coastal GasLink LP has sought to draw down on a $117 million irrevocable standby letter of credit (LOC) provided by PAPC based on a bona fide belief that Coastal GasLink LP's damages are in excess of the face value of the LOC. PAPC has applied for an injunction restraining Coastal GasLink LP from drawing on the LOC pending the completion of the arbitration between Coastal GasLink LP, PAPC, and Bonatti, which is the subject of further court proceedings.

Keystone XL

In 2021, TC Energy filed a Request for Arbitration to formally initiate a legacy North American Free Trade Agreement (NAFTA) claim to recover economic damages resulting from the revocation of the Presidential Permit for the Keystone XL pipeline project. In 2022, the International Centre for Settlement of Investment Disputes formally constituted a tribunal to hear TC Energy's request for arbitration under NAFTA. In April 2023, the tribunal suspended the proceeding, granting a request from the U.S. Department of State to decide the jurisdictional grounds of the case as a preliminary matter. A hearing on the jurisdictional matter is set to occur in second quarter of 2024. In April 2023, the Government of Alberta filed its own request for arbitration, which will proceed separately from the Company's claim. Termination activities undertaken in 2023, including asset dispositions and preservation, will continue through the first half of 2024. The Company will continue to coordinate with regulators, stakeholders and Indigenous groups to meet its environmental and regulatory commitments.

2016 Columbia Pipeline Acquisition Lawsuit

In 2023, the Delaware Chancery Court issued its decision in the class action lawsuit commenced by former shareholders of Columbia Pipeline Group Inc. (CPG) related to the acquisition of CPG by TC Energy in 2016. The Court found that the former CPG executives breached their fiduciary duties, that the former CPG Board breached its duty of care in overseeing the sale process and that TC Energy aided and abetted those breaches. The Court awarded US$1 per share in damages to the plaintiffs and total damages, which is presently estimated at US$400 million plus statutory interest. Post-trial briefing and argument has concluded and a decision from the Court allocating liability as between TC Energy and the CPG executives is expected sometime in the first half of 2024. Until the allocation of damages is known, the amount that TC Energy is liable for cannot be reasonably estimated, therefore, the Company has not accrued a provision for this claim at December 31, 2023. Management expects to proceed with an appeal following the Court's determination of total damages and TC Energy's allocated share.

Guarantees

TC Energy and its partner on the Sur de Texas pipeline, IEnova, have jointly guaranteed the financial performance of the entity which owns the pipeline. Such agreements include a guarantee and a letter of credit which are primarily related to the delivery of natural gas.

TC Energy and its joint venture partner on Bruce Power, BPC Generation Infrastructure Trust, have each severally guaranteed certain contingent financial obligations of Bruce Power related to a lease agreement and contractor and supplier services.

The Company and its partners in certain other jointly-owned entities have either: i) jointly and severally; ii) jointly or iii) severally guaranteed the financial performance of these entities. Such agreements include guarantees and letters of credit which are primarily related to construction services and the payment of liabilities. For certain of these entities, any payments made by TC Energy under these guarantees in excess of its ownership interest are to be reimbursed by its partners.

The carrying value of these guarantees has been recorded in Other long-term liabilities on the Consolidated balance sheet. Information regarding the Company's guarantees were as follows:

at December 31		2023		2022	
(millions of Canadian $)	Term	Potential Exposure[1]	Carrying Value	Potential Exposure[1]	Carrying Value
Sur de Texas	Renewable to 2053	**97**	**—**	100	—
Bruce Power	Renewable to 2065	**88**	**—**	88	—
Other jointly-owned entities	to 2043	**80**	**3**	81	3
		265	**3**	269	3

1 TC Energy's share of the potential estimated current or contingent exposure.

33. VARIABLE INTEREST ENTITIES

Consolidated VIEs

A significant portion of the Company's assets are held through VIEs in which the Company holds a 100 per cent voting interest, the VIE meets the definition of a business and the VIE's assets can be used for general corporate purposes. The consolidated VIEs whose assets cannot be used for purposes other than for the settlement of the VIE's obligations, or are not considered a business, were as follows:

at December 31 (millions of Canadian $)	2023[1]	2022
ASSETS		
Current Assets		
Cash and cash equivalents	**190**	60
Accounts receivable	**476**	98
Inventories	**90**	32
Other current assets	**49**	14
	805	204
Plant, Property and Equipment	**27,649**	3,997
Equity Investments	**823**	748
Regulatory Assets	**12**	—
Goodwill	**439**	449
	29,728	5,398
LIABILITIES		
Current Liabilities		
Accounts payable and other	**1,135**	234
Accrued interest	**210**	18
Current portion of long-term debt	**28**	31
	1,373	283
Regulatory Liabilities	**280**	78
Other Long-Term Liabilities	**56**	1
Deferred Income Tax Liabilities	**22**	16
Long-Term Debt	**11,388**	2,136
	13,119	2,514

1 Columbia Gas and Columbia Gulf were classified as a VIE upon TC Energy's sale of a 40 per cent non-controlling equity interest on October 4, 2023. Refer to Note 24, Non-controlling interests, and Note 31, Acquisitions and dispositions, for additional information.

Non-Consolidated VIEs

The carrying value of these VIEs and the maximum exposure to loss as a result of the Company's involvement with these VIEs were as follows:

at December 31 (millions of Canadian $)	2023	2022
Balance Sheet Exposure		
Equity investments		
Bruce Power	**6,241**	5,783
Pipeline equity investments and other	**1,411**	1,148
Off-Balance Sheet Exposure[1]		
Bruce Power	**1,538**	2,025
Coastal GasLink[2]	**855**	3,300
Pipeline equity investments	**58**	58
Maximum exposure to loss	**10,103**	12,314

1 Includes maximum potential exposure to guarantees and future funding commitments.

2 TC Energy is contractually obligated to fund the capital costs to complete the Coastal GasLink pipeline by funding the remaining equity requirements of Coastal GasLink LP through incremental capacity on the subordinated loan agreement with Coastal GasLink LP until final costs are determined. At December 31, 2023, the total capacity committed by TC Energy under this subordinated loan agreement was $3,375 million (December 31, 2022 – $1,262 million). In the year ended December 31, 2023, $2,520 million was drawn on the subordinated loan, reducing the Company's funding commitment under the subordinated loan agreement to $855 million. Refer to Note 8, Coastal GasLink, for further information.

In July 2022, the Company entered into revised project agreements relating to its investment in Coastal GasLink LP and committed to make additional equity contributions, which did not result in a change in the Company’s 35 per cent ownership. These revisions and additional equity contributions were determined to be a VIE reconsideration event for TC Energy’s investment in Coastal GasLink LP. The Company performed a re-assessment of control and determined that Coastal GasLink LP continued to meet the definition of a VIE in which the Company held a variable interest. The re-assessment further determined that TC Energy was not the primary beneficiary of Coastal GasLink LP as the Company does not have the power, either explicit or implicit through voting rights or otherwise, to direct the activities that most significantly impact the economic performance of Coastal GasLink LP. Accordingly, the Company continued to account for its investment using the equity method of accounting. Refer to Note 8, Coastal GasLink, for additional information.