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 2025 to that in 2024, and highlights significant changes between 2024 and 2023. 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, 2025, 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

Sean O'Donnell
Executive Vice-President and
Chief Financial Officer

February 12, 2026

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, 2025 and 2024, the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the years in the three-year period ended December 31, 2025, 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, 2025 and 2024, and the results of operations and its cash flows for each of the years in the three-year period ended December 31, 2025, 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, 2025, 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 12, 2026 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.

Determination of fair value of the Southeast Gateway pipeline

As discussed in Notes 2 and 9 to the consolidated financial statements, the Company recognized a sales-type lease for the Southeast Gateway pipeline and recorded net investment in lease of $6.6 billion and selling profit or loss of nil upon derecognition of the carrying value of the underlying assets. At lease commencement, the Company recognizes a net investment in lease equal to the present value of the future lease payments and the estimated residual value of the underlying assets discounted at the rate implicit in the lease. The carrying value of the underlying assets is derecognized, with related gains/losses, if any, recognized in the Consolidated statement of income.

We identified the determination of fair value of the Southeast Gateway pipeline as a critical audit matter. The extent of management judgment with regards to certain qualitative factors that support the conclusion that the fair value of the Southeast Gateway pipeline approximated the carrying value of its underlying assets required subjective auditor judgment. 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 this critical audit matter. This included controls related to the Company's determination that the fair value of the Southeast Gateway pipeline approximated the carrying value of its underlying assets. We evaluated the Company's qualitative assessment of factors that supported the Company's judgment that the fair value of the underlying assets approximated their carrying value. We evaluated the Company's forecasted cash flows derived from a market participant's expected use of the underlying assets to determine an implied rate of return, which was compared to estimated rates of return a market participant would require. In addition, we involved valuation professionals with specialized skills and knowledge, who assisted in:

- evaluating the implied return of the underlying assets by independently developing an expectation for the rate of return a market participant would expect by using publicly available market data for comparable entities; and
- evaluating the implied return of the underlying assets by comparing the implied EBITDA multiple to EBITDA multiples using publicly available market data for comparable entities.

Valuation of goodwill for the Columbia reporting unit

As discussed in Notes 2 and 13 to the consolidated financial statements, the goodwill balance as of December 31, 2025 for the Columbia reporting unit was $10,082 million. The Company performs an annual review for goodwill impairment at the reporting unit level which is one level below the Company's operating segments. 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 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 the reporting unit was determined by using a discounted cash flow model which requires the use of assumptions related to revenue and capital expenditure projections (collectively, the "key assumptions"). The Company elected to proceed directly to the quantitative goodwill impairment test as of December 31, 2025 for the Columbia reporting unit and determined that the fair value of the Columbia reporting unit, exceeded its carrying value, including goodwill, as of December 31, 2025. We identified the evaluation of the key assumptions used in 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.

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 determination of the fair value of the Columbia reporting unit and its evaluation of the key assumptions. We compared the Company's key assumptions used in the prior quantitative goodwill impairment test to actual results to assess the Company's ability to accurately forecast. We evaluated the Company's key assumptions in the December 31, 2025 impairment test by comparing them to actual historical results, the outcome of the Columbia Gas Settlement and to assumptions used in industry publications related to North American and global energy consumption and production forecasts.

/s/ KPMG LLP

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

Calgary, Canada
February 12, 2026

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, 2025, 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, 2025, 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, 2025 and 2024, the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the years in the three-year period ended December 31, 2025, and the related notes (collectively, the consolidated financial statements), and our report dated February 12, 2026 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 Consolidated Financial Statements. 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.

/s/ KPMG LLP

Chartered Professional Accountants
Calgary, Canada
February 12, 2026

Consolidated statement of income

year ended December 31 (millions of Canadian $, except per share amounts)	2025	2024	2023
Revenues (Note 6)			
Canadian Natural Gas Pipelines	**5,785**	5,600	5,173
U.S. Natural Gas Pipelines	**7,145**	6,339	6,229
Mexico Natural Gas Pipelines	**1,450**	870	846
Power and Energy Solutions	**845**	954	1,019
Corporate	**14**	8	—
	15,239	13,771	13,267
Income (Loss) from Equity Investments (Note 10)	**1,274**	1,558	1,310
Impairment of Equity Investment (Note 10)	**—**	—	(2,100)
Operating and Other Expenses			
Plant operating costs and other	**4,619**	4,413	4,073
Commodity purchases resold	**208**	217	80
Property taxes	**881**	820	781
Depreciation and amortization	**2,769**	2,535	2,446
	8,477	7,985	7,380
Net Gain (Loss) on Sale of Assets (Note 29)	**—**	620	—
Financial Charges			
Interest expense (Note 19)	**3,407**	3,019	2,966
Allowance for funds used during construction	**(453)**	(784)	(575)
Foreign exchange (gains) losses, net (Note 21)	**(157)**	147	(320)
Interest income and other	**(205)**	(324)	(272)
	2,592	2,058	1,799
Income (Loss) from Continuing Operations before Income Taxes	**5,444**	5,906	3,298
Income Tax Expense (Recovery) from Continuing Operations (Note 18)			
Current	**367**	495	864
Deferred	**771**	427	(22)
	1,138	922	842
Net Income (Loss) from Continuing Operations	**4,306**	4,984	2,456
Net Income (Loss) from Discontinued Operations, Net of Tax (Note 4)	**(212)**	395	612
Net Income (Loss)	**4,094**	5,379	3,068
Net income (loss) attributable to non-controlling interests (Note 22)	**575**	681	146
Net Income (Loss) Attributable to Controlling Interests	**3,519**	4,698	2,922
Preferred share dividends	**119**	104	93
Net Income (Loss) Attributable to Common Shares	**3,400**	4,594	2,829
Amounts Attributable to Common Shares			
Net income (loss) from continuing operations	**4,306**	4,984	2,456
Net income (loss) attributable to non-controlling interests (Note 22)	**575**	681	146
Net income (loss) attributable to controlling interests from continuing operations	**3,731**	4,303	2,310
Preferred share dividends	**119**	104	93
Net income (loss) attributable to common shares from continuing operations	**3,612**	4,199	2,217
Net income (loss) from discontinued operations, net of tax (Note 4)	**(212)**	395	612
Net Income (Loss) Attributable to Common Shares	**3,400**	4,594	2,829
Net Income (Loss) per Common Share - Basic and Diluted (Note 23)			
Continuing operations	**$3.47**	$4.05	$2.15
Discontinued operations	**($0.20)**	$0.38	$0.60
	$3.27	$4.43	$2.75
Dividends Declared per Common Share	**$3.40**	$3.7025	$3.72
Weighted Average Number of Common Shares (millions) (Note 23)			
Basic	**1,040**	1,038	1,030
Diluted	**1,040**	1,038	1,030

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 $)	2025	2024	2023
Net Income (Loss)	**4,094**	5,379	3,068
Other Comprehensive Income (Loss), Net of Tax			
Foreign currency translation gains and losses on net investment in foreign operations	**(978)**	1,602	(1,141)
Reclassification of foreign currency translation (gains) losses on net investment on disposal of foreign operations	**—**	(25)	—
Change in fair value of net investment hedges	**1**	(18)	17
Change in fair value of cash flow hedges	**(22)**	35	—
Reclassification to net income of (gains) losses on cash flow hedges	**31**	(16)	74
Unrealized actuarial gains (losses) on pension and other post-retirement benefit plans	**79**	83	(11)
Reclassification to net income of actuarial (gains) losses on pension and other post-retirement benefit plans	**—**	(6)	—
Other comprehensive income (loss) on equity investments	**2**	173	(211)
Other comprehensive income (loss) (Note 25)	**(887)**	1,828	(1,272)
Comprehensive Income (Loss)	**3,207**	7,207	1,796
Comprehensive income (loss) attributable to non-controlling interests	**64**	1,584	(220)
Comprehensive Income (Loss) Attributable to Controlling Interests	**3,143**	5,623	2,016
Preferred share dividends	**119**	104	93
Comprehensive Income (Loss) Attributable to Common Shares	**3,024**	5,519	1,923

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 $)	2025	2024	2023
Cash Generated from Operations			
Net income (loss)	**4,094**	5,379	3,068
Depreciation and amortization	**2,769**	2,788	2,778
Deferred income taxes (Note 18)	**766**	493	11
(Income) loss from equity investments (Notes 5 and 10)	**(1,274)**	(1,608)	(1,377)
Impairment of equity investment (Note 10)	**—**	—	2,100
Distributions received from operating activities of equity investments (Note 10)	**1,616**	1,675	1,254
Employee post-retirement benefits funding, net of expense (Note 26)	**3**	11	(17)
Equity allowance for funds used during construction	**(320)**	(512)	(367)
Unrealized (gains) losses on financial instruments (Note 27)	**(235)**	340	(342)
Expected credit loss provision (Note 27)	**83**	(22)	(83)
Foreign exchange (gains) losses, net – intercompany loan	**149**	(216)	44
Net (gain) loss on sale of assets (Note 29)	**—**	(620)	—
Asset impairment charge and other (Note 4)	**29**	21	(4)
Other	**169**	(232)	(4)
(Increase) decrease in operating working capital (Note 28)	**(503)**	199	207
Net cash provided by operations	**7,346**	7,696	7,268
Investing Activities			
Capital expenditures (Note 5)	**(5,270)**	(6,308)	(8,007)
Capital projects in development (Note 5)	**(16)**	(50)	(142)
Contributions to equity investments (Notes 5 and 10)	**(1,051)**	(4,683)	(4,149)
Other distributions from equity investments (Note 10)	**5**	3,686	23
Proceeds from sales of assets, net of transaction costs (Note 29)	**—**	791	33
Acquisitions, net of cash acquired (Note 29)	**—**	—	(307)
Loans to affiliate (issued) repaid, net	**—**	—	250
Deferred amounts and other	**(126)**	(345)	12
Net cash (used in) provided by investing activities	**(6,458)**	(6,909)	(12,287)
Financing Activities			
Notes payable issued (repaid), net	**876**	341	(6,299)
Long-term debt issued, net of issue costs	**5,413**	8,089	15,884
Long-term debt repaid (Notes 19 and 20)	**(6,116)**	(9,273)	(3,772)
Junior subordinated notes issued, net of issue costs	**2,545**	1,465	—
Dividends on common shares	**(3,507)**	(3,953)	(2,787)
Dividends on preferred shares	**(114)**	(99)	(92)
Common shares issued, net of issue costs	**104**	88	4
Preferred shares redeemed (Note 24)	**(250)**	—	—
Distributions to non-controlling interests and other	**(929)**	(755)	(173)
Contributions from non-controlling interests	**—**	21	—
Cash received from factoring arrangement (Note 9)	**351**	—	—
Loan from affiliate (Note 11)	**111**	—	—
Disposition of equity interest, net of transaction costs (Note 29)	**—**	419	5,328
Cash transferred to South Bow, net of debt settlements	**—**	(244)	—
Gains (losses) on settlement of financial instruments	**—**	27	—
Net cash (used in) provided by financing activities	**(1,516)**	(3,874)	8,093
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**(5)**	210	(16)
Increase (Decrease) in Cash and Cash Equivalents	**(633)**	(2,877)	3,058
Cash and Cash Equivalents - Beginning of year	**801**	3,678	620
Cash and Cash Equivalents - End of year	**168**	801	3,678

Includes continuing and discontinued operations. Refer to Note 4, Discontinued operations, for additional information related to cash flows from discontinued operations.

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

Consolidated balance sheet

at December 31 (millions of Canadian $)		2025	2024
ASSETS			
Current Assets			
Cash and cash equivalents		**168**	801
Accounts receivable		**2,794**	2,611
Inventories		**782**	747
Other current assets (Note 7)		**2,375**	1,339
Current assets of discontinued operations (Note 4)		**197**	235
		6,316	5,733
Plant, Property and Equipment (Note 8)		**71,054**	77,501
Net Investment in Leases (Note 9)		**8,110**	2,477
Equity Investments (Note 10)		**11,358**	10,636
Restricted Investments		**3,502**	2,998
Regulatory Assets (Note 12)		**2,913**	2,682
Goodwill (Note 13)		**13,016**	13,670
Other Long-Term Assets (Note 14)		**2,482**	2,410
Long-Term Assets of Discontinued Operations (Note 4)		**—**	136
		118,751	118,243
LIABILITIES			
Current Liabilities			
Notes payable (Note 15)		**1,200**	387
Accounts payable and other (Note 16)		**5,274**	5,297
Dividends payable		**901**	874
Accrued interest		**858**	828
Current portion of long-term debt (Note 19)		**1,545**	2,955
Current liabilities of discontinued operations (Note 4)		**181**	170
		9,959	10,511
Regulatory Liabilities (Note 12)		**5,841**	5,303
Other Long-Term Liabilities (Note 17)		**1,034**	1,051
Deferred Income Tax Liabilities (Note 18)		**7,677**	6,884
Long-Term Debt (Note 19)		**45,247**	44,976
Junior Subordinated Notes (Note 20)		**12,094**	11,048
Long-Term Liabilities of Discontinued Operations (Note 4)		**—**	110
		81,852	79,883
EQUITY			
Common shares, no par value (Note 23)		**30,218**	30,101
Issued and outstanding:	December 31, 2025 – 1,041 million shares December 31, 2024 – 1,039 million shares		
Preferred shares (Note 24)		**2,255**	2,499
Retained earnings (Accumulated deficit)		**(5,925)**	(5,241)
Accumulated other comprehensive income (loss) (Note 25)		**747**	233
Controlling Interests		**27,295**	27,592
Non-Controlling Interests (Note 22)		**9,604**	10,768
		36,899	38,360
		118,751	118,243

Commitments, Contingencies and Guarantees (Note 30)
Variable Interest Entities (Note 31)

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 $)	**2025**	**2024**	**2023**
Common Shares (Note 23)			
Balance at beginning of year	**30,101**	30,002	28,995
Shares issued:			
Exercise of stock options	**117**	99	4
Dividend reinvestment and share purchase plan	**—**	—	1,003
Balance at end of year	**30,218**	30,101	30,002
Preferred Shares (Note 24)			
Balance at beginning of year	**2,499**	2,499	2,499
Redemption of shares	**(244)**	—	—
Balance at end of year	**2,255**	2,499	2,499
Additional Paid-In Capital			
Balance at beginning of year	**—**	—	722
Issuance of stock options, net of exercises	**(7)**	(5)	9
Disposition of equity interest, net of transaction costs (Note 29)	**—**	(41)	(3,537)
Reclassification of additional paid-in capital deficit to accumulated deficit	**7**	46	2,806
Balance at end of year	**—**	—	—
Retained Earnings (Accumulated Deficit)			
Balance at beginning of year	**(5,241)**	(2,997)	819
Net income (loss) attributable to controlling interests	**3,519**	4,698	2,922
Common share dividends	**(3,537)**	(3,842)	(3,839)
Preferred share dividends	**(117)**	(104)	(93)
Spinoff of Liquids Pipelines business (Note 4)	**(542)**	(2,950)	—
Reclassification of additional paid-in capital deficit to accumulated deficit	**(7)**	(46)	(2,806)
Balance at end of year	**(5,925)**	(5,241)	(2,997)
Accumulated Other Comprehensive Income (Loss) (Note 25)			
Balance at beginning of year	**233**	49	955
Other comprehensive income (loss) attributable to controlling interests	**(376)**	946	(379)
Impact of non-controlling interest (Note 29)	**348**	(21)	(527)
Spinoff of Liquids Pipelines business (Note 4)	**542**	(741)	—
Balance at end of year	**747**	233	49
Equity Attributable to Controlling Interests	**27,295**	27,592	29,553
Equity Attributable to Non-Controlling Interests			
Balance at beginning of year	**10,768**	9,455	126
Net income (loss) attributable to non-controlling interests (Note 22)	**575**	681	146
Other comprehensive income (loss) attributable to non-controlling interests	**(511)**	903	(366)
Disposition of equity and non-controlling interests (Note 29)	**(348)**	461	9,451
Non-controlling interests on acquisition of Texas Wind Farms (Note 29)	**—**	—	222
Contributions from non-controlling interests	**—**	21	—
Distributions declared to non-controlling interests	**(880)**	(753)	(124)
Balance at end of year	**9,604**	10,768	9,455
Total Equity	**36,899**	38,360	39,008

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 four business segments: Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines, Mexico Natural Gas Pipelines and Power and Energy Solutions. These segments offer different products and services, including certain natural gas 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 40,984 km (25,467 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 49,587 km (30,811 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 3,600 km (2,235 miles) of regulated natural gas pipelines currently in operation.

Power and Energy Solutions

The Power and Energy Solutions segment primarily consists of the Company's investments in approximately 4,650 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.

Spinoff of Liquids Pipelines Business

On October 1, 2024, TC Energy completed the spinoff of its Liquids Pipelines business into the new public company, South Bow Corporation (South Bow) (the Spinoff Transaction). Refer to Note 4, Discontinued operations, for additional information.

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. Interests in consolidated entities owned by other parties are presented as 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.

The Spinoff Transaction represented a strategic shift that had a major effect on the Company's operations and consolidated financial results. Accordingly, the historical results of the Liquids Pipelines business are presented as discontinued operations and have been excluded from continuing operations and segment disclosures for all periods presented. The Notes to the consolidated financial statements reflect continuing operations only, unless otherwise indicated. Prior to the spinoff, the operations of the Liquids Pipelines business were materially reported as the Company's Liquids Pipelines segment. Refer to Note 4, Discontinued operations, and Note 5, Segmented information, for additional information.

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

Out-of-Period Adjustments

During second quarter 2025, the Company recorded out-of-period adjustments to reclassify a pro rata portion of its net investment hedge losses recorded in Accumulated other comprehensive income (loss) (AOCI).

The adjustments included (i) a reclassification of net investment hedge losses of $348 million from AOCI to Non-controlling interests (NCI) related to the sale of 40 per cent of Columbia Gas and Columbia Gulf on October 4, 2023, which was presented as Impact of non-controlling interest and Disposition of equity interests, respectively, in the Consolidated statement of equity; and (ii) a reclassification of net investment hedge losses of $542 million related to the spinoff of the Company's Liquids Pipelines business that occurred on October 1, 2024 from AOCI to Retained earnings (Accumulated deficit).

The Company determined that the impact of these out-of-period adjustments was not material, individually or in the aggregate, to any previously reported quarterly or annual financial statements and is not material to the Company's consolidated financial statements.

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 on the consolidated financial statements where the assumptions underlying these accounting estimates relate to matters that are highly uncertain at the time they are made or are subjective. These estimates and judgments include, but are not limited to:

- fair value of the Southeast Gateway pipeline used to record a net investment upon lease commencement (Note 9)
- fair value of reporting units that contain goodwill (Note 13).

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:

- recoverability and depreciation rates of plant, property and equipment (Note 8)
- allocation of consideration to lease and non-lease components in a contract that contains a lease (Note 9)
- assumptions used to measure the carrying amount of and expected credit losses on net investment in leases and certain contract assets (Notes 9 and 27)
- fair value of equity investments (Note 10)
- carrying value of regulatory assets and liabilities (Note 12)
- recognition of asset retirement obligations (Note 17)
- 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 18)
- assumptions used to measure retirement and other post-retirement benefit obligations (Note 26)
- fair value of financial instruments (Notes 26 and 27)
- commitments and provisions for contingencies and guarantees (Note 30).

TC Energy continues to assess climate-related impacts on the consolidated financial statements. There are ongoing developments in the sustainability 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 are subject to the authority of the Canada Energy Regulator (CER), the Alberta Energy Regulator or the BC Energy Regulator. In the U.S., regulated interstate natural gas pipelines and 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 National Energy Commission (CNE). 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.

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 some of this variable revenue to be constrained as it cannot be reliably estimated and, therefore, variable revenue is recognized only to the extent it is probable a significant reversal in cumulative revenue will not occur.

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

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 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.

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. interstate 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 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 leased pipelines. Revenues earned from these services are recognized ratably over the term of the contract.

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.

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 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 0.625 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 increase 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.

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, or upon modification, 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 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 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, or upon modification of a lease, 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, or upon modification of a lease. 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 net investment in lease and sales-type lease income.

At lease commencement, the Company recognizes a net investment in lease equal to the present value of both the future lease payments and the estimated residual value of the leased asset discounted at the rate implicit in the lease. 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 model 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 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 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 income 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 substantially related to its power generation facilities. The scope and timing of asset retirements related to the Company's natural gas 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, an asset is recorded 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

The Company no longer issues stock options to employees or officers. Stock options granted before 2024 were 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 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. For partial dispositions of foreign operations that do not result in a change of control, or dispositions of foreign operations other than by sale, gains and losses are reclassified within equity. 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 consistent with gains and losses arising from the translation of foreign operations, when the foreign operation is either entirely or partially disposed of.

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 liabilities or regulatory assets and are refunded to or collected from rate payers 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

Changes in Accounting Policies for 2025

Income Taxes

In December 2023, the FASB issued new guidance to enhance the transparency and usefulness of income tax disclosures through improvements to the rate reconciliation and income taxes paid information. The new guidance requires entities to disclose specific categories in the rate reconciliation and sets specific disaggregation requirements for reconciling items that meet certain thresholds. Additionally, entities are required to disclose disaggregated information on income taxes paid, income from continuing operations before tax and income tax expense from continuing operations. This new guidance was effective for annual periods beginning January 1, 2025. The Company adopted the guidance on a retrospective basis. The adoption of this guidance did not have a material impact on the Company's financial position or results of operations. Refer to Note 18, Income taxes, for additional information and the effects of the new guidance.

Future Accounting Changes

Disaggregation of Income Statement Expenses

In November 2024, the FASB issued new guidance requiring additional disclosure on the nature of expenses included in the income statement. The new standard requires disclosures about specific types of expenses included in the expense captions presented on the face of the income statement as well as disclosures about selling expenses. The new guidance is effective for annual periods beginning January 1, 2027 and interim periods beginning January 1, 2028. Early adoption is permitted. The guidance is applied prospectively with retrospective application permitted. The Company is currently assessing the impact of the standard on the Company's consolidated financial statements.

Internal-Use Software

In September 2025, the FASB issued updated guidance for accounting for internal-use software costs. The updated guidance removes references to project development stages and outlines revised guidance for when capitalization begins for internal-use software costs. The guidance is effective for annual and interim periods beginning January 1, 2028. Early adoption is permitted as of the beginning of an annual reporting period. The guidance can be applied prospectively, retrospectively, or with a modified transition approach. The Company is currently assessing the impact of the standard on the Company's consolidated financial statements.

Hedge Accounting Improvements

In November 2025, the FASB issued new guidance to further align hedge accounting with the economics of an entity's risk management activities. The amendments are intended to allow entities to achieve and maintain hedge accounting for highly effective hedges of forecasted transactions. The new guidance is effective for interim and annual reporting periods beginning January 1, 2027. Early adoption is permitted. The guidance is applied on a prospective basis for all hedging relationships that exist at the date of adoption. The Company is currently assessing the impact of the standard on the Company's consolidated financial statements.

Government Grants

In December 2025, the FASB established authoritative guidance on the recognition, measurement and presentation requirements for government grants received. The new guidance is effective for annual and interim periods beginning January 1, 2029. Early adoption is permitted. The guidance can be applied with a modified prospective, a modified retrospective, or a retrospective approach. The Company is currently assessing the impact of the standard on the Company's consolidated financial statements.

4. DISCONTINUED OPERATIONS

Spinoff of Liquids Pipelines Business

On October 1, 2024, TC Energy completed the spinoff of its Liquids Pipelines business. Pursuant to the Spinoff Transaction, TC Energy and South Bow executed a series of agreements to outline the parameters and guidelines that govern their ongoing relationship, including a Transition Services Agreement, Tax Matters Agreement and a Separation Agreement.

The Transition Services Agreement was established to specify certain services that TC Energy will provide to South Bow for a period of up to two years.

The Tax Matters Agreement governs TC Energy and South Bow's tax rights and obligations after the Spinoff Transaction. The agreement imposes certain restrictions on both TC Energy and South Bow in order to preserve the tax-free status of the spinoff. In the event the Spinoff Transaction is not tax-free, the agreement allocates tax liabilities by generally assigning responsibility to either TC Energy or South Bow to the extent that the failure to qualify is attributable to actions, events or transactions, or a breach of the representations or covenants made by that entity.

The Separation Agreement set forth the terms of the separation of the Liquids Pipelines business from the business of TC Energy, including the transfer of certain assets related to the Liquids Pipelines business from TC Energy to South Bow and the allocation of certain liabilities and obligations related to the Liquids Pipelines business between TC Energy and South Bow.

During 2025, TC Energy reached an agreement with South Bow with respect to liabilities the Company indemnified South Bow for under the Separation Agreement, releasing the Company from those liabilities. Inclusive of the recognition of the settlement, a net loss from discontinued operations of $183 million, net of tax was recognized. Payments related to the settlement commenced in fourth quarter 2025 and will be completed in 2026.

In addition, the Company revised its estimate of future recoveries, resulting in a $29 million impairment, which was included in Net income (loss) from discontinued operations, net of tax in the Consolidated statement of income.

Separation Costs

Liquids Pipelines business separation costs primarily include internal costs related to separation activities, legal, income tax, audit and other consulting fees, insurance provisions and net financial charges related to debt issued and held in escrow. For the years ended December 31, 2024 and 2023, Liquids Pipelines business separation costs of $197 million ($167 million after tax) and $40 million ($34 million after tax), respectively, were included in Net income (loss) from discontinued operations, net of tax in the Consolidated statement of income. There were no separation costs recognized for the year ended December 31, 2025.

Pensions

As part of the Spinoff Transaction, certain TC Energy employees became employees of South Bow. Prior to the Spinoff Transaction, these employees in Canada and the U.S. participated in DB Plans, DC Plans and savings plans, as applicable. Effective October 1, 2024, the benefit obligations under the DB Plans in respect of the employees moving from TC Energy to South Bow were transferred to South Bow. An asset transfer application related to the Canadian DB Plan outlining the proposed transfer of assets from TC Energy to South Bow has received regulatory approval. During the year ended December 31, 2025, $105 million was transferred to South Bow. As at December 31, 2025, $17 million of assets in the Canadian DB Plan remain in the TC Energy DB Plan trust and are reflected as Current assets of discontinued operations with a corresponding obligation to South Bow reflected as Current liabilities of discontinued operations on the Consolidated balance sheet. The Company expects the remaining assets to be fully transferred mid-2026. As at December 31, 2024, the assets related to the U.S. DB Plan were fully transferred to South Bow.

South Bow Debt

On August 28, 2024, South Bow Canadian Infrastructure Holdings Ltd. and 6297782 LLC, two wholly-owned subsidiaries of the Company at the time, completed an offering of approximately $7.9 billion Canadian-dollar equivalent of senior unsecured notes and junior subordinated notes. Approximately $6.2 billion Canadian-dollar equivalent of the net proceeds was placed in escrow pending the completion of the Spinoff Transaction on October 1, 2024 and US$1.3 billion of senior unsecured notes were used to repay a TransCanada PipeLines Limited (TCPL) term loan. Upon completion of the Spinoff Transaction, the escrowed funds were released to South Bow and used to repay indebtedness owed by South Bow and its subsidiaries to TC Energy and its subsidiaries.

Presentation of Discontinued Operations

As described in Note 2, Accounting policies, upon completion of the Spinoff Transaction, the Liquids Pipelines business was accounted for as discontinued operations. The Company's presentation of discontinued operations includes revenues and expenses directly attributable to the Liquids Pipelines business.

Prior year comparatives present the Liquids Pipelines business as discontinued operations.

Income from Discontinued Operations

year ended December 31 (millions of Canadian $)	**2025**	**2024**	**2023**
Revenues	—	2,217	2,667
Income (Loss) from Equity Investments	—	50	67
Operating and Other Expenses			
Plant operating costs and other	**216**	806	814
Commodity purchases resold	—	387	437
Property taxes	—	84	116
Depreciation and amortization	—	253	332
Asset impairment charge and other	**29**	21	(4)
	245	1,551	1,695
Segmented Earnings (Losses) from Discontinued Operations	**(245)**	716	1,039
Financial Charges			
Interest expense	—	218	297
Interest income and other	**(28)**	(21)	30
	(28)	197	327
Income (Loss) from Discontinued Operations before Income Taxes	**(217)**	519	712
Income tax expense (recovery)	**(5)**	124	100
Net Income (Loss) from Discontinued Operations, Net of Tax	**(212)**	395	612

Assets and Liabilities of Discontinued Operations

at December 31 (millions of Canadian $)	2025	2024
ASSETS		
Current Assets		
Other current assets	**197**	235
	197	235
Other Long-Term Assets	**—**	136
	197	371
LIABILITIES		
Current Liabilities		
Accounts payable and other	**181**	170
	181	170
Other Long-Term Liabilities	**—**	110
	181	280

The Spinoff Transaction resulted in derecognition of the net assets of the Liquids Pipelines segment in the amount of $3,691 million. The reduction in net assets was reflected as a $2,950 million decrease in Retained earnings (Accumulated deficit) and a $741 million decrease in AOCI for the year ended December 31, 2024.

For the year ended December 31, 2025, the Company recorded $542 million related to the Spinoff Transaction as an out-of-period adjustment to reclassify a pro rata portion of its net investment hedge losses recorded in AOCI to Retained earnings (Accumulated deficit). Refer to Note 2, Accounting policies, for additional information.

Cash Flows from Discontinued Operations

year ended December 31 (millions of Canadian $)	2025	2024	2023
Net cash (used in) provided by operations	**(185)**	670	1,026
Net cash (used in) provided by investing activities	**24**	(89)	87

5. SEGMENTED INFORMATION

The Company's chief operating decision maker is the President and Chief Executive Officer. The chief operating decision maker uses segmented earnings (losses) to assess the performance of the business segments, assist with capital investment decisions and benchmark to TC Energy's competitors.

Information regarding the Company's business segments is as follows:

year ended December 31, 2025 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Power and Energy Solutions	Corporate [1]	Total
Revenues	5,785	7,145	1,450	845	14	15,239
Intersegment revenues[2]	—	99	—	52	(151)	—
	5,785	7,244	1,450	897	(137)	15,239
Income (loss) from equity investments	112	301	94	767	—	1,274
Operating costs[2]	(2,210)	(2,581)	(262)	(778)	123	(5,708)
Depreciation and amortization	(1,523)	(1,037)	(96)	(113)	—	(2,769)
Segmented Earnings (Losses)	2,164	3,927	1,186	773	(14)	8,036
Interest expense						(3,407)
Allowance for funds used during construction						453
Foreign exchange gains (losses), net						157
Interest income and other						205
Income (Loss) from Continuing Operations before Income Taxes						5,444
Income tax (expense) recovery from continuing operations						(1,138)
Net Income (Loss) from Continuing Operations						4,306
Net Income (Loss) from Discontinued Operations, Net of Tax						(212)
Net Income (Loss)						4,094
Net (income) loss attributable to non-controlling interests						(575)
Net Income (Loss) Attributable to Controlling Interests						3,519
Preferred share dividends						(119)
Net Income (Loss) Attributable to Common Shares						3,400
Capital Spending[3]						
Capital expenditures	1,340	3,316	522	61	31	5,270
Capital projects in development	—	—	—	16	—	16
Contributions to equity investments	65	141	—	845	—	1,051
	1,405	3,457	522	922	31	6,337

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 Operating costs 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, 2024 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Power and Energy Solutions	Corporate [1]	Total
Revenues	5,600	6,339	870	954	8	13,771
Intersegment revenues[2]	—	99	—	49	(148)	—
	5,600	6,438	870	1,003	(140)	13,771
Income (loss) from equity investments	34	341	283	900	—	1,558
Operating costs[2]	(2,246)	(2,381)	(132)	(700)	9 [3]	(5,450)
Depreciation and amortization	(1,382)	(955)	(92)	(101)	(5) [3]	(2,535)
Other segment items[4]	10	610	—	—	—	620
Segmented Earnings (Losses)	2,016	4,053	929	1,102	(136)	7,964
Interest expense						(3,019)
Allowance for funds used during construction						784
Foreign exchange gains (losses), net						(147)
Interest income and other						324
Income (Loss) from Continuing Operations before Income Taxes						5,906
Income tax (expense) recovery from continuing operations						(922)
Net Income (Loss) from Continuing Operations						4,984
Net income (loss) from Discontinued Operations, Net of Tax						395
Net Income (Loss)						5,379
Net Income (loss) attributable to non-controlling interests						(681)
Net Income (Loss) Attributable to Controlling Interests						4,698
Preferred share dividends						(104)
Net Income (Loss) Attributable to Common Shares						4,594
Capital Spending[5]						
Capital expenditures	1,273	2,568	2,228	62	50	6,181
Capital projects in development	—	5	—	45	—	50
Contributions to equity investments[6]	827	2	—	717	—	1,546
	2,100	2,575	2,228	824	50	7,777
Discontinued operations						127
						7,904

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 Operating costs 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 Includes shared costs and depreciation previously allocated to the Liquids Pipelines segment. Refer to Note 4, Discontinued operations, for additional information.

4 Other segment items include a Net gain (loss) on sale of assets.

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

6 Contributions to equity investments in the Canadian Natural Gas Pipelines segment of $3.1 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 10, Equity investments, for additional information.

year ended December 31, 2023 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Power and Energy Solutions	Corporate [1]	Total
Revenues	5,173	6,229	846	1,019	—	13,267
Intersegment revenues[2]	—	101	—	22	(123)	—
	5,173	6,330	846	1,041	(123)	13,267
Income (loss) from equity investments	220	324	78	688	—	1,310
Impairment of equity investment	(2,100)	—	—	—	—	(2,100)
Operating costs[2]	(2,058)	(2,189)	(39)	(633)	(15) [3]	(4,934)
Depreciation and amortization	(1,325)	(934)	(89)	(92)	(6) [3]	(2,446)
Segmented Earnings (Losses)	(90)	3,531	796	1,004	(144)	5,097
Interest expense						(2,966)
Allowance for funds used during construction						575
Foreign exchange gains (losses), net						320
Interest income and other						272
Income (Loss) from Continuing Operations before Income Taxes						3,298
Income tax (expense) recovery from continuing operations						(842)
Net Income (Loss) from Continuing Operations						2,456
Net Income (Loss) from Discontinued Operations, Net of Tax						612
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[4]						
Capital expenditures	2,953	2,536	2,292	144	33	7,958
Capital projects in development	—	—	—	142	—	142
Contributions to equity investments	3,231	124	—	794	—	4,149
	6,184	2,660	2,292	1,080	33	12,249
Discontinued operations						49
						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 Operating costs 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 Includes shared costs and depreciation previously allocated to the Liquids Pipelines segment. Refer to Note 4, Discontinued operations, for additional information.

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

at December 31 (millions of Canadian $)	2025	2024
Total Assets by Segment		
Canadian Natural Gas Pipelines	**31,371**	31,167
U.S. Natural Gas Pipelines	**56,617**	56,304
Mexico Natural Gas Pipelines	**16,342**	15,995
Power and Energy Solutions	**10,764**	10,217
Corporate	**3,460**	4,189
	118,554	117,872
Discontinued Operations	**197**	371
	118,751	118,243

Geographic Information

year ended December 31 (millions of Canadian $)	2025	2024	2023
Revenues			
Canada – domestic	**5,617**	5,579	5,337
Canada – export	**968**	953	821
United States	**7,204**	6,369	6,263
Mexico	**1,450**	870	846
	15,239	13,771	13,267

at December 31 (millions of Canadian $)	2025	2024
Plant, Property and Equipment		
Canada	**26,078**	26,354
United States	**40,976**	40,580
Mexico	**4,000**	10,567
	71,054	77,501

6. REVENUES

Disaggregation of Revenues

year ended December 31, 2025 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Power and Energy Solutions	Total
Revenues from contracts with customers					
Capacity arrangements and transportation	**5,785**	**5,698**	**445**	**—**	**11,928**
Power generation	**—**	**—**	**—**	**236**	**236**
Natural gas storage and other[1]	**—**	**1,141**	**218**	**440**	**1,799**
	5,785	**6,839**	**663**	**676**	**13,963**
Sales-type lease income[2]	**—**	**—**	**787**	**—**	**787**
Other revenues[3]	**—**	**306**	**—**	**169**	**475**
	5,785	**7,145**	**1,450**	**845**	**15,225**
Corporate revenues[4]					**14**
					15,239

1 The Mexico Natural Gas Pipelines segment includes $192 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 Transportadora de Gas Natural de La Huasteca (TGNH) pipelines. Refer to Note 9, Leases, for additional information.

2 Represents the sales-type lease income on the in-service TGNH pipelines. Refer to Note 9, Leases, for additional information.

3 Includes income from the Company's marketing activities, financial instruments and operating lease income. Refer to Note 9, Leases, and Note 27, Risk management and financial instruments, for additional information.

4 Revenues generated from the Transition Services Agreement with South Bow. Refer to Note 4, Discontinued operations, for additional information.

year ended December 31, 2024 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Power and Energy Solutions	Total
Revenues from contracts with customers					
Capacity arrangements and transportation	5,586	5,382	438	—	11,406
Power generation	—	—	—	266	266
Natural gas storage and other[1,2]	14	869	124	383	1,390
	5,600	6,251	562	649	13,062
Sales-type lease income[3]	—	—	308	—	308
Other revenues[4]	—	88	—	305	393
	5,600	6,339	870	954	13,763
Corporate revenues[5]					8
					13,771

1 The Canadian Natural Gas Pipelines segment includes $14 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 The Mexico Natural Gas Pipelines segment includes $98 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 9, Leases, for additional information.

3 Represents the sales-type lease income on the in-service TGNH pipelines. Refer to Note 9, Leases, for additional information.

4 Includes income from the Company's marketing activities, financial instruments and operating lease income. Refer to Note 9, Leases, and Note 27, Risk management and financial instruments, for additional information.

5 Includes $7 million of revenues generated from the Transition Services Agreement with South Bow. Refer to Note 4, Discontinued operations, for additional information.

year ended December 31, 2023 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Power and Energy Solutions	Total
Revenues from contracts with customers					
Capacity arrangements and transportation	5,141	5,107	442	—	10,690
Power generation	—	—	—	427	427
Natural gas storage and other[1,2]	32	874	125	363	1,394
	5,173	5,981	567	790	12,511
Sales-type lease income[3]	—	—	279	—	279
Other revenues[4]	—	248	—	229	477
	5,173	6,229	846	1,019	13,267

1 The Canadian Natural Gas Pipelines segment 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 The Mexico Natural Gas Pipelines segment 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 9, Leases, for additional information.

3 Represents the sales-type lease income on the in-service TGNH pipelines. Refer to Note 9, Leases, for additional information.

4 Includes income from the Company's marketing activities, financial instruments and operating lease income. Refer to Note 9, Leases, and Note 27, Risk management and financial instruments, for additional information.

Contract Balances

at December 31 (millions of Canadian $)	2025	2024	Affected line item on the Consolidated balance sheet
Receivables from contracts with customers	**1,822**	1,452	Accounts receivable
Contract assets (Note 7)	**216**	165	Other current assets
Long-term contract assets (Note 14)	**627**	608	Other long-term assets
Contract liabilities[1] (Note 16)	**46**	30	Accounts payable and other

1 During the year ended December 31, 2025, $21 million (2024 – $41 million) of revenues were recognized, which 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 primarily represent unearned revenue for contracted services.

Future Revenues from Remaining Performance Obligations

As at December 31, 2025, future revenues from long-term pipeline capacity arrangements and transportation as well as natural gas storage and other contracts extending through 2055 are approximately $33.8 billion, of which approximately $7.0 billion is expected to be recognized in 2026.

A significant portion of the Company's revenues are not included in the future revenue disclosure above, as the Company has elected the following disclosure exemptions:

- revenues related to flow-through operating costs, or other similar variable consideration, that are recognized at the amount for which the Company has the right to invoice the customer
- variable consideration relating to interruptible transportation service revenues and power generation revenues where there is uncertainty in estimating the amount of future revenue
- revenues for periods extending beyond the current rate settlement term for the Company's U.S. natural gas pipelines' regulated transportation and storage contracts where the maximum tariff rate is to be collected from shippers
- revenues for periods extending beyond the current rate settlement term for the Company's Canadian natural gas pipelines' regulated firm capacity contracts
- revenues related to assets under construction, which are recognized when the asset is placed in service.

7. OTHER CURRENT ASSETS

at December 31 (millions of Canadian $)	**2025**	**2024**
Net investment in leases (Note 9)	**1,256**	333
Fair value of derivative instruments (Note 27)	**438**	347
Contract assets (Note 6)	**216**	165
Cash provided as collateral	**93**	128
Prepaid expenses	**82**	86
Emissions credits	**67**	75
Regulatory assets (Note 12)	**58**	123
Other	**165**	82
	2,375	1,339

8. PLANT, PROPERTY AND EQUIPMENT

at December 31	2025			2024		
(millions of Canadian $)	Cost	Accumulated Depreciation	Net Book Value	Cost	Accumulated Depreciation	Net Book Value
Canadian Natural Gas Pipelines						
NGTL System						
Pipeline	**20,806**	**8,037**	**12,769**	20,497	7,413	13,084
Compression	**7,277**	**2,732**	**4,545**	7,146	2,497	4,649
Metering and other	**1,685**	**903**	**782**	1,668	883	785
	29,768	**11,672**	**18,096**	29,311	10,793	18,518
Under construction	**663**	**—**	**663**	503	—	503
	30,431	**11,672**	**18,759**	29,814	10,793	19,021
Canadian Mainline						
Pipeline	**11,126**	**8,355**	**2,771**	10,907	8,165	2,742
Compression	**4,661**	**3,500**	**1,161**	4,540	3,448	1,092
Metering and other	**797**	**344**	**453**	749	331	418
	16,584	**12,199**	**4,385**	16,196	11,944	4,252
Under construction	**121**	**—**	**121**	163	—	163
	16,705	**12,199**	**4,506**	16,359	11,944	4,415
Other Canadian Natural Gas Pipelines[1]						
Other	**2,947**	**1,777**	**1,170**	2,927	1,742	1,185
Under construction	**19**	**—**	**19**	31	—	31
	2,966	**1,777**	**1,189**	2,958	1,742	1,216
	50,102	**25,648**	**24,454**	49,131	24,479	24,652
U.S. Natural Gas Pipelines						
Columbia Gas						
Pipeline	**14,996**	**1,610**	**13,386**	14,826	1,472	13,354
Compression	**6,169**	**741**	**5,428**	6,153	677	5,476
Metering and other	**4,529**	**502**	**4,027**	4,570	455	4,115
	25,694	**2,853**	**22,841**	25,549	2,604	22,945
Under construction	**675**	**—**	**675**	891	—	891
	26,369	**2,853**	**23,516**	26,440	2,604	23,836
ANR						
Pipeline	**3,092**	**744**	**2,348**	2,477	745	1,732
Compression	**4,933**	**948**	**3,985**	4,446	938	3,508
Metering and other	**1,867**	**509**	**1,358**	1,832	521	1,311
	9,892	**2,201**	**7,691**	8,755	2,204	6,551
Under construction	**362**	**—**	**362**	853	—	853
	10,254	**2,201**	**8,053**	9,608	2,204	7,404

at December 31	2025			2024		
(millions of Canadian $)	Cost	Accumulated Depreciation	Net Book Value	Cost	Accumulated Depreciation	Net Book Value
Other U.S. Natural Gas Pipelines						
Columbia Gulf	**4,427**	**274**	**4,153**	4,127	304	3,823
GTN	**3,325**	**1,476**	**1,849**	3,405	1,467	1,938
Great Lakes	**2,577**	**1,509**	**1,068**	2,602	1,537	1,065
Other[2]	**1,646**	**655**	**991**	1,695	628	1,067
	11,975	**3,914**	**8,061**	11,829	3,936	7,893
Under construction	**643**	**—**	**643**	694	—	694
	12,618	**3,914**	**8,704**	12,523	3,936	8,587
	49,241	**8,968**	**40,273**	48,571	8,744	39,827
Mexico Natural Gas Pipelines[3]						
Pipeline	**2,468**	**545**	**1,923**	2,590	523	2,067
Compression	**449**	**113**	**336**	476	107	369
Metering and other	**394**	**107**	**287**	398	99	299
	3,311	**765**	**2,546**	3,464	729	2,735
Under construction	**1,454**	**—**	**1,454**	7,807	—	7,807
	4,765	**765**	**4,000**	11,271	729	10,542
Power and Energy Solutions						
Natural Gas Power Generation	**1,322**	**719**	**603**	1,273	671	602
Natural Gas Storage and Other	**887**	**308**	**579**	873	281	592
Renewable Power Generation	**737**	**83**	**654**	779	54	725
	2,946	**1,110**	**1,836**	2,925	1,006	1,919
Under construction	**56**	**—**	**56**	56	—	56
	3,002	**1,110**	**1,892**	2,981	1,006	1,975
Corporate	**895**	**460**	**435**	944	439	505
	108,005	**36,951**	**71,054**	112,898	35,397	77,501

1 Includes Foothills, Ventures LP and Great Lakes Canada.
2 Includes North Baja, Tuscarora, Louisiana Intrastate, Crossroads, U.S. Energy Marketing and mineral rights business.
3 During the year ended December 31, 2025, the Company derecognized $6,595 million (2024 – nil) of Plant, property and equipment and recorded a corresponding asset to net investment in leases for the in-service TGNH pipelines. Refer to Note 9, Leases, for additional information.

9. 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 $)	**2025**	**2024**
Operating lease cost[1]	**112**	117
Sublease income	**(5)**	(6)
Net operating lease cost	**107**	111

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 $)	**2025**	**2024**
Cash paid for amounts included in the measurement of operating lease liabilities	**76**	74
ROU assets obtained in exchange for new operating lease liabilities	**18**	96

at December 31	**2025**	**2024**
Weighted average remaining lease term	**11 years**	13 years
Weighted average discount rate	**3.4%**	3.3%

Maturities of operating lease liabilities are as follows:

at December 31 (millions of Canadian $)	**2025**	**2024**
Less than one year	**73**	73
One to two years	**66**	73
Two to three years	**63**	66
Three to four years	**63**	64
Four to five years	**59**	63
More than five years	**185**	275
Total operating lease payments	**509**	614
Imputed interest	**(78)**	(103)
Operating lease liabilities	**431**	511

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

at December 31 (millions of Canadian $)	2025	2024
Accounts payable and other (Note 16)	**61**	60
Other long-term liabilities (Note 17)	**370**	451
	431	511

As at December 31, 2025, the carrying value of the ROU assets recorded under operating leases was $402 million (2024 – $480 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 2026 and 2035.

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 fixed portion of the operating lease income recorded by the Company for the year ended December 31, 2025 was $109 million (2024 – $114 million; 2023 – $112 million).

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

at December 31 (millions of Canadian $)	2025	2024
Less than one year	**80**	107
One to two years	**9**	76
Two to three years	**10**	9
Three to four years	**10**	10
Four to five years	**10**	10
More than five years	**45**	55
	164	267

At December 31, 2025, the cost and accumulated depreciation for facilities accounted for as operating leases was $697 million and $371 million, respectively (2024 – $697 million and $351 million, respectively).

Sales-Type Leases

The Tamazunchale, Villa de Reyes, Tula and Southeast Gateway pipelines are part of a U.S. dollar-denominated take-or-pay Transportation Service Agreement (TSA) that extends through 2055 between TGNH and the Comisión Federal de Electricidad (CFE).

The consolidated TSA contains multiple lease and non-lease components. The lease components within the TSA represent the capacity available to the CFE provided by the in-service pipelines within TGNH at December 31, 2025. The non-lease components represent the Company's services with respect to operation and maintenance of the TGNH pipelines in service. 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.

Transportadora de Gas Natural de la Huasteca

In September 2025, TC Energy entered into a factoring arrangement with the CFE and a major domestic bank in Mexico to factor monthly invoices for services provided on the TGNH system in 2025. Invoices for August to October were factored to the bank without recourse to TC Energy and TC Energy continued to receive invoiced amounts within the contractual payment period.

The factoring arrangement resulted in a lease modification for accounting purposes of the existing TGNH TSA with the CFE, with no change to the lease classification upon reassessment. As such, the Company reallocated contract consideration to the lease and non-lease components of the contract using an expected cost plus margin approach based on the updated operating and maintenance services stand-alone selling price for each non-lease component as of the date of modification. The residual amount of consideration from this process was then allocated to the lease component. The change in allocation was accounted for prospectively. The rate implicit in the lease was adjusted to the rate at which the modified net investment in lease equaled the carrying value of the net investment in lease directly prior to the effective date of the modification.

Under lease accounting, TC Energy recorded factored amounts in Accounts payable and other, and the corresponding receivables were not derecognized on the Consolidated balance sheet. Cash received from the factoring arrangement were included in Financing activities in the Consolidated statement of cash flows. During 2025, TC Energy assigned and received payment for receivables having an aggregate face value of $351 million (US$251 million).

Southeast Gateway Pipeline

During second quarter 2025, the Company announced the completion of the Southeast Gateway pipeline. The Company determined that the pipeline is a sales-type lease between TGNH and the CFE that commenced when the asset was made available to the customer. At the inception of the agreement in 2022 and as revised in third quarter 2025 when the Company entered into a factoring arrangement with the CFE, the Company allocated the expected contract consideration to the non-lease component for the provisioning of operating and maintenance services based on the estimated stand-alone selling price using an expected cost plus margin approach. The residual amount of consideration from this process was then allocated to the lease component. The Company's estimate of future operating costs influenced the allocation of contract consideration between lease and non-lease components, the timing of income recognized under the contract and the calculation of the rate implicit in the lease.

The TGNH pipelines, which includes the Southeast Gateway pipeline, are rate-regulated and the tolls are designed to recover the cost of providing service. On this basis, the Company applied judgment to determine that, at the inception of the lease arrangement, the fair value of the underlying assets approximated the carrying value and the residual value approximated the remaining carrying value at the end of the lease term. The fair value was a non-recurring measurement classified in Level III of the fair value hierarchy. The Company estimated that if the assets were purchased at their carrying value, they would yield a return to the purchaser that is in line with current market participant expectations.

During 2025, the Company recorded a net investment in lease of $6.6 billion (US$4.8 billion) associated with the Southeast Gateway pipeline lease commencement, with no selling profit or losses recorded upon derecognition of the underlying asset. The Company recorded an expected credit loss provision of $113 million in Plant operating costs and other, relating to the initial net investment in lease balance.

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

at December 31 (millions of Canadian $)	**2025**	**2024**
Less than one year	**1,256**	333
One to two years	**1,000**	333
Two to three years	**1,000**	333
Three to four years	**1,000**	333
Four to five years	**1,000**	333
More than five years	**24,508**	8,499
	29,764	10,164

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 $)	2025	2024
Net Investment in Leases		
Minimum lease payments	**29,764**	10,164
Unearned lease income	**(20,397)**	(7,323)
Lease receivable	**9,367**	2,841
Expected credit loss provision[1]	**(141)**	(59)
Present value of unguaranteed residual value	**140**	28
	9,366	2,810
Current portion included in Other current assets (Note 7)	**(1,256)**	(333)
	8,110	2,477

1 Includes $2 million gain (2024 – $6 million loss) on foreign currency translation.

For the year ended December 31, 2025, the Company recorded $787 million (2024 – $308 million; 2023 - $279 million) of sales-type lease income.

For the year ended December 31, 2025, the Company recorded an $84 million ECL expense (2024 – $23 million recovery; 2023 – $73 million recovery) relating to net investment in leases in Plant operating costs and other. Refer to Note 27, Risk management and financial instruments, for additional information.

10. EQUITY INVESTMENTS

		Income (Loss) from Equity Investments			Equity Investments	
	Ownership Interest at	year ended December 31			at December 31	
(millions of Canadian $)	December 31, 2025	2025	2024	2023	2025	2024
Canadian Natural Gas Pipelines						
TQM[1]	50%	**17**	17	17	**158**	160
Coastal GasLink[1]	35%	**95**	17	203	**896**	1,006
U.S. Natural Gas Pipelines						
Northern Border	50%	**145**	130	101	**766**	647
Millennium	47.5%	**70**	95	109	**(22)**	(21)
Iroquois	50%	**70**	100	98	**216**	221
Other	Various	**16**	16	16	**137**	135
Mexico Natural Gas Pipelines						
Sur de Texas	60%	**94**	283	78	**1,427**	1,403
Power and Energy Solutions						
Bruce Power[1]	48.3%	**767**	900	690	**7,780**	7,043
Other	Various	**—**	—	(2)	**—**	42
		1,274	1,558	1,310	**11,358**	10,636

1 Classified as a VIE. Refer to Note 31, Variable interest entities, for additional information.

Distributions and Contributions

Distributions received from equity investments and contributions made to equity investments for the years ended December 31, 2025, 2024 and 2023 were as follows:

year ended December 31 (millions of Canadian $)	2025	2024	2023
Distributions			
Distributions received from operating activities of equity investments	**1,616**	1,607	1,158
Coastal GasLink LP subordinated loan repayment[1,2]	**—**	3,147	—
Other[1]	**5**	539	23
	1,621	5,293	1,181
Contributions[1]			
Contributions made to other equity investments	**986**	719	918
Contributions to Coastal GasLink LP[2]	**65**	3,964	3,231
	1,051	4,683	4,149

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

2 In December 2024, TC Energy made an equity contribution of $3,137 million to Coastal GasLink LP, which used the funds to repay the balance owing to TC Energy under the subordinated loan agreement. The contribution and repayment were included in Investing activities in the Consolidated statement of cash flows. Refer to Note 11, Loans with affiliates, for additional information.

Coastal GasLink Pipeline Limited Partnership

In November 2024, Coastal GasLink Pipeline Limited Partnership (Coastal GasLink LP) executed a commercial agreement with LNG Canada (LNGC) and each of the five LNGC participants (LNGC Participants) that declared commercial in-service for the Coastal GasLink pipeline, enabling toll collection from customers retroactive to October 1, 2024. The agreement also provided for a one-time payment of $199 million from LNGC Participants to TC Energy in recognition of completed work and final cost settlement, payable upon the earlier of three months following the LNG facility's declared in-service date or December 15, 2025.

Effective July 12, 2025, the LNG facility was declared in-service by LNGC. Pursuant to the commercial agreement, TC Energy received the one-time payment of $199 million, settled through a cash distribution in October 2025. This payment, which accrues entirely to TC Energy under the contractual arrangements between the Coastal GasLink LP partners, was recognized as an in-substance distribution from Coastal GasLink LP and reflected in Accounts receivable and Equity investments on the Company's Consolidated balance sheet as at December 31, 2024.

The Coastal GasLink project reached mechanical completion in November 2023 and was ready to deliver commissioning gas to the LNGC facility by the end of 2023. These milestones entitled Coastal GasLink LP to receive a $200 million incentive payment from LNGC, which was recorded as Accounts receivable on the Consolidated balance sheet and Income (loss) from equity investments in the Consolidated statement of income as at and for the year ended December 31, 2023. The incentive payment was settled through a cash distribution in February 2024.

In February 2023, Coastal GasLink LP announced an increase in the revised capital cost of the Coastal GasLink pipeline. The increase in project costs and the expectation that additional equity contributions under the subordinated loan agreement would be predominantly funded by TC Energy was an indication of significant adverse impact on the estimated fair value of the Company’s investment in Coastal GasLink LP. The Company completed valuation assessments and concluded that the fair value of its investment in Coastal GasLink LP was below its carrying value, which resulted in a pre-tax impairment charge of $2,100 million in 2023 and cumulative impairment charges of $5,148 million, or $4,586 million after tax, between December 31, 2022 and September 30, 2023. No further indication of other-than-temporary impairments of the Company's investment in Coastal GasLink LP have since been identified and no further impairment charges have been recorded.

At December 31, 2025, the carrying value of the Company's investment in Coastal GasLink LP was $896 million (2024 – $1,006 million).

Summarized Financial Information of Equity Investments

year ended December 31 (millions of Canadian $)	2025	2024	2023
Income			
Revenues	**7,493**	6,962	6,197
Operating and other expenses	**(4,412)**	(3,783)	(3,343)
Net income	**2,405**	3,026	2,457
Net income attributable to TC Energy	**1,274**	1,558	1,310

at December 31 (millions of Canadian $)	2025	2024
Balance Sheet		
Current assets	**3,438**	3,959
Non-current assets	**47,233**	44,835
Current liabilities	**(1,888)**	(2,111)
Non-current liabilities	**(22,389)**	(21,729)

At December 31, 2025, the cumulative carrying value of the Company's equity investments was $834 million (2024 – $769 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.

11. LOANS WITH 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 operates the Coastal GasLink pipeline.

Subordinated Loan Agreement

TC Energy has a subordinated loan agreement with Coastal GasLink LP under which the Company advances non-revolving loans at floating market-based interest rates to Coastal GasLink LP to fund capital costs associated with the Coastal GasLink Pipeline project.

Coastal GasLink LP partners, including TC Energy, are contractually obligated to contribute equity to Coastal GasLink LP to ultimately fund the settlement of amounts outstanding under the subordinated loan agreement, with an expectation that such equity will predominantly be contributed by TC Energy. Because of this expectation, amounts drawn under the subordinated loan agreement have been accounted for as in-substance equity contributions, presented as Contributions to equity investments in the Company's Consolidated statement of cash flows. Repayments of amounts owed by Coastal GasLink LP to the Company have been accounted for as in-substance equity distributions, presented in Other distributions from equity investments in the Company's Consolidated statement of cash flows.

On December 17, 2024, following the declared commercial in-service of the pipeline, Coastal GasLink LP repaid the $3,147 million balance owing to TC Energy under the subordinated loan agreement. The Company's share of equity contributions required to fund Coastal GasLink LP's repayment of the outstanding loan balance amounted to $3,137 million. Unused committed capacity available for use by Coastal GasLink LP at December 31, 2025 was $163 million (December 31, 2024 – $228 million).

Subordinated Demand Revolving Credit Facility Agreement

The Company has a subordinated demand revolving credit facility agreement with Coastal GasLink LP to provide additional short-term liquidity and funding flexibility to projects under construction. Facilities available through this agreement bear interest at floating market-based rates and have a combined capacity of $120 million at December 31, 2025 and 2024 with no outstanding balances at December 31, 2025 and 2024.

Sur de Texas

TC Energy holds a 60 per cent equity interest in a joint venture with IEnova Infraestructura Marina Holding B.V. (IEnova) to own the Sur de Texas pipeline, operated by TC Energy. On December 15, 2025, TC Energía Mexicana, S. de R.L. de C.V. (TCEM) entered into a subordinated demand revolving credit facility to borrow funds from the joint venture at a floating interest rate. The facility has a capacity of US$270 million, maturing in December 2028. At December 31, 2025, the unused capacity available for use by TCEM was $259 million (US$189 million) and the outstanding balance of the loan was $111 million (US$81 million), which is presented in Other long-term liabilities on the Company's Consolidated balance sheet.

12. 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 established rates, provided the rates are designed to recover the costs of providing the 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. 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. The Impact Assessment Agency of Canada continues to assess designated projects.

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. Subject to the terms of any settlement, 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 currently operates under the terms of the 2025-2029 Revenue Requirement Settlement, which was approved by the CER in September 2024 (the 2025-2029 NGTL Settlement). The 2025-2029 NGTL Settlement enables an investment framework that supports the approval by the Company's Board of Directors (Board) to allocate up to $3.3 billion of capital towards progression of the Multi-Year Growth Plan for expansion facilities to meet commitments on the NGTL System. It is comprised of multiple distinct projects with various targeted in-service dates, beginning in 2026, subject to final Company and regulatory approvals.

The 2025-2029 NGTL Settlement maintains an ROE of 10.1 per cent on 40 per cent deemed common equity while increasing NGTL System depreciation rates, with an incentive that allows the NGTL System the opportunity to further increase depreciation rates if tolls fall below specified levels or if growth projects are undertaken. The 2025-2029 NGTL Settlement introduces a new incentive mechanism to reduce both physical emissions and emission compliance costs, which builds on the incentive mechanism for certain operating costs where variances from projected amounts and emissions savings are shared with customers. A provision for review exists in the 2025-2029 NGTL Settlement if tolls exceed a pre-determined level or if final Company approvals of the multi-year growth plan are not obtained.

NGTL System's 2023 and 2024 results reflected the terms of the 2020-2024 Revenue Requirement Settlement which included an approved ROE of 10.1 per cent on 40 per cent deemed common equity, provided the NGTL System the opportunity to increase depreciation rates if tolls fell below specified levels and provided an incentive mechanism for certain operating costs where variances from projected amounts were shared with its customers.

Canadian Mainline

In April 2020, the CER approved the six-year unanimous negotiated settlement (the 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 and the remainder commenced amortization in 2024, according to the terms outlined in the 2021-2026 Mainline Settlement as predetermined thresholds per the settlement agreement were met.

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 operates under a settlement approved by FERC in October 2025 (the 2025 Columbia Gas Settlement). As part of the settlement, there is a moratorium on any further rate changes until April 1, 2028, and Columbia Gas must file for new rates with an effective date no later than April 1, 2031. The settlement also included additional rate step ups in April 2026 and April 2027 to reflect anticipated modernization-related spend.

ANR Pipeline

ANR Pipeline operates under rates established through a 2022 FERC-approved rate settlement (the 2022 ANR Settlement). In 2023, previously accrued rate refund liabilities, including interest, were refunded to customers. The 2022 ANR Settlement included a moratorium on rate changes until November 1, 2025, and required ANR to file for new rates with an effective date no later than August 1, 2028. The settlement also provided for a rate step up effective August 2024 related to certain modernization projects and an additional rate step up effective no later than August 1, 2028. In April 2025, ANR filed a Section 4 Rate Case with FERC requesting an increase to maximum transportation rates effective November 1, 2025, subject to refund. As of December 31, 2025, ANR is pursuing a collaborative process to find a mutually beneficial outcome with customers.

Columbia Gulf

Columbia Gulf operates under a settlement approved by FERC in August 2023, effective March 1, 2024 (the 2023 Columbia Gulf Settlement). The 2023 Columbia Gulf Settlement includes a moratorium on 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 rate settlement approved by FERC in April 2022 (the 2022 Great Lakes Settlement), which maintains Great Lakes' existing maximum transportation rates through October 31, 2025. The 2022 Great Lakes Settlement contained a moratorium until October 31, 2025. In April 2025, Great Lakes filed a Section 4 Rate Case with FERC requesting an increase to maximum transportation rates effective November 1, 2025, subject to refund. As of December 31, 2025, Great Lakes is pursuing a collaborative process to find a mutually beneficial outcome with customers.

Tuscarora

Tuscarora operates under rates established as part of the FERC-approved rate settlement in September 2023 (the 2023 Tuscarora Settlement). The 2023 Tuscarora Settlement provided for phased rate reductions as of February 1, 2023, and additionally as of February 1, 2025. The 2023 Tuscarora Settlement contains a moratorium that expires December 1, 2028. Tuscarora is required to file new rates by December 1, 2028.

Gas Transmission Northwest

Gas Transmission Northwest (GTN) operates under rates established as part of the FERC-approved rate settlement in October 2024 (the 2024 GTN Settlement). The 2024 GTN Settlement maintains the currently effective rates (the pre-filed rates) from April 1, 2024, through March 31, 2026. GTN will then reduce its pre-filed rates starting on April 1, 2026, through March 31, 2027. The 2024 GTN Settlement contains a moratorium that expires March 31, 2027. GTN is required to file new rates by April 1, 2027.

Mexico Regulated Operations

TC Energy's natural gas pipelines in Mexico are regulated by the CNE. While the majority of the Company's capacity is subscribed under a long-term contractual rate, the CNE sets rates for interruptible services. The rates in effect on TC Energy's Mexico natural gas pipelines 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)	2025	2024
Regulatory Assets			
Deferred income taxes[1]	n/a	**2,760**	2,593
Operating and debt-service regulatory assets[2]	1	**—**	56
Foreign exchange on long-term debt[1,3]	1-4	**23**	39
Other	n/a	**188**	117
		2,971	2,805
Less: Current portion included in Other current assets (Note 7)		**58**	123
		2,913	2,682
Regulatory Liabilities			
Pipeline abandonment trust balances[4]	n/a	**3,143**	2,686
Deferred income taxes – U.S. Tax Reform[5]	n/a	**1,098**	1,197
Canadian Mainline short-term adjustment and toll-stabilization accounts[6,7]	n/a	**705**	553
Cost of removal[8]	n/a	**407**	376
Canadian Mainline bridging amortization account[6]	5	**268**	322
Pensions and other post-retirement benefits[9]	n/a	**266**	122
Deferred income taxes[1]	n/a	**195**	188
Operating and debt-service regulatory liabilities[2]	1	**134**	50
ANR post-employment and retirement benefits other than pension[10]	n/a	**43**	45
Canadian Mainline long-term adjustment account[6,11]	1	**37**	74
Other	n/a	**77**	43
		6,373	5,656
Less: Current portion included in Accounts payable and other (Note 16)		**532**	353
		5,841	5,303

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 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.

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

5 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.

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

7 Under the terms of the 2021-2026 Mainline Settlement, a portion of the STAA account commenced amortization in 2023 and the remainder commenced amortization in 2024, as predetermined thresholds were met, over the terms outlined per the settlement agreement.

8 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.

9 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.

10 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 $43 million (US$32 million) balance at December 31, 2025 is subject to resolution through future regulatory proceedings and, accordingly, a settlement period cannot be determined at this time.

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

13. GOODWILL

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

at December 31	2025		2024	
(millions)	Canadian dollars	U.S. dollars[1]	Canadian dollars	U.S. dollars[1]
Columbia	**10,082**	**7,351**	10,588	7,351
ANR	**2,669**	**1,946**	2,803	1,946
Great Lakes	**167**	**122**	176	122
North Baja	**66**	**48**	70	48
Tuscarora	**32**	**23**	33	23
	13,016	**9,490**	13,670	9,490

1 Represents gross amounts of goodwill as at December 31, 2025 and 2024 of US$10,828 million, net of accumulated impairment of US$1,338 million.

Changes in Goodwill were as follows:

(millions of Canadian $)	U.S. Natural Gas Pipelines
Balance at January 1, 2024	12,532
Foreign exchange rate changes	1,138
Balance at December 31, 2024	13,670
Foreign exchange rate changes	**(654)**
Balance at December 31, 2025	**13,016**

As part of the annual goodwill impairment assessment at December 31, 2025, the Company evaluated qualitative factors impacting the fair value of the underlying reporting units for all reporting units other than the Columbia reporting unit. It was determined that it was more likely than not that the fair value of all reporting units exceeded their carrying amounts, including goodwill.

Columbia

The Company elected to proceed directly to a quantitative annual impairment test at December 31, 2025 for the $10,082 million (US$7,351 million) of goodwill related to the Columbia reporting unit subsequent to the 2025 Columbia Gas Settlement. To determine fair value, the Company used a discounted cash flow model incorporating projections of future cash flows as well as a valuation multiple and applied a risk-adjusted discount rate which involved significant estimates and judgments. The fair value measurement is classified as Level III in the fair value hierarchy. It was determined that the fair value of the Columbia reporting unit exceeded its carrying value, including goodwill, at December 31, 2025.

Great Lakes

The estimated fair value of the Great Lakes reporting unit in excess of its carrying value was less than 10 per cent at the date of the last quantitative goodwill impairment test in 2022. Any future reductions in cash flow forecasts or adverse changes in other key assumptions could result in a future impairment of the goodwill balance.

14. OTHER LONG-TERM ASSETS

at December 31 (millions of Canadian $)	**2025**	**2024**
Employee post-retirement benefits (Note 26)	**967**	758
Contract assets (Note 6)	**627**	608
Deferred income tax assets (Note 18)	**356**	428
Fair value of derivative instruments (Note 27)	**161**	122
Capital projects in development	**81**	164
Other	**290**	330
	2,482	2,410

15. NOTES PAYABLE

at December 31 (millions of Canadian $, unless otherwise noted)	2025 Outstanding	2025 Weighted Average Interest Rate per Annum	2024 Outstanding	2024 Weighted Average Interest Rate per Annum
Canada[1]	**584**	**3.9%**	308	4.7%
U.S. (2025 – US$449; 2024 – US$55)	**616**	**4.1%**	79	4.7%
	1,200		387	

1 At December 31, 2025, Notes payable consisted of Canadian dollar-denominated notes of $68 million (2024 – nil) and U.S. dollar-denominated notes of US$348 million (2024 – US$214 million).

At December 31, 2025, Notes payable reflects short-term borrowings in Canada by TCPL and in the U.S. by TransCanada PipeLine USA Ltd. (TCPL USA) and Columbia Pipelines Holdings Company LLC (CPHC). At December 31, 2024, there were no amounts outstanding at CPHC.

At December 31, 2025, total committed revolving and demand credit facilities were $11.9 billion (2024 – $12.2 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) Borrowers	Description	Matures	2025 Total Facilities	2025 Unused Capacity[1]	2024 Total Facilities
Committed, syndicated, revolving, extendible, senior unsecured credit facilities[2]:					
TCPL	Supports commercial paper program and for general corporate purposes	December 2030	**3.0**	**2.9**	3.0
TCPL / TCPL USA	Supports commercial paper programs and for general corporate purposes of the borrowers, guaranteed by TCPL	December 2026	**US 1.0**	**US 0.8**	US 1.0
TCPL / TCPL USA	Supports commercial paper programs and for general corporate purposes of the borrowers, guaranteed by TCPL	December 2028	**US 2.5**	**US 2.3**	US 2.5
Columbia Pipelines Holding Company LLC[3]	Supports commercial paper program and general corporate purposes of the borrower	December 2028	**US 1.5**	**US 1.1**	US 1.5
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** [4]	**1.3**	2.0 [4]

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, 2025, the Company was in compliance with all financial covenants.
3 Columbia Pipelines Holding Company LLC is a partially-owned subsidiary of TC Energy with 40 per cent non-controlling interest.
4 Or the U.S. dollar equivalent.

For the year ended December 31, 2025, the cost to maintain the above facilities was $15 million (2024 – $18 million; 2023 – $16 million).

16. ACCOUNTS PAYABLE AND OTHER

at December 31 (millions of Canadian $)	2025	2024
Trade payables	**3,263**	3,699
Regulatory liabilities (Note 12)	**532**	353
Fair value of derivative instruments (Note 27)	**380**	507
Factoring arrangement (Note 9)	**351**	—
Gas transportation and exchange payable	**158**	118
Emissions expense payable	**91**	101
Operating lease liabilities (Note 9)	**61**	60
Contract liabilities (Note 6)	**46**	30
Income tax liabilities	**38**	143
Other	**354**	286
	5,274	5,297

17. OTHER LONG-TERM LIABILITIES

at December 31 (millions of Canadian $)	2025	2024
Operating lease liabilities (Note 9)	**370**	451
Fair value of derivative instruments (Note 27)	**149**	209
Asset retirement obligations	**119**	108
Loan from affiliate (Note 11)	**111**	—
Employee post-retirement benefits (Note 26)	**69**	94
Other	**216**	189
	1,034	1,051

18. INCOME TAXES

Geographic Components of Income before Income Taxes

year ended December 31 (millions of Canadian $)	2025	2024	2023
Canada	**1,959**	1,469	(194)
Foreign	**3,485**	4,437	3,492
Income before Income Taxes	**5,444**	5,906	3,298

Provision for Income Taxes

year ended December 31 (millions of Canadian $)	2025	2024	2023
Current			
Canada - federal	**54**	90	34
Canada - provincial	**5**	71	40
Foreign	**308**	334	790
	367	495	864
Deferred			
Canada - federal	**213**	80	3
Canada - provincial	**139**	56	3
Foreign	**419**	291	(28)
	771	427	(22)
Income Tax Expense	**1,138**	922	842

Reconciliation of Income Tax Expense

year ended December 31	2025		2024		2023	
(millions of Canadian $, unless otherwise noted)	Amount	Percentage	Amount	Percentage	Amount	Percentage
Income before income taxes	**5,444**		5,906		3,298	
Canadian federal statutory income tax rate	**15%**		15%		15%	
Expected income tax expense	**817**		886		495	
Canadian federal reconciling items						
Income tax differential related to regulated operations	**(24)**	**(0.4%)**	(68)	(1.2%)	(108)	(3.3%)
Non-taxable capital (gain) loss	**(20)**	**(0.4%)**	12	0.2%	113	3.4%
Changes in valuation allowances	**—**	**—**	3	0.1%	114	3.5%
Effect of cross-border taxes	**(25)**	**(0.5%)**	(23)	(0.4%)	(27)	(0.8%)
Canadian provincial taxes[1]	**143**	**2.6%**	103	1.7%	22	0.7%
Foreign reconciling items						
United States						
Rate differential	**177**	**3.3%**	168	2.8%	136	4.1%
State and local income taxes, net of federal effect	**(28)**	**(0.5%)**	123	2.1%	76	2.3%
Income from non-controlling interests	**(125)**	**(2.3%)**	(121)	(2.0%)	(31)	(0.9%)
Other	**(16)**	**(0.3%)**	(12)	(0.2%)	(8)	(0.2%)
Mexico						
Mexico foreign exchange exposure	**213**	**3.9%**	(246)	(4.2%)	163	4.9%
Rate differential	**57**	**1.0%**	234	4.0%	94	2.9%
Income from equity investments	**(28)**	**(0.5%)**	(84)	(1.4%)	(23)	(0.7%)
Income tax differential related to regulated operations	**(45)**	**(0.8%)**	(109)	(1.8%)	(79)	(2.4%)
Withholding tax	**41**	**0.8%**	35	0.6%	12	0.4%
Other	**8**	**0.1%**	2	—	2	0.1%
Other foreign jurisdictions	**(2)**	**—**	3	0.1%	(91)	(2.8%)
Other adjustments	**(5)**	**(0.1%)**	16	0.3%	(18)	(0.5%)
Income Tax Expense	**1,138**	**20.9%**	922	15.7%	842	25.7%

1 Ontario provincial tax comprises the majority of Canada provincial taxes.

Deferred Income Tax Assets and Liabilities

at December 31 (millions of Canadian $)	2025	2024
Deferred Income Tax Assets		
Tax loss and credit carryforwards	**1,728**	1,987
Disallowed interest carryforward	**100**	115
Regulatory and other deferred amounts	**644**	612
Unrealized foreign exchange losses on long-term debt	**290**	467
Other	**57**	143
	2,819	3,324
Less: Valuation allowance	**789**	931
	2,030	2,393
Deferred Income Tax Liabilities		
Difference in accounting and tax bases of plant, property and equipment	**6,792**	6,488
Equity investments	**1,478**	1,280
Taxes on future revenue requirement	**654**	612
Financial instruments	**176**	168
Other	**251**	301
	9,351	8,849
Net Deferred Income Tax Liabilities	**7,321**	6,456

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

at December 31 (millions of Canadian $)	2025	2024
Deferred Income Tax Assets		
Other long-term assets (Note 14)	**356**	428
Deferred Income Tax Liabilities		
Deferred income tax liabilities	**7,677**	6,884
Net Deferred Income Tax Liabilities	**7,321**	6,456

The following table provides details of the tax loss and credit carryforwards and valuation allowances:

at December 31, 2025 (millions of Canadian $)	Unused Amounts	Deferred Tax Asset	Valuation Allowance	Expiry Years
Tax Loss and Credit Carryforwards				
Operating losses	**5,838**	**1,302**	**—**	**2026-2045**
Foreign federal and state operating losses	**1,746**	**173**	**41**	**2026-2037**
Capital loss	**618**	**74**	**74**	**Indefinite**
Minimum tax	**—**	**179**	**42**	**2033-Indefinite**
		1,728	**157**	
Restricted Interest and Financing Expense	**424**	**100**	**—**	**Indefinite**
Unrealized Foreign Exchange on Long-Term Debt	**—**	**290**	**290**	
Equity Investments	**—**	**342**	**342**	
			789	

TC Energy recorded a decrease in valuation allowance in the year primarily resulting from unrealized foreign exchange movements.

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, 2025 by approximately $2,198 million (2024 – $1,728 million) if there had been a provision for these taxes.

Income Tax Payments (Refunds)

at December 31 (millions of Canadian $)	2025	2024	2023
Jurisdiction			
Canada - federal	**73**	53	61
Canada - provincial	**17**	6	(1)
United States	**368**	302	692
Mexico	**84**	34	26
Other - foreign	**1**	(8)	13
	543	387	791

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 $)	2025	2024	2023
Unrecognized tax benefit at beginning of year	**72**	85	91
Gross increase - tax positions in prior years	**2**	3	9
Gross decrease - tax positions in prior years	**(4)**	(2)	(1)
Gross increase - tax positions in current year	**18**	5	16
Gross decrease - tax positions in current year	**—**	(2)	—
Settlement	**—**	(13)	—
Lapse of statutes of limitations	**(5)**	(4)	(30)
Unrecognized Tax Benefit at End of Year	**83**	72	85

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, 2025 reflects $7 million interest expense (2024 – $1 million recovery; 2023 – $3 million expense). At December 31, 2025, the Company accrued $26 million in interest expense (2024 – $19 million; 2023 – $20 million). The Company incurred no penalties associated with income tax uncertainties related to income tax expense for the years ended December 31, 2025, 2024 and 2023 and no penalties were accrued as at December 31, 2025, 2024 and 2023.

The Company has substantially concluded all Canadian federal and provincial income tax matters for the years through 2017. Substantially all material U.S. federal, state and local income tax matters have been concluded for years through 2019. Substantially all material Mexico income tax matters have been concluded for years through 2019.

19. LONG-TERM DEBT

at December 31		2025		2024	
(millions of Canadian $, unless otherwise noted)	Maturity Dates	Outstanding	Interest Rate[1]	Outstanding	Interest Rate[1]
TRANSCANADA PIPELINES LIMITED					
Medium Term Notes					
Canadian	2026 to 2055	**14,241**	**4.8%**	13,141	4.7%
Senior Unsecured Notes					
U.S. (2025 – US$10,850 and 2024 – US$11,792)	2028 to 2049	**14,882**	**5.5%**	16,985	5.5%
		29,123		30,126	
NOVA GAS TRANSMISSION LTD.					
Medium Term Notes					
Canadian	2026 to 2030	**417**	**7.1%**	504	7.4%
U.S. (2025 and 2024 – US$33)	2026	**45**	**7.5%**	47	7.5%
		462		551	
COLUMBIA PIPELINES OPERATING COMPANY LLC					
Senior Unsecured Notes					
U.S. (2025 and 2024 – US$6,500)	2030 to 2063	**8,915**	**6.2%**	9,362	6.0%
COLUMBIA PIPELINES HOLDING COMPANY LLC					
Senior Unsecured Notes					
U.S. (2025 – US$2,650; 2024 – US$1,900)	2026 to 2034	**3,634**	**5.7%**	2,737	5.9%
ANR PIPELINE COMPANY					
Senior Unsecured Notes					
U.S. (2025 – US$1,640; 2024 – US$1,047)	2026 to 2037	**2,249**	**4.3%**	1,509	3.7%
TC PIPELINES, LP					
Senior Unsecured Notes					
U.S. (2025 – US$500 and 2024 – US$850)	2027	**686**	**4.0%**	1,224	4.2%
GAS TRANSMISSION NORTHWEST LLC					
Senior Unsecured Notes					
U.S. (2025 and 2024 – US$375)	2030 to 2035	**514**	**4.4%**	540	4.4%
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP					
Unsecured Term Loan					
U.S. (2025 – US$205; 2024 – nil)	2028	**281**	**5.0%**	—	—
Senior Unsecured Notes					
U.S. (2025 – US$83; 2024 – US$104)	2028 to 2030	**114**	**7.6%**	150	7.6%
		395		150	
TC ENERGÍA MEXICANA, S. DE R.L. DE C.V.					
Senior Unsecured Term Loan					
U.S. (2025 – US$693; 2024 – US$1,370)	2028	**950**	**6.3%**	1,973	7.2%
		46,928		48,172	
Current portion of long-term debt		**(1,545)**		(2,955)	
Unamortized debt discount and issue costs		**(251)**		(252)	
Fair value adjustments[2]		**115**		11	
		45,247		44,976	

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 The fair value adjustments include $93 million (2024 – $109 million) related to the acquisition of Columbia Pipeline Group, Inc. These adjustments also include a decrease of $17 million (2024 – decrease of $139 million) related to hedged interest rate risk and an increase of $39 million (2024 - increase of $41 million) related to discontinued hedge interest rate risk. Refer to Note 27, Risk management and financial instruments, for additional information.

Long-Term Debt Issued

The Company issued long-term debt over the three years ended December 31, 2025 as follows:

(millions of Canadian $, unless otherwise noted)					
Company	**Issue Date**	**Type**	**Maturity Date**	**Amount**	**Interest Rate**
TRANSCANADA PIPELINES LIMITED					
	November 2025	Medium Term Notes	November 2055	850	5.13%
	February 2025	Medium Term Notes	February 2035	1,000	4.58%
	August 2024	Term Loan[1]	August 2024	US 1,242	Floating
	May 2023	Senior Unsecured Term Loan[2]	May 2026	US 1,024	Floating
	March 2023	Senior Unsecured Notes[3]	March 2026	US 850	6.20%
	March 2023	Senior Unsecured Notes[3]	March 2026	US 400	Floating
	March 2023	Medium Term Notes	July 2030	1,250	5.28%
	March 2023	Medium Term Notes[3]	March 2026	600	5.42%
	March 2023	Medium Term Notes[3]	March 2026	400	Floating
COLUMBIA PIPELINES HOLDING COMPANY LLC					
	November 2025	Senior Unsecured Notes	November 2032	US 750	5.00%
	September 2024	Senior Unsecured Notes	October 2031	US 400	5.10%
	January 2024	Senior Unsecured Notes	January 2034	US 500	5.68%
	August 2023	Senior Unsecured Notes	August 2028	US 700	6.04%
	August 2023	Senior Unsecured Notes	August 2026	US 300	6.06%
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP					
	October 2025	Unsecured Term Loan	October 2028	US 205	Floating
ANR PIPELINE COMPANY					
	September 2025	Senior Unsecured Notes	September 2031	US 250	5.23%
	September 2025	Senior Unsecured Notes	September 2035	US 350	5.69%
COLUMBIA PIPELINES OPERATING COMPANY LLC					
	March 2025	Senior Unsecured Notes	February 2035	US 550	5.44%
	March 2025	Senior Unsecured Notes	February 2055	US 450	5.96%
	September 2024	Senior Unsecured Notes	October 2054	US 400	5.70%
	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%
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

1 In August 2024, TCPL entered into a term loan to facilitate the Spinoff Transaction and, in August 2024, the term loan was fully repaid and retired upon delivery of senior unsecured notes issued by 6297782 LLC. Refer to Note 4, Discontinued operations, for additional information.

2 Fully repaid and retired in September 2023.

3 In October 2024, callable notes were repaid and retired at par.

Long-Term Debt Retired/Repaid

The Company retired/repaid long-term debt over the three years ended December 31, 2025 as follows:

(millions of Canadian $, unless otherwise noted) Company	Retirement/ Repayment Date	Type	Amount	Interest Rate
TRANSCANADA PIPELINES LIMITED				
	November 2025	Senior Unsecured Notes	US 850	4.88%
	October 2025	Senior Unsecured Notes	US 92	7.06%
	July 2025	Medium Term Notes	750	3.30%
	October 2024	Senior Unsecured Notes	US 1,250	1.00%
	October 2024	Senior Unsecured Notes[1]	US 850	6.20%
	October 2024	Senior Unsecured Notes[2]	US 739	2.50%
	October 2024	Senior Unsecured Notes[2]	US 441	4.88%
	October 2024	Senior Unsecured Notes[1]	US 400	Floating
	October 2024	Senior Unsecured Notes[2]	US 313	4.75%
	October 2024	Senior Unsecured Notes[2]	US 201	5.00%
	October 2024	Senior Unsecured Notes[2]	US 180	5.10%
	October 2024	Medium Term Notes[1]	600	5.42%
	October 2024	Medium Term Notes[2]	575	4.18%
	October 2024	Medium Term Notes[1]	400	Floating
	August 2024	Term Loan[3]	US 1,242	Floating
	June 2024	Medium Term Notes	750	Floating
	October 2023	Senior Unsecured Notes	US 625	3.75%
	September 2023	Senior Unsecured Term Loan	US 1,024	Floating
	July 2023	Medium Term Notes	750	3.69%
ANR PIPELINE COMPANY				
	June 2025	Senior Unsecured Notes	US 7	7.00%
	February 2024	Senior Unsecured Notes	US 125	7.38%
NOVA GAS TRANSMISSION LTD.				
	May 2025	Medium Term Notes	87	8.90%
	March 2024	Debentures	100	9.90%
	April 2023	Debentures	US 200	7.88%
COLUMBIA PIPELINES OPERATING COMPANY LLC				
	March 2025	Senior Unsecured Notes	US 1,000	4.50%
TC PIPELINES, LP				
	March 2025	Senior Unsecured Notes	US 350	4.38%
TC ENERGÍA MEXICANA, S. DE R.L. DE C.V.				
	Various 2025	Senior Unsecured Term Loan	US 677	Floating
	Various 2024	Senior Unsecured Term Loan	US 430	Floating
	Various 2024	Senior Unsecured Revolving Credit Facility	US 185	Floating
	Various 2023	Senior Unsecured Revolving Credit Facility	US 315	Floating
TUSCARORA GAS TRANSMISSION COMPANY				
	November 2023	Unsecured Term Loan	US 32	Floating

1 In October 2024, callable notes were repaid and retired at par.
2 In October 2024, TCPL purchased and cancelled notes at a 7.73 per cent weighted average discount, as a settlement of cash tender offers.
3 In August 2024, TCPL entered into a term loan to facilitate the Spinoff Transaction and, in August 2024, the term loan was fully repaid and retired upon delivery of senior unsecured notes issued by 6297782 LLC. Refer to Note 4, Discontinued operations, for additional information.

On February 5, 2026, TCPL retired $241 million of medium term notes bearing interest at a fixed rate of 8.29 per cent.

In October 2024, TCPL commenced and completed its cash tender offers to purchase and cancel certain senior unsecured notes and medium term notes at a 7.73 per cent weighted average discount. In addition, the Company repaid and retired outstanding callable notes at par. These extinguishments of debt resulted in a pre-tax net gain of $228 million, primarily due to the fair value discount and recognition of unamortized debt issue costs related to these notes. The net gain on debt extinguishment was recorded in Interest expense in the Consolidated statement of income.

Principal Repayments

At December 31, 2025, principal repayments for the next five years on the Company's long-term debt are approximately as follows:

(millions of Canadian $)	**2026**	**2027**	**2028**	**2029**	**2030**
Principal repayments on long-term debt	1,545	3,122	5,196	1,309	4,573

Interest Expense

year ended December 31			
(millions of Canadian $)	**2025**	**2024**	**2023**
Interest on long-term debt	**2,537**	2,800	2,562
Interest on junior subordinated notes	**678**	638	617
Interest on short-term debt	**95**	60	165
Capitalized interest	**(10)**	(191)	(187)
Amortization and other financial charges[1]	**107**	158	106
Gain on debt extinguishment	**—**	(228)	—
	3,407	3,237	3,263
Interest allocated to discontinued operations (Note 4)	**—**	(218)	(297)
	3,407	3,019	2,966

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

The Company made interest payments of $3,284 million in 2025 (2024 – $3,398 million; 2023 – $2,931 million) on long-term debt, junior subordinated notes and short-term debt, net of interest capitalized.

20. JUNIOR SUBORDINATED NOTES

at December 31		2025		2024	
(millions of Canadian $, unless otherwise noted)	Maturity Date	Outstanding	Effective Interest Rate[1]	Outstanding	Effective Interest Rate[1]
TRANSCANADA PIPELINES LIMITED					
US$750 issued 2015 at 5.88%[2,3,4]	—	**—**	**—**	1,080	7.5%
$1,000 issued 2025 at 5.20%[5]	2056	**1,000**	**5.3%**	—	—
US$750 issued 2025 at 7.00%[6]	2065	**1,028**	**7.2%**	—	—
US$1,000 issued 2007 at 6.35%[7]	2067	**1,372**	**6.0%**	1,440	6.2%
US$1,200 issued 2016 at 6.13%[3,4]	2076	**1,646**	**7.6%**	1,729	8.0%
US$1,500 issued 2017 at 5.55%[3,4]	2077	**2,057**	**6.7%**	2,161	7.2%
$1,500 issued 2017 at 4.90%[3,4]	2077	**1,500**	**5.6%**	1,500	6.8%
US$1,100 issued 2019 at 5.75%[3,4]	2079	**1,509**	**7.3%**	1,584	7.7%
$500 issued 2021 at 4.45%[3,8]	2081	**500**	**4.5%**	500	5.7%
US$800 issued 2022 at 5.85%[3,8]	2082	**1,097**	**7.1%**	1,152	7.3%
US$370 issued 2025 at 6.25%	2085	**508**	**6.6%**	—	—
		12,217		11,146	
Unamortized debt discount and issue costs		**(123)**		(98)	
		12,094		11,048	

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 In May 2025, TCPL exercised its option to fully repay and retire the US$750 million junior subordinated notes that had a maturity date of 2075.
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 five years and resets every five years thereafter, subject to a rate-reset minimum.
6 The coupon rate is initially a fixed interest rate for the first five years and resets every five years thereafter.
7 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.
8 The coupon rate is initially a fixed interest rate for the first 10 years and resets every five years thereafter.

Junior Subordinated Notes Issued

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

In October 2025, TCPL issued US$370 million of junior subordinated notes maturing in 2085 with a fixed interest rate of 6.25 per cent. The junior subordinated notes are callable at TCPL's option at any time on or after November 1, 2030 at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption.

In August 2025, TCPL issued $1.0 billion of junior subordinated notes maturing in 2056 with a fixed interest rate of 5.20 per cent per year until February 15, 2031. The rate on the junior subordinated notes will reset every five years commencing February 2031 until February 2056 to the then Five-Year Government of Canada Yield, as defined in the document governing the subordinated notes, plus 2.148 per cent per annum, subject to a rate-reset minimum. The junior subordinated notes are callable at TCPL's option at any time from November 15, 2030 to February 15, 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.

In February 2025, TCPL issued US$750 million of junior subordinated notes maturing in 2065 with a fixed interest rate of 7.00 per cent per year until June 1, 2030, and resetting every five years thereafter. The rate on the junior subordinated notes will reset every five years commencing June 2030 until June 2065 to the then Five-Year Treasury Rate, as defined in the document governing the subordinated notes, plus 2.614 per cent per annum. The junior subordinated notes are callable at TCPL's option at any time from March 1, 2030 to June 1, 2030 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 junior subordinated notes issued in 2025, TCPL has the option to defer payment of interest for one or more periods of up to ten years without giving rise to an event of default and without permitting acceleration of payment. TC Energy and TCPL would be prohibited from declaring or paying dividends during any deferral period.

Junior Subordinated Notes Retired/Repaid

In May 2025, TCPL exercised its option to fully repay and retire the US$750 million junior subordinated notes that had a maturity date of 2075, bearing interest at 5.88 per cent to TransCanada Trust (the Trust). The related unamortized debt issue costs of $11 million were included in Interest expense in the Consolidated statement of income. All of the proceeds from the repayment were used by the Trust to fund the redemption price of the US$750 million in aggregate principal amount of outstanding Trust Notes - Series 2015-A, in May 2025 pursuant to their terms.

21. FOREIGN EXCHANGE (GAINS) LOSSES, NET

year ended December 31 (millions of Canadian $)	**2025**	**2024**	**2023**
Derivative instruments held for trading (Note 27)	**(352)**	418	(401)
Other	**195**	(271)	81
	(157)	147	(320)

22. 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:

(millions of Canadian $)	**Non-Controlling Interests Ownership at December 31, 2025**	**Income (Loss) Attributable to Non-Controlling Interests**			**Non-Controlling Interests**	
		year ended December 31			**at December 31**	
		2025	**2024**	**2023**	**2025**	**2024**
Columbia Gas and Columbia Gulf	40% [1]	**631**	571	143	**8,779**	9,844
Portland Natural Gas Transmission System	nil [1]	**—**	30	41	**—**	—
Texas Wind Farms	100% [1,2]	**(38)**	(29)	(38)	**123**	168
TGNH	13.01% [1]	**(18)**	109	—	**702**	756
		575	681	146	**9,604**	10,768

1 Refer to Note 29, Acquisitions and dispositions, for additional information.

2 Tax equity investors own 100 per cent of the Class A Membership Interests, to which a percentage of earnings, tax attributes and cash flows are allocated. TC Energy owns 100 per cent of the Class B Membership Interests.

23. COMMON SHARES

	Number of Shares (thousands)	Amount (millions of Canadian $)
Outstanding at January 1, 2023	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
Exercise of options	1,607	99
Outstanding at December 31, 2024	1,039,095	30,101
Exercise of options	**1,740**	**117**
Outstanding at December 31, 2025	**1,040,835**	**30,218**

Common Shares Issued and Outstanding

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

Common Shares After Spinoff Transaction

On October 1, 2024, as part of the Spinoff Transaction, TC Energy shareholders received one new TC Energy common share and 0.2 of a South Bow common share in exchange for each TC Energy common share held.

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.

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.

Basic and Diluted Net Income (Loss) per Common Share

Net income (loss) from continuing operations per common share is calculated by dividing Net income (loss) from continuing operations attributable to common shares by the weighted average number of common shares outstanding. Net income (loss) from discontinued operations is calculated by dividing Net income (loss) from discontinued operations 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 at December 31 (millions)	**2025**	**2024**	**2023**
Basic	**1,040**	1,038	1,030
Diluted	**1,040**	1,038	1,030

Stock Options

	Number of Options (thousands)	Weighted Average Exercise Prices[1]	Weighted Average Remaining Contractual Life (years)
Options outstanding at January 1, 2025	**4,474**	**$60.69**	
Options exercised	**(1,740)**	**$59.34**	
Options forfeited/expired	**(373)**	**$62.77**	
Options Outstanding at December 31, 2025	**2,361**	**$61.37**	**2.8**
Options Exercisable at December 31, 2025	**1,898**	**$63.22**	**2.4**

1 Exercise prices of TC Energy stock options were adjusted in 2024 for the change in value of the TC Energy common shares following the Spinoff Transaction.

At December 31, 2025, an additional 3,994,688 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. Commencing in 2024, the Company no longer issues stock options to employees or officers. 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
Weighted average fair value	$7.88
Expected life (years)[1]	5.1
Interest rate	2.9%
Volatility[2]	24%
Dividend yield	6.3%

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 $7 million in 2025 (2024 – $6 million; 2023 – $9 million). At December 31, 2025, unrecognized compensation costs related to non-vested stock options were $0.8 million and are expected to be fully recognized over a period of 0.1 years.

The following table summarizes additional stock option information:

year ended December 31 (millions of Canadian $, unless otherwise noted)	2025	2024	2023
Total intrinsic value of options exercised	**20**	17	—
Total fair value of options that have vested	**62**	99	76
Total options vested	**0.8 million**	1.5 million	1.5 million

As at December 31, 2025, the aggregate intrinsic values of the total options exercisable and the total options outstanding were $23 million and $34 million, respectively (2024 - $20 million and $34 million, respectively).

Shareholder Rights Plan

TC Energy's Shareholder Rights Plan is designed to provide the Board of Directors 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.

24. PREFERRED SHARES

at December 31, 2025	Number of Shares Outstanding (thousands)	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] 2025	2024	2023
							(millions of Canadian $)		
Cumulative First Preferred Shares									
Series 1	18,424	4.94% [4]	$1.23475	$25.00	December 31, 2029	Series 2	**456**	456	360
Series 2	3,576	Floating [5]	Floating	$25.00	December 31, 2029	Series 1	**83**	83	179
Series 3	11,715	4.10% [4]	$1.0255	$25.00	June 30, 2030 [6]	Series 4	**289**	246	246
Series 4	2,285	Floating [5]	Floating	$25.00	June 30, 2030 [6]	Series 3	**54**	97	97
Series 5	12,071	1.95%	$0.48725	$25.00	January 30, 2026	Series 6	**294**	294	294
Series 6	1,929	Floating [5]	Floating	$25.00	January 30, 2026	Series 5	**48**	48	48
Series 7	24,000	5.99% [4]	$1.49625	$25.00	April 30, 2029	Series 8	**589**	589	589
Series 9	16,703	5.08% [4]	$1.27	$25.00	October 30, 2029	Series 10	**410**	410	442
Series 10	1,297	Floating [5]	Floating	$25.00	October 30, 2029	Series 9	**32**	32	—
Series 11	—	—	—	—	—	—	**—**	244	244
							2,255	2,499	2,499

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), or 2.35 per cent (Series 10). 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), or 2.35 per cent (Series 9).

3 Net of underwriting commissions and deferred income taxes.

4 The fixed rate dividend for Series 3 preferred shares increased from 1.69 per cent to 4.10 per cent on June 30, 2025, and is due to reset on every fifth anniversary thereafter. The fixed rate dividends for Series 1, Series 7 and Series 9 preferred shares increased from 3.48 per cent to 4.94 per cent on December 31, 2024, 3.90 per cent to 5.99 per cent on April 30, 2024 and from 3.76 per cent to 5.08 per cent on October 30, 2024, respectively, and are due to reset on every fifth anniversary thereafter. No Series 7 preferred shares were converted on the April 30, 2024 conversion date.

5 The floating quarterly dividend rate for the Series 2 preferred shares is 4.14 per cent for the period starting December 31, 2025 to, but excluding, March 31, 2026. The floating quarterly dividend rate for the Series 4 preferred shares is 3.50 per cent for the period starting December 31, 2025 to, but excluding, March 31, 2026. The floating quarterly dividend rate for the Series 6 preferred shares is 3.97 per cent for the period starting October 30, 2025 to, but excluding, January 30, 2026 The floating quarterly dividend rate for the Series 10 preferred shares is 4.78 per cent for the period starting October 30, 2025 to, but excluding, January 30, 2026. These rates will reset each quarter going forward.

6 Adjusted to July 2, 2030 to account for applicable business days.

The holders of preferred shares are entitled to receive a fixed or floating cumulative quarterly preferential dividend 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, Series 6 and Series 10 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 November 28, 2025, TC Energy redeemed all 10 million issued and outstanding Series 11 preferred shares at a redemption price of $25.00 per share and paid the final quarterly dividend of $0.2094375 per Series 11 preferred share for the period up to but excluding November 28, 2025. The Company used the proceeds from the October 2025 issuance of US$370 million of Junior Subordinated Notes to finance this preferred share redemption. Prior to the redemption of the Series 11 preferred shares, Series 12 preferred shares were issuable upon conversion of the Series 11 preferred shares, subject to certain conditions, on previously set conversion dates. At the time of the redemption and cancellation of the Series 11 preferred shares, there were no Series 12 preferred shares outstanding.

On June 30, 2025, 104,778 Series 3 preferred shares were converted, on a one-for-one basis, into Series 4 preferred shares and 1,822,829 Series 4 preferred shares were converted, on a one-for-one basis, into Series 3 preferred shares.

On December 31, 2024, 42,200 Series 1 preferred shares were converted, on a one-for-one basis, into Series 2 preferred shares and 3,889,020 Series 2 preferred shares were converted, on a one-for-one basis, into Series 1 preferred shares.

On October 30, 2024, 1,297,203 Series 9 preferred shares were converted, on a one-for-one basis, into Series 10 preferred shares.

25. 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, 2025 (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	**(970)**	**(8)**	**(978)**
Change in fair value of net investment hedges	**1**	**—**	**1**
Change in fair value of cash flow hedges (Note 27)	**(31)**	**9**	**(22)**
Reclassification to net income of (gains) losses on cash flow hedges	**43**	**(12)**	**31**
Unrealized actuarial gains (losses) on pension and other post-retirement benefit plans	**104**	**(25)**	**79**
Other comprehensive income (loss) on equity investments	**2**	**—**	**2**
Other Comprehensive Income (Loss)	**(851)**	**(36)**	**(887)**

year ended December 31, 2024 (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	1,582	20	1,602
Reclassification of foreign currency translation (gains) losses on net investment on disposal of foreign operations[1]	(25)	—	(25)
Change in fair value of net investment hedges	(23)	5	(18)
Change in fair value of cash flow hedges (Note 27)	46	(11)	35
Reclassification to net income of (gains) losses on cash flow hedges	(20)	4	(16)
Unrealized actuarial gains (losses) on pension and other post-retirement benefit plans	107	(24)	83
Reclassification to net income of actuarial (gains) losses on pension and other post-retirement benefit plans	(6)	—	(6)
Other comprehensive income (loss) on equity investments	230	(57)	173
Other Comprehensive Income (Loss)	1,891	(63)	1,828

1 Represents the controlling and non-controlling currency translation adjustment gains related to PNGTS. Refer to Note 29, Acquisitions and dispositions, for additional information.

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)

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, 2023	441	(109)	(44)	667	955
Other comprehensive income (loss) before reclassifications[1]	(231)	—	(11)	(195)	(437)
Amounts reclassified from AOCI	—	74	—	(16)	58
Net current period other comprehensive income (loss)	(231)	74	(11)	(211)	(379)
Impact of non-controlling interest[2]	(527)	—	—	—	(527)
AOCI balance at December 31, 2023	(317)	(35)	(55)	456	49
Other comprehensive income (loss) before reclassifications[1]	692	35	83	188	998
Amounts reclassified from AOCI[3]	(15)	(16)	(6)	(15)	(52)
Net current period other comprehensive income (loss)	677	19	77	173	946
Impact of non-controlling interest[4]	(21)	—	—	—	(21)
Impact of spinoff of Liquids Pipelines business[5]	(741)	—	—	—	(741)
AOCI balance at December 31, 2024	(402)	(16)	22	629	233
Other comprehensive income (loss) before reclassifications[1]	**(466)**	**(22)**	**79**	**3**	**(406)**
Amounts reclassified from AOCI[6]	**—**	**31**	**—**	**(1)**	**30**
Net current period other comprehensive income (loss)	**(466)**	**9**	**79**	**2**	**(376)**
Impact of non-controlling interest[2]	**348**	**—**	**—**	**—**	**348**
Impact of spinoff of Liquids Pipelines business[5]	**542**	**—**	**—**	**—**	**542**
AOCI balance at December 31, 2025	**22**	**(7)**	**101**	**631**	**747**

1 Other comprehensive income (loss) before reclassifications of currency translation adjustments are net of non-controlling interest losses of $511 million (2024 – gains of $903 million; 2023 – losses of $366 million).

2 Represents the AOCI and adjustment attributable to the 40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf upon its sale in October 2023. Refer to Note 29, Acquisitions and dispositions and Note 2, Accounting policies, for additional information.

3 Includes the controlling interest of the AOCI attributable to PNGTS recognized in Net gain (loss) on sale of assets upon the sale of PNGTS in August 2024. Refer to Note 29, Acquisitions and dispositions, for additional information.

4 Represents the AOCI attributable to the CFE's 13.01 per cent non-controlling equity interest in TGNH. Refer to Note 29, Acquisitions and dispositions, for additional information.

5 Represents the AOCI and adjustment attributable to the Spinoff Transaction. Refer to Note 4, Discontinued operations and Note 2, Accounting policies, for additional information.

6 Gains 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 $9 million ($7 million, net of tax) at December 31, 2025. 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.

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

year ended December 31	Amounts reclassified from AOCI			Affected line item in the Consolidated statement of income
(millions of Canadian $)	**2025**	**2024**	**2023**	
Cash flow hedges				
Commodities	**19**	32	(85)	Revenues (Power and Energy Solutions)
Foreign Exchange	**(50)**	—	—	Interest expense and Foreign exchange gains (losses), net
Interest rate	**(12)**	(12)	(12)	Interest expense
	(43)	20	(97)	Total before tax
	12	(4)	23	Income tax (expense) recovery
	(31)	16	(74)	Net of tax
Pension and other post-retirement benefit plan adjustments				
Amortization of actuarial gains (losses)	**—**	6	—	Plant operating costs and other[1]
	—	6	—	Total before tax
	—	—	—	Income tax (expense) recovery
	—	6	—	Net of tax
Equity investments				
Equity income (loss)	**3**	19	22	Income (loss) from equity investments
	(2)	(4)	(6)	Income tax (expense) recovery
	1	15	16	Net of tax
Currency translation adjustments				
Foreign currency translation gains on disposal of foreign operations	**—**	15	—	Net gain (loss) on sale of assets
	—	—	—	Income tax (expense) recovery
	—	15	—	Net of tax

1 These AOCI components are included in the computation of net benefit cost (recovery). Refer to Note 26, Employee post-retirement benefits, for additional information.

26. 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, benefits provided for new members were 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. On January 1, 2024 the Canadian DB Plans were closed to new entrants. Employees hired on and after January 1, 2024 will participate in the Canadian DC Plan.

On January 1, 2025, there was an amendment to the Canadian OPEB Plan which closed the plan for any eligible active employees that did 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 eight years at December 31, 2025 (2024 – nine years; 2023 – nine years).

The Company also provides its employees with DC Plans and savings plans in Canada, DC Plans in 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 11 years at December 31, 2025 (2024 – 12 years and 2023 – 12 years). In 2025, the Company expensed $72 million (2024 – $71 million and 2023 – $64 million) for the savings and DC Plans.

As part of the Spinoff Transaction, certain TC Energy employees became employees of South Bow. Prior to the Spinoff Transaction, these employees in Canada and the U.S. participated in DB Plans, DC Plans and savings plans, as applicable. Effective October 1, 2024, the benefit obligations under the DB Plans in respect of the employees moving from TC Energy to South Bow were transferred to South Bow. An asset transfer application related to the Canadian DB Plan outlining the proposed transfer of assets from TC Energy to South Bow has received regulatory approval. During the year ended December 31, 2025, $105 million was transferred to South Bow. As at December 31, 2025, $17 million of assets in the Canadian DB Plan remain in the TC Energy DB Plan trust and are reflected as Current assets of discontinued operations with a corresponding obligation to South Bow reflected as Current liabilities of discontinued operations on the Consolidated balance sheet. The Company expects the remaining assets to be fully transferred mid-2026. As at December 31, 2024, the assets related to the U.S. DB Plan were fully transferred to South Bow.

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

year ended December 31 (millions of Canadian $)	**2025**	**2024**	**2023**
DB Plans	**—**	—	28
Other post-retirement benefit plans	**8**	8	9
Savings and DC Plans	**72**	71	64
	80	79	101

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, 2025 was nil (2024 – $111 million; 2023 – $244 million).

The most recent actuarial valuation of the pension plans for funding purposes was as at January 1, 2025 and the next required valuation is at January 1, 2026.

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

at December 31	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
(millions of Canadian $)	2025	2024	2025	2024
Change in Benefit Obligation[1]				
Benefit obligation – beginning of year	**3,342**	3,356	**288**	285
Service cost	**101**	108	**1**	1
Interest cost	**162**	160	**15**	14
Employee contributions	**11**	11	**2**	2
Benefits paid	**(228)**	(194)	**(22)**	(24)
Actuarial (gain) loss[2]	**(80)**	(39)	**(26)**	(5)
South Bow - transition of benefit obligation[3]	**—**	(118)	**—**	(1)
Foreign exchange rate changes	**(35)**	58	**(9)**	16
Benefit obligation – end of year	**3,273**	3,342	**249**	288
Change in Plan Assets				
Plan assets at fair value – beginning of year	**3,948**	3,697	**339**	358
Actual return on plan assets	**390**	485	**22**	17
Employer contributions[4,5]	**—**	—	**8**	(41)
Employee contributions	**11**	11	**2**	2
Benefits paid	**(228)**	(194)	**(22)**	(25)
South Bow - transition of plan assets[3]	**—**	(119)	**—**	—
Foreign exchange rate changes	**(40)**	68	**(16)**	28
Plan assets at fair value – end of year	**4,081**	3,948	**333**	339
Funded Status – Plan Surplus	**808**	606	**84**	51

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 increase in the actuarial (gain) loss on the defined benefit plan obligation is primarily attributable to an increase in the weighted discount rate from 4.90 per cent in 2024 to 5.10 per cent in 2025 and an increase in the rate of return. The actuarial (gain) loss on the OPEB Plan obligation is primarily due to changes in demographic assumptions.
3 Reflects the impact of the Spinoff Transaction of the Liquids Pipelines business on October 1, 2024.
4 The Company reduced letters of credit by $111 million in the Canadian DB Plan (2024 – $133 million) for funding purposes.
5 OPEB surplus of nil (2024 - $49 million) was transferred to pay future active employee medical expenses.

Additional pension benefit plan assets were as follows:

at December 31	Pension Benefit Plans	
(millions of Canadian $)	2025	2024
TC Energy plan assets at fair value	**4,081**	3,948
South Bow plan assets held in trust[1]	**17**	110
Plan assets at fair value – end of year	**4,098**	4,058

1 Related to the transfer of pension assets to South Bow. The remaining South Bow pension assets will be adjusted to fair value on the date of the transfer. At December 31, 2025, $17 million is reflected in Other current assets of discontinued operations (2024 - $110 million reflected in Other long-term assets of discontinued operations).

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	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
(millions of Canadian $)	2025	2024	2025	2024
Other long-term assets (Note 14)	**808**	606	**159**	152
Accounts payable and other	**—**	—	**(6)**	(7)
Other long-term liabilities (Note 17)	**—**	—	**(69)**	(94)
	808	606	**84**	51

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 $)	2025	2024	2025	2024
Projected benefit obligation[1]	**—**	—	**(76)**	(101)
Plan assets at fair value	**—**	—	**—**	—
Funded Status – Plan Deficit	**—**	—	**(76)**	(101)

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 $)	2025	2024
Accumulated benefit obligation	**(3,086)**	(3,097)
Plan assets at fair value[1]	**4,098**	4,058
Funded Status – Plan Surplus	**1,012**	961

1 Includes an estimated $17 million (2024 - $110 million) for future transfer to South Bow. The remaining South Bow pension assets will be adjusted to fair value on the date of the transfer.

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, 2025 and December 31, 2024.

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
	2025	2024	2025
Fixed income securities	**45%**	37%	**30% to 55%**
Equity securities	**40%**	49%	**20% to 55%**
Other investments	**15%**	14%	**10% to 35%**
	100%	100%	

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

at December 31			Percentage of Plan Assets	
(millions of Canadian $)	**2025**	**2024**	**2025**	**2024**
Fixed income securities	**26**	44	**0.6%**	1.1%
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 27, Risk management and financial instruments, for additional information.

at December 31 (millions of Canadian $, unless otherwise noted)	Quoted Prices in Active Markets (Level I)		Significant Other Observable Inputs (Level II)		Significant Unobservable Inputs (Level III)		Total		Percentage of Total Portfolio	
	2025	**2024**	**2025**	**2024**	**2025**	**2024**	**2025**	**2024**	**2025**	**2024**
Asset Category[1]										
Cash and Cash Equivalents	**130**	138	**—**	—	**—**	—	**130**	138	**3%**	3%
Equity Securities:										
Canadian	**129**	128	**—**	—	**—**	—	**129**	128	**3%**	3%
U.S.	**969**	1,234	**—**	—	**—**	—	**969**	1,234	**22%**	28%
International	**107**	182	**220**	209	**—**	—	**327**	391	**7%**	9%
Global	**—**	—	**104**	100	**—**	—	**104**	100	**2%**	2%
Emerging	**33**	66	**132**	150	**—**	—	**165**	216	**4%**	5%
Fixed Income Securities:										
Canadian Bonds:										
Federal	**—**	—	**16**	55	**—**	—	**16**	55	**—**	1%
Provincial	**—**	—	**514**	312	**—**	—	**514**	312	**12%**	7%
Municipal	**—**	—	**19**	14	**—**	—	**19**	14	**—**	—
Corporate	**—**	—	**483**	323	**—**	—	**483**	323	**11%**	7%
U.S. Bonds:										
Federal	**147**	151	**260**	255	**—**	—	**407**	406	**9%**	9%
Municipal	**—**	—	**1**	1	**—**	—	**1**	1	**—**	—
Corporate	**185**	246	**193**	158	**—**	—	**378**	404	**9%**	9%
International:										
Government	**3**	4	**19**	17	**—**	—	**22**	21	**1%**	1%
Corporate	**—**	—	**96**	66	**—**	—	**96**	66	**2%**	2%
Mortgage backed	**40**	37	**20**	23	**—**	—	**60**	60	**1%**	1%
Net forward contracts	**—**	—	**(184)**	(201)	**—**	—	**(184)**	(201)	**(4%)**	(4%)
Other Investments:										
Real estate	**—**	—	**—**	—	**292**	276	**292**	276	**7%**	6%
Infrastructure	**—**	—	**—**	—	**315**	282	**315**	282	**7%**	7%
Private equity funds	**—**	—	**—**	—	**55**	32	**55**	32	**1%**	1%
Funds held on deposit	**130**	138	**—**	—	**—**	—	**130**	138	**3%**	3%
Derivatives	**—**	—	**3**	1	**—**	—	**3**	1	**—**	—
	1,873	2,324	**1,896**	1,483	**662**	590	**4,431**	4,397	**100%**	100%

1 Includes $17 million (2024 - $110 million) for future transfer to South Bow.

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

(millions of Canadian $, pre-tax)	
Balance at December 31, 2023	562
Purchases and sales	(15)
Realized and unrealized gains (losses)	43
Balance at December 31, 2024	590
Purchases and sales	**59**
Realized and unrealized gains (losses)	**13**
Balance at December 31, 2025	**662**

In 2026, the Company expects to make funding contributions of $8 million for the other post-retirement benefit plans, approximately $76 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 2026.

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

at December 31 (millions of Canadian $)	**Pension Benefits**	**Other Post-Retirement Benefits**
2026	223	22
2027	224	22
2028	226	22
2029	228	21
2030	230	21
2031 to 2035	1,158	98

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, 2025. 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**	
	2025	**2024**	**2025**	**2024**
Discount rate	**5.10%**	4.90%	**5.45%**	5.45%
Rate of compensation increase	**3.05%**	3.05%	**—**	—

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**		
	2025	**2024**	**2023**	**2025**	**2024**	**2023**
Discount rate	**4.90%**	4.75%	5.15%	**5.45%**	5.15%	5.45%
Expected long-term rate of return on plan assets	**6.75%**	6.60%	6.45%	**4.75%**	4.50%	4.50%
Rate of compensation increase	**3.05%**	3.15%	3.25%	**—**	—	—

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 6.70 per cent weighted-average annual rate of increase in the per capita cost of covered health care benefits was assumed for 2026 measurement purposes. The rate was assumed to decrease gradually to 4.85 per cent by 2036 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 $)	**2025**	**2024**	**2023**	**2025**	**2024**	**2023**
Service cost[1]	**101**	108	93	**1**	1	3
Other components of net benefit cost[1]						
Interest cost	**162**	160	158	**15**	14	16
Expected return on plan assets	**(250)**	(248)	(234)	**(16)**	(14)	(16)
Amortization of past service cost	**—**	—	—	**(2)**	—	—
Amortization of regulatory asset	**—**	—	—	**—**	(2)	—
	(88)	(88)	(76)	**(3)**	(2)	—
Net Benefit Cost Recognized	**13**	20	17	**(2)**	(1)	3

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	**2025**		**2024**		**2023**	
(millions of Canadian $)	**Pension Benefits**	**Other Post-Retirement Benefits**	**Pension Benefits**	**Other Post-Retirement Benefits**	**Pension Benefits**	**Other Post-Retirement Benefits**
Net loss (gain)	**(114)**	**(13)**	(24)	—	71	6

Pre-tax amounts recognized in OCI were as follows:

year ended December 31	**2025**		**2024**		**2023**	
(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	**—**	**—**	6	—	—	—
Funded status adjustment	**(91)**	**(13)**	(101)	(6)	33	(18)
	(91)	**(13)**	(95)	(6)	33	(18)

27. 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 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 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.

Physical and transition risks

Climate-related physical and transition risks may influence demand for, or the operation of, TC Energy's assets, which could affect the Company’s financial performance. TC Energy evaluates the financial resilience of its asset portfolio against a range of future pricing and supply and demand outcomes as part of the Company's strategic planning process.

TC Energy manages exposure to climate-related transition risks and resulting policy changes through its 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. Physical and transition risks are factored into capital planning, enterprise risk management, financial risk management and operational activities. In addition, the Company is actively working to reduce methane emissions intensity from our natural gas transmission and gas storage assets.

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. This exposure grows as the Company's U.S. dollar-denominated operations grow. 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 (loss) from equity investments and Income tax expense (recovery). 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 and cross-currency interest rate swaps as appropriate.

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

at December 31	2025		2024	
(millions of Canadian $, unless otherwise noted)	Fair Value	Notional Amount	Fair Value[1,2]	Notional Amount
U.S. dollar cross-currency interest rate swaps[3]	—	—	(11)	US 100

1 Fair value equals carrying value.

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

3 In 2025 and 2024, Net income (loss) included net realized gains of less than $1 million related to the interest component of cross-currency swap settlements which are reported within Interest expense in the Consolidated statement of income.

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

at December 31 (millions of Canadian $, unless otherwise noted)	2025	2024
Notional amount	**25,700 (US 18,700)**	26,000 (US 18,000)
Fair value	**25,800 (US 18,800)**	25,700 (US 17,800)

Counterparty Credit Risk

TC Energy's exposure to counterparty credit risk includes its cash and cash equivalents, accounts receivable, 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, 2025, the Company recorded an $84 million ECL expense (2024 – $23 million recovery; 2023 - $73 million recovery) with respect to the net investment in leases associated with the in-service TGNH pipelines and $1 million ECL recovery (2024 – $1 million expense; 2023 – $10 million recovery) for contract assets related to certain other Mexico natural gas pipelines. At December 31, 2025, the balance of the ECL provision was $141 million (2024 – $59 million) with respect to the net investment in leases associated with in-service TGNH pipelines. The ECL provision is driven primarily by a probability of default measure for the counterparty, which is calculated using information published by an external third party.

Other than the ECL provision noted above, the Company had no significant credit losses at December 31, 2025 and 2024. At December 31, 2025 and 2024, 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 in addition to the Company's LMCI equity securities which are classified in Level I of the fair value hierarchy. Certain other non-derivative financial instruments included in Cash and cash equivalents, Accounts receivable, Other current assets, Net investment in leases, Restricted investments, 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.

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	2025		2024	
(millions of Canadian $)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion (Note 19)[1,2]	**(46,792)**	**(47,720)**	(47,931)	(48,318)
Junior subordinated notes (Note 20)	**(12,094)**	**(12,061)**	(11,048)	(10,824)
	(58,886)	**(59,781)**	(58,979)	(59,142)

1 Long-term debt is recorded at amortized cost, except for $4.0 billion (2024 – $4.0 billion) that is attributed to hedged risk and recorded at fair value.

2 Net income (loss) for 2025 included unrealized losses of $122 million (2024 – unrealized gains of $128 million) for fair value adjustments attributable to the hedged interest rate risk associated with interest rate swap fair value hedging.

The following tables summarize additional information about the Company's restricted investments that were classified as available-for-sale assets and equity securities with readily determinable fair values:

at December 31	2025		2024	
(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	**—**	**94**	—	33
Maturing within 1-5 years	**26**	**251**	3	256
Maturing within 5-10 years	**1,846**	**4**	1,578	—
Maturing after 10 years	**—**	**16**	—	—
Fair value of equity securities[2,4]	**1,252**	**94**	1,070	64
	3,124	**459**	2,651	353

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 and, in 2025, funds have also been set aside to pay for certain active employee medical benefits.
2 Available-for-sale assets and equity securities with readily determinable fair values 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	2025		2024		2023	
(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)	**167**	**(1)**	218	9	179	13
Net realized gains (losses)[3]	**21**	**22**	3	2	(28)	—

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 liabilities or regulatory assets 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, 2025 (millions of Canadian $)	Cash Flow Hedges	Fair Value Hedges	Held for Trading	Total Fair Value of Derivative Instruments[1]
Other current assets (Note 7)				
Commodities[2]	13	—	371	384
Foreign exchange	9	—	42	51
Interest rate	—	3	—	3
	22	3	413	438
Other long-term assets (Note 14)				
Commodities[2]	2	—	122	124
Foreign exchange	—	—	15	15
Interest rate	—	22	—	22
	2	22	137	161
Total Derivative Assets	24	25	550	599
Accounts payable and other (Note 16)				
Commodities[2]	(1)	—	(341)	(342)
Foreign exchange	—	—	(30)	(30)
Interest rate	—	(8)	—	(8)
	(1)	(8)	(371)	(380)
Other long-term liabilities (Note 17)				
Commodities[2]	(1)	—	(61)	(62)
Foreign exchange	(51)	—	(2)	(53)
Interest rate	—	(34)	—	(34)
	(52)	(34)	(63)	(149)
Total Derivative Liabilities	(53)	(42)	(434)	(529)
Total Derivatives	(29)	(17)	116	70

1 Fair value equals carrying value.

2 Includes purchases and sales of power and natural gas.

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

at December 31, 2024 (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 7)					
Commodities[2]	18	—	—	287	305
Foreign exchange	—	—	—	42	42
	18	—	—	329	347
Other long-term assets (Note 14)					
Commodities[2]	9	—	—	104	113
Foreign exchange	—	—	—	9	9
	9	—	—	113	122
Total Derivative Assets	27	—	—	442	469
Accounts payable and other (Note 16)					
Commodities[2]	(1)	—	—	(291)	(292)
Foreign exchange	—	—	(11)	(183)	(194)
Interest rate	—	(21)	—	—	(21)
	(1)	(21)	(11)	(474)	(507)
Other long-term liabilities (Note 17)					
Commodities[2]	(1)	—	—	(46)	(47)
Foreign exchange	—	—	—	(44)	(44)
Interest rate	—	(118)	—	—	(118)
	(1)	(118)	—	(90)	(209)
Total Derivative Liabilities	(2)	(139)	(11)	(564)	(716)
Total Derivatives	25	(139)	(11)	(122)	(247)

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

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.

Non-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 $)	2025	2024	2025	2024
Long-term debt	**(4,068)**	(3,935)	**(22)**	98

1 At December 31, 2025, adjustments for discontinued hedging relationships included in this balance was a liability of $39 million (2024 – $41 million).

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, 2025	Power	Natural Gas	Foreign Exchange	Interest Rate
Net sales (purchases)[1]	**10,221**	**26**	**—**	**—**
Millions of U.S. dollars	**—**	**—**	**6,342**	**2,950**
Millions of Mexican pesos	**—**	**—**	**15,750**	**—**
Maturity dates	**2026-2044**	**2026-2032**	**2026-2030**	**2030-2034**

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

at December 31, 2024	Power	Natural Gas	Foreign Exchange	Interest Rate
Net sales (purchases)[1]	10,192	53	—	—
Millions of U.S. dollars	—	—	5,648	2,800
Millions of Mexican pesos	—	—	16,750	—
Maturity dates	2025-2044	2025-2031	2025-2027	2030-2034

1 Volumes for power and natural gas derivatives are in GWh and Bcf, 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 $)	2025	2024	2023
Derivative Instruments Held for Trading[1]			
Unrealized gains (losses) in the year			
Commodities[2]	**25**	(71)	132
Foreign exchange (Note 21)	**210**	(266)	246
Interest rate	**—**	(71)	—
Realized gains (losses) in the year			
Commodities	**(10)**	199	192
Foreign exchange (Note 21)	**142**	(152)	155
Interest rate	**8**	29	—
Derivative Instruments in Hedging Relationships			
Realized gains (losses) in the year			
Commodities	**24**	33	(2)
Foreign exchange	**10**	—	—
Interest rate	**(30)**	(52)	(43)

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 in the Consolidated statement of income. Realized and unrealized gains (losses) on foreign exchange and interest rate held-for-trading derivative instruments are included on a net basis in Foreign exchange (gains) losses, net and Interest expense, respectively, in the Consolidated statement of income.

2 In 2025, unrealized gains of $2 million were reclassified to Net Income (loss) from AOCI related to discontinued cash flow hedges (2024 – unrealized gains of $6 million; 2023 – nil).

Derivatives in cash flow hedging relationships

The components of OCI (Note 25) related to the change in fair value of derivatives in cash flow hedging relationships before tax were as follows:

year ended December 31 (millions of Canadian $, pre-tax)	2025	2024	2023
Gains (losses) in fair value of derivative instruments recognized in OCI[1]			
Commodities	**7**	46	—
Foreign exchange	**(38)**	—	—
	(31)	46	—

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 $)	2025	2024	2023
Fair Value Hedges			
Interest rate contracts[1]			
Hedged items	**(179)**	(126)	(98)
Derivatives designated as hedging instruments	**(30)**	(52)	(43)
Cash Flow Hedges			
Reclassification of gains (losses) on derivative instruments from AOCI to Net income (loss)[2,3]			
Commodities[4]	**19**	32	(85)
Foreign exchange[5]	**(50)**	—	—
Interest rate[1]	**(12)**	(12)	(12)

1 Presented within Interest expense in the Consolidated statement of income.

2 Refer to Note 25, Other comprehensive income (loss) and accumulated other comprehensive income (loss), for the components of OCI related to derivatives in cash flow hedging relationships.

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. In 2025, unrealized gains of $2 million were reclassified to Net Income (loss) from AOCI related to discontinued cash flow hedges (2024 - unrealized gains of $6 million; 2023 – nil).

5 Presented within Interest expense and Foreign exchange (gains) losses, net 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, 2025 (millions of Canadian $)	Gross Derivative Instruments	Amounts Available for Offset[1]	Net Amounts
Derivative Instrument Assets			
Commodities	**508**	**(367)**	**141**
Foreign exchange	**66**	**(48)**	**18**
Interest rate	**25**	**(5)**	**20**
	599	**(420)**	**179**
Derivative Instrument Liabilities			
Commodities	**(404)**	**367**	**(37)**
Foreign exchange	**(83)**	**48**	**(35)**
Interest rate	**(42)**	**5**	**(37)**
	(529)	**420**	**(109)**

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

at December 31, 2024 (millions of Canadian $)	Gross Derivative Instruments	Amounts Available for Offset[1]	Net Amounts
Derivative Instrument Assets			
Commodities	418	(290)	128
Foreign exchange	51	(49)	2
	469	(339)	130
Derivative Instrument Liabilities			
Commodities	(339)	290	(49)
Foreign exchange	(238)	49	(189)
Interest rate	(139)	—	(139)
	(716)	339	(377)

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 $93 million and letters of credit of $73 million at December 31, 2025 (2024 – $133 million and $59 million, respectively) to its counterparties.
At December 31, 2025, the Company held less than $1 million in cash collateral and $102 million in letters of credit (2024 – less than $1 million and $75 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, 2025, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $5 million (2024 – net liability of $10 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, 2025, 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, 2025 (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	**154**	**279**	**75**	**508**
Foreign exchange	**—**	**66**	**—**	**66**
Interest rate	**—**	**25**	**—**	**25**
Derivative Instrument Liabilities				
Commodities	**(151)**	**(252)**	**(1)**	**(404)**
Foreign exchange	**—**	**(83)**	**—**	**(83)**
Interest rate	**—**	**(42)**	**—**	**(42)**
	3	**(7)**	**74**	**70**

1 There were no transfers from Level II to Level III for the year ended December 31, 2025.

The Company has entered into contracts, which commenced in 2025 and with terms ranging from 15 to 20 years, to sell 50 MW of power 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, 2024 (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	126	214	78	418
Foreign exchange	—	51	—	51
Derivative Instrument Liabilities				
Commodities	(116)	(217)	(6)	(339)
Foreign exchange	—	(238)	—	(238)
Interest rate	—	(139)	—	(139)
	10	(329)	72	(247)

1 There were no transfers from Level II to Level III for the year ended December 31, 2024.

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)	2025	2024
Balance at beginning of year	**72**	(11)
Net gains (losses) included in Net income (loss)	**21**	54
Transfers to Level II	**(4)**	29
Purchases	**(1)**	—
Settlements	**(14)**	—
Balance at End of Year[1]	**74**	72

1 Revenues include unrealized gains of $21 million attributed to derivatives in the Level III category that were still held at December 31, 2025 (2024 – unrealized gains of $54 million).

28. CHANGES IN OPERATING WORKING CAPITAL

year ended December 31 (millions of Canadian $)	2025[1]	2024[1]	2023[1]
(Increase) decrease in Accounts receivable	**(332)**	(13)	(394)
(Increase) decrease in Inventories	**(55)**	(16)	(56)
(Increase) decrease in Other current assets	**(159)**	(97)	618
Increase (decrease) in Accounts payable and other	**13**	365	(206)
Increase (decrease) in Accrued interest	**30**	(40)	245
(Increase) Decrease in Operating Working Capital	**(503)**	199	207

1 Includes continuing and discontinued operations.

29. ACQUISITIONS AND DISPOSITIONS

U.S. Natural Gas Pipelines

Portland Natural Gas Transmission System (PNGTS)

In August 2024, the Company and its partner, Northern New England Investment Company, Inc., a subsidiary of Énergir L.P. (Énergir), completed the sale of PNGTS to a third party for a gross purchase price of approximately $1.6 billion (US$1.1 billion), including the third party's assumption of US$250 million of senior notes outstanding at PNGTS, split pro rata according to the PNGTS ownership interests (TC Energy – 61.7 per cent, Énergir – 38.3 per cent). The Company's share of the proceeds was $743 million (US$546 million), net of transaction costs. The pre-tax gain attributable to the Company of $572 million (US$408 million) was included in Net gain (loss) on sale of assets in the Consolidated statement of income, and the after-tax gain attributable to the Company was $456 million (US$323 million). The gain includes foreign currency translation gains of $15 million which were reclassified from AOCI to Net income (loss).

Columbia Gas and Columbia Gulf

In October 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 for the year ended December 31, 2023.

At December 31, 2024, as part of the contingent consideration included in the sale, TC Energy accrued a one-time special distribution to GIP of $33 million (US$23 million), or $24 million (US$17 million) net of tax, in Additional paid-in capital.

For the year ended December 31, 2025, the Company recorded $348 million as an out-of-period adjustment to reclassify a pro rata portion of its net investment hedge losses from AOCI to NCI related to the sale of 40 per cent of Columbia Gas and Columbia Gulf on October 4, 2023. Refer to Note 2, Accounting policies, for additional information.

Mexico Natural Gas Pipelines

Transportadora de Gas Natural de la Huasteca

In second quarter 2024, in accordance with the terms of the Company's strategic alliance, and in exchange for cash and non-cash consideration of $561 million (US$411 million), the CFE became a partner in TGNH with a 13.01 per cent equity interest. The transaction was accounted for as an equity transaction, of which $588 million was recognized in Non-controlling interests and $21 million was recognized as AOCI attributable to the CFE’s non-controlling interest. The difference between these amounts and the consideration received was recorded as a reduction to Additional paid-in capital of $27 million.

Power and Energy Solutions

Texas Wind Farms

In the first half of 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 are 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.

30. 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 2025 were $340 million (2024 – $347 million; 2023 – $335 million).

The Company has entered into PPAs with solar and wind-power generating facilities with terms extending to 2038 that require the purchase of generated energy and associated environmental attributes. At December 31, 2025, the total planned capacity secured under the PPAs is approximately 750 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, 2025, TC Energy had approximately $0.8 billion of capital expenditure commitments, primarily consisting of $0.6 billion for its U.S. natural gas pipelines, primarily related to construction costs associated with ANR and other pipeline projects.

Contingencies

TC Energy is subject to laws and regulations governing environmental quality and pollution control. At December 31, 2025, the Company had accrued approximately $6 million (2024 – $8 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 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.

The following contingencies were concluded during the year ended December 31, 2025:

2016 Columbia Pipeline Acquisition Lawsuit

In 2018, former shareholders of Columbia Pipeline Group Inc. (CPG) commenced a class action lawsuit related to the acquisition of CPG by TC Energy in 2016. In 2023, the Delaware Chancery Court (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. TC Energy's allocated share of damages was an estimated US$350 million, plus post-judgment interest. TC Energy appealed the decision to the Delaware Supreme Court and on June 17, 2025, the Supreme Court issued its decision reversing the Court's finding of liability against TC Energy. On July 10, 2025, the Court granted the final order vacating its prior judgment and dismissing plaintiffs' claims against TC Energy. As a result, this matter is now concluded in TC Energy's favour with no liability. There is no further right of appeal.

Pacific Atlantic Pipeline Construction Ltd.

Coastal GasLink LP and Pacific Atlantic Pipeline Construction Ltd., one of the prime contractors on the Coastal GasLink pipeline, and their parent company Bonatti S.p.A, have reached a mutually acceptable resolution to their disputes. The settlement is not an admission of liability by either party and the parties have mutually released their respective claims in the arbitration. Details of the arbitration and the settlement are confidential, but it does include the retention by Coastal GasLink LP of the letter of credit funds drawn in 2024 and the settlement did not have a material impact on TC Energy's financial statements.

Macro Spiecapag Coastal GasLink Joint Venture

Coastal GasLink LP and Macro Spiecapag Coastal GasLink Joint Venture have reached a mutually acceptable resolution to their disputes. The settlement is not an admission of liability by either party and the parties have mutually released their respective claims in the arbitration. Details of the arbitration and the settlement are confidential and the settlement did not have a material impact on TC Energy's financial statements.

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 delivery of natural gas. 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		2025		2024	
(millions of Canadian $)	Term	Potential Exposure[1]	Carrying Value	Potential Exposure[1]	Carrying Value
Bruce Power	Renewable to 2065	**88**	**—**	88	—
Sur de Texas	Renewable to 2053	**78**	**—**	93	—
Other jointly-owned entities	to 2032	**54**	**1**	59	1
		220	**1**	240	1

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

31. 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 $)	2025	2024
ASSETS		
Current Assets		
Cash and cash equivalents	**167**	311
Accounts receivable	**989**	839
Inventories	**211**	205
Other current assets	**65**	121
	1,432	1,476
Plant, Property and Equipment	**49,445**	49,904
Equity Investments	**979**	865
Restricted Investments	**1,150**	950
Regulatory Assets	**109**	53
Goodwill	**456**	479
Other Long-Term Assets	**93**	59
	53,664	53,786
LIABILITIES		
Current Liabilities		
Notes payable	**535**	—
Accounts payable and other	**1,703**	1,866
Accrued interest	**216**	202
Current portion of long-term debt	**575**	2,062
	3,029	4,130
Regulatory Liabilities	**1,458**	1,232
Other Long-Term Liabilities	**51**	70
Deferred Income Tax Liabilities	**7**	7
Long-Term Debt	**13,904**	12,387
	18,449	17,826

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 $)	2025	2024
Balance Sheet Exposure		
Equity Investments		
Bruce Power	**7,780**	7,043
Coastal GasLink	**896**	1,006
Other equity investments	**158**	160
Off-Balance Sheet Exposure[1]		
Bruce Power	**1,955**	1,877
Coastal GasLink[2]	**200**	265
Other equity investments	**—**	2
Maximum exposure to loss	**10,989**	10,353

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. In December 2024, TC Energy made an equity contribution of $3,137 million to Coastal GasLink LP, which used the funds to repay the $3,147 million balance owing to TC Energy under the subordinated loan agreement. The repayment reduced the Company's funding commitment under the subordinated loan agreement to $228 million. In October 2025, TC Energy made an additional $65 million in equity contributions to Coastal GasLink LP, which reduced the Company's funding commitment under the subordinated loan agreement to $163 million. In addition to the subordinated loan agreement, TC Energy has entered into an equity contribution agreement to fund a maximum of $37 million for its proportionate share of the equity requirements related to the Cedar Link project.