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 2022 to that in 2021, and highlights significant changes between 2021 and 2020. 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, 2022, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes.

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

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

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

François L. Poirier
President and
Chief Executive Officer

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

February 13, 2023

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, 2022 and 2021, the related consolidated statements of income, comprehensive income, cash flows, and equity for each of the years in the three-year period ended December 31, 2022, 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, 2022 and 2021, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2022, 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, 2022, 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 13, 2023 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.

Assessment of control of Coastal GasLink Limited Partnership under the variable interest model

As discussed in Notes 2, 7, 11, 12 and 32 to the consolidated financial statements, in July 2022, the Company entered into revised project agreements (collectively, the July 2022 agreements) relating to its investment in Coastal GasLink Limited Partnership (Coastal GasLink LP) and committed to make additional equity contributions. These revisions and additional equity contributions were determined to be a variable interest entity (VIE) reconsideration event for the Company's investment in Coastal GasLink LP. The Company performed a re-assessment of control and determined that Coastal GasLink LP continued to meet the definition of a VIE in which the Company held a variable interest. The re-assessment further determined that the Company was not the primary beneficiary of Coastal GasLink LP as the Company does not have the power, either explicit or implicit through voting rights or otherwise, to direct the activities that most significantly impact the economic performance of Coastal GasLink LP. Accordingly, the Company continued to account for its investment using the equity method of accounting. The carrying value of the Company's equity investment in Coastal GasLink LP was nil and its maximum exposure to loss as it relates to its investment in Coastal GasLink LP was $3.3 billion as of December 31, 2022.

We identified the determination of the primary beneficiary under the VIE model for the Company's interest in Coastal GasLink LP following the reconsideration event as a critical audit matter. Evaluating whether the July 2022 agreements, which included changes to the governing documents and contractual arrangements relating to Coastal GasLink LP, would provide the Company with the substantive power to direct the activities of Costal GasLink LP that most significantly impacted its economic performance, required an increased extent of audit effort due to the complexity of the July 2022 agreements.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of internal control related to the re-assessment of control as a result of the reconsideration event, including the determination of the primary beneficiary. In addition, we performed the following:

- inquired of management and inspected relevant internal materials and the July 2022 agreements to obtain an understanding and evaluate the business purpose of the reconsideration event and its impact on the risks Coastal GasLink LP was designed to create and pass along to its variable interest holders and on the overall governance at Coastal GasLink LP
- evaluated management's determination of:
  - the activities that most significantly impact the economic performance of Coastal GasLink LP
  - how decisions about the most significant activities are made and the party or parties that make them, including whether the Company's economic interest in Coastal GasLink LP provides actual or effective power beyond its stated power
  - whether the Company had substantive power to direct the activities of Coastal GasLink LP that most significantly impact its economic performance

by comparing to relevant internal materials and the July 2022 agreements, as well as other publicly disclosed information.

Evaluation of the Company's maximum exposure to loss resulting from its involvement with Coastal GasLink LP
As discussed in Notes 7 and 32 to the consolidated financial statements, the maximum exposure to loss as a result of the Company's involvement with Coastal GasLink LP, a VIE, as of December 31, 2022 was $3.3 billion. As discussed in Note 2, 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. Under the terms of the July 2022 agreements, the Company is contractually obligated to fund the capital costs to complete the Coastal GasLink pipeline which is estimated to be $3.3 billion (capital costs to complete) through additional equity contributions in Coastal GasLink LP (future funding requirements), which are subject to any final cost sharing between the Coastal GasLink LP partners. The determination of the Company's maximum exposure to loss involves an estimate of capital costs to complete.

We identified the evaluation of the Company's maximum exposure to loss resulting from its involvement with Coastal GasLink LP as a critical audit matter. The estimate of capital costs to complete involved significant audit effort, subjectivity, and judgment. 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 estimate of capital costs to complete and resulting maximum exposure to loss. In addition, we performed the following:

- evaluated the estimate of capital costs to complete used in the Company's determination of its maximum exposure to loss by:
  - inspecting the July 2022 agreements and documents with contractors
  - gaining an understanding of the status of pipeline construction project activities and the related risks by comparing to status reports provided to the partners of Coastal GasLink LP, governance committee minutes, and interviewing project personnel
- tested the Company's maximum exposure to loss resulting from its involvement with Coastal GasLink LP using the estimate of capital costs to complete and future funding requirements in accordance with the July 2022 agreements.

Qualitative goodwill impairment indicators for the Columbia reporting unit

As discussed in Notes 2 and 14 to the consolidated financial statements, the goodwill balance as of December 31, 2022 for the Columbia Pipeline Group, Inc. (Columbia) reporting unit was $9,948 million. The Company assesses goodwill for impairment testing annually or more frequently if events or changes in circumstances indicate that the carrying value of a reporting unit, including goodwill, might be impaired. The Company performed qualitative assessments to determine whether events or changes in circumstances indicate that the Columbia reporting unit goodwill might be impaired. This qualitative assessment was performed as of December 31, 2022.

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

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

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

Valuation of goodwill for the ANR reporting unit

As discussed in Notes 2 and 14 to the consolidated financial statements, the goodwill balance as of December 31, 2022 for the American Natural Resources (ANR) reporting unit was $2,634 million. The Company assesses goodwill for impairment testing annually or more frequently if events or changes in circumstances indicate that the carrying value of a reporting unit, including goodwill, might be impaired. The Company has the option to first assess qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment assessment. In respect of the ANR reporting unit, the Company elected to proceed directly to the quantitative goodwill impairment test as of December 31, 2022 following the passage of time from the previous test as of December 31, 2016, and following the ANR settlement-in-principle in 2022. The quantitative goodwill impairment assessment involves determining the fair value of a reporting unit and comparing that value to the carrying value of the reporting unit, including goodwill. Fair value is estimated using a discounted cash flow model which requires the use of assumptions related to revenue and capital expenditure projections, the valuation multiple and the discount rate (key assumptions). It was determined that the fair value of the ANR reporting unit exceeded its carrying value, including goodwill, as of December 31, 2022.

We identified the valuation of goodwill for the ANR 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 ANR reporting unit. In addition, the audit effort associated with this estimate required specialized skills and knowledge.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls related to the critical audit matter. This included controls related to the Company's determination of the fair value of the ANR reporting unit and key assumptions. We compared the Company's historical revenue and capital expenditure projections to actual results to assess the Company's ability to accurately forecast. We evaluated the Company's revenue and capital expenditure projections by comparing them to the actual results and the outcomes of the ANR settlement-in-principle in 2022. We also compared the Company's revenue and capital expenditure projections to assumptions used in industry publications related to North American and global energy consumption and natural gas production forecasts. In addition, we involved a valuation professional with specialized skills and knowledge, who assisted in:

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

Valuation of goodwill for the Great Lakes reporting unit

As discussed in Notes 2 and 14 to the consolidated financial statements, the Company performed a quantitative goodwill impairment test for the Great Lakes reporting unit during first quarter 2022. The Company assesses goodwill for impairment testing annually or more frequently if events or changes in circumstances indicate that the carrying value of a reporting unit, including goodwill, might be impaired. In respect of the Great Lakes reporting unit, the Company performed the quantitative goodwill impairment test following an unopposed rate case settlement. The quantitative goodwill impairment assessment involves determining the fair value of a reporting unit and comparing that value to the carrying value of the reporting unit, including goodwill. Fair value is estimated using a discounted cash flow model which requires the use of assumptions related to revenue and capital expenditure projections, the valuation multiple and the discount rate (key assumptions). It was determined that the estimated fair value of the Great Lakes reporting unit no longer exceeded its carrying value and a pre-tax goodwill impairment charge of $571 million was recorded during the period.

We identified the valuation of goodwill for the Great Lakes 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 used to estimate fair value could have had a significant effect on the Company’s determination of the fair value of the Great Lakes reporting unit. In addition, the audit effort associated with this estimate required specialized skills and knowledge.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls related to the critical audit matter. This included controls related to the Company’s determination of the fair value of the Great Lakes reporting unit and key assumptions. We compared the Company’s historical revenue and capital expenditure projections to actual results to assess the Company’s ability to accurately forecast. We evaluated the Company’s revenue and capital expenditure projections by comparing them to the actual results and the outcomes of the unopposed rate case settlement with shippers during first quarter of 2022. We also compared the Company’s revenue projections to assumptions used in industry publications related to North American and global energy consumption and natural gas production forecasts. In addition, we involved a valuation professional with specialized skills and knowledge, who assisted in:

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

KPMG LLP

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

Calgary, Canada
February 13, 2023

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, 2022, 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, 2022, 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, 2022 and 2021, the related consolidated statements of income, comprehensive income, cash flows, and equity for each of the years in the three-year period ended December 31, 2022, and the related notes (collectively, the consolidated financial statements), and our report dated February 13, 2023 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting included in the Company's Management's Discussion and Analysis. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

KPMG LLP

Chartered Professional Accountants
Calgary, Canada
February 13, 2023

Consolidated statement of income

year ended December 31 (millions of Canadian $, except per share amounts)	2022	2021	2020
Revenues (Note 5)			
Canadian Natural Gas Pipelines	**4,764**	4,519	4,469
U.S. Natural Gas Pipelines	**5,933**	5,233	5,031
Mexico Natural Gas Pipelines	**688**	605	716
Liquids Pipelines	**2,668**	2,306	2,371
Power and Energy Solutions	**924**	724	412
	14,977	13,387	12,999
Income from Equity Investments (Note 11)	**1,054**	898	1,019
Impairment of Equity Investment (Notes 7 and 11)	**(3,048)**	—	—
Operating and Other Expenses			
Plant operating costs and other	**4,932**	4,098	3,878
Commodity purchases resold	**534**	87	—
Property taxes	**848**	774	727
Depreciation and amortization	**2,584**	2,522	2,590
Goodwill and asset impairment charges and other (Notes 6 and 14)	**453**	2,775	—
	9,351	10,256	7,195
Net Gain/(Loss) on Sale of Assets (Note 30)	**—**	30	(50)
Financial Charges			
Interest expense (Note 20)	**2,588**	2,360	2,228
Allowance for funds used during construction	**(369)**	(267)	(349)
Foreign exchange loss/(gain), net (Note 22)	**185**	(10)	(28)
Interest income and other	**(146)**	(190)	(185)
	2,258	1,893	1,666
Income before Income Taxes	**1,374**	2,166	5,107
Income Tax Expense (Note 19)			
Current	**415**	305	252
Deferred	**174**	(185)	(58)
	589	120	194
Net Income	**785**	2,046	4,913
Net income attributable to non-controlling interests (Note 23)	**37**	91	297
Net Income Attributable to Controlling Interests	**748**	1,955	4,616
Preferred share dividends	**107**	140	159
Net Income Attributable to Common Shares	**641**	1,815	4,457
Net Income per Common Share (Note 24)			
Basic	**$0.64**	$1.87	$4.74
Diluted	**$0.64**	$1.86	$4.74
Dividends Declared per Common Share	**$3.60**	$3.48	$3.24
Weighted Average Number of Common Shares (millions) (Note 24)			
Basic	**995**	973	940
Diluted	**996**	974	940

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 $)	2022	2021	2020
Net Income	**785**	2,046	4,913
Other Comprehensive Income/(Loss), Net of Income Taxes			
Foreign currency translation gains and losses on net investment in foreign operations	**1,494**	(108)	(609)
Change in fair value of net investment hedges	**(36)**	(2)	36
Change in fair value of cash flow hedges	**(39)**	(10)	(583)
Reclassification to net income of gains and losses on cash flow hedges	**42**	55	489
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	**63**	158	12
Reclassification to net income of actuarial gains and losses on pension and other post-retirement benefit plans	**6**	14	17
Other comprehensive income/(loss) on equity investments	**867**	535	(280)
Other comprehensive income/(loss) (Note 26)	**2,397**	642	(918)
Comprehensive Income	**3,182**	2,688	3,995
Comprehensive income attributable to non-controlling interests	**45**	81	259
Comprehensive Income Attributable to Controlling Interests	**3,137**	2,607	3,736
Preferred share dividends	**107**	140	159
Comprehensive Income Attributable to Common Shares	**3,030**	2,467	3,577

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 $)	2022	2021	2020
Cash Generated from Operations			
Net income	**785**	2,046	4,913
Depreciation and amortization	**2,584**	2,522	2,590
Goodwill and asset impairment charges and other (Notes 6 and 14)	**453**	2,775	—
Deferred income taxes (Note 19)	**174**	(185)	(58)
Income from equity investments (Note 11)	**(1,054)**	(898)	(1,019)
Impairment of equity investment (Notes 7 and 11)	**3,048**	—	—
Distributions received from operating activities of equity investments (Note 11)	**1,025**	975	1,123
Employee post-retirement benefits funding, net of expense (Note 27)	**(29)**	(5)	(19)
Net (gain)/loss on sale of assets (Note 30)	**—**	(30)	50
Equity allowance for funds used during construction	**(248)**	(191)	(235)
Unrealized losses/(gains) on financial instruments	**135**	194	(103)
Expected credit loss provision	**163**	—	—
Foreign exchange losses on loan receivable from affiliate (Note 12)	**28**	41	86
Other	**(50)**	(67)	57
Increase in operating working capital (Note 29)	**(639)**	(287)	(327)
Net cash provided by operations	**6,375**	6,890	7,058
Investing Activities			
Capital expenditures (Note 4)	**(6,678)**	(5,924)	(8,013)
Capital projects in development (Note 4)	**(49)**	—	(122)
Contributions to equity investments (Notes 4, 7 and 11)	**(3,433)**	(1,210)	(765)
Keystone XL contractual recoveries (Note 6)	**571**	—	—
Proceeds from sales of assets, net of transaction costs	**—**	35	3,407
Loans to affiliate issued, net (Notes 7 and 12)	**(11)**	(239)	—
Other distributions from equity investments (Note 11)	**2,632**	73	—
Deferred amounts and other	**(41)**	(447)	(559)
Net cash used in investing activities	**(7,009)**	(7,712)	(6,052)
Financing Activities			
Notes payable issued/(repaid), net	**766**	1,003	(220)
Long-term debt issued, net of issue costs	**2,508**	10,730	5,770
Long-term debt repaid	**(1,338)**	(7,758)	(3,977)
Junior subordinated notes issued, net of issue costs	**1,008**	495	—
Gain/(loss) on settlement of financial instruments	**23**	(10)	(130)
Redeemable non-controlling interest repurchased (Note 6)	**—**	(633)	—
Contributions from redeemable non-controlling interest (Note 6)	**—**	—	1,033
Dividends on common shares	**(3,192)**	(3,317)	(2,987)
Dividends on preferred shares	**(106)**	(141)	(159)
Distributions to non-controlling interests	**(44)**	(74)	(221)
Distributions on Class C Interests (Note 6)	**(43)**	(16)	—
Common shares issued, net of issue costs	**1,905**	148	91
Preferred shares redeemed (Note 25)	**(1,000)**	(500)	—
Acquisition of TC PipeLines, LP transaction costs (Note 23)	**—**	(15)	—
Net cash provided by/(used in) financing activities	**487**	(88)	(800)
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**94**	53	(19)
(Decrease)/Increase in Cash and Cash Equivalents	**(53)**	(857)	187
Cash and Cash Equivalents			
Beginning of year	**673**	1,530	1,343
Cash and Cash Equivalents			
End of year	**620**	673	1,530

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

Consolidated balance sheet

at December 31 (millions of Canadian $)	2022	2021
ASSETS		
Current Assets		
Cash and cash equivalents	**620**	673
Accounts receivable	**3,624**	3,092
Loans receivable from affiliates (Note 12)	**—**	1,217
Inventories	**936**	724
Other current assets (Note 8)	**2,152**	1,717
	7,332	7,423
Plant, Property and Equipment (Note 9)	**75,940**	70,182
Net Investment in Leases (Note 10)	**1,895**	—
Equity Investments (Note 11)	**9,535**	8,441
Long-Term Loans Receivable from Affiliate (Notes 7 and 12)	**—**	238
Restricted Investments	**2,108**	2,182
Regulatory Assets (Note 13)	**1,910**	1,767
Goodwill (Note 14)	**12,843**	12,582
Other Long-Term Assets (Note 15)	**2,785**	1,403
	114,348	104,218
LIABILITIES		
Current Liabilities		
Notes payable (Note 16)	**6,262**	5,166
Accounts payable and other (Note 17)	**7,149**	5,099
Dividends payable	**930**	879
Accrued interest	**668**	577
Current portion of long-term debt (Note 20)	**1,898**	1,320
	16,907	13,041
Regulatory Liabilities (Note 13)	**4,520**	4,300
Other Long-Term Liabilities (Note 18)	**1,017**	1,059
Deferred Income Tax Liabilities (Note 19)	**7,648**	6,142
Long-Term Debt (Note 20)	**39,645**	37,341
Junior Subordinated Notes (Note 21)	**10,495**	8,939
	80,232	70,822
EQUITY		
Common shares, no par value (Note 24)	**28,995**	26,716
Issued and outstanding: December 31, 2022 – 1,018 million shares December 31, 2021 – 981 million shares		
Preferred shares (Note 25)	**2,499**	3,487
Additional paid-in capital	**722**	729
Retained earnings	**819**	3,773
Accumulated other comprehensive income/(loss) (Note 26)	**955**	(1,434)
Controlling Interests	**33,990**	33,271
Non-controlling interests (Note 23)	**126**	125
	34,116	33,396
	114,348	104,218

Commitments, Contingencies and Guarantees (Note 31)

Variable Interest Entities (Note 32)

Subsequent Event (Note 33)

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

On behalf of the Board:

François L. Poirier, Director

Una M. Power, Director

Consolidated statement of equity

year ended December 31 (millions of Canadian $)	2022	2021	2020
Common Shares (Note 24)			
Balance at beginning of year	**26,716**	24,488	24,387
Shares issued:			
Under public offering, net of issue costs	**1,754**	—	—
Dividend reinvestment and share purchase plan	**342**	—	—
Exercise of stock options	**183**	165	101
Acquisition of TC PipeLines, LP, net of transaction costs (Note 23)	**—**	2,063	—
Balance at end of year	**28,995**	26,716	24,488
Preferred Shares (Note 25)			
Balance at beginning of year	**3,487**	3,980	3,980
Redemption of shares	**(988)**	(493)	—
Balance at end of year	**2,499**	3,487	3,980
Additional Paid-In Capital			
Balance at beginning of year	**729**	2	—
Issuance of stock options, net of exercises	**(7)**	(6)	2
Keystone XL project-level credit facility retirement and issuance of Class C Interests (Note 6)	**—**	737	—
Acquisition of TC PipeLines, LP (Note 23)	**—**	(398)	—
Repurchase of redeemable non-controlling interest (Note 6)	**—**	394	—
Balance at end of year	**722**	729	2
Retained Earnings			
Balance at beginning of year	**3,773**	5,367	3,955
Net income attributable to controlling interests	**748**	1,955	4,616
Common share dividends	**(3,595)**	(3,409)	(3,045)
Preferred share dividends	**(95)**	(133)	(159)
Redemption of preferred shares	**(12)**	(7)	—
Balance at end of year	**819**	3,773	5,367
Accumulated Other Comprehensive Income/(Loss) (Note 26)			
Balance at beginning of year	**(1,434)**	(2,439)	(1,559)
Other comprehensive income/(loss) attributable to controlling interests	**2,389**	652	(880)
Acquisition of TC PipeLines, LP (Note 23)	**—**	353	—
Balance at end of year	**955**	(1,434)	(2,439)
Equity Attributable to Controlling Interests	**33,990**	33,271	31,398
Equity Attributable to Non-Controlling Interests			
Balance at beginning of year	**125**	1,682	1,634
Net income attributable to non-controlling interests	**37**	90	307
Other comprehensive income/(loss) attributable to non-controlling interests	**8**	(10)	(38)
Distributions declared to non-controlling interests	**(44)**	(74)	(221)
Acquisition of TC PipeLines, LP (Note 23)	**—**	(1,563)	—
Balance at end of year	**126**	125	1,682
Total Equity	**34,116**	33,396	33,080

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

Notes to consolidated financial statements

1. DESCRIPTION OF TC ENERGY'S BUSINESS

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

Canadian Natural Gas Pipelines

The Canadian Natural Gas Pipelines segment primarily consists of the Company's investments in 40,792 km (25,347 miles) of regulated natural gas pipelines currently in operation.

U.S. Natural Gas Pipelines

The U.S. Natural Gas Pipelines segment primarily consists of the Company's investments in 50,164 km (31,170 miles) of regulated natural gas pipelines, 532 Bcf of regulated natural gas storage facilities and other assets currently in operation.

Mexico Natural Gas Pipelines

The Mexico Natural Gas Pipelines segment primarily consists of the Company's investments in 2,775 km (1,723 miles) of regulated natural gas pipelines currently in operation.

Liquids Pipelines

The Liquids Pipelines segment primarily consists of the Company's investments in 4,856 km (3,019 miles) of crude oil pipeline systems currently in operation which connect Alberta and U.S. crude oil supplies to U.S. refining markets in Illinois, Oklahoma and Texas.

Power and Energy Solutions

For the period ended December 31, 2022, the Power and Storage segment has been renamed the Power and Energy Solutions segment, which primarily consists of the Company's investments in approximately 4,300 MW of power generation facilities and 118 Bcf of non-regulated natural gas storage facilities. These assets are located in Alberta, Ontario, Québec and New Brunswick. In addition, TC Energy has physical and virtual power purchase agreements (PPAs) in Canada and the U.S. to buy and/or sell power from wind and solar facilities. These PPAs have the potential to be leases, derivatives or revenue arrangements depending on the contractual terms of the agreement.

2. ACCOUNTING POLICIES

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

Basis of Presentation

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

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

Use of Estimates and Judgments

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

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

- assessment of goodwill impairment indicators and fair value of reporting units that contain goodwill (Note 14)
- capital cost estimates to complete the Coastal GasLink pipeline used to measure TC Energy's maximum exposure to loss resulting from its involvement with Coastal GasLink Limited Partnership (Coastal GasLink LP) and in measuring the fair value of TC Energy's equity investment in Coastal GasLink LP (Notes 7 and 32).

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

- valuation of Keystone XL assets (Note 6)
- recoverability and depreciation rates of plant, property and equipment (Note 9)
- allocation of consideration to lease and non-lease components in a contract that contains a lease (Note 10)
- assumptions used to measure the carrying amount of (Note 10) and expected credit losses (Note 28) on net investment in leases and certain contract assets
- fair value of equity investments not otherwise noted above (Note 11)
- carrying value of regulatory assets and liabilities (Note 13)
- assumptions used to measure the environmental remediation liability from the Keystone pipeline rupture (Note 17)
- recognition of asset retirement obligations (Note 18)
- provisions for income taxes, including valuation allowances and releases (Note 19)
- assumptions used to measure retirement and other post-retirement benefit obligations (Note 27)
- fair value of financial instruments (Note 28)
- fair value of assets and liabilities acquired in a business combination (Note 30)
- provisions for commitments, contingencies and guarantees (Note 31).

TC Energy continues to assess the impact of climate change on the consolidated financial statements. The Company has announced internal greenhouse gas reduction targets and closely monitors regulatory initiatives that may impact its existing businesses. There were also recent developments in the ESG frameworks and regulatory initiatives that could further impact accounting estimates and judgments including, but not limited to, assessment of asset useful lives, goodwill valuation, impairment of plant, property and equipment and accrued environmental costs. The impact of these changes is continuously assessed to ensure any changes in assumptions that would impact estimates listed above are adjusted on a timely basis.

Actual results could differ from these estimates.

Regulation

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

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

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

Revenue Recognition

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

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

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

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

Canadian Natural Gas Pipelines

Capacity Arrangements and Transportation

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

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

Other

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

U.S. Natural Gas Pipelines

Capacity Arrangements and Transportation

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

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

Natural Gas Storage and Other

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

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

Mexico Natural Gas Pipelines

Capacity Arrangements and Transportation

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

Liquids Pipelines

Capacity Arrangements and Transportation

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

Power and Energy Solutions

Power

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

Natural Gas Storage and Other

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

Cash and Cash Equivalents

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

Inventories

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

Assets Held for Sale

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

Plant, Property and Equipment

Natural Gas Pipelines

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

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

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

Other

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

Liquids Pipelines

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

Power and Energy Solutions

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

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

Corporate

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

Capital Projects in Development

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

Leases

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

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

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

Lessee Accounting Policy

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

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

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

Lessor Accounting Policy

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

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

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

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

Impairment of Long-Lived Assets

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

Impairment of Equity Method Investments

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

Acquisitions and Goodwill

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

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

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

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

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 on the Consolidated statement of income, and is presented on the Consolidated balance sheet as a reduction to the carrying value of the related financial asset.

Restricted Investments

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

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

Income Taxes

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

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

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

Asset Retirement Obligations

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

In determining the fair value of ARO, the following assumptions are used:

- the expected retirement date
- the scope and cost of abandonment and reclamation activities that are required
- appropriate inflation and discount rates.

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

Environmental Liabilities and Emission Allowances and Credits

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

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

Stock Options and Other Compensation Programs

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

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

Employee Post-Retirement Benefits

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

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

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

Foreign Currency Transactions and Translation

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

Gains and losses arising from translation of foreign operations' functional currencies to the Company's Canadian dollar reporting currency are reflected in OCI until the operations are sold, at which time the gains and losses are reclassified to net income. Asset and liability accounts are translated at the period-end exchange rates while revenues, expenses, gains and losses are translated at the exchange rates in effect at the time 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 and 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 on the Consolidated statement of cash flows.

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

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

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

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

Long-Term Debt Transaction Costs and Issuance Costs

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

Guarantees

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

Variable Interest Entities

A VIE is a legal entity that does not have sufficient equity at risk to finance its activities without additional subordinated financial support or is structured such that equity investors lack the ability to make significant decisions relating to the entity's operations through voting rights or do not substantively participate in the gains and losses of the entity. The assessment of whether an entity is a VIE and, if so, whether the Company is the primary beneficiary, is completed at the inception of the entity or at a reconsideration event.

Consolidated VIEs

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

Non-Consolidated VIEs

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

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

3. ACCOUNTING CHANGES

Changes in Accounting Policies for 2022

Reference Rate Reform

In March 2020, FASB issued optional guidance with respect to the expected cessation of certain reference interest rates. The guidance provides optional expedients for contracts and hedging relationships that are affected by reference rate reform if certain criteria are met. In December 2022, FASB issued an update to defer the sunset date of the guidance to December 31, 2024. For eligible hedging relationships, the Company has applied the optional expedient allowing an entity to assume that the hedged forecasted transaction in a cash flow hedge is probable of occurring. The Company expects to use practical expedients available in the guidance to treat contract modifications as events that do not require contract remeasurement or reassessment of previous accounting determinations. As such, these changes are not expected to have a material impact on the Company's consolidated financial statements.

Government Assistance

In November 2021, the FASB issued new guidance that expands annual disclosure requirements for entities that account for a transaction with a government by applying a grant or contribution accounting model by analogy to other accounting guidance. Entities are required to disclose the nature of the transactions, the related accounting policies used to account for the transactions, the effect of the transactions on an entity's financial statements and any significant terms and conditions of the transaction. This new guidance is effective for annual disclosure requirements at December 31, 2022 and can be applied either prospectively or retrospectively, with early application permitted. The Company adopted the guidance effective January 1, 2022 on a prospective basis and it did not have a material impact on the Company's consolidated financial statements.

Contract Assets and Liabilities from Contracts with Customers

In October 2021, the FASB issued new guidance that amends the accounting for contract assets and liabilities from contracts with customers acquired in a business combination. At the acquisition date, an acquirer should account for the contract assets and liabilities in accordance with guidance on revenue from contracts with customers. This new guidance is effective January 1, 2023 and is applied prospectively with early adoption permitted. Early adoption requires the application of the amendments retrospectively to all business combinations with an acquisition date in the year of early adoption. The Company elected to adopt the new guidance effective January 1, 2022 and it did not have any impact on the Company's consolidated financial statements.

4. SEGMENTED INFORMATION

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

1 Includes intersegment eliminations.

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

3 Income from equity investments includes the Company's proportionate share of Sur de Texas foreign exchange gains and losses on the peso-denominated loans from affiliates which are fully offset in Foreign exchange loss, net by the corresponding foreign exchange losses and gains on the affiliate receivable balance until March 15, 2022, when it was fully repaid upon maturity. Refer to Note 12, Loans receivable from affiliates, for additional information.

4 Contributions to equity investments in the Corporate segment of $1.2 billion are offset by the equivalent amount in Other distributions from equity investments, although they are reported on a gross basis in the Company's Consolidated statement of cash flows. Refer to Note 12, Loans receivable from affiliates, for additional information.

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

1 Includes intersegment eliminations.

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

3 Income from equity investments includes the Company's proportionate share of Sur de Texas foreign exchange gains and losses on the peso-denominated loans from affiliates which are fully offset in Foreign exchange gain, net by the corresponding foreign exchange losses and gains on the affiliate receivable balance. Refer to Note 12, Loans receivable from affiliates, for additional information.

year ended December 31, 2020 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Energy Solutions	Corporate[1]	Total
Revenues	4,469	5,031	716	2,371	412	—	12,999
Intersegment revenues	—	165	—	—	20	(185) [2]	—
	4,469	5,196	716	2,371	432	(185)	12,999
Income from equity investments	12	264	127	75	455	86 [3]	1,019
Plant operating costs and other	(1,631)	(1,485)	(57)	(654)	(220)	169 [2]	(3,878)
Property taxes	(284)	(337)	—	(101)	(5)	—	(727)
Depreciation and amortization	(1,273)	(801)	(117)	(332)	(67)	—	(2,590)
Net gain/(loss) on sale of assets	364	—	—	—	(414)	—	(50)
Segmented Earnings	1,657	2,837	669	1,359	181	70	6,773
Interest expense							(2,228)
Allowance for funds used during construction							349
Foreign exchange gain, net[3]							28
Interest income and other							185
Income before Income Taxes							5,107
Income tax expense							(194)
Net Income							4,913
Net income attributable to non-controlling interests							(297)
Net Income Attributable to Controlling Interests							4,616
Preferred share dividends							(159)
Net Income Attributable to Common Shares							4,457
Capital Spending							
Capital expenditures	3,503	2,785	173	1,315	179	58	8,013
Capital projects in development	—	—	—	122	—	—	122
Contributions to equity investments	105	—	—	5	655	—	765
	3,608	2,785	173	1,442	834	58	8,900

1 Includes intersegment eliminations.

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

3 Income from equity investments includes the Company's proportionate share of Sur de Texas foreign exchange gains and losses on the peso-denominated loans from affiliates which are fully offset in Foreign exchange gain, net by the corresponding foreign exchange losses and gains on the affiliate receivable balance. Refer to Note 12, Loans receivable from affiliates, for additional information.

at December 31 (millions of Canadian $)	2022	2021
Total Assets by Segment		
Canadian Natural Gas Pipelines	**27,456**	25,452
U.S. Natural Gas Pipelines	**50,038**	45,502
Mexico Natural Gas Pipelines	**9,231**	7,547
Liquids Pipelines	**15,587**	14,951
Power and Energy Solutions	**8,272**	6,563
Corporate	**3,764**	4,203
	114,348	104,218

Geographic Information

year ended December 31 (millions of Canadian $)	2022	2021	2020
Revenues			
Canada – domestic	**4,942**	4,603	4,392
Canada – export	**1,322**	1,226	1,059
United States	**8,025**	6,953	6,832
Mexico	**688**	605	716
	14,977	13,387	12,999

at December 31 (millions of Canadian $)	2022	2021
Plant, Property and Equipment		
Canada	**27,232**	24,890
United States	**43,505**	39,335
Mexico	**5,203**	5,957
	75,940	70,182

5. REVENUES

Disaggregation of Revenues

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

1 Includes $68 million of fee revenues from an affiliate related to development and construction of the Coastal GasLink pipeline project which is 35 per cent owned by TC Energy as at December 31, 2022. Refer to Note 30, Acquisitions and dispositions, for additional information.
2 Includes $37 million of revenues generated from non-lease components for the provision of operating and maintenance services with respect to sales-type leases on the in-service TGNH pipelines. Refer to Note 10, Leases, for additional information.
3 Represents the sales-type lease income on the in-service TGNH pipelines. Refer to Note 10, Leases, for additional information.
4 Other revenues include income from the Company's operating lease arrangements, marketing activities and financial instruments. Refer to Note 10, Leases, and Note 28, Risk management and financial instruments, for additional information on income from operating lease arrangements and financial instruments, respectively.
5 Other revenues from U.S. Natural Gas Pipelines include the amortization of the net regulatory liabilities resulting from H.R.1, the Tax Cuts and Jobs Act (U.S. Tax Reform). Refer to Note 13, Rate-regulated businesses, for additional information.

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

1 Includes $87 million of fee revenues from an affiliate related to development and construction of the Coastal GasLink pipeline project which is 35 per cent owned by TC Energy as at December 31, 2021. Refer to Note 30, Acquisitions and dispositions, for additional information.
2 Other revenues include income from the Company's operating lease arrangements, marketing activities and financial instruments. Refer to Note 10, Leases, and Note 28, Risk management and financial instruments, for additional information on income from operating lease arrangements and financial instruments, respectively.
3 Other revenues from U.S. Natural Gas Pipelines include the amortization of the net regulatory liabilities resulting from U.S. Tax Reform. Refer to Note 13, Rate-regulated businesses, for additional information.

year ended December 31, 2020 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Energy Solutions	Total
Revenues from contracts with customers						
Capacity arrangements and transportation	4,408	4,301	607	2,206	—	11,522
Power generation	—	—	—	—	192	192
Natural gas storage and other[1]	61	654	109	3	106	933
	4,469	4,955	716	2,209	298	12,647
Other revenues[2,3]	—	76	—	162	114	352
	4,469	5,031	716	2,371	412	12,999

1 Includes $138 million of fee revenues from affiliates, of which $77 million was related to the construction of the Sur de Texas pipeline which is 60 per cent owned by TC Energy and $61 million was related to development and construction of the Coastal GasLink pipeline project which is 35 per cent owned by TC Energy as at December 31, 2020. Refer to Note 30, Acquisitions and dispositions, for additional information.

2 Other revenues include income from the Company's operating lease arrangements, marketing activities and financial instruments. Refer to Note 10, Leases, and Note 28, Risk management and financial instruments, for additional information on income from operating lease arrangements and financial instruments, respectively.

3 Other revenues from U.S. Natural Gas Pipelines include the amortization of the net regulatory liabilities resulting from U.S. Tax Reform. Refer to Note 13, Rate-regulated businesses, for additional information.

Contract Balances

at December 31 (millions of Canadian $)	2022	2021	Affected line item on the Consolidated balance sheet
Receivables from contracts with customers	**1,907**	1,627	Accounts receivable
Contract assets (Note 8)	**155**	202	Other current assets
Long-term contract assets (Note 15)	**355**	249	Other long-term assets
Contract liabilities[1] (Note 17)	**62**	90	Accounts payable and other
Long-term contract liabilities (Note 18)	**32**	184	Other long-term liabilities

1 During the year ended December 31, 2022, $51 million (2021 – $95 million) of revenues were recognized that were included in contract liabilities at the beginning of the year.

Contract assets and long-term contract assets primarily relate to the Company's right to revenues for services completed but not invoiced at the reporting date on long-term committed capacity natural gas pipelines contracts. The change in contract assets is primarily related to the transfer to Accounts receivable when these rights become unconditional and the customer is invoiced, as well as the recognition of additional revenues that remain to be invoiced. Contract liabilities and long-term contract liabilities primarily represent unearned revenue for contracted services. In the prior year, contract liabilities and long-term contract liabilities primarily related to force majeure fixed capacity payments received on long-term capacity arrangements in Mexico. During the year ended December 31, 2022, and under the terms of the consolidated Transportation Service Agreement (TSA), the contract liability relating to the in-service TGNH pipelines was netted against certain contract asset balances and settled against the initial recording of the net investment in leases on the Consolidated balance sheet.

Future Revenues from Remaining Performance Obligations

As at December 31, 2022, future revenues from long-term pipeline capacity arrangements and transportation as well as natural gas storage and other contracts extending through 2055 are approximately $23.3 billion, of which approximately $3.8 billion is expected to be recognized in 2023.

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

- right to invoice practical expedient – applied to all U.S. and certain Mexico rate-regulated natural gas pipeline capacity arrangements and flow-through revenues
- variable consideration practical expedient – applied to the following variable revenues:
  - interruptible transportation service revenues as volumes cannot be estimated
  - liquids pipelines capacity revenues based on volumes transported
  - power generation revenues related to market prices that are subject to factors outside the Company's influence
- contracts for a duration of one year or less.

In addition, future revenues from the Company's Canadian natural gas pipelines' regulated firm capacity contracts include fixed revenues only for the time periods that approved tolls under current rate settlements are in effect and certain. Future revenues exclude lease income from the Company's Mexico natural gas pipelines on projects that have not been placed into service.

6. KEYSTONE XL

Asset Impairment Charge and Other

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

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

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

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

In 2022, the Company revised its estimate of contractual and legal obligations related to termination activities based on a review of costs and commitments incurred, which resulted in a $54 million reduction to the asset impairment charge. The Company paid $24 million in 2022 (2021 – $192 million) towards contractual and legal obligations related to termination activities. At December 31, 2022, the remaining balance accrued was $48 million.

For the year ended December 31, 2022, the Company sold plant and equipment with a carrying value of approximately $25 million (2021 – $16 million), resulting in a gain of $64 million (2021 – nil). The Company expects to dispose of the remaining assets in 2023.

In 2022, as part of the Keystone XL impairment charge and other, the Company recognized a $96 million U.S. minimum tax related to the termination of the Keystone XL pipeline project.

Redeemable Non-Controlling Interest and Long-Term Debt

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

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

The changes in Redeemable non-controlling interest classified in mezzanine equity were as follows:

(millions of Canadian $)	
Balance at January 1, 2021	393
Net income attributable to redeemable non-controlling interest	1
Class A Interests repurchased	(394)
Balance at December 31, 2021	—

7. COASTAL GASLINK

Impairment of Equity Investment in Coastal GasLink LP

July 2022 Amended Coastal GasLink Agreements

On July 28, 2022, amended agreements were executed between Coastal GasLink LP, LNG Canada, TC Energy and its Coastal GasLink LP partners (collectively, the July 2022 agreements). These amendments revised the commercial terms between LNG Canada and Coastal GasLink LP, as well as funding provisions between the partners of Coastal GasLink LP and required TC Energy to make a contractual equity contribution to Coastal GasLink LP in the amount of $1.9 billion, which did not result in a change in the Company's 35 per cent ownership. Refer to Note 32, Variable interest entities, for additional information.

The $1.9 billion contractual equity contribution was accrued and initially recognized in Equity investments on the Consolidated balance sheet at the time of signing the July 2022 agreements and is being paid in installments over the period August 2022 to February 2023. At December 31, 2022, $0.5 billion of this equity contribution remained in Accounts payable and other on the Consolidated balance sheet.

Under the terms of the July 2022 agreements, any additional equity financing required by Coastal GasLink LP to fund construction of the pipeline beyond the $1.9 billion equity contribution will initially be financed through a subordinated loan agreement between TC Energy and Coastal GasLink LP. Any amounts outstanding on this loan will be repaid by Coastal GasLink LP to TC Energy, once final costs are known, which will be determined after the pipeline is placed in service. Coastal GasLink LP partners, including TC Energy, will contribute equity to Coastal GasLink LP to ultimately fund Coastal GasLink LP's repayment of this subordinated loan to TC Energy. The Company expects that these additional equity contributions will be predominantly funded by TC Energy but will not result in a change to the Company's 35 per cent ownership.

Capital Cost Update and Impairment

In the fourth quarter of 2022, the Company announced that it expected a material increase in project costs and to the Company's corresponding funding requirements. On February 1, 2023, TC Energy announced that the revised capital cost of the Coastal GasLink pipeline project was expected to be approximately $14.5 billion. While this estimate includes contingencies for certain factors that may be outside the control of Coastal GasLink LP, such as challenging conditions in the Western Canadian labour market, shortages of skilled labour, the impacts of contractor underperformance, as well as drought conditions and erosion and sediment control challenges, as with any complex construction project, the final capital cost is subject to certain risks and uncertainties. The increase in project costs and the Company's corresponding funding requirements were indicators that a decrease in the value of the Company's equity investment had occurred.

As a result, the Company completed a valuation assessment and concluded that the fair value of TC Energy's investment was below its carrying value at December 31, 2022. The Company determined that this was an other-than-temporary impairment of its equity investment in Coastal GasLink LP and a pre-tax impairment charge of $3,048 million ($2,643 million after tax) was recognized in fourth quarter 2022 in Impairment of equity investment in the Consolidated statement of income in the Canadian Natural Gas Pipelines segment. The pre-impairment carrying value of the investment in Coastal GasLink LP at December 31, 2022 consisted of amounts in Equity investments ($2,798 million) and Loans receivable from affiliates ($250 million), which were reduced to a nil balance.

TC Energy expects to fund an additional $3.3 billion related to the revised estimated capital cost to complete the Coastal GasLink pipeline, and a significant portion of the Company's future investment in Coastal GasLink LP is expected to be impaired. The Company will continue to assess for other-than-temporary declines in the fair value of this investment, and the extent of any future impairment charges will depend on the outcome of the valuation assessment performed at the respective reporting date.

The fair value of TC Energy's investment in Coastal GasLink LP at December 31, 2022 was estimated using a 40-year discounted cash flow model. Cash inflows in the model were estimated using contractually agreed upon terms and extension provisions in the TSAs between Coastal GasLink LP and the LNG Canada participants.

For cash outflows in the model, the increase in estimated capital cost and the Company's corresponding funding requirements have the most significant impact on the determination of the fair value of TC Energy's investment in Coastal GasLink LP. The cash flow analysis included a capital cost estimate for the Coastal GasLink pipeline of $14.5 billion. Any change from this capital cost estimate will have an approximate dollar-for-dollar impact on the Company's future funding requirements, subject to any final cost sharing between the Coastal GasLink LP partners, and will impact the estimated fair value of, and the Company's recovery of, its equity investment in Coastal GasLink LP in future periods.

Other assumptions included in the discounted cash flow model include discount rate, long-term project financing plans and estimated completion date. Changes to these other assumptions would not reasonably expect to change the impairment recorded in the fourth quarter of 2022.

A deferred income tax recovery was recognized on the pre-tax impairment charge, net of certain unrealized tax losses not recognized. Refer to Note 19, Income taxes, for additional information.

Subordinated Loan Agreement

In 2021, TC Energy entered into a subordinated loan agreement with Coastal GasLink LP. This loan agreement was amended as part of the July 2022 agreements, and subsequent draws on this loan by Coastal GasLink LP will be provided through an interest-bearing loan, subject to a floating market-based interest rate to fund the capital cost to complete the Coastal GasLink pipeline, which is estimated to be $3.3 billion. As at December 31, 2022, the total capacity committed by TC Energy under this subordinated loan agreement was $1.3 billion. The committed capacity under this loan is expected to increase in the future as required to support additional financing requirements. Any amounts outstanding will be repaid by Coastal GasLink LP to TC Energy, once final costs are known, which will be determined after the pipeline is placed in service. Coastal GasLink LP partners, including TC Energy, will contribute equity to Coastal GasLink LP to ultimately fund Coastal GasLink LP's repayment of this subordinated loan to TC Energy. The Company expects that, in accordance with the July 2022 agreements, these additional equity contributions will be predominantly funded by TC Energy but will not result in a change to the Company's 35 per cent ownership.

As noted above, the $250 million balance outstanding on this loan at December 31, 2022 was reduced to nil as part of the impairment charge recognized in fourth quarter 2022.

The table below reflects the changes in this loan balance for the year ended December 31, 2022.

(millions of Canadian $)	
Outstanding balance as at December 31, 2021	238
Issuances[1]	**112**
Repayments[1]	**(100)**
Outstanding balance at December 31, 2022	**250**
Impairment	**(250)**
Carrying value at December 31, 2022	**—**

1 Presented on a net basis on the Company's Consolidated statement of cash flows.

8. OTHER CURRENT ASSETS

at December 31 (millions of Canadian $)	2022	2021
Fair value of derivative contracts (Note 28)	**614**	169
Current portion of Keystone environmental provision recovery (Note 17)	**410**	—
Current portion of net investment in leases (Note 10)	**291**	—
Contract assets (Note 5)	**155**	202
Keystone XL assets held for sale	**122**	138
Prepaid expenses	**118**	112
Cash provided as collateral	**106**	273
Keystone XL contractual recoveries (Note 6)	**86**	640
Regulatory assets (Note 13)	**67**	53
Other	**183**	130
	2,152	1,717

9. PLANT, PROPERTY AND EQUIPMENT

at December 31	2022			2021		
(millions of Canadian $)	Cost	Accumulated Depreciation	Net Book Value	Cost	Accumulated Depreciation	Net Book Value
Canadian Natural Gas Pipelines						
NGTL System						
Pipeline	**18,119**	**6,285**	**11,834**	14,892	5,751	9,141
Compression	**6,265**	**2,224**	**4,041**	6,191	2,065	4,126
Metering and other	**1,518**	**769**	**749**	1,458	705	753
	25,902	**9,278**	**16,624**	22,541	8,521	14,020
Under construction	**1,552**	**—**	**1,552**	2,285	—	2,285
	27,454	**9,278**	**18,176**	24,826	8,521	16,305
Canadian Mainline						
Pipeline	**10,472**	**7,852**	**2,620**	10,423	7,698	2,725
Compression	**4,328**	**3,247**	**1,081**	4,165	3,125	1,040
Metering and other	**692**	**285**	**407**	652	264	388
	15,492	**11,384**	**4,108**	15,240	11,087	4,153
Under construction	**269**	**—**	**269**	139	—	139
	15,761	**11,384**	**4,377**	15,379	11,087	4,292
Other Canadian Natural Gas Pipelines[1]						
Other	**1,984**	**1,624**	**360**	1,937	1,567	370
Under construction	**455**	**—**	**455**	58	—	58
	2,439	**1,624**	**815**	1,995	1,567	428
	45,654	**22,286**	**23,368**	42,200	21,175	21,025
U.S. Natural Gas Pipelines						
Columbia Gas						
Pipeline	**12,471**	**1,069**	**11,402**	11,205	799	10,406
Compression	**5,190**	**495**	**4,695**	4,522	381	4,141
Metering and other	**4,026**	**346**	**3,680**	3,657	257	3,400
	21,687	**1,910**	**19,777**	19,384	1,437	17,947
Under construction	**659**	**—**	**659**	433	—	433
	22,346	**1,910**	**20,436**	19,817	1,437	18,380
ANR						
Pipeline	**2,066**	**641**	**1,425**	1,820	557	1,263
Compression	**3,785**	**734**	**3,051**	2,559	565	1,994
Metering and other	**1,666**	**440**	**1,226**	1,391	422	969
	7,517	**1,815**	**5,702**	5,770	1,544	4,226
Under construction	**328**	**—**	**328**	833	—	833
	7,845	**1,815**	**6,030**	6,603	1,544	5,059

at December 31 (millions of Canadian $)	2022 Cost	2022 Accumulated Depreciation	2022 Net Book Value	2021 Cost	2021 Accumulated Depreciation	2021 Net Book Value
Other U.S. Natural Gas Pipelines						
Columbia Gulf	**3,511**	**224**	**3,287**	2,749	178	2,571
GTN	**2,964**	**1,239**	**1,725**	2,701	1,071	1,630
Great Lakes	**2,367**	**1,387**	**980**	2,162	1,255	907
Other[2]	**1,928**	**760**	**1,168**	1,755	657	1,098
	10,770	**3,610**	**7,160**	9,367	3,161	6,206
Under construction	**328**	**—**	**328**	533	—	533
	11,098	**3,610**	**7,488**	9,900	3,161	6,739
	41,289	**7,335**	**33,954**	36,320	6,142	30,178
Mexico Natural Gas Pipelines[3]						
Pipeline	**2,299**	**348**	**1,951**	2,957	476	2,481
Compression	**374**	**59**	**315**	480	80	400
Metering and other	**487**	**113**	**374**	626	155	471
	3,160	**520**	**2,640**	4,063	711	3,352
Under construction	**2,547**	**—**	**2,547**	2,590	—	2,590
	5,707	**520**	**5,187**	6,653	711	5,942
Liquids Pipelines						
Keystone Pipeline System						
Pipeline	**9,777**	**2,056**	**7,721**	9,209	1,758	7,451
Pumping equipment	**1,064**	**288**	**776**	1,020	252	768
Tanks and other	**3,723**	**859**	**2,864**	3,534	737	2,797
	14,564	**3,203**	**11,361**	13,763	2,747	11,016
Under construction	**96**	**—**	**96**	72	—	72
	14,660	**3,203**	**11,457**	13,835	2,747	11,088
Intra-Alberta Pipelines	**199**	**19**	**180**	199	14	185
	14,859	**3,222**	**11,637**	14,034	2,761	11,273
Power and Energy Solutions						
Natural Gas Power Generation	**1,260**	**642**	**618**	1,267	605	662
Natural Gas Storage and Other	**820**	**238**	**582**	797	216	581
	2,080	**880**	**1,200**	2,064	821	1,243
Under construction	**80**	**—**	**80**	5	—	5
	2,160	**880**	**1,280**	2,069	821	1,248
Corporate	**900**	**386**	**514**	836	320	516
	110,569	**34,629**	**75,940**	102,112	31,930	70,182

1 Includes Foothills, Ventures LP and Great Lakes Canada.

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

3 During the year ended December 31, 2022, the Company derecognized $2,319 million of Plant, property and equipment and recorded a corresponding asset for net investment in leases for the in-service TGNH pipelines. Refer to Note 10, Leases, for additional information.

10. 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. 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 $)	2022	2021
Operating lease cost[1]	**106**	105
Sublease income	**(5)**	(8)
Net operating lease cost	**101**	97

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 $)	2022	2021
Cash paid for amounts included in the measurement of operating lease liabilities	**67**	69
ROU assets obtained in exchange for new operating lease liabilities	**49**	7

at December 31	2022	2021
Weighted average remaining lease term	**8 years**	9 years
Weighted average discount rate	**3.5%**	3.5%

Maturities of operating lease liabilities are as follows:

(millions of Canadian $)	2022	2021
Less than one year	**68**	63
One to two years	**65**	60
Two to three years	**62**	58
Three to four years	**60**	55
Four to five years	**54**	54
More than five years	**187**	213
Total operating lease payments	**496**	503
Imputed interest	**(63)**	(74)
Operating lease liabilities	**433**	429

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

at December 31 (millions of Canadian $)	**2022**	**2021**
Accounts payable and other	**54**	49
Other long-term liabilities (Note 18)	**379**	380
	433	429

As at December 31, 2022, the carrying value of the ROU assets recorded under operating leases was $415 million (2021 – $415 million) and is included in Plant, property and equipment on the Consolidated balance sheet.

As a Lessor

Operating Leases

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

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

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

The fixed portion of the operating lease income recorded by the Company for the year ended December 31, 2022 was $118 million (2021 – $126 million; 2020 – $130 million).

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

(millions of Canadian $)	**2022**	**2021**
Less than one year	**113**	113
One to two years	**111**	111
Two to three years	**94**	110
Three to four years	**70**	94
Four to five years	**—**	70
	388	498

The cost and accumulated depreciation for facilities accounted for as operating leases was $802 million and $360 million, respectively, at December 31, 2022 (2021 – $812 million and $340 million, respectively).

Sales-Type Leases

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

The consolidated TSA contains a lease with multiple lease and non-lease components. The lease components represent the capacity available to the CFE provided by the in-service pipelines which, at December 31, 2022, included the Tamazunchale pipeline, the north section of the Villa de Reyes pipeline and the east section of the Tula pipeline. The non-lease components represent the Company's services with respect to operation and maintenance of the TGNH pipelines in service.

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

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

At lease commencement, the Company recognized an aggregate net investment in sales-type leases. The TGNH pipelines 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 following table lists the components of the aggregate Net investment in leases reflected on the Company's Consolidated balance sheet:

(millions of Canadian $)	**December 31, 2022**
Net Investment in Leases	
Minimum lease payments	**9,457**
Unearned lease income	**(7,132)**
Lease receivable	**2,325**
Expected credit loss provision[1]	**(150)**
Present value of unguaranteed residual value	**11**
	2,186
Current portion included in Other current assets (Note 8)	**(291)**
	1,895

1 Includes $1 million of foreign currency translation losses.

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

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

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

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

For the year ended December 31, 2022, the Company recorded a $149 million (2021 and 2020 – nil) ECL provision in Plant operating costs and other relating to net investment in leases. Refer to Note 28, Risk management and financial instruments, for additional information.

11. EQUITY INVESTMENTS

(millions of Canadian $)	Ownership Interest at December 31, 2022	Income from Equity Investments year ended December 31			Equity Investments at December 31	
		2022	**2021**	**2020**	**2022**	**2021**
Canadian Natural Gas Pipelines						
TQM[1]	50.0%	**17**	12	12	**165**	118
Coastal GasLink[1]	35.0%	**1**	—	—	**—**	386
U.S. Natural Gas Pipelines						
Northern Border	50.0%	**92**	80	100	**516**	505
Millennium	47.5%	**103**	91	96	**500**	474
Iroquois	50.0%	**77**	55	52	**237**	392
Other	Various	**20**	18	16	**122**	137
Mexico Natural Gas Pipelines						
Sur de Texas	60.0%	**150**	160	213	**1,050**	835
Liquids Pipelines						
Grand Rapids[1]	50.0%	**54**	54	53	**964**	980
Port Neches Link LLC[2]	95.0%	**—**	—	—	**149**	103
HoustonLink Pipeline[1]	50.0%	**1**	1	—	**19**	18
Northern Courier[1,3]	nil	**—**	16	22	**—**	—
Power and Energy Solutions						
Bruce Power[1]	48.3%	**537**	411	439	**5,783**	4,493
Other	Various	**2**	—	16	**30**	—
		1,054	898	1,019	**9,535**	8,441

1 Classified as a non-consolidated VIE. Refer to Note 32, Variable interest entities, for additional information.

2 Classified as a non-consolidated VIE in 2021. Refer to Note 32, Variable interest entities, for additional information.

3 In November 2021, TC Energy sold its remaining 15 per cent equity interest in Northern Courier. Refer to Note 30, Acquisitions and dispositions, for additional information.

Impairment of Equity Investment

On February 1, 2023, Coastal GasLink LP announced that the revised capital cost of the Coastal GasLink pipeline project is expected to be approximately $14.5 billion. The increase in the expected capital cost of the project caused TC Energy to re-evaluate its investment in Coastal GasLink LP, resulting in a pre-tax impairment charge of $3,048 million ($2,643 million after tax) recorded in fourth quarter 2022. Refer to Note 7, Coastal GasLink, for additional information.

Distributions and Contributions

Distributions received from equity investments and contributions made to equity investments for the years ended December 31, 2022, 2021 and 2020 were as follows:

year ended December 31 (millions of Canadian $)	**2022**	**2021**	**2020**
Distributions			
Sur de Texas debt repayments[1,2]	**2,404**	73	—
Distributions received from operating activities of equity investments	**1,025**	975	1,123
Other[1]	**228**	—	—
	3,657	1,048	1,123
Contributions			
Contributions to Coastal GasLink[1]	**1,414**	92	101
Sur de Texas debt financing[1,2]	**1,199**	—	—
Contributions made to other equity investments[1]	**820**	1,118	664
	3,433	1,210	765

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

2 Represents TC Energy's proportionate share of the Sur de Texas debt financing requirements and subsequent repayments. Refer to Note 12, Loans receivable from affiliates, for further information on 2022 refinancing activities with the Sur de Texas joint venture.

Summarized Financial Information of Equity Investments

year ended December 31 (millions of Canadian $)	**2022**	**2021**	**2020**
Income			
Revenues	**5,891**	5,447	5,838
Operating and other expenses	**(3,390)**	(3,293)	(3,341)
Net income	**2,147**	1,859	2,047
Net income attributable to TC Energy	**1,054**	898	1,019

at December 31 (millions of Canadian $)	**2022**	**2021**
Balance Sheet		
Current assets	**3,414**	3,498
Non-current assets	**37,713**	30,165
Current liabilities	**(2,856)**	(2,540)
Non-current liabilities	**(17,690)**	(16,400)

At December 31, 2022, the cumulative carrying value of the Company's equity investments was $299 million lower than the cumulative underlying equity in the net assets primarily due to the 2022 impairment of the equity investment in Coastal GasLink LP, partially offset by fair value adjustments at the time of acquisition or partial monetization as well as interest capitalized during construction. Refer to Note 7, Coastal GasLink, for additional information. At December 31, 2021, the cumulative carrying value of the Company's equity investments was $1,109 million higher than the cumulative underlying equity in the net assets primarily due to fair value adjustments at the time of acquisition or partial monetization as well as interest capitalized during construction.

12. LOANS RECEIVABLE FROM AFFILIATES

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

Sur de Texas

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

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

year ended December 31 (millions of Canadian $)	**2022**	**2021**	**2020**	**Affected line item in the Consolidated statement of income**
Interest income[1]	**19**	87	110	Interest income and other
Interest expense[2]	**(19)**	(87)	(110)	Income from equity investments
Foreign exchange losses[1]	**(28)**	(41)	(86)	Foreign exchange loss/(gain), net
Foreign exchange gains[1]	**28**	41	86	Income from equity investments

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

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

Coastal GasLink Pipeline Limited Partnership

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

Subordinated Demand Revolving Credit Facility

The Company has a subordinated demand revolving credit facility with Coastal GasLink LP to provide additional short-term liquidity and funding flexibility to the project. The facility bears interest at a floating market-based rate and had a capacity of $100 million with an outstanding balance of nil at December 31, 2022 (2021 – $1 million) reflected in Loans receivable from affiliates under Current assets on the Company's Consolidated balance sheet.

Subordinated Loan Agreement

In 2021, TC Energy entered into a subordinated loan agreement with Coastal GasLink LP. This loan agreement was amended on July 28, 2022. Refer to Note 7, Coastal GasLink, for additional information.

13. RATE-REGULATED BUSINESSES

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

Canadian Regulated Operations

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

TC Energy's Canadian natural gas transmission services are supplied under natural gas transportation tariffs that provide for cost recovery, including return of and on capital as approved by the CER. Rates charged for these services are typically set through a process that involves filing an application with the regulator wherein forecasted operating costs, including a return of and on capital, determine the revenue requirement for the upcoming year or multiple years. To the extent actual costs and revenues are more or less than forecasted costs and revenues, the regulators generally allow 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 2020-2024 Revenue Requirement Settlement which includes an ROE of 10.1 per cent on 40 per cent deemed common equity. This settlement provides the NGTL System the opportunity to increase depreciation rates if tolls fall below specified levels and an incentive mechanism for certain operating costs where variances from projected amounts are shared between the NGTL System and its customers.

Canadian Mainline

The Canadian Mainline currently operates under the terms of the 2015-2030 Tolls Application approved in 2014 (the 2014 Decision). The terms in the 2015-2020 six-year settlement of the 2014 Decision, which ended December 31, 2020, included an ROE of 10.1 per cent on 40 per cent deemed common equity, an incentive mechanism that had both upside and downside risk and a $20 million after-tax annual TC Energy contribution to reduce the revenue requirement. Toll stabilization was achieved through the use of deferral accounts, namely the bridging amortization account and the long-term adjustment account (LTAA), to capture the surplus or shortfall between the Company's revenues and cost of service for each year over the 2015-2020 six-year fixed-toll term of the 2014 Decision. The 2014 Decision also directed TC Energy to file an application to review tolls for the 2018-2020 period. In December 2018, a decision was received on the 2018-2020 Tolls Review which included an accelerated amortization of the December 31, 2017 LTAA balance and an increase to the composite depreciation rate from 3.2 per cent to 3.9 per cent.

In April 2020, the CER approved the six-year unanimous negotiated settlement (2021-2026 Mainline Settlement) effective January 1, 2021. Similar to the previous settlement, the 2021-2026 Mainline Settlement maintains a base equity return of 10.1 per cent on 40 per cent deemed common equity and includes an incentive to either achieve cost efficiencies and/or increase revenues on the pipeline with a beneficial sharing mechanism to both the shippers and TC Energy. An estimate of the remaining LTAA balance at the end of 2020 was included as an adjustment in the calculation of Mainline fixed tolls and amortized over the settlement term. Similar to the LTAA, the short-term adjustment accounts (STAA) captures the surplus or shortfall between system revenues and cost of service each year under the 2021-2026 Mainline Settlement and the Company will commence amortization over the remaining settlement term when predetermined thresholds per the settlement agreement are met.

U.S. Regulated Operations

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

Columbia Gas

Columbia Gas' natural gas transportation and storage services are provided under a tariff at rates subject to FERC approval. Columbia Gas reached a settlement with its customers effective February 2021 and received FERC approval on February 25, 2022. As part of the settlement, there is a moratorium on any further rate changes until April 1, 2025. Columbia Gas must file for new rates with an effective date no later than April 1, 2026. Previously accrued rate refund liabilities were refunded to customers, including interest, in second quarter 2022.

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

ANR Pipeline

ANR Pipeline operated under rates established through a 2016 FERC-approved rate settlement until July 31, 2022. To meet terms of the 2016 settlement, on January 28, 2022, ANR Pipeline filed a Section 4 Rate Case with FERC requesting an increase to maximum transportation rates. On December 14, 2022 ANR Pipeline filed a Stipulation and Agreement of Settlement (ANR Settlement) with FERC. The ANR Settlement reflects the agreement of ANR Pipeline and its shippers and FERC staff to resolve all outstanding issues pertaining to the original rate case filing on January 28, 2022. The ANR Settlement was uncontested and is currently awaiting final FERC approval which is expected in early 2023.

Columbia Gulf

Columbia Gulf reached a rate settlement with its customers, which was approved by FERC in December 2019, increasing Columbia Gulf's recourse rates which took effect on August 1, 2020. This settlement established a rate case and tariff filing moratorium, which expired on August 1, 2022, and Columbia Gulf is required to file a general rate case under Section 4 of the NGA no later than January 31, 2027, with new rates to be effective August 1, 2027.

Great Lakes

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

On March 18, 2022, Great Lakes filed a rate settlement (2022 Great Lakes Settlement) with FERC that satisfies the obligations from the 2017 settlement that Great Lakes file for rates to become effective no later than October 1, 2022. The 2022 Great Lakes Settlement, approved by FERC on April 26, 2022, maintains Great Lakes' existing maximum transportation rates through October 31, 2025. The 2022 Great Lakes Settlement contains a moratorium until October 31, 2025. Great Lakes will be required to file for new rates no later than April 30, 2025, with such new rates effective no later than November 1, 2025.

Tuscarora

Tuscarora operates under rates established as part of the FERC-approved rate settlement effective August 1, 2019. Under the terms of this settlement, Tuscarora is required to file for new rates to be effective no later than February 1, 2023. Tuscarora filed a general NGA Section 4 Rate Case with FERC on July 29, 2022, requesting an increase to its maximum rates effective February 1, 2023, subject to refund.

Mexico Regulated Operations

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

Regulatory Assets and Liabilities

at December 31 (millions of Canadian $)	2022	2021	Remaining Recovery/ Settlement Period (years)
Regulatory Assets			
Deferred income taxes[1]	**1,817**	1,509	n/a
Pensions and other post-retirement benefits[1,2]	**28**	203	n/a
Foreign exchange on long-term debt[1,3]	**19**	3	1-7
Operating and debt-service regulatory assets[4]	**2**	1	1
Other	**111**	104	n/a
	1,977	1,820	
Less: Current portion included in Other current assets (Note 8)	**67**	53	
	1,910	1,767	
Regulatory Liabilities			
Pipeline abandonment trust balances[5]	**2,014**	2,086	n/a
Deferred income taxes – U.S. Tax Reform[6]	**1,197**	1,141	n/a
Canadian Mainline bridging amortization account[7]	**429**	483	8
Cost of removal[8]	**337**	254	n/a
Canadian Mainline short-term adjustment and toll-stabilization accounts[7,9]	**284**	60	n/a
Canadian Mainline long-term adjustment account[7,10]	**149**	186	4
Deferred income taxes[1]	**181**	139	n/a
Operating and debt-service regulatory liabilities[4]	**50**	32	1
ANR post-employment and retirement benefits other than pension[11]	**43**	40	n/a
Pensions and other post-retirement benefits[2]	**10**	13	n/a
Other	**99**	66	n/a
	4,793	4,500	
Less: Current portion included in Accounts payable and other (Note 17)	**273**	200	
	4,520	4,300	

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 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.

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 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.

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

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

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

8 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 Under the terms of the 2021-2026 Mainline Settlement, the STAA account will commence amortization when predetermined thresholds are met, over the term outlined per the settlement agreement.

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

11 This balance represents the amount ANR estimates it would be required to refund to its customers for post-retirement and post-employment benefit amounts collected through its FERC-approved rates that have not been used to pay benefits to its employees. Pursuant to a FERC-approved rate settlement, the $43 million (US$32 million) balance at December 31, 2022 is subject to resolution through future regulatory proceedings and, accordingly, a settlement period cannot be determined at this time.

14. GOODWILL

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

at December 31 (millions)	2022 Canadian dollars	2022 US dollars	2021 Canadian dollars	2021 US dollars
Columbia Pipeline Group, Inc.	**9,948**	**7,351**	9,303	7,351
ANR	**2,634**	**1,946**	2,464	1,946
Great Lakes	**165**	**122**	725	573
North Baja	**65**	**48**	61	48
Tuscarora	**31**	**23**	29	23
	12,843	**9,490**	12,582	9,941

Changes in Goodwill were as follows:

(millions of Canadian $)	U.S. Natural Gas Pipelines
Balance at January 1, 2021	12,679
Foreign exchange rate changes	(97)
Balance at December 31, 2021[1]	12,582
Great Lakes impairment charge	**(571)**
Foreign exchange rate changes	**832**
Balance at December 31, 2022[1]	**12,843**

1 Represents gross amount of goodwill as at December 31, 2022 of $14,578 million (2021 – $13,746 million), net of accumulated impairment of $1,735 million (2021 – $1,164 million).

As part of the annual goodwill impairment assessment at December 31, 2022, the Company evaluated qualitative factors impacting the fair value of the underlying reporting units for all reporting units other than the ANR reporting unit. It was determined that it was more likely than not that the fair value of these reporting units exceeded their carrying amounts, including goodwill.

ANR

The Company elected to proceed directly to a quantitative annual impairment test at December 31, 2022 for the $2,634 million (US$1,946 million) of goodwill related to the ANR reporting unit following the passage of time from the previous test at December 31, 2016, and subsequent to the ANR settlement-in-principle in 2022. It was determined that the fair value of ANR exceeded its carrying value, including goodwill at December 31, 2022.

Great Lakes

During first quarter 2022, TC Energy elected to pursue an unanticipated opportunity to extend the existing recourse rates on Great Lakes. This prompted the Company to re-evaluate the impact of maintaining recourse rates at the current level as opposed to moving forward with the previously presumed Great Lakes rate case process in 2022.

On March 18, 2022, Great Lakes reached a pre-filing settlement with its customers and filed an unopposed rate case settlement with FERC by which Great Lakes and the settling parties agreed to maintain existing recourse rates through October 31, 2025. While the settlement created short-term rate certainty, it prompted a re-evaluation of Great Lakes' long-term free cash flows. With recourse rates maintained at the current level for the next three years, the expectation of increased contracting, growth and other near-term commercial and regulatory opportunities were negatively impacted.

Management performed a quantitative impairment test that evaluated a range of assumptions through a discounted cash flow analysis using a risk-adjusted discount rate. It was determined that the estimated fair value of the Great Lakes reporting unit no longer exceeded its carrying value, including goodwill and that an impairment charge was necessary. As a result, the Company recorded a pre-tax goodwill impairment charge of $571 million ($531 million after tax) within the U.S. Natural Gas Pipelines segment that is included in Goodwill and asset impairment charges and other in the Company's Consolidated statement of income. The remaining goodwill balance related to Great Lakes is US$122 million at December 31, 2022 (December 31, 2021 – US$573 million). There is a risk that continued reductions in future cash flow forecasts and adverse changes in other key assumptions could result in a future impairment of the goodwill balance relating to Great Lakes.

The Company elected to allocate the goodwill impairment charge first to goodwill that is non-deductible for income tax purposes, with any remaining charge allocated to tax-deductible goodwill. The majority of the Great Lakes goodwill impairment charge was allocated to non-deductible goodwill and the income tax recovery of $40 million was attributable to the portion of the goodwill that was deductible for income tax purposes.

The estimated fair value measurements used in the Company's goodwill impairment analysis is classified as Level III. In the determination of the fair value utilized in the quantitative goodwill impairment test for each reporting unit, the Company used its projections of future cash flows and applied a risk-adjusted discount rate which involved significant estimates and judgments.

Asset Divestiture Program

TC Energy has announced an asset divestiture program that may involve the divestiture of reporting units, or portions thereof. To the extent that a sale transaction indicates a value lower than previously estimated, goodwill could be impaired. These divestitures could include assets that have associated goodwill. In the event of a partial sale of such assets, the anticipated proceeds will be considered in management's assessment of fair value of the retained interest and any associated goodwill.

15. OTHER LONG-TERM ASSETS

at December 31 (millions of Canadian $)	**2022**	**2021**
Deferred income tax assets (Note 19)	**1,070**	509
Employee post-retirement benefits (Note 27)	**563**	312
Long-term contract assets (Note 5)	**355**	249
Keystone environmental provision recovery (Note 17)	**240**	—
Capital projects in development	**99**	42
Fair value of derivative contracts (Note 28)	**91**	48
Keystone XL contractual recoveries (Note 6)	**44**	50
Other	**323**	193
	2,785	1,403

16. NOTES PAYABLE

(millions of Canadian $, unless otherwise noted)	2022 Outstanding at December 31	2022 Weighted Average Interest Rate per Annum at December 31	2021 Outstanding at December 31	2021 Weighted Average Interest Rate per Annum at December 31
Canada[1]	**5,971**	**4.9%**	4,953	0.4%
U.S. (2022 – nil; 2021 – US$54)	**—**	**—**	68	0.3%
Mexico (2022 – US$215; 2021 – US$115)[2]	**291**	**6.0%**	145	1.7%
	6,262		5,166	

1 At December 31, 2022, Notes payable consisted of Canadian dollar-denominated notes of $2,810 million (2021 – $1,989 million) and U.S. dollar-denominated notes of US$2,336 million (2021 – US$2,341 million).

2 The demand senior unsecured revolving credit facility for the Company's Mexico subsidiary can be drawn in either Mexican pesos or U.S. dollars, up to the total facility amount of MXN$5.0 billion or the U.S. dollar equivalent.

On November 22, 2022, TransCanada PipeLines Limited (TCPL) entered into a 364-day $1.5 billion senior unsecured term loan bearing interest at a floating rate. At December 31, 2022 and 2021, Notes payable reflects short-term borrowings in Canada by TCPL, in the U.S. by TransCanada PipeLine USA Ltd. (TCPL USA) and in Mexico by a wholly-owned Mexican subsidiary.

At December 31, 2022, total committed revolving and demand credit facilities were $12.9 billion (2021 – $12.4 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	2022 Total Facilities	2022 Unused Capacity[1]	2021 Total Facilities
Committed, syndicated, revolving, extendible, senior unsecured credit facilities[2]:					
TCPL	Supports TCPL's Canadian dollar commercial paper program and for general corporate purposes	December 2027	**3.0**	**1.7**	3.0
TCPL / TCPL USA / Columbia / TransCanada American Investments Ltd.	Supports TCPL's and TCPL USA's U.S. dollar commercial paper programs and for general corporate purposes of the borrowers, guaranteed by TCPL	December 2023	**US 3.0**	**US 0.6**	US 4.5
TCPL / TCPL USA / Columbia / TransCanada American Investments Ltd.	Supports TCPL's and TCPL USA's U.S. dollar commercial paper programs and for general and corporate purposes of the borrowers, guaranteed by TCPL	December 2025	**US 2.5**	**US 2.5**	US 1.0
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	**2.1** [3]	**1.0**	2.1 [3]
Mexico subsidiary	For Mexico general corporate purposes, guaranteed by TCPL	Demand	**MXN 5.0** [3]	**MXN 0.8**	MXN 5.0 [3]

1 Unused capacity is net of commercial paper outstanding and facility draws.

2 Provisions of various trust indentures and credit arrangements with the Company's subsidiaries can restrict their ability to declare and pay dividends or make distributions under certain circumstances. If such restrictions apply, they may, in turn, have an impact on the Company's ability to declare and pay dividends on common and preferred shares. These trust indentures and credit arrangements also require the Company to comply with various affirmative and negative covenants and maintain certain financial ratios. At December 31, 2022, the Company was in compliance with all financial covenants.

3 Or the U.S. dollar equivalent.

For the year ended December 31, 2022, the cost to maintain the above facilities was $14 million (2021 – $17 million; 2020 – $21 million).

17. ACCOUNTS PAYABLE AND OTHER

at December 31 (millions of Canadian $)	2022	2021
Trade payables	**4,330**	4,183
Fair value of derivative contracts (Note 28)	**871**	221
Keystone environmental provision	**650**	—
Coastal GasLink contractual contribution (Notes 7, 11 and 32)	**537**	—
Regulatory liabilities (Note 13)	**273**	200
Contract liabilities (Note 5)	**62**	90
Class C Interests (Note 6)	**37**	75
Other	**389**	330
	7,149	5,099

Keystone Environmental Provision

In December 2022, a pipeline rupture occurred in Washington County, Kansas on the Cushing Extension section of the Keystone Pipeline System. At December 31, 2022, the Company accrued an environmental remediation liability of $650 million, before expected insurance recoveries, and not including potential fines and penalties which are currently indeterminable. This amount represents the Company's estimate of costs relating to emergency response, environmental remediation and cleanup activities required to fully remediate the site and has been recorded on an undiscounted basis. The accrual is based on certain assumptions such as the scope of remediation efforts that are subject to revision in future periods which could result in future modifications of this accrual. Therefore, it is reasonably possible that the Company will incur additional costs beyond the amounts accrued. TC Energy has accrued the minimum estimated cost of environmental remediation; however, the Company is currently unable to estimate a maximum range of possible costs.

TC Energy has appropriate insurance policies in place and it is probable that the majority of estimated environmental remediation costs will be eligible for recovery under the Company's existing insurance coverage. The Company has recorded an asset of $410 million in Other current assets and $240 million in Other long-term assets, representing the expected recovery of the estimated environmental remediation costs. Estimated insured amounts expected to be recovered from insurers are presented in the same income statement line as the environmental remediation costs. To the extent costs beyond the amounts accrued are incurred, they will be evaluated under the Company's existing insurance policies. The Company expects remediation activities to be substantially completed within a year.

18. OTHER LONG-TERM LIABILITIES

at December 31 (millions of Canadian $)	2022	2021
Operating lease obligations (Note 10)	**379**	380
Fair value of derivative contracts (Note 28)	**151**	47
Employee post-retirement benefits (Note 27)	**111**	174
Asset retirement obligations	**79**	61
Long-term contract liabilities (Note 5)	**32**	184
Other	**265**	213
	1,017	1,059

19. INCOME TAXES

Geographic Components of Income before Income Taxes

year ended December 31 (millions of Canadian $)	2022	2021	2020
Canada	**(2,154)**	(292)	691
Foreign	**3,528**	2,458	4,416
Income before Income Taxes	**1,374**	2,166	5,107

Provision for Income Taxes

year ended December 31 (millions of Canadian $)	2022	2021	2020
Current			
Canada	**43**	29	(54)
Foreign	**372**	276	306
	415	305	252
Deferred			
Canada	**(467)**	(327)	(224)
Foreign	**641**	142	166
	174	(185)	(58)
Income Tax Expense	**589**	120	194

Reconciliation of Income Tax Expense

year ended December 31 (millions of Canadian $)	2022	2021	2020
Income before income taxes	**1,374**	2,166	5,107
Federal and provincial statutory tax rate	**23.0%**	23.0%	24.0%
Expected income tax expense	**316**	498	1,226
Foreign income tax rate differentials	**(271)**	(230)	(258)
Income tax differential related to regulated operations	**(174)**	(139)	(228)
Income from non-controlling interests and equity investments	**(54)**	(70)	(141)
Valuation allowance/(releases)	**199**	(8)	(400)
Non-taxable capital (gains) and losses	**173**	—	(62)
Settlement of Mexico prior years' income tax assessments	**196**	—	—
U.S. minimum tax	**96**	—	—
Non-deductible goodwill impairment	**91**	—	—
Impact of Mexico inflationary adjustments	**24**	32	7
Other	**(7)**	37	50
Income Tax Expense	**589**	120	194

Deferred Income Tax Assets and Liabilities

at December 31 (millions of Canadian $)	2022	2021
Deferred Income Tax Assets		
Tax loss and credit carryforwards	**1,519**	1,163
Regulatory and other deferred amounts	**571**	537
Unrealized foreign exchange losses on long-term debt	**333**	130
Other	**193**	46
	2,616	1,876
Less: Valuation allowance	**640**	229
	1,976	1,647
Deferred Income Tax Liabilities		
Difference in accounting and tax bases of plant, property and equipment	**6,686**	5,616
Equity investments	**1,152**	1,219
Taxes on future revenue requirement	**397**	333
Financial instruments	**126**	—
Other	**193**	112
	8,554	7,280
Net Deferred Income Tax Liabilities	**6,578**	5,633

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

at December 31 (millions of Canadian $)	2022	2021
Deferred Income Tax Assets		
Other long-term assets (Note 15)	**1,070**	509
Deferred Income Tax Liabilities		
Deferred income tax liabilities	**7,648**	6,142
Net Deferred Income Tax Liabilities	**6,578**	5,633

At December 31, 2022, the Company has recognized the benefit of non-capital loss carryforwards of $5,429 million (2021 – $4,067 million) for federal and provincial purposes in Canada, which expire from 2030 to 2042. The Company has not yet recognized the benefit of capital loss carryforwards of $251 million (2021 – $21 million) for federal and provincial purposes in Canada which have no expiry date. The Company also has Ontario corporate minimum tax (CMT) credits of $126 million (2021 – $113 million), which expire from 2026 to 2042. As of December 31, 2022, the Company has not recognized the benefit of CMT credits of $22 million (2021 – nil).

At December 31, 2022, the Company has fully utilized the benefit of net operating loss carryforwards (2021 – US$446 million) for federal purposes in the U.S.

At December 31, 2022, the Company has recognized the benefit of net operating loss carryforwards of US$69 million (2021 – US$10 million) in Mexico, which expire from 2024 to 2032.

TC Energy recorded an income tax valuation allowance of $640 million and $229 million against the deferred income tax asset balances at December 31, 2022 and 2021, respectively. The increase in the valuation allowance is primarily a result of the foreign exchange movement on unrecognized capital losses and the unrealized capital losses on the Coastal GasLink equity investment. At December 31, 2022, the Company recorded $173 million in valuation allowance as a result of the Coastal GasLink equity investment impairment that resulted in a portion of the impairment having unrealized non-taxable capital losses. These losses have not been recognized as of December 31, 2022. At each reporting date, the Company considers new evidence, both positive and negative, that could affect its view of the future realization of deferred tax assets. As at December 31, 2022, the Company determined there was sufficient positive evidence to conclude that it is more likely than not that the net deferred tax assets will be realized.

At December 31, 2020, the Company recorded $400 million in valuation allowance releases primarily a result of the final investment decision to proceed with the construction of the Keystone XL pipeline, the sale of the Ontario natural gas-fired power plants and the sale of a 65 per cent equity interest in Coastal GasLink LP. Refer to Note 30, Acquisitions and dispositions, for additional information on the sale of the Ontario natural gas-fired power plants and Coastal GasLink LP equity sale.

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, 2022 by approximately $1,216 million (2021 – $896 million) if there had been a provision for these taxes.

Income Tax Payments

Income tax payments of $394 million, net of refunds, were made in 2022 (2021 – payments, net of refunds, of $371 million; 2020 – payments, net of refunds, of $252 million).

Reconciliation of Unrecognized Tax Benefit

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

at December 31 (millions of Canadian $)	2022	2021	2020
Unrecognized tax benefit at beginning of year	**80**	52	29
Gross increases – tax positions in prior years	**6**	5	26
Gross decreases – tax positions in prior years	**—**	(1)	(2)
Gross increases – tax positions in current year	**7**	26	1
Lapse of statutes of limitations	**(2)**	(2)	(2)
Unrecognized Tax Benefit at End of Year	**91**	80	52

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, 2022 reflects $6 million interest expense (2021 – $1 million; 2020 – $4 million). At December 31, 2022, the Company had accrued $18 million in interest expense (2021 – $12 million; 2020 – $11 million). The Company incurred no penalties associated with income tax uncertainties related to Income tax expense for the years ended December 31, 2022, 2021 and 2020 and no penalties were accrued as at December 31, 2022, 2021 and 2020.

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

TC Energy and its subsidiaries are subject to either Canadian federal and provincial income tax, U.S. federal, state and local income tax or the relevant income tax in other international jurisdictions. The Company has substantially concluded all Canadian federal and provincial income tax matters for the years through 2014. Substantially all material U.S. federal, state and local income tax matters have been concluded for years through 2015. Substantially all material Mexico income tax matters have been concluded for years through 2014, except as further described below.

Mexico Tax Audit

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

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

20. LONG-TERM DEBT

Outstanding amounts		**2022**		**2021**	
(millions of Canadian $, unless otherwise noted)	**Maturity Dates**	**Outstanding at December 31**	**Interest Rate**[1]	**Outstanding at December 31**	**Interest Rate**[1]
TRANSCANADA PIPELINES LIMITED					
Medium Term Notes					
Canadian	2023 to 2052	**13,966**	**4.5%**	12,491	4.2%
Senior Unsecured Notes					
U.S. (2022 – US$15,542; 2021 – US$16,542)	2023 to 2049	**21,032**	**4.9%**	20,936	4.8%
		34,998		33,427	
NOVA GAS TRANSMISSION LTD.					
Debentures and Notes					
Canadian	2024	**100**	**9.9%**	100	9.9%
U.S. (2022 and 2021 – US$200)	2023	**271**	**7.9%**	254	7.9%
Medium Term Notes					
Canadian	2025 to 2030	**504**	**7.4%**	504	7.4%
U.S. (2022 and 2021 – US$33)	2026	**44**	**7.5%**	41	7.5%
		919		899	
COLUMBIA PIPELINE GROUP, INC.					
Senior Unsecured Notes[2]					
U.S. (2022 and 2021 – US$1,500)	2025 to 2045	**2,030**	**4.9%**	1,898	4.9%
ANR PIPELINE COMPANY					
Senior Unsecured Notes					
U.S. (2022 – US$1,172; 2021 – US$372)	2024 to 2037	**1,587**	**4.1%**	472	5.3%
TC PIPELINES, LP					
Senior Unsecured Notes					
U.S. (2022 and 2021 – US$850)	2025 to 2027	**1,150**	**4.2%**	1,076	4.2%
GAS TRANSMISSION NORTHWEST LLC					
Senior Unsecured Notes					
U.S. (2022 and 2021 – US$325)	2030 to 2035	**440**	**4.3%**	411	4.3%

Outstanding amounts		**2022**		**2021**	
(millions of Canadian $, unless otherwise noted)	**Maturity Dates**	**Outstanding at December 31**	**Interest Rate**[1]	**Outstanding at December 31**	**Interest Rate**[1]
PORTLAND NATURAL GAS TRANSMISSION SYSTEM					
Senior Unsecured Notes					
U.S. (2022 and 2021 – US$250)	2030 to 2031	**338**	**2.8%**	316	2.8%
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP					
Senior Unsecured Notes					
U.S. (2022 – US$146; 2021 – US$167)	2028 to 2030	**198**	**7.6%**	211	7.6%
TUSCARORA GAS TRANSMISSION COMPANY					
Unsecured Term Loan					
U.S. (2022 – US$34; 2021 – US$36)	2024	**46**	**6.5%**	46	1.3%
		41,706		38,756	
Current portion of long-term debt		**(1,898)**		(1,320)	
Unamortized debt discount and issue costs		**(239)**		(243)	
Fair value adjustments[3]		**76**		148	
		39,645		37,341	

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 Certain subsidiaries of Columbia have guaranteed the principal payments of Columbia's senior unsecured notes. Each guarantor of Columbia's obligations is required to comply with covenants under the debt indenture and, in the event of default, the guarantors would be obligated to pay the principal and related interest.

3 The fair value adjustments include $140 million (2021 – $148 million) related to the acquisition of Columbia Pipeline Group, Inc. These adjustments also include a decrease of $64 million (2021 – nil) related to hedged interest rate risk. Refer to Note 28, Risk management and financial instruments for additional information.

Principal Repayments

At December 31, 2022, principal repayments for the next five years on the Company's long-term debt are approximately as follows:

(millions of Canadian $)	**2023**	**2024**	**2025**	**2026**	**2027**
Principal repayments on long-term debt	1,898	2,782	2,827	2,278	3,113

Long-Term Debt Issued

The Company issued long-term debt over the three years ended December 31, 2022 as follows:

(millions of Canadian $, unless otherwise noted) Company	Issue Date	Type	Maturity Date	Amount	Interest Rate
TRANSCANADA PIPELINES LIMITED					
	May 2022	Medium Term Notes	May 2032	800	5.33%
	May 2022	Medium Term Notes	May 2026	400	4.35%
	May 2022	Medium Term Notes	May 2052	300	5.92%
	October 2021	Senior Unsecured Notes	October 2024	US 1,250	1.00%
	October 2021	Senior Unsecured Notes	October 2031	US 1,000	2.50%
	June 2021	Medium Term Notes	June 2024	750	Floating
	June 2021	Medium Term Notes	June 2031	500	2.97%
	June 2021	Medium Term Notes	September 2047	250	4.33% [1]
	April 2020	Senior Unsecured Notes	April 2030	US 1,250	4.10%
	April 2020	Medium Term Notes	April 2027	2,000	3.80%
ANR PIPELINE COMPANY					
	May 2022	Senior Unsecured Notes	May 2032	US 300	3.43%
	May 2022	Senior Unsecured Notes	May 2034	US 200	3.58%
	May 2022	Senior Unsecured Notes	May 2037	US 200	3.73%
	May 2022	Senior Unsecured Notes	May 2029	US 100	3.26%
PORTLAND NATURAL GAS TRANSMISSION SYSTEM					
	October 2021	Senior Unsecured Notes	October 2031	US 125	2.68%
	October 2020	Senior Unsecured Notes	October 2030	US 125	2.84%
TUSCARORA GAS TRANSMISSION COMPANY					
	August 2021	Unsecured Term Loan	August 2024	US 13	Floating
KEYSTONE XL SUBSIDIARIES[2]					
	Various	Project-Level Credit Facility	June 2021	US 849	Floating
COLUMBIA PIPELINE GROUP, INC.[3]					
	January 2021	Unsecured Term Loan	June 2022	US 4,040	Floating
GAS TRANSMISSION NORTHWEST LLC					
	June 2020	Senior Unsecured Notes	June 2030	US 175	3.12%
COASTAL GASLINK PIPELINE LIMITED PARTNERSHIP[4]					
	April 2020	Senior Secured Credit Facilities	April 2027	1,603	Floating

1 Reflects coupon rate on re-opening of a pre-existing Medium Term Notes (MTN) issue. The MTNs were issued at a premium to par, resulting in a re-issuance yield of 4.186 per cent.

2 In January 2021, the Company established a US$4.1 billion project-level credit facility to support the construction of the Keystone XL pipeline, which was fully guaranteed by the Government of Alberta and non-recourse to TC Energy. The availability of this credit facility was subsequently reduced to US$1.6 billion and all amounts outstanding were fully repaid by the Government of Alberta in June 2021. Refer to Note 6, Keystone XL, for additional information.

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

4 In April 2020, Coastal GasLink LP entered into secured long-term project financing credit facilities. In May 2020, TC Energy completed the sale of a 65 per cent equity interest in Coastal GasLink LP and subsequently accounts for its remaining 35 per cent interest using the equity method. Immediately preceding the equity sale, Coastal GasLink LP made an initial draw of $1.6 billion on the credit facilities, of which approximately $1.5 billion was paid to TC Energy. Refer to Note 30, Acquisitions and dispositions, for additional information.

Long-Term Debt Retired/Repaid

The Company retired/repaid long-term debt over the three years ended December 31, 2022 as follows:

(millions of Canadian $, unless otherwise noted) Company	Retirement/ Repayment Date	Type	Amount	Interest Rate
TRANSCANADA PIPELINES LIMITED				
	December 2022	Medium Term Notes	25	9.95%
	August 2022	Senior Unsecured Notes	US 1,000	2.50%
	November 2021	Medium Term Notes	500	3.65%
	January 2021	Debentures	US 400	9.875%
	November 2020	Debentures	250	11.80%
	October 2020	Senior Unsecured Notes	US 1,000	3.80%
	March 2020[1]	Senior Unsecured Notes	US 750	4.60%
COLUMBIA PIPELINE GROUP, INC.				
	December 2021	Unsecured Term Loan[2]	US 4,040	Floating
	June 2020	Senior Unsecured Notes	US 750	3.30%
NORTH BAJA PIPELINE, LLC				
	December 2021	Unsecured Term Loan	US 50	Floating
TC PIPELINES, LP				
	November 2021	Unsecured Term Loan	US 450	Floating
	March 2021	Senior Unsecured Notes	US 350	4.65%
ANR PIPELINE COMPANY				
	November 2021	Senior Unsecured Notes	US 300	9.625%
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP				
	November 2021	Senior Unsecured Notes	US 10	9.09%
PORTLAND NATURAL GAS TRANSMISSION SYSTEM				
	October 2021	Unsecured Loan Facility	US 93	Floating
	October 2020	Unsecured Loan Facility	US 99	Floating
KEYSTONE XL SUBSIDIARIES[3]				
	June 2021	Project-Level Credit Facility	US 849	Floating
GAS TRANSMISSION NORTHWEST LLC				
	June 2020	Senior Unsecured Notes	US 100	5.29%

1 Related unamortized debt issue costs of $8 million were included in Interest expense in the Consolidated statement of income for the year ended December 31, 2020.

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

3 In June 2021, in accordance with the terms of the guarantee, the Government of Alberta repaid the US$849 million outstanding balance under the Keystone XL project-level credit facility bearing interest at a floating rate, subsequent to which it was terminated, resulting in no cash impact to TC Energy. Refer to Note 6, Keystone XL, for additional information.

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

Interest Expense

year ended December 31 (millions of Canadian $)	2022	2021	2020
Interest on long-term debt	**1,883**	1,841	1,963
Interest on junior subordinated notes	**543**	453	470
Interest on short-term debt	**153**	10	46
Capitalized interest	**(27)**	(22)	(294)
Amortization and other financial charges[1]	**36**	78	43
	2,588	2,360	2,228

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

The Company made interest payments of $2,478 million in 2022 (2021 – $2,299 million; 2020 – $2,203 million) on long-term debt, junior subordinated notes and short-term debt, net of interest capitalized.

21. JUNIOR SUBORDINATED NOTES

Outstanding loan amount (millions of Canadian $, unless otherwise noted)	Maturity Date	2022 Outstanding at December 31	2022 Effective Interest Rate[1]	2021 Outstanding at December 31	2021 Effective Interest Rate[1]
TRANSCANADA PIPELINES LIMITED					
US$1,000 notes issued 2007 at 6.35%[2]	2067	**1,353**	**6.2%**	1,265	4.0%
US$750 notes issued 2015 at 5.875%[3,4]	2075	**1,015**	**7.4%**	949	5.0%
US$1,200 notes issued 2016 at 6.125%[3,4]	2076	**1,624**	**8.0%**	1,519	5.8%
US$1,500 notes issued 2017 at 5.55%[3,4]	2077	**2,030**	**7.1%**	1,899	4.7%
$1,500 notes issued 2017 at 4.90%[3,4]	2077	**1,500**	**6.8%**	1,500	4.5%
US$1,100 notes issued 2019 at 5.75%[3,4]	2079	**1,488**	**7.6%**	1,392	5.4%
$500 notes issued 2021 at 4.45%[3,5]	2081	**500**	**5.7%**	500	4.0%
US$800 notes issued 2022 at 5.85%[3,5]	2082	**1,083**	**7.2%**	—	—
		10,593		9,024	
Unamortized debt discount and issue costs		**(98)**		(85)	
		10,495		8,939	

1 The effective interest rate is calculated by discounting the expected future interest payments using the coupon rate and any estimated future rate resets, adjusted for issue costs and discounts.

2 Junior subordinated notes of US$1 billion were issued in 2007 at a fixed rate of 6.35 per cent and converted in 2017 to a floating interest rate that is reset quarterly to the three-month LIBOR plus 2.21 per cent.

3 The Junior subordinated notes were issued to TransCanada Trust (the Trust), a financing trust subsidiary wholly-owned by TCPL. While the obligations of the Trust are fully and unconditionally guaranteed by TCPL on a subordinated basis, the Trust is not consolidated in TC Energy's financial statements since TCPL does not have a variable interest in the Trust and the only substantive assets of the Trust are junior subordinated notes of TCPL.

4 The coupon rate is initially a fixed interest rate for the first 10 years and converts to a floating rate thereafter.

5 The coupon rate is initially a fixed interest rate for the first 10 years and resets every five years thereafter.

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

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

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

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

22. FOREIGN EXCHANGE LOSS/(GAIN), NET

year ended December 31 (millions of Canadian $)	2022	2021	2020
Derivative instruments held for trading (Note 28)	**151**	(37)	(93)
Other	**34**	27	65
	185	(10)	(28)

23. NON-CONTROLLING INTERESTS

TC PipeLines, LP

Acquisition

In December 2020, the Company entered into a definitive agreement and plan of merger to acquire all the outstanding common units of TC PipeLines, LP not beneficially owned by TC Energy or its affiliates in exchange for TC Energy common shares. Upon close of the transaction on March 3, 2021, TC PipeLines, LP common unitholders received 0.70 TC Energy common shares for each issued and outstanding publicly-held TC PipeLines, LP common unit representing, in aggregate, 37,955,093 TC Energy common shares. As a result, TC PipeLines, LP became an indirect, wholly-owned subsidiary of TC Energy.

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

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

Non-controlling interests

Prior to the March 3, 2021 acquisition described above, the non-controlling interests in TC PipeLines, LP were 74.5 per cent (2020 – 74.5 per cent). Subsequent to this acquisition, the remaining non-controlling interest on the Consolidated balance sheet is related to the Company's 61.7 per cent investment in Portland Natural Gas Transmission System (PNGTS), which is held by TC PipeLines, LP.

The Company's Net income attributable to non-controlling interests included in the Consolidated statement of income were as follows:

year ended December 31 (millions of Canadian $)	2022	2021	2020
Non-controlling interest in TC PipeLines, LP	**—**	60	284
Non-controlling interest in PNGTS	**37**	30	23
Redeemable non-controlling interest (Note 6)	**—**	1	(10)
	37	91	297

24. COMMON SHARES

	Number of Shares (thousands)	Amount (millions of Canadian $)
Outstanding at January 1, 2020	938,400	24,387
Exercise of options	1,664	101
Outstanding at December 31, 2020	940,064	24,488
Acquisition of TC PipeLines, LP, net of transaction costs (Note 23)	37,955	2,063
Exercise of options	2,797	165
Outstanding at December 31, 2021	980,816	26,716
Issued under public offering[1]	**28,400**	**1,754**
Dividend reinvestment and share purchase plan	**5,916**	**342**
Exercise of options	**2,830**	**183**
Outstanding at December 31, 2022	**1,017,962**	**28,995**

1 Net of underwriting commissions and deferred income taxes.

Common Shares Issued and Outstanding

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

Common Shares Issued Under Public Offering

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

Dividend Reinvestment and Share Purchase Plan

Under the Company's Dividend Reinvestment and Share Purchase Plan (DRP), eligible holders of common and preferred shares of TC Energy can reinvest their dividends and make optional cash payments to obtain additional TC Energy common shares. Commencing with the dividends declared on July 27, 2022, the Company reinstated the issuance of common shares from treasury at a two per cent discount. For dividends declared between January 1, 2020 and July 27, 2022, common shares purchased with reinvested cash dividends under the DRP were acquired on the open market at 100 per cent of the weighted average purchase price.

Acquisition of TC PipeLines, LP

On March 3, 2021, TC Energy issued 37,955,093 common shares to acquire all the outstanding publicly-held common units of TC PipeLines, LP. Refer to Note 23, Non-controlling interests, for additional information.

TC Energy Corporation At-the-Market Equity Issuance Program

In December 2020, the Company established an At-the-Market (ATM) program that allowed, from time to time, for the issuance of common shares from treasury at the prevailing market price when sold through the Toronto Stock Exchange, the New York Stock Exchange or any other existing trading market for TC Energy common shares in Canada or the United States. The ATM program was effective for a 25-month period to assist in managing the Company's capital structure. Under this program, the Company had the ability to issue up to $1.0 billion in common shares or the U.S. dollar equivalent. In January 2023, the ATM program expired with no common shares issued thereunder.

Basic and Diluted Net Income per Common Share

Net income per common share is calculated by dividing Net income attributable to common shares by the weighted average number of common shares outstanding. The weighted average number of shares for the diluted earnings per share calculation includes options exercisable under TC Energy's Stock Option Plan and, subsequent to July 27, 2022, common shares issuable from treasury under the DRP.

Weighted Average Common Shares Outstanding (millions)	2022	2021	2020
Basic	**995**	973	940
Diluted	**996**	974	940

Stock Options

	Number of Options (thousands)	Weighted Average Exercise Prices	Weighted Average Remaining Contractual Life (years)
Options outstanding at January 1, 2022	**7,769**	**$61.29**	
Options granted	**1,396**	**$66.49**	
Options exercised	**(2,830)**	**$58.09**	
Options forfeited/expired	**(226)**	**$63.96**	
Options Outstanding at December 31, 2022	**6,109**	**$63.86**	**4.4**
Options Exercisable at December 31, 2022	**3,175**	**$63.13**	**3.4**

At December 31, 2022, an additional 3,656,518 common shares were reserved for future issuance from treasury under TC Energy's Stock Option Plan. The contractual life of options granted is seven years. Options may be exercised at a price determined at the time the option is awarded and vest equally on the anniversary date in each of the three years following the award. Forfeiture of stock options results from their expiration and, if not previously vested, upon resignation or termination of the option holder's employment.

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

year ended December 31	2022	2021	2020
Weighted average fair value	**$8.24**	$7.39	$7.73
Expected life (years)[1]	**5.4**	5.4	5.7
Interest rate	**1.6%**	0.5%	1.5%
Volatility[2]	**22%**	25%	17%
Dividend yield	**5.5%**	6.0%	4.2%

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 $10 million in 2022 (2021 – $12 million; 2020 – $12 million). At December 31, 2022, unrecognized compensation costs related to non-vested stock options were $12 million. The cost is expected to be fully recognized over a weighted average period of 1.9 years.

The following table summarizes additional stock option information:

year ended December 31 (millions of Canadian $, unless otherwise noted)	2022	2021	2020
Total intrinsic value of options exercised	**33**	28	31
Total fair value of options that have vested	**89**	110	101
Total options vested	**1.6 million**	1.9 million	2.0 million

As at December 31, 2022, the aggregate intrinsic values of the total options exercisable and the total options outstanding were each less than $1 million.

Shareholder Rights Plan

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

25. PREFERRED SHARES

at December 31, 2022	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] 2022	2021	2020
							(millions of Canadian $)		
Cumulative First Preferred Shares									
Series 1	14,577	3.479%	$0.86975	$25.00	December 31, 2024	Series 2	**360**	360	360
Series 2	7,423	Floating [4]	Floating	$25.00	December 31, 2024	Series 1	**179**	179	179
Series 3	9,997	1.694%	$0.4235	$25.00	June 30, 2025	Series 4	**246**	246	246
Series 4	4,003	Floating [4]	Floating	$25.00	June 30, 2025	Series 3	**97**	97	97
Series 5	12,071	1.949% [5]	$0.48725	$25.00	January 30, 2026	Series 6	**294**	294	310
Series 6	1,929	Floating [4]	Floating	$25.00	January 30, 2026	Series 5	**48**	48	32
Series 7	24,000	3.903%	$0.97575	$25.00	April 30, 2024	Series 8	**589**	589	589
Series 9	18,000	3.762%	$0.9405	$25.00	October 30, 2024	Series 10	**442**	442	442
Series 11	10,000	3.351%	$0.83775	$25.00	November 28, 2025	Series 12	**244**	244	244
Series 13	—	—	—	—	—	—	**—**	—	493
Series 15	—	—	—	—	—	—	**—**	988	988
							2,499	3,487	3,980

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

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

3 Net of underwriting commissions and deferred income taxes.

4 The floating quarterly dividend rate for the Series 2 preferred shares is 6.053 per cent for the period starting December 30, 2022 to, but excluding, March 31, 2023. The floating quarterly dividend rate for the Series 4 preferred shares is 5.413 per cent for the period starting December 30, 2022 to, but excluding, March 31, 2023. The floating quarterly dividend rate for the Series 6 preferred shares is 5.192 per cent for the period starting October 30, 2022 to, but excluding, January 30, 2023. These rates will reset each quarter going forward.

5 The fixed rate dividend for Series 5 preferred shares decreased from 2.263 per cent to 1.949 per cent on January 30, 2021 and is due to reset on every fifth anniversary thereafter.

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

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

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

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

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

In June 2020, 401,590 Series 3 preferred shares were converted, on a one-for-one basis, into Series 4 preferred shares and 1,865,362 Series 4 preferred shares were converted, on a one-for-one basis, into Series 3 preferred shares.

26. 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, 2022 (millions of Canadian $)	Before Tax Amount	Income Tax Recovery/ (Expense)	Net of Tax Amount
Foreign currency translation gains and losses on net investment in foreign operations	**1,410**	**84**	**1,494**
Change in fair value of net investment hedges	**(48)**	**12**	**(36)**
Change in fair value of cash flow hedges	**(58)**	**19**	**(39)**
Reclassification to net income of gains and losses on cash flow hedges	**63**	**(21)**	**42**
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	**81**	**(18)**	**63**
Reclassification to net income of actuarial gains and losses on pension and other post-retirement benefit plans	**9**	**(3)**	**6**
Other comprehensive income on equity investments	**1,156**	**(289)**	**867**
Other Comprehensive Income	**2,613**	**(216)**	**2,397**

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

year ended December 31, 2020 (millions of Canadian $)	Before Tax Amount	Income Tax Recovery/ (Expense)	Net of Tax Amount
Foreign currency translation gains and losses on net investment in foreign operations	(647)	38	(609)
Change in fair value of net investment hedges	48	(12)	36
Change in fair value of cash flow hedges	(771)	188	(583)
Reclassification to net income of gains and losses on cash flow hedges	649	(160)	489
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	15	(3)	12
Reclassification to net income of actuarial gains and losses on pension and other post-retirement benefit plans	23	(6)	17
Other comprehensive loss on equity investments	(373)	93	(280)
Other Comprehensive Loss	(1,056)	138	(918)

The changes in AOCI by component were as follows:

(millions of Canadian $)	Currency Translation Adjustments	Cash Flow Hedges	Pension and Other Post-Retirement Benefit Plan Adjustments	Equity Investments	Total[1]
AOCI balance at January 1, 2020	(730)	(58)	(314)	(457)	(1,559)
Other comprehensive (loss)/income before reclassifications[2]	(543)	(567)	12	(292)	(1,390)
Amounts reclassified from AOCI	—	482	17	11	510
Net current period other comprehensive (loss)/income	(543)	(85)	29	(281)	(880)
AOCI balance at December 31, 2020	(1,273)	(143)	(285)	(738)	(2,439)
Other comprehensive (loss)/income before reclassifications[2]	(98)	(11)	158	506	555
Amounts reclassified from AOCI	—	55	14	28	97
Net current period other comprehensive (loss)/income	(98)	44	172	534	652
Acquisition of TC PipeLines, LP[3]	362	(13)	—	4	353
AOCI balance at December 31, 2021	(1,009)	(112)	(113)	(200)	(1,434)
Other comprehensive income/(loss) before reclassifications[2]	**1,450**	**(39)**	**63**	**870**	**2,344**
Amounts reclassified from AOCI[4]	**—**	**42**	**6**	**(3)**	**45**
Net current period other comprehensive income	**1,450**	**3**	**69**	**867**	**2,389**
AOCI balance at December 31, 2022	**441**	**(109)**	**(44)**	**667**	**955**

1 All amounts are net of tax. Amounts in parentheses indicate losses recorded to OCI.

2 Other comprehensive income/(loss) before reclassifications on currency translation adjustments, cash flow hedges and equity investments are net of non-controlling interest gains of $8 million (2021 – losses of $12 million; 2020 – losses of $30 million), nil (2021 – gains of $1 million; 2020 – losses of $16 million), and nil (2021 – gains of $1 million; 2020 – gains of $1 million), respectively.

3 Represents the AOCI attributable to non-controlling interests of TC PipeLines, LP which was reclassified to AOCI on the Consolidated balance sheet upon completion of the acquisition of all the outstanding publicly-held common units of TC PipeLines, LP on March 3, 2021. Refer to Note 23, Non-controlling interests, for additional information.

4 Losses related to cash flow hedges reported in AOCI and expected to be reclassified to net income in the next 12 months are estimated to be $84 million ($64 million, net of tax) at December 31, 2022. 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**			
(millions of Canadian $)	**2022**	**2021**	**2020**	**Affected Line Item in the Consolidated Statement of Income**[1]
Cash flow hedges				
Commodities	**(47)**	(22)	(1)	Revenues (Power and Energy Solutions)
Interest rate	**(16)**	(46)	(28)	Interest expense
Interest rate	**—**	—	(613)	Net gain/(loss) on sale of assets[2]
	(63)	(68)	(642)	Total before tax
	21	13	160	Income tax expense
	(42)	(55)	(482)	Net of tax[3]
Pension and other post-retirement benefit plan adjustments				
Amortization of actuarial losses	**(11)**	(22)	(23)	Plant operating costs and other[4]
Settlement gain	**2**	2	—	Plant operating costs and other[4]
	(9)	(20)	(23)	Total before tax
	3	6	6	Income tax expense
	(6)	(14)	(17)	Net of tax
Equity investments				
Equity income	**4**	(37)	(15)	Income from equity investments
	(1)	9	4	Income tax expense
	3	(28)	(11)	Net of tax

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

2 Represents a loss of $613 million ($459 million, net of tax) related to a contractually required derivative instrument used to hedge the interest rate risk associated with project-level financing of the Coastal GasLink construction. The derivative instrument was derecognized as part of the sale of a 65 per cent equity interest in Coastal GasLink LP. Refer to Note 30, Acquisitions and dispositions, for additional information.

3 Amounts reclassified from AOCI on cash flow hedges are net of non-controlling interest of nil (2021 – nil; 2020 – losses of $7 million).

4 These AOCI components are included in the computation of net benefit cost. Refer to Note 27, Employee post-retirement benefits, for additional information.

27. 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 consecutive years of employment. Effective January 1, 2019, there were certain amendments made to the Canadian DB Plan for new members whereby, subsequent to that date, benefits provided for these new members are based on years of service and highest average earnings over five consecutive years of employment. Upon commencement of retirement, pension benefits in the Canadian DB Plan increase annually by a portion of the increase in the Consumer Price Index for employees hired prior to January 1, 2019. The Company's U.S. DB Plan is closed to non-union new entrants and all non-union hires participate in the DC Plan. Net actuarial gains or losses are amortized out of AOCI over the EARSL of Plan participants, which was approximately nine years at December 31, 2022 (2021 – 10 years; 2020 – nine years).

The Company also provides its employees with savings plans in Canada and Mexico, DC Plans consisting of a 401(k) Plan in the U.S. and post-employment benefits other than pensions, including termination benefits and life insurance and medical benefits beyond those provided by government-sponsored plans. Net actuarial gains or losses for the plans are amortized out of AOCI over the EARSL of employees, which was approximately 12 years at December 31, 2022 (2021 and 2020 – 11 years). In 2022, the Company expensed $64 million (2021 and 2020 – $58 million) for the savings and DC Plans.

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

year ended December 31 (millions of Canadian $)	**2022**	**2021**	**2020**
DB Plans	**78**	105	124
Other post-retirement benefit plans	**8**	8	9
Savings and DC Plans	**64**	58	58
	150	171	191

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. After the cash contributions noted above, no additional letters of credit were provided to the Canadian DB Plan in 2022 (2021 – $20 million; 2020 – $13 million). Total letters of credit provided to the Canadian DB plan at December 31, 2022 was $322 million.

The most recent actuarial valuation of the pension plans for funding purposes was as at January 1, 2022 and the next required valuation is at January 1, 2023.

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

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

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

The Company's funded status at December 31 was comprised of the following:

at December 31	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
(millions of Canadian $)	**2022**	2021	**2022**	2021
Change in Benefit Obligation[1]				
Benefit obligation – beginning of year	**4,027**	4,326	**419**	457
Service cost	**145**	171	**5**	6
Interest cost	**125**	119	**13**	12
Employee contributions	**6**	6	**2**	1
Benefits paid	**(324)**	(372)	**(24)**	(21)
Actuarial gain	**(949)**	(208)	**(120)**	(35)
Curtailment	**—**	(5)	**—**	3
Foreign exchange rate changes	**51**	(10)	**15**	(4)
Benefit obligation – end of year	**3,081**	4,027	**310**	419
Change in Plan Assets				
Plan assets at fair value – beginning of year	**4,145**	4,038	**431**	441
Actual return on plan assets	**(483)**	376	**(89)**	5
Employer contributions[2]	**78**	105	**8**	8
Employee contributions	**6**	6	**2**	1
Benefits paid	**(324)**	(372)	**(24)**	(21)
Foreign exchange rate changes	**59**	(8)	**26**	(3)
Plan assets at fair value – end of year	**3,481**	4,145	**354**	431
Funded Status – Plan Surplus	**400**	118	**44**	12

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 Excludes a nil (2021 – $20 million) letter of credit provided to the Canadian DB Plan for funding purposes.

The actuarial gain realized on the defined benefit plan obligation is primarily attributable to an increase in the weighted average discount rate from 3.05 per cent in 2021 to 5.15 per cent in 2022.

The actuarial gain realized on the other post-retirement benefit plan obligation is primarily due to the increase in the weighted average discount rate from 3.10 per cent in 2021 to 5.45 per cent in 2022.

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 $)	**2022**	2021	**2022**	2021
Other long-term assets (Note 15)	**400**	119	**163**	193
Accounts payable and other	**—**	—	**(8)**	(8)
Other long-term liabilities (Note 18)	**—**	(1)	**(111)**	(173)
	400	118	**44**	12

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 $)	**2022**	2021	**2022**	2021
Projected benefit obligation[1]	**—**	(2,687)	**(119)**	(183)
Plan assets at fair value	**—**	2,686	**—**	—
Funded Status – Plan Deficit	**—**	(1)	**(119)**	(183)

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 $)	**2022**	2021
Accumulated benefit obligation	**(2,880)**	(3,714)
Plan assets at fair value	**3,481**	4,145
Funded Status – Plan Surplus	**601**	431

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, 2022 and December 31, 2021.

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
	2022	2021	**2022**
Fixed income securities	**38%**	34%	**25% to 50%**
Equity securities	**44%**	53%	**30% to 55%**
Other investments	**18%**	13%	**10% to 25%**
	100%	100%	

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

at December 31			Percentage of Plan Assets	
(millions of Canadian $)	**2022**	2021	**2022**	2021
Fixed income securities	**7**	7	**0.2%**	0.2%
Equity securities	**3**	5	**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 other post-retirement benefits measured at fair value, which have been categorized into the three categories based on a fair value hierarchy. For additional information on the fair value hierarchy, refer to Note 28, Risk management and financial instruments.

at December 31	Quoted Prices in Active Markets (Level I)		Significant Other Observable Inputs (Level II)		Significant Unobservable Inputs (Level III)		Total		Percentage of Total Portfolio	
(millions of Canadian $)	**2022**	2021	**2022**	2021	**2022**	2021	**2022**	2021	**2022**	2021
Asset Category										
Cash and Cash Equivalents	**55**	68	**1**	2	**—**	—	**56**	70	**1**	2
Equity Securities:										
Canadian	**117**	269	**—**	148	**—**	—	**117**	417	**3**	9
U.S.	**897**	649	**—**	164	**—**	—	**897**	813	**24**	18
International	**172**	126	**172**	354	**—**	—	**344**	480	**9**	10
Global	**—**	111	**75**	313	**—**	—	**75**	424	**2**	9
Emerging	**50**	25	**127**	120	**—**	—	**177**	145	**5**	3
Fixed Income Securities:										
Canadian Bonds:										
Federal	**—**	—	**221**	226	**—**	—	**221**	226	**6**	5
Provincial	**—**	—	**249**	331	**—**	—	**249**	331	**6**	7
Municipal	**—**	—	**12**	16	**—**	—	**12**	16	**—**	—
Corporate	**—**	—	**108**	147	**—**	—	**108**	147	**3**	4
U.S. Bonds:										
Federal	**177**	433	**158**	15	**—**	—	**335**	448	**9**	10
Municipal	**—**	—	**1**	1	**—**	—	**1**	1	**—**	—
Corporate	**345**	67	**94**	143	**—**	—	**439**	210	**11**	5
International:										
Government	**5**	6	**6**	7	**—**	—	**11**	13	**—**	—
Corporate	**—**	—	**58**	73	**—**	—	**58**	73	**1**	2
Mortgage backed	**36**	42	**1**	5	**—**	—	**37**	47	**1**	1
Net forward contracts	**—**	—	**(78)**	—	**—**	—	**(78)**	—	**(2)**	—
Other Investments:										
Real estate	**—**	—	**—**	—	**336**	283	**336**	283	**9**	6
Infrastructure	**—**	—	**—**	—	**296**	281	**296**	281	**8**	6
Private equity funds	**—**	—	**—**	—	**—**	1	**—**	1	**—**	—
Funds held on deposit	**144**	150	**—**	—	**—**	—	**144**	150	**4**	3
	1,998	1,946	**1,205**	2,065	**632**	565	**3,835**	4,576	**100**	100

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

(millions of Canadian $, pre-tax)	
Balance at December 31, 2020	417
Purchases and sales	100
Realized and unrealized gains	48
Balance at December 31, 2021	565
Purchases and sales	**52**
Realized and unrealized gains	**15**
Balance at December 31, 2022	**632**

The Company's expected funding contributions in 2023 are approximately $32 million for the DB Plans, $6 million for the other post-retirement benefit plans and approximately $69 million for the savings plans and DC Plans. The Company does not expect to issue additional letters of credit to the Canadian DB Plan for the funding of solvency requirements.

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

(millions of Canadian $)	**Pension Benefits**	**Other Post-Retirement Benefits**
2023	210	25
2024	214	24
2025	217	24
2026	221	23
2027	224	23
2028 to 2032	1,160	111

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, 2022. 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**	
	2022	**2021**	**2022**	**2021**
Discount rate	**5.15%**	3.05%	**5.45%**	3.10%
Rate of compensation increase	**3.30%**	2.95%	**—**	—

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**		
	2022	**2021**	**2020**	**2022**	**2021**	**2020**
Discount rate	**3.05%**	2.70%	3.20%	**3.10%**	2.80%	3.35%
Expected long-term rate of return on plan assets	**6.10%**	6.15%	6.40%	**3.25%**	3.00%	3.50%
Rate of compensation increase	**3.00%**	2.60%	3.00%	—	—	—

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, asset mix and anticipated benefit payments from plan assets 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 6.10 per cent weighted-average annual rate of increase in the per capita cost of covered health care benefits was assumed for 2023 measurement purposes. The rate was assumed to decrease gradually to 4.80 per cent by 2030 and remain at this level thereafter.

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

year ended December 31	**Pension Benefit Plans**			**Other Post-Retirement Benefit Plans**		
(millions of Canadian $)	**2022**	**2021**	**2020**	**2022**	**2021**	**2020**
Service cost[1]	**145**	171	155	**5**	6	6
Other components of net benefit cost[1]						
Interest cost	**125**	119	133	**13**	12	14
Expected return on plan assets	**(239)**	(234)	(230)	**(14)**	(13)	(14)
Amortization of actuarial loss	**10**	23	21	**1**	2	2
Amortization of regulatory asset	**12**	27	25	**1**	2	2
Curtailment gain	**—**	(5)	—	**—**	—	—
Settlement gain – AOCI	**(2)**	(2)	—	**—**	—	—
	(94)	(72)	(51)	**1**	3	4
Net Benefit Cost Recognized	**51**	99	104	**6**	9	10

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:

year ended December 31	**2022**		**2021**		**2020**	
(millions of Canadian $)	**Pension Benefits**	**Other Post-Retirement Benefits**	**Pension Benefits**	**Other Post-Retirement Benefits**	**Pension Benefits**	**Other Post-Retirement Benefits**
Net loss	**38**	**24**	147	5	358	22

Pre-tax amounts recognized in OCI were as follows:

year ended December 31	**2022**		**2021**		**2020**	
(millions of Canadian $)	**Pension Benefits**	**Other Post-Retirement Benefits**	**Pension Benefits**	**Other Post-Retirement Benefits**	**Pension Benefits**	**Other Post-Retirement Benefits**
Amortization of net loss from AOCI to net income	**(10)**	**(1)**	(23)	(2)	(21)	(2)
Curtailment	**—**	**—**	—	3	—	—
Settlement	**2**	**—**	2	—	—	—
Funded status adjustment	**(101)**	**20**	(190)	(18)	(18)	3
	(109)	**19**	(211)	(17)	(39)	1

28. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

Risk Management Overview

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

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

Market Risk

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

Derivative contracts the Company uses to assist in managing exposure to market risk may include the following:

- Forwards and futures contracts – agreements to purchase or sell a specific financial instrument or commodity at a specified price and date in the future
- Swaps – agreements between two parties to exchange streams of payments over time according to specified terms
- Options – agreements that convey the right, but not the obligation of the purchaser to buy or sell a specific amount of a financial instrument or commodity at a fixed price, either at a fixed date or at any time within a specified period.

Commodity price risk

The following strategies may be used to manage the Company's exposure to market risk resulting from commodity price risk management activities in the Company's non-regulated businesses:

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

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

Climate change also presents a potential financial impact to commodity prices and volumes. TC Energy's exposure to climate change-related risk and resulting policy changes is managed through the Company's business model, which is based on a long-term, low-risk strategy whereby the majority of TC Energy's earnings are underpinned by regulated cost-of-service arrangements and/or long-term contracts. In addition, scenario planning against several demand outlooks and monitoring of key signposts is also considered as part of the Company's long-term corporate strategic planning process.

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. For eligible hedging relationships affected by the expected cessation of certain reference interest rates, the Company has applied the optional expedient allowing an entity to assume that the hedged forecasted transaction in a cash flow hedge is probable of occurring and, therefore, these changes are not expected to have a material impact on the consolidated financial statements. Refer to Note 3, Accounting changes, for additional information on Reference Rate Reform.

Foreign exchange risk

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

A portion of the Company's Mexico Natural Gas Pipelines monetary assets and liabilities are peso-denominated, while the functional currency for TC Energy's Mexico operations is 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 peso-denominated income tax exposure for these entities, leading to fluctuations in Income from equity investments and Income tax expense. As the Company's U.S. dollar-denominated monetary assets and liabilities in our Mexico operations continue to grow, this exposure increases. These exposures are managed using foreign exchange derivatives.

Net investment in foreign operations

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

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

at December 31	2022		2021	
(millions of Canadian $, unless otherwise noted)	Fair Value[1,2]	Notional Amount	Fair Value[1,2]	Notional Amount
U.S. dollar foreign exchange options (maturing 2023 to 2024)	**(22)**	**US 3,600**	(4)	US 3,800
U.S. dollar cross-currency interest rate swaps (maturing 2023 to 2025)[3]	**(5)**	**US 300**	23	US 400
	(27)	**US 3,900**	19	US 4,200

1 Fair value equals carrying value.

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

3 In 2022, Net income includes net realized gains of $1 million (2021 – gains of $1 million) related to the interest component of cross-currency swap settlements which are reported within Interest expense.

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

at December 31		
(millions of Canadian $, unless otherwise noted)	2022	2021
Notional amount	**32,500 (US 24,000)**	30,700 (US 24,200)
Fair value	**30,800 (US 22,700)**	35,500 (US 28,100)

Counterparty Credit Risk

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

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, 2022, the Company recorded a $149 million (2021 and 2020 – nil) ECL provision with respect to the net investment in leases associated with the in-service TGNH pipelines and a $14 million (2021 and 2020 – nil) ECL provision for contract assets related to certain other Mexico Natural Gas pipelines.

Other than the ECL provision noted above, the Company had no significant credit losses at December 31, 2022 and 2021. At December 31, 2022 and 2021, 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.

Non-Derivative Financial Instruments

Fair value of non-derivative financial instruments

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

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 (millions of Canadian $)	2022 Carrying Amount	2022 Fair Value	2021 Carrying Amount	2021 Fair Value
Long-term debt, including current portion (Note 20)[1,2]	**(41,543)**	**(39,505)**	(38,661)	(45,615)
Junior subordinated notes (Note 21)	**(10,495)**	**(9,415)**	(8,939)	(9,236)
	(52,038)	**(48,920)**	(47,600)	(54,851)

1 Long-term debt is recorded at amortized cost, except for US$1.6 billion (2021 – nil) that is attributed to hedged risk and recorded at fair value.

2 Net income for 2022 included unrealized gains of $64 million (2021 – nil) for fair value adjustments attributable to the hedged interest rate risk associated with interest rate swap fair value hedging relationships on US$1.6 billion of long-term debt at December 31, 2022 (2021 – nil). There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

Available-for-sale assets summary

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

at December 31 (millions of Canadian $)	2022 LMCI Restricted Investments	2022 Other Restricted Investments[1]	2021 LMCI Restricted Investments	2021 Other Restricted Investments[1]
Fair value of fixed income securities[2,3]				
Maturing within 1 year	**—**	**54**	—	26
Maturing within 1-5 years	**—**	**106**	8	107
Maturing within 5-10 years	**1,153**	**—**	1,150	—
Maturing after 10 years	**77**	**—**	84	—
Fair value of equity securities[2,4]	**749**	**—**	817	—
	1,979	**160**	2,059	133

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

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

3 Classified in Level II of the fair value hierarchy.

4 Classified in Level I of the fair value hierarchy.

year ended December 31 (millions of Canadian $)	2022 LMCI Restricted Investments[1]	2022 Other Restricted Investments[2]	2021 LMCI Restricted Investments[1]	2021 Other Restricted Investments[2]	2020 LMCI Restricted Investments[1]	2020 Other Restricted Investments[2]
Net unrealized (losses)/gains	**(244)**	**(7)**	45	(2)	130	1
Net realized (losses)/gains[3]	**(32)**	**—**	3	—	20	1

1 Gains and 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 assets or regulatory liabilities.

2 Gains and losses on other restricted investments are included in Interest income and other in the Company's Consolidated statement of income.

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

Derivative Instruments

Fair value of derivative instruments

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

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

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

Balance sheet presentation of derivative instruments

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

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

1 Fair value equals carrying value.

2 Includes purchases and sales of power, natural gas and liquids.

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

at December 31, 2021 (millions of Canadian $)	Cash Flow Hedges	Net Investment Hedges	Held for Trading	Total Fair Value of Derivative Instruments[1]
Other current assets (Note 8)				
Commodities[2]	—	—	122	122
Foreign exchange	—	10	37	47
	—	10	159	169
Other long-term assets (Note 15)				
Commodities[2]	—	—	8	8
Foreign exchange	—	32	6	38
Interest rate	2	—	—	2
	2	32	14	48
Total Derivative Assets	2	42	173	217
Accounts payable and other (Note 17)				
Commodities[2]	(23)	—	(138)	(161)
Foreign exchange	—	(4)	(46)	(50)
Interest rate	(10)	—	—	(10)
	(33)	(4)	(184)	(221)
Other long-term liabilities (Note 18)				
Commodities[2]	(4)	—	(6)	(10)
Foreign exchange	—	(19)	(10)	(29)
Interest rate	(8)	—	—	(8)
	(12)	(19)	(16)	(47)
Total Derivative Liabilities	(45)	(23)	(200)	(268)
Total Derivatives	(43)	19	(27)	(51)

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

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

Derivatives in fair value hedging relationships

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

at December 31	Carrying Amount		Fair Value Hedging Adjustments[1]	
(millions of Canadian $)	2022	2021	2022	2021
Long-term debt	**(2,101)**	**—**	**64**	**—**

1 At December 31, 2022 and 2021, adjustments for discontinued hedging relationships included in these balances were nil.

Notional and maturity summary

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

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

1 Volumes for power, natural gas and liquids derivatives are in GWh, Bcf and MMBbls, respectively. In 2022, TC Energy updated this presentation to a net basis as it better reflects the Company's trading positions and how it manages its business.

at December 31, 2021	Power	Natural Gas	Liquids	Foreign Exchange	Interest Rate
Net sales/(purchases)[1]	490	(52)	4	—	—
Millions of U.S. dollars	—	—	—	6,636	650
Millions of Mexican pesos	—	—	—	5,500	—
Maturity dates	2022-2026	2022-2027	2022	2022-2026	2024-2026

1 Volumes for power, natural gas and liquids derivatives are in GWh, Bcf and MMBbls, respectively. In 2022, TC Energy updated this presentation to a net basis as it better reflects the Company's trading positions and how it manages its business.

Unrealized and Realized Gains and 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 $)	2022	2021	2020
Derivative Instruments Held For Trading[1]			
Amount of unrealized gains/(losses) in the year			
Commodities	**14**	9	(23)
Foreign exchange (Note 22)	**(149)**	(203)	126
Amount of realized gains/(losses) in the year			
Commodities	**759**	287	183
Foreign exchange (Note 22)	**(2)**	240	(33)
Derivative Instruments in Hedging Relationships[2]			
Amount of realized (losses)/gains in the year			
Commodities	**(73)**	(44)	6
Interest rate	**(3)**	(32)	(16)

1 Realized and unrealized gains and losses on held-for-trading derivative instruments used to purchase and sell commodities are included on a net basis in Revenues. Realized and unrealized gains and losses on foreign exchange held-for-trading derivative instruments are included on a net basis in Foreign exchange (loss)/gain, net.

2 In 2022, there were no gains or losses included in Net Income relating to discontinued cash flow hedges where it was probable that the anticipated transaction would not occur (2021 – realized loss of $10 million, 2020 – nil).

Derivatives in cash flow hedging relationships

The components of OCI (Note 26) related to the change in fair value of derivatives in cash flow hedging relationships before tax and including the portion attributable to non-controlling interests were as follows:

year ended December 31 (millions of Canadian $, pre-tax)	2022	2021	2020
Change in fair value of derivative instruments recognized in OCI[1]			
Commodities	**(94)**	(35)	(5)
Interest rate	**36**	22	(766)
	(58)	(13)	(771)

1 No amounts have been excluded from the assessment of hedge effectiveness. Amounts in parentheses indicate losses recorded to OCI and AOCI.

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 $)	2022	2021	2020
Fair Value Hedges			
Interest rate contracts[1]			
Hedged items	**(30)**	—	(3)
Derivatives designated as hedging instruments	**(1)**	—	1
Cash Flow Hedges			
Reclassification of losses on derivative instruments from AOCI to Net income[2,3]			
Commodity contracts[4]	**(47)**	(22)	(1)
Interest rate contracts[1]	**(16)**	(46)	(648)

1 Presented within Interest expense in the Consolidated statement of income, except for a loss of $613 million recorded in May 2020 related to a contractually required derivative instrument used to hedge the interest rate risk associated with project-level financing for the Coastal GasLink construction. This derivative instrument was derecognized as part of the sale of a 65 per cent equity interest in Coastal GasLink LP. The loss was included in Net gain/(loss) on sale of assets. Refer to Note 30, Acquisitions and dispositions, for additional information.

2 Refer to Note 26, Other comprehensive income/(loss) and accumulated other comprehensive income/(loss), for the components of OCI related to derivatives in cash flow hedging relationships including the portion attributable to non-controlling interests.

3 There are no amounts recognized in earnings that were excluded from effectiveness testing.

4 Presented within Revenues (Power and Energy Solutions) in the Consolidated statement of income.

Offsetting of derivative instruments

The Company enters into derivative contracts with the right to offset in the normal course of business as well as in the event of default. TC Energy has no master netting agreements, however, similar contracts are entered into containing rights to offset. The Company has elected to present the fair value of derivative instruments with the right to offset on a gross basis on the Consolidated balance sheet.

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

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

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

at December 31, 2021 (millions of Canadian $)	Gross Derivative Instruments	Amounts Available for Offset[1]	Net Amounts
Derivative Instrument Assets			
Commodities	130	(91)	39
Foreign exchange	85	(54)	31
Interest rate	2	(1)	1
	217	(146)	71
Derivative Instrument Liabilities			
Commodities	(171)	91	(80)
Foreign exchange	(79)	54	(25)
Interest rate	(18)	1	(17)
	(268)	146	(122)

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 $138 million and letters of credit of $68 million at December 31, 2022 (2021 – $144 million and $130 million, respectively) to its counterparties. At December 31, 2022, the Company held less than $1 million in cash collateral and $10 million in letters of credit (2021 – nil and $6 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, 2022, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $19 million (2021 – $5 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, 2022, 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 and the Company uses the most observable inputs available or, if not available, long-term broker quotes to estimate the fair value for these transactions. 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, 2022 (millions of Canadian $)	**Quoted Prices in Active Markets (Level I)**	**Significant Other Observable Inputs (Level II)**[1]	**Significant Unobservable Inputs (Level III)**[1]	**Total**
Derivative Instrument Assets				
Commodities	**515**	**142**	**2**	**659**
Foreign exchange	**—**	**34**	**—**	**34**
Interest rate	**—**	**12**	**—**	**12**
Derivative Instrument Liabilities				
Commodities	**(478)**	**(242)**	**(13)**	**(733)**
Foreign exchange	**—**	**(213)**	**—**	**(213)**
Interest rate	**—**	**(76)**	**—**	**(76)**
	37	**(343)**	**(11)**	**(317)**

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

at December 31, 2021 (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	39	91	—	130
Foreign exchange	—	85	—	85
Interest rate	—	2	—	2
Derivative Instrument Liabilities				
Commodities	(49)	(116)	(6)	(171)
Foreign exchange	—	(79)	—	(79)
Interest rate	—	(18)	—	(18)
	(10)	(35)	(6)	(51)

1 There were no transfers from Level II to Level III for the year ended December 31, 2021.

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)	2022	2021
Balance at beginning of year	**(6)**	(4)
Net losses included in Net income	**(10)**	(3)
Net losses included in OCI	**(3)**	—
Transfers out of Level III	**7**	—
Settlements	**1**	1
Balance at End of Year[1]	**(11)**	(6)

1 Revenues include unrealized losses of $10 million attributed to derivatives in the Level III category that were still held at December 31, 2022 (2021 – unrealized losses of $3 million).

29. CHANGES IN OPERATING WORKING CAPITAL

year ended December 31 (millions of Canadian $)	2022	2021	2020
(Increase)/decrease in Accounts receivable	**(575)**	(925)	129
Increase in Inventories	**(190)**	(93)	(55)
Decrease/(increase) in Other current assets	**118**	(141)	(221)
(Decrease)/increase in Accounts payable and other	**(83)**	890	(162)
Increase/(decrease) in Accrued interest	**91**	(18)	(18)
Increase in Operating Working Capital	**(639)**	(287)	(327)

30. ACQUISITIONS AND DISPOSITIONS

Canadian Natural Gas Pipelines

Coastal GasLink LP

In May 2020, TC Energy completed the sale of a 65 per cent equity interest in Coastal GasLink LP to third parties for net proceeds of $656 million before post-closing adjustments resulting in a pre-tax gain of $364 million ($402 million after tax). The pre-tax gain included $231 million related to the required remeasurement of the Company's retained 35 per cent equity interest to fair value which was based on the proceeds realized for the 65 per cent equity interest, and also incorporated the reclassification from AOCI to income of the fair value of a derivative instrument used to hedge the interest rate risk associated with project-level financing for the Coastal GasLink construction. The $402 million after-tax gain also reflected the utilization of previously unrecognized tax loss benefits. The pre-tax gain was included in Net gain/(loss) on sale of assets in the Consolidated statement of income. As part of this transaction, TC Energy was contracted by Coastal GasLink LP to construct and operate the pipeline. TC Energy uses the equity method to account for its remaining 35 per cent equity interest in the Company's consolidated financial statements.

Immediately preceding the equity sale, Coastal GasLink LP drew down $1.6 billion on the secured long-term project financing credit facilities, of which approximately $1.5 billion was paid to TC Energy.

Liquids Pipelines

Northern Courier

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

Power and Energy Solutions

TransCanada Turbines Ltd.

In November 2020, TC Energy acquired the remaining 50 per cent ownership interest in TransCanada Turbines Ltd. (TC Turbines) for cash consideration of US$67 million. TC Turbines provides industrial gas turbine maintenance, parts, repair and overhaul services. The acquisition was accounted for as a business combination and the evaluation of assigned fair value of acquired assets and liabilities did not result in recognition of goodwill. TC Energy previously accounted for its 50 per cent interest in TC Turbines as an equity investment but commenced full consolidation of TC Turbines as of the date of acquisition, which did not have a material impact on Revenues and Net income of the Company. In addition, the pro forma incremental impact on the Company's Revenues and Net income for each of the periods presented was not material.

Ontario Natural Gas-fired Power Plants

In April 2020, the Company completed the sale of the Halton Hills and Napanee power plants as well as its 50 per cent interest in Portlands Energy Centre to a subsidiary of Ontario Power Generation Inc. for net proceeds of approximately $2.8 billion before post-closing adjustments. The total pre-tax loss of $676 million ($470 million after tax) on this transaction included losses accrued during 2019 while classified as an asset held for sale and a 2021 post-close adjustment and also reflected utilization of previously unrecognized tax loss benefits. The pre-tax loss was included in Net gain/(loss)on sale of assets in the Consolidated statement of income. This loss may be amended in the future upon the settlement of existing insurance claims.

31. 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 2022 were $362 million (2021 – $239 million; 2020 – $224 million).

The Company has entered into PPAs with solar and wind-power generating facilities ranging from one to 15 years that require the purchase of generated energy and associated environmental attributes. At December 31, 2022, the total planned capacity secured under the PPAs is approximately 1,020 MW with the generation subject to operating availability and capacity factors. 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, 2022, TC Energy had the following capital expenditure commitments:

- approximately $1.0 billion for its Canadian natural gas pipelines, primarily related to construction costs associated with NGTL System expansion projects
- approximately $0.3 billion for its U.S. natural gas pipelines, primarily related to construction costs associated with ANR and Columbia Gas pipeline projects
- approximately $1.7 billion for its Mexico natural gas pipelines, primarily related to construction of the Southeast Gateway pipeline
- approximately $0.3 billion for its Power and Energy Solutions business, primarily related to the Company's proportionate share of commitments for Bruce Power's life extension program.

Contingencies

TC Energy is subject to laws and regulations governing environmental quality and pollution control. At December 31, 2022, the Company had accrued approximately $20 million (2021 – $30 million) related to operating facilities, which represents the present value of the estimated future amount it expects to spend to remediate the sites. However, additional liabilities may be incurred as assessments take place and remediation efforts continue.

TC Energy and its subsidiaries are subject to various legal proceedings, arbitrations and actions arising in the normal course of business. The amounts involved in such proceedings are not reasonably estimable as the final outcome of such legal proceedings cannot be predicted with certainty. It is the opinion of management that the ultimate resolution of such proceedings and actions will not have a material impact on the Company's consolidated financial position or results of operations.

Keystone XL

In September 2022, the International Centre for Settlement of Investment Disputes (ICSID) formally constituted a tribunal to hear TC Energy's request for arbitration under NAFTA where the Company is seeking to recover more than US$15 billion in economic damages resulting from the revocation of the Presidential Permit for the Keystone XL pipeline project. This claim is in an early stage and the timing and outcome is unknown at present. Termination activities undertaken in 2022, including asset dispositions and preservation, will continue throughout 2023. The Company will continue to coordinate with regulators, stakeholders and Indigenous groups to meet its environmental and regulatory commitments.

Guarantees

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

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

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

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

at December 31		**2022**		**2021**	
(millions of Canadian $)	**Term**	**Potential Exposure**[1]	**Carrying Value**	**Potential Exposure**[1]	**Carrying Value**
Sur de Texas	Renewable to 2053	**100**	**—**	93	—
Bruce Power	Renewable to 2065	**88**	**—**	88	—
Other jointly-owned entities	to 2043	**81**	**3**	80	4
		269	**3**	261	4

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

32. 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 $)	2022	2021
ASSETS		
Current Assets		
Cash and cash equivalents	**60**	72
Accounts receivable	**98**	70
Inventories	**32**	28
Other current assets	**14**	13
	204	183
Plant, Property and Equipment	**3,997**	3,672
Equity Investments	**748**	890
Goodwill	**449**	421
	5,398	5,166
LIABILITIES		
Current Liabilities		
Accounts payable and other	**234**	232
Accrued interest	**18**	17
Current portion of long-term debt	**31**	29
	283	278
Regulatory Liabilities	**78**	66
Other Long-Term Liabilities	**1**	1
Deferred Income Tax Liabilities	**16**	13
Long-Term Debt	**2,136**	2,025
	2,514	2,383

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 $)	2022	2021
Balance sheet		
Loans receivable from affiliates (Notes 7 and 12)[1]	—	1
Equity investments		
Bruce Power	**5,783**	4,493
Coastal GasLink (Note 7)[1]	—	386
Pipeline equity investments and other	**1,148**	1,219
Long-term loans receivable from affiliate (Note 7)	—	238
Off-balance sheet[2]		
Bruce Power[3]	**2,025**	974
Coastal GasLink[4]	**3,300**	3,037
Pipeline equity investments	**58**	171
Maximum exposure to loss	**12,314**	10,519

1 The pre-impairment balances in Equity investments ($2,798 million) and Loans receivable from affiliates ($250 million) at December 31, 2022 related to TC Energy's investment in Coastal GasLink LP were reduced to a nil balance and an impairment charge was recognized in fourth quarter 2022 in Impairment of equity investment in the Consolidated statement of income.

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

3 On March 7, 2022, the IESO verified Bruce Power's Unit 3 MCR program final cost and schedule duration estimate submitted in December 2021. As at December 31, 2022, the maximum exposure includes TC Energy's portion of capital to be invested under the Unit 3 MCR program as well as the expected increase in the capital to be invested under the Asset Management program through 2027.

4 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. The committed capacity under the subordinated loan agreement was $1,262 million as at December 31, 2022 and will increase in the future as required to support the estimated $3.3 billion of additional equity financing requirements through completion of construction of the Coastal GasLink pipeline. The determination of the Company's maximum exposure to loss involves an estimate of the capital costs to complete the Coastal GasLink pipeline.

In July 2022, the Company entered into revised project agreements relating to its investment in Coastal GasLink LP and committed to make additional equity contributions, which did not result in a change in the Company's 35 per cent ownership. These revisions and additional equity contributions were determined to be a VIE reconsideration event for TC Energy's investment in Coastal GasLink LP. The Company performed a re-assessment of control and determined that Coastal GasLink LP continued to meet the definition of a VIE in which the Company held a variable interest. The re-assessment further determined that TC Energy was not the primary beneficiary of Coastal GasLink LP as the Company does not have the power, either explicit or implicit through voting rights or otherwise, to direct the activities that most significantly impact the economic performance of Coastal GasLink LP. Accordingly, the Company continued to account for its investment using the equity method of accounting. Refer to Note 7, Coastal GasLink, for additional information.

33. SUBSEQUENT EVENT

Mexico Debt Issuance

On January 17, 2023, a wholly-owned Mexican subsidiary entered into a US$1.8 billion senior unsecured term loan and a US$500 million senior unsecured credit facility. Both the term loan and the revolving commitment are due in January 2028 and bear interest at a floating rate.