TC Energy reports strong third quarter 2023 operating and financial results and achieves mechanical completion on Coastal GasLink ahead of target

Comparable EBITDA now expected to be at the upper end of 2023 outlook

CALGARY, Alberta – November 8, 2023 – TC Energy Corporation (TSX, NYSE: TRP) (TC Energy or the Company) released its third quarter results today. François Poirier, TC Energy's President and Chief Executive Officer commented, "During the third quarter, we made monumental progress on Coastal GasLink and have achieved mechanical completion ahead of our year-end target. The team's exceptional safety and construction execution on this challenging project means that we have reached 100 per cent pipeline installation, including the successful hydrotesting of the full 670 km pipeline length. The project remains on track with the approximately $14.5 billion cost estimate." Poirier continued, "We are also delivering on our 2023 strategic priorities, including strengthening the balance sheet with the recent receipt of $5.3 billion of asset sale proceeds that will be utilized for debt repayment and funding, along with maximizing the value of our assets with the announced intention to spin off our Liquids Pipelines business. Our focus on safety and the reliability of our assets continues to deliver strong year-over-year growth, and we remain on track to deliver a record year for 2023 comparable EBITDA despite macroeconomic headwinds."

Highlights

(All financial figures are unaudited and in Canadian dollars unless otherwise noted)

- Delivered approximately seven per cent comparable EBITDA[1] growth of $2.6 billion in third quarter 2023 compared to $2.5 billion in third quarter 2022. Segmented earnings were $0.6 billion in third quarter 2023 compared to $1.8 billion in third quarter 2022, largely due to the after-tax impairment charge of $1,179 million for the three months ended September 30, 2023 related to TC Energy's equity investment in Coastal GasLink Pipeline Limited Partnership (Coastal GasLink LP)
- Third quarter 2023 results were underpinned by solid utilization and reliability across our assets. While our Natural Gas Pipelines business does not carry material volumetric or price risk, strong utilization rates demonstrate the demand for our services and the longer-term criticality of our assets
  - NGTL System receipts averaged 14.0 Bcf/d, up 0.5 Bcf/d from third quarter 2022
  - NGTL System daily receipts reached 14.6 Bcf on August 6, 2023, the highest single day average on the pipeline
  - U.S. Natural Gas Pipelines LNG deliveries averaged 3.1 Bcf/d, up 1.4 per cent from third quarter 2022
  - U.S. Natural Gas Pipelines business achieved a new record of deliveries to power generators of 5.2 Bcf on July 28, 2023
  - Gas Transmission Northwest (GTN) system achieved an all-time delivery record of 2.96 Bcf on July 25, 2023
  - Keystone Pipeline System achieved 93.7 per cent operational reliability year-to-date
  - Successfully completed two open seasons on Marketlink, supporting the sustained demand for Canadian crude on the Keystone Pipeline and Marketlink systems
  - Alberta cogeneration power plant fleet achieved approximately 98 per cent peak price availability
  - Bruce Power achieved 94 per cent availability and successfully completed the Unit 6 Major Component Replacement (MCR) within budget and ahead of schedule

[1] Comparable EBITDA is a non-GAAP measure used throughout this news release. This measure does not have any standardized meaning under GAAP and therefore is unlikely to be comparable to similar measures presented by other companies. The most directly comparable GAAP measure is Segmented earnings. For more information on non-GAAP measures, refer to the Non-GAAP Measures section of this news release.

- Third quarter 2023 financial results:
  - Net losses attributable to common shares of $0.2 billion or $0.19 per common share compared to net income of $0.8 billion or $0.84 per common share in third quarter 2022. Comparable earnings[2] of $1.0 billion or $1.00 per common share compared to $1.1 billion or $1.07 per common share in 2022
  - Comparable EBITDA of $2.6 billion compared to $2.5 billion in 2022 and segmented earnings of $0.6 billion compared to $1.8 billion in 2022
- Reflecting strong year-to-date operational and financial performance, we now expect 2023 comparable EBITDA to be at the upper end of the five to seven per cent outlook compared to 2022, while 2023 comparable earnings per common share is expected to be generally consistent with 2022
- Year to date, we have placed approximately $5 billion of projects into service on our natural gas and liquids pipeline systems, as well as the Bruce Power Unit 6 MCR which was declared commercially operational on September 14, 2023
- Placed the lateral section of the Villa de Reyes (VdR) pipeline in commercial service
- Placed substantially all assets of the NGTL System/Foothills West Path Delivery Program into service on November 1, 2023
- On October 4, 2023, we successfully completed the sale of a 40 per cent non-controlling equity interest in Columbia Gas Transmission, LLC (Columbia Gas) and Columbia Gulf Transmission, LLC (Columbia Gulf) systems to Global Infrastructure Partners (GIP) for total cash proceeds of $5.3 billion (US$3.9 billion), which were directed towards reducing leverage
- Coastal GasLink has achieved mechanical completion, ahead of its year-end target and the project remains on track with the cost estimate of approximately $14.5 billion
- The Southeast Gateway Pipeline project continues to progress to our US$4.5 billion cost estimate and schedule. Land rights and rights of way negotiations have closed and all critical permits for onshore construction have been received. We are advancing construction of on-shore facilities and landfalls. Offshore engineering is complete and offshore installation expected to commence prior to the end of 2023
- Approved the Bison XPress expansion project on Northern Border and Bison systems that will replace and upgrade certain facilities and provide production egress from the Bakken basin to a delivery point at the Cheyenne Hub
- GTN XPress project received FERC approval to expand the GTN system that will provide for the transport of incremental contracted export capacity facilitated by the NGTL System/Foothills West Path Delivery Program
- John E. Lowe will be appointed as TC Energy's Board Chair, effective January 1, 2024
- Progressing proposed Liquids Pipelines spinoff with the announcement of the Board Chair and company name, South Bow Corporation
- Declared a quarterly dividend of $0.93 per common share for the quarter ending December 31, 2023.

[2] Comparable earnings and comparable earnings per common share are non-GAAP measures used throughout this news release. These measures do not have any standardized meaning under GAAP and therefore are unlikely to be comparable to similar measures presented by other companies. The most directly comparable GAAP measures are Net income attributable to common shares and Net income per common share, respectively. For more information on non-GAAP measures, refer to the Non-GAAP Measures section of this news release.

(millions of $, except per share amounts)	three months ended September 30 2023	three months ended September 30 2022	nine months ended September 30 2023	nine months ended September 30 2022
Income				
Net income (loss) attributable to common shares	**(197)**	841	**1,366**	2,088
per common share – basic	**($0.19)**	$0.84	**$1.33**	$2.11
Segmented earnings (losses)				
Canadian Natural Gas Pipelines	**(799)**	409	**(782)**	1,152
U.S. Natural Gas Pipelines	**782**	714	**2,576**	1,735
Mexico Natural Gas Pipelines	**210**	113	**646**	395
Liquids Pipelines	**253**	268	**702**	801
Power and Energy Solutions	**234**	289	**741**	535
Corporate	**(36)**	(9)	**(74)**	12
Total segmented earnings (losses)	**644**	1,784	**3,809**	4,630
Comparable EBITDA				
Canadian Natural Gas Pipelines	**781**	713	**2,301**	2,038
U.S. Natural Gas Pipelines	**968**	926	**3,160**	2,948
Mexico Natural Gas Pipelines	**232**	204	**597**	542
Liquids Pipelines	**398**	332	**1,078**	1,002
Power and Energy Solutions	**256**	295	**754**	704
Corporate	**(3)**	(9)	**(9)**	(16)
Comparable EBITDA	**2,632**	2,461	**7,881**	7,218
Depreciation and amortization	**(690)**	(653)	**(2,061)**	(1,914)
Interest expense included in comparable earnings	**(865)**	(666)	**(2,413)**	(1,866)
Allowance for funds used during construction	**164**	116	**443**	254
Foreign exchange gains (losses), net included in comparable earnings	**(25)**	6	**78**	32
Interest income and other included in comparable earnings	**63**	35	**157**	93
Income tax (expense) recovery included in comparable earnings	**(220)**	(202)	**(749)**	(554)
Net (income) loss attributable to non-controlling interests	**(1)**	(8)	**(18)**	(28)
Preferred share dividends	**(23)**	(21)	**(69)**	(85)
Comparable earnings	**1,035**	1,068	**3,249**	3,150
Comparable earnings per common share	**$1.00**	$1.07	**$3.16**	$3.19
Net cash provided by operations	**1,824**	1,701	**5,408**	4,350
Comparable funds generated from operations[i]	**1,755**	1,637	**5,575**	5,068
Capital spending[ii]	**3,289**	2,594	**9,313**	5,822
Dividends declared				
per common share	**$0.93**	$0.90	**$2.79**	$2.70
Basic common shares outstanding (millions)				
– weighted average for the period	**1,035**	1,000	**1,028**	988
– issued and outstanding at end of period	**1,037**	1,012	**1,037**	1,012

i Comparable funds generated from operations is a non-GAAP measure used throughout this release. This measure does not have any standardized meaning under GAAP and therefore is unlikely to be comparable in similar measures presented by other companies. The most directly comparable GAAP measure is Net cash provided by operations. For more information on non-GAAP measures, refer to the Non-GAAP Measures section of this release.

ii Includes Capital expenditures, Capital projects in development and Contributions to equity investments. Refer to the Financial condition – Cash (used in) provided by investing activities section for additional information.

CEO Message

In the third quarter of 2023, we made significant progress towards our 2023 strategic priorities that include safely executing on major projects including Coastal GasLink and Southeast Gateway, bringing other capacity capital projects into service, accelerating our deleveraging by advancing our $5+ billion asset divestiture program, and continuing to maximize the value and performance of our assets through safe operations and reliable service.

Project execution: Coastal GasLink achieves mechanical completion, while continuing to advance Southeast Gateway
We are pleased to announce that the **Coastal GasLink** project has achieved mechanical completion ahead of our year-end target. In October, the project achieved 100 per cent pipe installation following the final weld at the base of Cable Crane Hill. This monumental milestone includes the installation of all 800 water crossings and the successful hydrotesting of the full length of the 670 km pipeline. Achieving mechanical completion allows us to safely commence the introduction of natural gas. With the most challenging work completed, we have substantially mitigated the remaining risks associated with the project, and the cost estimate of approximately $14.5 billion remains on track. Throughout the remainder of 2023, the project will complete pipeline commissioning activities to be ready to deliver commissioning gas to the LNG Canada facility by the end of the year, and we will continue reclamation work in 2024. In Mexico, our team made important progress on the **Southeast Gateway Pipeline** project. Land rights and rights of way negotiations have closed, and all critical permits for onshore construction have been received. Onshore construction at the three landfall sites continues to progress on plan, with all land acquisitions complete. Offshore engineering is complete and concrete coating is on track, supporting offshore installation which is expected to commence prior to the end of 2023. We also placed the lateral section of the VdR pipeline into commercial service, serving power generation in the state of Guanajuato. With the support of the Comisión Federal de Electricidad (CFE) and state governments, we are targeting the south section of VdR to be in-service by the second half of 2024.

Accelerating deleveraging by advancing our $5+ billion asset divestiture program
On October 4, we announced the successful completion of the sale of a 40 per cent non-controlling equity interest in our Columbia Gas and Columbia Gulf systems to GIP, for total cash proceeds of $5.3 billion (US$3.9 billion). Cash proceeds from this transaction were directed towards reducing our year-end 2023 debt-to-EBITDA[3] metric by over 0.4 times. Closing of this transaction is a major step towards reaching TC Energy's 2024 year-end leverage target of 4.75 times debt-to-EBITDA. As we announced in July, we continue to evaluate an incremental $3 billion of capital rotation opportunities to further support our deleveraging targets. Collectively, these actions are expected to enable TC Energy to continue strengthening its balance sheet and reinforce long-term, sustainable annual dividend growth of three to five per cent.

Demand for our services during nine months of the year drives nine per cent year-over-year growth in comparable EBITDA
Strong operational performance during the third quarter is a testament to our ability to safely and reliably deliver essential services across North America. Within our integrated Natural Gas Pipelines business, total NGTL System receipts averaged 14.0 Bcf/d and the NGTL System achieved record single-day receipts of 14.6 Bcf on August 6. U.S. Natural Gas (USNG) LNG deliveries averaged 3.1 Bcf/d during the quarter, up 1.4 per cent compared to third quarter 2022, and our USNG business achieved a new record for deliveries to power generators of 5.2 Bcf on July 28. Our GTN system also achieved an all-time delivery record of 2.96 Bcf on July 25. In October, FERC approved our GTN XPress project, an expansion of the GTN system that will provide for incremental contracted export capacity facilitated by the NGTL System/Foothills West Path Delivery Program with an anticipated in-service date in 2024. The Liquids Pipelines business has delivered approximately eight per cent comparable EBITDA growth year-to-date compared to 2022. Ensuring the continued delivery of all contracted volumes, the Keystone Pipeline System has achieved 93.7 per cent operational reliability year-to-date. Marketlink throughput increased over 250,000 Bbl/d year-over-year, driven by strong demand and additional last-mile connectivity. Throughout the year we have successfully completed two open seasons on Marketlink, supporting the sustained demand for Canadian crude on the Keystone Pipeline and Marketlink systems. Within Power and Energy Solutions, the Alberta cogeneration power plant fleet

[3] Debt-to-EBITDA is a non-GAAP ratio. Adjusted debt and adjusted comparable EBITDA are non-GAAP measures used to calculate debt-to-EBITDA. See the Forward-looking information, Non-GAAP measures and Reconciliation sections for more information.

reached approximately 98 per cent peak price availability, while Bruce Power achieved 94 per cent availability in the quarter. Highlighting our shared commitment to project execution, Bruce Power announced the successful completion of the Unit 6 MCR within budget and ahead of schedule. Unit 6 has fully returned to service, achieving a significant milestone in Ontario's largest clean-energy initiative and one of Canada's largest infrastructure projects.

2023 outlook and dividend declaration

Reflecting strong year-to-date operational and financial performance, we now expect 2023 comparable EBITDA to be at the upper end of the five to seven per cent outlook compared to 2022 and 2023 comparable earnings per share to be generally consistent with 2022. Total capital expenditures for 2023 are now expected to be approximately $12.0 billion to $12.5 billion. While the estimated capital costs associated with our major projects remains consistent, the increase from the range as outlined in our 2022 Annual Report is primarily related to shifts in timing for some of our growth projects and maintenance capital expenditures in our natural gas pipelines businesses, as well as the foreign exchange impact of a stronger U.S. dollar. We continue to work on cost mitigation strategies and assess developments in our construction projects and market conditions for changes to our overall capital program. To date, we have placed approximately $5 billion of assets into service on budget, further supporting comparable EBITDA growth. Beyond 2024, we remain committed to limiting annual sanctioned net capital expenditures to $6 billion to $7 billion. At this level, we believe we can continue to grow our business at a commensurate rate with our dividend growth outlook of three to five per cent, while also providing the optionality to further reduce leverage and/or return incremental capital to shareholders. TC Energy's Board of Directors declared a quarterly dividend of $0.93 per common share for the quarter ending December 31, 2023, equating to $3.72 on an annualized basis.

Executing on commitment of enhanced governance

On November 8, TC Energy announced on behalf of its Board of Directors that John E. Lowe will be appointed as Chair of the Board, effective January 1, 2024. Delivering on his commitment to align with TC Energy's revised governance guidelines regarding board commitments as outlined in the 2023 Management Information Circular, Siim A. Vanaselja has announced he will be stepping down as Board Chair effective December 31, 2023. Mr. Vanaselja joined the Board of Directors in 2014 and was appointed as Board Chair in 2017. He will continue to serve as a valued member of the Board to ensure an orderly succession and allow TC Energy the continued benefit of his expertise. Mr. Lowe has been a member of TC Energy's Board of Directors since 2015 and currently serves as Chair of the Governance committee, a member of the Health, Safety, Sustainability and Environment committee, and has previously served as Chair of the Audit committee. Mr. Lowe's extensive governance experience is paired with over 25 years of various executive and management positions within the midstream and energy industry.

Progressing our proposed Liquids Pipelines spinoff

We have already achieved significant milestones in the few short months following our July 27 announcement to spin off our Liquids Pipelines business to create two independent, investment-grade, publicly listed companies. First, we announced that Hal Kvisle has agreed to be appointed as Chair of South Bow Corporation Board of Directors. Hal has extensive industry experience and intimate knowledge of TC Energy's highly competitive North American liquids system. Second, we remain on track with all major separation activities to successfully execute the transaction during the second half of 2024, including required regulatory and tax status applications. And third, we are excited to announce South Bow Corporation as the name of the new Liquids Pipeline Company. This name symbolizes the historical roots of the company in Alberta, Canada, while acknowledging the pipeline system's strategic corridor, which enables the company to deliver a premium service to the strongest U.S. demand markets. This symbolism—grounded in history and pointing towards our future—is reflective of the new company's vision, which is rooted in safety and operational excellence and guided by a team dedicated to providing highly competitive service to our customers and ultimately, North America.

The series of announcements TC Energy has made in recent months are complementary efforts. When taken together, spinning off the Liquids Pipelines business, integrating our natural gas businesses and advancing deleveraging targets through asset sales, all directly serve our long-term strategy and commitment to maximizing the value of our assets. As we look forward, we are aligning our portfolio mix and strategy to protect and enhance the value of our strategic corridors to deliver long term enduring shareholder value.

Teleconference and Webcast

We will hold a teleconference and webcast on Wednesday, November 8, 2023 at 6:30 a.m. (MST) / 8:30 a.m. (EST) to discuss our third quarter 2023 financial results and company developments. Presenters will include François Poirier, President and Chief Executive Officer; Joel Hunter, Executive Vice-President and Chief Financial Officer; and other members of the executive leadership team.

Members of the investment community and other interested parties are invited to participate by calling **1.800.319.4610**. No passcode is required. Please dial in 15 minutes prior to the start of the call. Alternatively, participants may pre-register for the call here. Upon registering, you will receive a calendar booking by email with dial in details and a unique PIN. This process will bypass the operator and avoid the queue. Registration will remain open until the end of the conference call.

A live webcast of the teleconference will be available on TC Energy's website at www.TCEnergy.com/events or via the following URL: https://www.gowebcasting.com/12930. The webcast will be available for the replay following the meeting.

A replay of the teleconference will be available two hours after the conclusion of the call until midnight EST on November 15, 2023. Please call 1.855.669.9658 and enter passcode 0502.

The unaudited interim Condensed consolidated financial statements and Management's Discussion and Analysis (MD&A) are available on our website at www.TCEnergy.com and will be filed today under TC Energy's profile on SEDAR+ at www.sedarplus.ca and with the U.S. Securities and Exchange Commission on EDGAR at www.sec.gov.

About TC Energy

We're a team of 7,000+ energy problem solvers working to move, generate and store the energy North America relies on. Today, we're taking action to make that energy more sustainable and more secure. We're innovating and modernizing to reduce emissions from our business. And, we're delivering new energy solutions – from natural gas and renewables to carbon capture and hydrogen – to help other businesses and industries decarbonize too. Along the way, we invest in communities and partner with our neighbours, customers and governments to build the energy system of the future.

TC Energy's common shares trade on the Toronto (TSX) and New York (NYSE) stock exchanges under the symbol TRP. To learn more, visit us at **www.TCEnergy.com**

Forward-Looking Information

This release contains certain information that is forward-looking and is subject to important risks and uncertainties and is based on certain key assumptions. Forward-looking statements are usually accompanied by words such as "anticipate", "expect", "believe", "may", "will", "should", "estimate" or other similar words. Forward-looking statements in this document may include, but are not limited to, statements on the progress of Coastal GasLink, Southeast Gateway and GTN XPress projects, including mechanical completion, offshore installations and in-service dates, our projected comparable EBITDA and debt-to-EBITDA leverage metrics for 2023 and 2024, our targeted leverage metrics, and our expected capital expenditures and dividend outlook and the proposed Liquids Pipelines spinoff, including the structure, conditions, timing and tax effect thereof. Our forward-looking information is subject to important risks and uncertainties and is based on certain key assumptions. Forward-looking statements in this document are intended to provide TC Energy security holders and potential investors with information regarding TC Energy and its subsidiaries, including management's assessment of TC Energy's and its subsidiaries' future plans and financial outlook. All forward-looking statements reflect TC Energy's beliefs and assumptions based on information available at the time the statements were made and as such are not guarantees of future performance. As actual results could vary significantly from the forward-looking information, you should not put undue reliance on forward-looking information and should not use future-oriented information or financial outlooks for anything other than their intended purpose. We do not update our forward-looking information due to new information or future events, unless we are required to by law. For additional information on the assumptions made, and the risks and uncertainties which could cause actual results to differ from the anticipated results, refer to the most recent Quarterly Report to Shareholders and the 2022 Annual Report filed under TC Energy's profile on SEDAR+ at **www.sedarplus.ca** and with the U.S. Securities and Exchange Commission at **www.sec.gov** and the "Forward-looking information" section of our Report on Sustainability and our GHG Emissions Reduction Plan which are available on our website at **www.TCEnergy.com**.

Non-GAAP Measures

This release contains references to the following non-GAAP measures: comparable EBITDA, comparable earnings, comparable earnings per common share and comparable funds generated from operations. It also contains references to debt-to-EBITDA, a non-GAAP ratio, which is calculated using adjusted debt and adjusted comparable EBITDA, each of which are non-GAAP measures. These non-GAAP measures do not have any standardized meaning as prescribed by GAAP and therefore may not be comparable to similar measures presented by other entities. These non-GAAP measures are calculated by adjusting certain GAAP measures for specific items we believe are significant but not reflective of our underlying operations in the period. These comparable measures are calculated on a consistent basis from period to period and are adjusted for specific items in each period, as applicable except as otherwise described in the Condensed consolidated financial statements and MD&A. Refer to: (i) each business segment for a reconciliation of comparable EBITDA to segmented earnings (losses); (ii) Consolidated results section for reconciliations of comparable earnings and comparable earnings per common share to Net income attributable to common shares and Net income per common share, respectively; and (iii) Financial condition section for a reconciliation of comparable funds generated from operations to Net cash provided by operations. Refer to the Non-GAAP Measures section of the MD&A in our most recent quarterly report for more information about the non-GAAP measures we use, the MD&A is included in this release. The MD&A can be found on SEDAR+ at **www.sedarplus.ca** under TC Energy's profile.

With respect to non-GAAP measures used in the calculation of debt-to-EBITDA, adjusted debt is defined as the sum of Reported Total debt, including Notes payable, Long-term debt, Current portion of long-term debt and Junior subordinated notes, as reported on our Consolidated balance sheet as well as Operating lease liabilities recognized on our Consolidated balance sheet and 50 per cent of Preferred shares as reported on our Consolidated balance sheet due to the debt-like nature of their contractual and financial obligations, less Cash and cash equivalents as reported on our Consolidated balance sheet and 50 per cent of Junior subordinated notes as reported on our Consolidated balance sheet due to the equity-like nature of their contractual and financial obligations. Adjusted comparable EBITDA is calculated as comparable EBITDA excluding operating lease costs recorded in Plant operating costs and other in our Consolidated statement of income and adjusted for Distributions received in excess of (income) loss from equity investments as reported in our Consolidated statement of cash flows which is more reflective of the cash flows available to TC Energy to service our debt and other long-term commitments. We believe that debt-to-EBITDA provides investors with useful information as it reflects our ability to service our debt and other long-term commitments. See the Reconciliation section for reconciliations of adjusted debt and adjusted comparable EBITDA for the years ended December 31, 2021 and 2022.

Reconciliation

The following is a reconciliation of adjusted debt and adjusted comparable EBITDA[i].

	year ended December 31	
(millions of Canadian $)	**2022**	**2021**
Reported total debt	58,300	52,766
Management adjustments:		
Debt treatment of preferred shares[ii]	1,250	1,744
Equity treatment of junior subordinated notes[iii]	(5,248)	(4,470)
Cash and cash equivalents	(620)	(673)
Operating lease liabilities	433	429
Adjusted debt	54,115	49,796
Comparable EBITDA[iv]	9,901	9,368
Operating lease cost	106	105
Distributions received in excess of (income) loss from equity investments	(29)	77
Adjusted Comparable EBITDA	9,978	9,550
Adjusted Debt/Adjusted Comparable EBITDA[i]	5.4	5.2

i Comparable EBITDA is a non-GAAP measure. Management methodology. Individual rating agency calculations will differ.

ii 50 per cent debt treatment on $2.5 billion of preferred shares as of December 31, 2022.

iii 50 per cent equity treatment on $10.5 billion of junior subordinated notes as of December 31, 2022. U.S. dollar-denominated notes translated at December 31, 2022, U.S./Canada foreign exchange rate of 1.35.

iv Comparable EBITDA is a non-GAAP financial measure. See the Forward-looking information and Non-GAAP measures sections for more information.

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Quarterly report to shareholders

Third quarter 2023

Financial highlights

(millions of $, except per share amounts)	three months ended September 30		nine months ended September 30	
	2023	**2022**	**2023**	**2022**
Income				
Revenues	**3,940**	3,799	**11,698**	10,936
Net income (loss) attributable to common shares	**(197)**	841	**1,366**	2,088
per common share – basic	**($0.19)**	$0.84	**$1.33**	$2.11
Comparable EBITDA[1]	**2,632**	2,461	**7,881**	7,218
Comparable earnings	**1,035**	1,068	**3,249**	3,150
per common share	**$1.00**	$1.07	**$3.16**	$3.19
Cash flows				
Net cash provided by operations	**1,824**	1,701	**5,408**	4,350
Comparable funds generated from operations	**1,755**	1,637	**5,575**	5,068
Capital spending[2]	**3,289**	2,594	**9,313**	5,822
Dividends declared				
per common share	**$0.93**	$0.90	**$2.79**	$2.70
Basic common shares outstanding (millions)				
– weighted average for the period	**1,035**	1,000	**1,028**	988
– issued and outstanding at end of period	**1,037**	1,012	**1,037**	1,012

1 Additional information on Segmented earnings (losses), the most directly comparable GAAP measure, can be found in the Consolidated results section.

2 Includes Capital expenditures, Capital projects in development and Contributions to equity investments. Refer to the Financial condition – Cash (used in) provided by investing activities section for additional information.

Management’s discussion and analysis

November 7, 2023

This management’s discussion and analysis (MD&A) contains information to help the reader make investment decisions about TC Energy Corporation (TC Energy). It discusses our business, operations, financial position, risks and other factors for the three and nine months ended September 30, 2023 and should be read with the accompanying unaudited Condensed consolidated financial statements for the three and nine months ended September 30, 2023, which have been prepared in accordance with U.S. GAAP.

This MD&A should also be read in conjunction with our December 31, 2022 audited Consolidated financial statements and notes and the MD&A in our 2022 Annual Report. Capitalized and abbreviated terms that are used but not otherwise defined herein are defined in our 2022 Annual Report. Certain comparative figures have been adjusted to reflect the current period's presentation.

FORWARD-LOOKING INFORMATION

We disclose forward-looking information to help the reader understand management's assessment of our future plans and financial outlook and our future prospects overall.

Statements that are ***forward looking*** are based on certain assumptions and on what we know and expect today and generally include words like ***anticipate, expect, believe, may, will, should, estimate*** or other similar words.

Forward-looking statements in this MD&A include information about the following, among other things:
- our financial and operational performance, including the performance of our subsidiaries
- expectations about strategies and goals for growth and expansion, including acquisitions
- expected cash flows and future financing options available along with portfolio management
- expectations about the new Liquids Pipelines Company following the completion of the spinoff transaction, including the management and credit ratings thereof
- expectations regarding the size, structure, timing, conditions and outcome of ongoing and future transactions, including the monetization of certain pipelines, the spinoff transaction and our asset divestiture program
- expected dividend growth
- expected access to and cost of capital
- expected energy demand levels
- expected costs and schedules for planned projects, including projects under construction and in development
- expected capital expenditures, contractual obligations, commitments and contingent liabilities, including environmental remediation costs
- expected regulatory processes and outcomes
- statements related to our GHG emissions reduction goals
- expected outcomes with respect to legal proceedings, including arbitration and insurance claims
- the expected impact of future tax and accounting changes
- the commitments and targets contained in our Report on Sustainability and GHG Emissions Reduction Plan
- expected industry, market and economic conditions, including their impact on our customers and suppliers.

Forward-looking statements do not guarantee future performance. Actual events and results could be significantly different because of assumptions, risks or uncertainties related to our business or events that happen after the date of this MD&A.

Our forward-looking information is based on the following key assumptions and subject to the following risks and uncertainties:

Assumptions

- realization of expected benefits from acquisitions, divestitures, the spinoff transaction and energy transition
- regulatory decisions and outcomes
- planned and unplanned outages and the use of our pipelines, power and storage assets
- integrity and reliability of our assets
- anticipated construction costs, schedules and completion dates
- access to capital markets, including portfolio management
- expected industry, market and economic conditions, including the impact of these on our customers and suppliers
- inflation rates, commodity and labour prices
- interest, tax and foreign exchange rates
- nature and scope of hedging.

Risks and uncertainties

- realization of expected benefits from acquisitions, divestitures, the spinoff transaction and energy transition
- the terms, timing and completion of the spinoff transaction, including the timely receipt of all necessary approvals and tax rulings
- our ability to successfully implement our strategic priorities, including Focus Project, and whether they will yield the expected benefits
- our ability to implement a capital allocation strategy aligned with maximizing shareholder value
- the operating performance of our pipelines, power generation and storage assets
- amount of capacity sold and rates achieved in our pipeline businesses
- the amount of capacity payments and revenues from power generation assets due to plant availability
- production levels within supply basins
- construction and completion of capital projects
- cost, availability of and inflationary pressures on labour, equipment and materials
- the availability and market prices of commodities
- access to capital markets on competitive terms
- interest, tax and foreign exchange rates
- performance and credit risk of our counterparties
- regulatory decisions and outcomes of legal proceedings, including arbitration and insurance claims
- our ability to effectively anticipate and assess changes to government policies and regulations, including those related to the environment
- our ability to realize the value of tangible assets and contractual recoveries
- competition in the businesses in which we operate
- unexpected or unusual weather
- acts of civil disobedience
- cyber security and technological developments
- ESG-related risks
- impact of energy transition on our business
- economic conditions in North America as well as globally
- global health crises, such as pandemics and epidemics and the impacts related thereto.

You can read more about these factors and others in this MD&A and in other reports we have filed with Canadian securities regulators and the SEC, including the MD&A in our 2022 Annual Report.

As actual results could vary significantly from the forward-looking information, you should not put undue reliance on forward-looking information and should not use future-oriented information or financial outlooks for anything other than their intended purpose. We do not update our forward-looking statements due to new information or future events unless we are required to by law.

FOR MORE INFORMATION

You can find more information about TC Energy in our Annual Information Form and other disclosure documents, which are available on SEDAR+ (www.sedarplus.ca).

NON-GAAP MEASURES

This MD&A references the following non-GAAP measures:

- comparable EBITDA
- comparable EBIT
- comparable earnings
- comparable earnings per common share
- funds generated from operations
- comparable funds generated from operations.

These measures do not have any standardized meaning as prescribed by GAAP and therefore may not be comparable to similar measures presented by other entities. Discussions throughout this MD&A on the factors impacting comparable earnings are consistent with the factors that impact net income attributable to common shares, except where noted otherwise. Discussions throughout this MD&A on the factors impacting comparable earnings before interest, taxes, depreciation and amortization (comparable EBITDA) and comparable earnings before interest and taxes (comparable EBIT) are consistent with the factors that impact segmented earnings, except where noted otherwise.

Comparable measures

We calculate comparable measures by adjusting certain GAAP measures for specific items we believe are significant but not reflective of our underlying operations in the period. Except as otherwise described herein, these comparable measures are calculated on a consistent basis from period to period and are adjusted for specific items in each period, as applicable.

Our decision not to adjust for a specific item in reporting comparable measures is subjective and made after careful consideration. Specific items may include:

- gains or losses on sales of assets or assets held for sale
- income tax refunds, valuation allowances and adjustments resulting from changes in legislation and enacted tax rates
- expected credit loss provisions on net investment in leases and certain contract assets in Mexico
- legal, contractual, bankruptcy and other settlements
- impairment of goodwill, plant, property and equipment, equity investments and other assets
- acquisition and integration costs
- restructuring costs
- unrealized fair value adjustments related to risk management activities of Bruce Power's funds invested for post-retirement benefits
- unrealized gains and losses from changes in the fair value of derivatives related to financial and commodity price risk management activities.

We exclude from comparable measures the unrealized gains and losses from changes in the fair value of derivatives related to financial and commodity price risk management activities. These derivatives generally provide effective economic hedges but do not meet the criteria for hedge accounting. The changes in fair value, including our proportionate share of changes in fair value related to Bruce Power, are recorded in net income. As these amounts do not accurately reflect the gains and losses that will be realized at settlement, we do not consider them reflective of our underlying operations.

In second quarter 2023, we announced plans to separate into two independent, investment-grade, publicly listed companies through the proposed spinoff of our Liquids Pipelines business. A separation management office was established guiding the successful coordination and governance including the development of a separation agreement and a transition service agreement between the two entities once the proposed spinoff is complete. Separation costs related to the proposed spinoff include employee-related transaction costs, legal, tax, audit and other consulting fees, which have been excluded from comparable measures as we do not consider them reflective of our ongoing underlying operations.

In second quarter 2023, we accrued an additional amount for environmental remediation costs related to the Milepost 14 incident. We have appropriate insurance policies in place and we believe that it remains probable that the majority of environmental remediation costs will be eligible for recovery under our existing insurance coverage. We expect to receive a portion of these insurance proceeds from our wholly-owned captive insurance subsidiary, which resulted in an impact to net income in the consolidated financial results of TC Energy in second quarter 2023. This amount has been excluded from comparable measures as it is not reflective of our ongoing underlying operations.

In 2023, TransCanada PipeLines Limited (TCPL) entered into an unsecured revolving credit facility with Transportadora de Gas Natural de la Huasteca (TGNH). The loan receivable and loan payable are eliminated upon consolidation; however, due to the differences in the currency that each entity reports its financial results, there is an impact to net income reflecting the translation of the loan receivable and payable to TC Energy's reporting currency. As the amounts do not accurately reflect what will be realized at settlement, beginning in second quarter 2023, we excluded from comparable measures the unrealized foreign exchange gains and losses on the loan receivable as well as the corresponding unrealized foreign exchange gains and losses on the loan payable.

In late 2022, we launched the Focus Project to identify opportunities to improve safety, productivity and cost-effectiveness and to date have identified a broad set of opportunities expected to improve safety and financial performance over the long term. Certain initiatives have been implemented and we expect to continue designing and implementing additional initiatives beyond 2023, with benefits in the form of enhanced productivity and cost-effectiveness expected to be realized in the future. Beginning in second quarter 2023, we recognized expenses in Plant operating costs and other, primarily related to Focus Project costs for external consulting and severance, some of which are not recoverable through regulatory and commercial tolling structures. These amounts have been excluded from comparable measures as they are not reflective of our ongoing underlying operations.

Prior to full repayment in first quarter 2022, we excluded from comparable measures the unrealized foreign exchange gains and losses on the peso-denominated loan receivable from an affiliate as well as the corresponding proportionate share of Sur de Texas foreign exchange gains and losses, as the amounts did not accurately reflect the gains and losses that would be realized at settlement. These amounts offset within each reporting period, resulting in no impact on net income.

The following table identifies our non-GAAP measures against their most directly comparable GAAP measures:

Comparable measure	GAAP measure
comparable EBITDA	segmented earnings (losses)
comparable EBIT	segmented earnings (losses)
comparable earnings	net income (loss) attributable to common shares
comparable earnings per common share	net income (loss) per common share
funds generated from operations	net cash provided by operations
comparable funds generated from operations	net cash provided by operations

Comparable EBITDA and comparable EBIT

Comparable EBITDA represents segmented earnings (losses) adjusted for certain specific items, excluding charges for depreciation and amortization. We use comparable EBITDA as a measure of our earnings from ongoing operations as it is a useful indicator of our performance and is also presented on a consolidated basis. Comparable EBIT represents segmented earnings (losses) adjusted for specific items and is an effective tool for evaluating trends in each segment. Refer to each business segment for a reconciliation to segmented earnings (losses).

Comparable earnings and comparable earnings per common share

Comparable earnings represents earnings attributable to common shareholders on a consolidated basis, adjusted for specific items. Comparable earnings is comprised of segmented earnings (losses), Interest expense, AFUDC, Foreign exchange gains (losses), net, Interest income and other, Income tax (expense) recovery, Non-controlling interests and Preferred share dividends, adjusted for specific items. Refer to the Consolidated results section for reconciliations to Net income (loss) attributable to common shares and Net income (loss) per common share.

Funds generated from operations and comparable funds generated from operations

Funds generated from operations reflects net cash provided by operations before changes in operating working capital. The components of changes in working capital are disclosed in our 2022 Consolidated financial statements. We believe funds generated from operations is a useful measure of our consolidated operating cash flows because it excludes fluctuations from working capital balances, which do not necessarily reflect underlying operations in the same period, and is used to provide a consistent measure of the cash generating ability of our businesses. Comparable funds generated from operations is adjusted for the cash impact of specific items noted above. Refer to the Financial condition section for a reconciliation to Net cash provided by operations.

Consolidated results

(millions of $, except per share amounts)	three months ended September 30		nine months ended September 30	
	2023	**2022**	**2023**	**2022**
Canadian Natural Gas Pipelines	**(799)**	409	**(782)**	1,152
U.S. Natural Gas Pipelines	**782**	714	**2,576**	1,735
Mexico Natural Gas Pipelines	**210**	113	**646**	395
Liquids Pipelines	**253**	268	**702**	801
Power and Energy Solutions	**234**	289	**741**	535
Corporate	**(36)**	(9)	**(74)**	12
Total segmented earnings (losses)	**644**	1,784	**3,809**	4,630
Interest expense	**(865)**	(666)	**(2,418)**	(1,866)
Allowance for funds used during construction	**164**	116	**443**	254
Foreign exchange gains (losses), net	**(45)**	(277)	**231**	(317)
Interest income and other	**63**	35	**121**	93
Income (loss) before income taxes	**(39)**	992	**2,186**	2,794
Income tax (expense) recovery	**(134)**	(122)	**(733)**	(593)
Net income (loss)	**(173)**	870	**1,453**	2,201
Net (income) loss attributable to non-controlling interests	**(1)**	(8)	**(18)**	(28)
Net income (loss) attributable to controlling interests	**(174)**	862	**1,435**	2,173
Preferred share dividends	**(23)**	(21)	**(69)**	(85)
Net income (loss) attributable to common shares	**(197)**	841	**1,366**	2,088
Net income (loss) per common share – basic	**($0.19)**	$0.84	**$1.33**	$2.11

Net income (loss) attributable to common shares decreased by $1,038 million or $1.03 per common share and $722 million or $0.78 per common share for the three and nine months ended September 30, 2023, respectively, compared to the same periods in 2022. The following specific items were recognized in Net income (loss) attributable to common shares and were excluded from comparable earnings:

2023 results

- an after-tax impairment charge of $1,179 million and $2,017 million for the three and nine months ended September 30, 2023 related to our equity investment in Coastal GasLink Pipeline Limited Partnership (Coastal GasLink LP). Refer to Note 5, Coastal GasLink, of our Condensed consolidated financial statements for additional information
- a $48 million after-tax charge as a result of the FERC Administrative Law Judge initial decision on Keystone issued in February 2023 in respect of a tolling-related complaint pertaining to amounts recognized from 2018 to 2022, which consists of a one-time pre-tax charge of $57 million and included accrued pre-tax carrying charges of $5 million recognized in first quarter 2023
- a $14 million and $39 million after-tax expense for the three and nine months ended September 30, 2023 related to Focus Project costs. Refer to the Recent developments – Corporate section for additional information
- a $36 million after-tax accrued insurance expense recorded in second quarter 2023 related to the Milepost 14 incident. Refer to the Recent developments – Liquids section for additional information
- an $11 million after-tax expense due to separation costs incurred in third quarter 2023 related to the proposed spinoff of our Liquids Pipelines business. Refer to the Recent developments – Liquids section for additional information
- preservation and other costs for Keystone XL pipeline project assets of $2 million and $10 million after tax, for the three and nine months ended September 30, 2023, which could not be accrued as part of the Keystone XL asset impairment charge

- an after-tax unrealized foreign exchange gain of $20 million and $11 million for the three and nine months ended September 30, 2023 on the peso-denominated intercompany loan between TCPL and TGNH. Refer to the Corporate section for additional information
- an $80 million after-tax recovery for the nine months ended September 30, 2023 on the expected credit loss provision related to the TGNH net investment in leases and certain contract assets in Mexico.

2022 results

- an after-tax goodwill impairment charge of $531 million in first quarter 2022 related to Great Lakes
- a $195 million income tax expense incurred in the first half of 2022 for the settlement related to prior years' income tax assessments in Mexico
- a $50 million after-tax expected credit loss provision related to the TGNH net investment in leases recognized in third quarter 2022
- preservation and other costs for Keystone XL pipeline project assets of $3 million and $11 million after tax for the three and nine months ended September 30, 2022, which could not be accrued as part of the Keystone XL asset impairment charge.

Net income in each period included unrealized gains and losses on our proportionate share of Bruce Power's fair value adjustment on funds invested for post-retirement benefits and derivatives related to its risk management activities, as well as unrealized gains and losses from changes in our risk management activities, all of which we exclude along with the above noted items, to arrive at comparable earnings. A reconciliation of Net income (loss) attributable to common shares to comparable earnings is shown in the following table.

RECONCILIATION OF NET INCOME (LOSS) ATTRIBUTABLE TO COMMON SHARES TO COMPARABLE EARNINGS

	three months ended September 30		nine months ended September 30	
(millions of $, except per share amounts)	**2023**	2022	**2023**	2022
Net income (loss) attributable to common shares	**(197)**	841	**1,366**	2,088
Specific items (net of tax):				
Coastal GasLink impairment charge	**1,179**	—	**2,017**	—
Keystone FERC decision	**—**	—	**48**	—
Focus Project costs	**14**	—	**39**	—
Milepost 14 insurance expense	**—**	—	**36**	—
Liquids separation costs	**11**	—	**11**	—
Keystone XL preservation and other	**2**	3	**10**	11
Foreign exchange (gains) losses, net – intercompany loan	**(20)**	—	**(11)**	—
Expected credit loss provision on net investment in leases and certain contract assets in Mexico	**—**	50	**(80)**	50
Great Lakes goodwill impairment charge	**—**	—	**—**	531
Settlement of Mexico prior years' income tax assessments	**—**	—	**—**	195
Bruce Power unrealized fair value adjustments	**6**	(2)	**—**	22
Risk management activities[1]	**40**	176	**(187)**	253
Comparable earnings	**1,035**	1,068	**3,249**	3,150
Net income (loss) per common share	**($0.19)**	$0.84	**$1.33**	$2.11
Specific items (net of tax):				
Coastal GasLink impairment charge	**1.14**	—	**1.96**	—
Keystone FERC decision	**—**	—	**0.05**	—
Focus Project costs	**0.01**	—	**0.04**	—
Milepost 14 insurance expense	**—**	—	**0.03**	—
Liquids separation costs	**0.01**	—	**0.01**	—
Keystone XL preservation and other	**—**	—	**0.01**	0.01
Foreign exchange (gains) losses, net – intercompany loan	**(0.02)**	—	**(0.01)**	—
Expected credit loss provision on net investment in leases and certain contract assets in Mexico	**—**	0.05	**(0.08)**	0.05
Great Lakes goodwill impairment charge	**—**	—	**—**	0.54
Settlement of Mexico prior years' income tax assessments	**—**	—	**—**	0.20
Bruce Power unrealized fair value adjustments	**0.01**	—	**—**	0.02
Risk management activities	**0.04**	0.18	**(0.18)**	0.26
Comparable earnings per common share	**$1.00**	$1.07	**$3.16**	$3.19

1 Risk management activities	three months ended September 30		nine months ended September 30	
(millions of $)	**2023**	2022	**2023**	2022
U.S. Natural Gas Pipelines	**36**	15	**109**	13
Liquids Pipelines	**(59)**	23	**(54)**	58
Canadian Power	**(4)**	2	**(25)**	(26)
U.S. Power	**4**	(1)	**5**	(5)
Natural Gas Storage	**12**	9	**73**	(56)
Foreign exchange	**(40)**	(283)	**142**	(321)
Income tax attributable to risk management activities	**11**	59	**(63)**	84
Total unrealized gains (losses) from risk management activities	**(40)**	(176)	**187**	(253)

COMPARABLE EBITDA TO COMPARABLE EARNINGS

Comparable EBITDA represents segmented earnings (losses) adjusted for the specific items described above and excludes charges for depreciation and amortization. For further information on our reconciliation of comparable EBITDA to segmented earnings (losses) refer to the business segment financial results sections.

	three months ended September 30		nine months ended September 30	
(millions of $, except per share amounts)	**2023**	2022	**2023**	2022
Comparable EBITDA				
Canadian Natural Gas Pipelines	**781**	713	**2,301**	2,038
U.S. Natural Gas Pipelines	**968**	926	**3,160**	2,948
Mexico Natural Gas Pipelines	**232**	204	**597**	542
Liquids Pipelines	**398**	332	**1,078**	1,002
Power and Energy Solutions	**256**	295	**754**	704
Corporate	**(3)**	(9)	**(9)**	(16)
Comparable EBITDA	**2,632**	2,461	**7,881**	7,218
Depreciation and amortization	**(690)**	(653)	**(2,061)**	(1,914)
Interest expense included in comparable earnings	**(865)**	(666)	**(2,413)**	(1,866)
Allowance for funds used during construction	**164**	116	**443**	254
Foreign exchange gains (losses), net included in comparable earnings	**(25)**	6	**78**	32
Interest income and other included in comparable earnings	**63**	35	**157**	93
Income tax (expense) recovery included in comparable earnings	**(220)**	(202)	**(749)**	(554)
Net (income) loss attributable to non-controlling interests	**(1)**	(8)	**(18)**	(28)
Preferred share dividends	**(23)**	(21)	**(69)**	(85)
Comparable earnings	**1,035**	1,068	**3,249**	3,150
Comparable earnings per common share	**$1.00**	$1.07	**$3.16**	$3.19

Comparable EBITDA – 2023 versus 2022

Comparable EBITDA increased by $171 million for the three months ended September 30, 2023 compared to the same period in 2022 primarily due to the net effect of the following:

- increased EBITDA in Canadian Natural Gas Pipelines mainly due to the impact of higher flow-through costs on our Canadian rate-regulated pipelines and increased rate-base earnings on the NGTL System
- increased EBITDA from Liquids Pipelines primarily due to the foreign exchange impact of a stronger U.S. dollar on the translation of our U.S. dollar-denominated operations and higher long-haul contracted volumes as well as higher volumes on the U.S. Gulf Coast section of the Keystone Pipeline System, partially offset by higher operating costs
- increased U.S. dollar-denominated EBITDA from Mexico Natural Gas Pipelines primarily due to earnings from TGNH assets placed in commercial service in third quarter 2022 as well as the lateral section of the Villa de Reyes pipeline which was placed in service in August 2023
- increased U.S. dollar-denominated EBITDA from U.S. Natural Gas Pipelines as a result of higher net earnings from new contracts in ANR and incremental earnings from growth projects placed in service, partially offset by lower earnings from our mineral rights business due to lower commodity prices
- decreased Power and Energy Solutions EBITDA attributable to reduced earnings from Canadian Power due to lower realized power prices and lower contributions from marketing activities, partially offset by lower natural gas fuel costs; lower contributions from Bruce Power mainly due to lower generation, partially offset by lower depreciation expense, a higher contract price and fewer planned outage days; and increased earnings from Natural Gas Storage and other from higher TC Turbines contributions and higher realized Alberta natural gas storage spreads
- the positive foreign exchange impact of a stronger U.S. dollar on the Canadian dollar equivalent segmented earnings (losses) in our U.S. dollar-denominated operations. U.S. dollar-denominated comparable EBITDA increased by US$75 million compared to 2022 which was translated at a rate of 1.34 in 2023 versus 1.31 in 2022. Refer to the Foreign exchange section for additional information.

Comparable EBITDA increased by $663 million for the nine months ended September 30, 2023 compared to the same period in 2022 primarily due to the net effect of the following:

- increased EBITDA in Canadian Natural Gas Pipelines mainly due to the impact of higher flow-through costs on our Canadian rate-regulated pipelines and increased rate-base earnings on the NGTL System, partially offset by lower Coastal GasLink development fee revenue due to timing of revenue recognition
- increased EBITDA from Liquids Pipelines primarily due to the foreign exchange impact of a stronger U.S. dollar on the translation of our U.S. dollar-denominated operations and higher long-haul contracted volumes as well as higher volumes on the U.S. Gulf Coast section of the pipeline, partially offset by higher operating costs; and lower uncontracted volumes on the Keystone Pipeline System related to the Milepost 14 incident
- higher Power and Energy Solutions EBITDA attributable to increased contributions from Bruce Power due to a higher contract price, reduced outage costs with fewer planned outage days and lower depreciation expense as well as increased earnings from Canadian Power due to the net impact of higher realized power prices, lower natural gas fuel costs and reduced contributions from marketing activities, partially offset by decreased Natural Gas Storage and other results from lower realized Alberta natural gas storage spreads and increased business development costs across the segment
- increased U.S. dollar-denominated EBITDA from U.S. Natural Gas Pipelines due to a net increase in earnings from ANR following the FERC-approved settlement for an increase in transportation rates effective August 2022; incremental earnings from growth projects placed in service; higher realized earnings related to our U.S. natural gas marketing business, partially offset by higher operational costs reflective of increased system utilization and lower earnings from our mineral rights business due to lower commodity prices

- higher U.S. dollar-denominated EBITDA from Mexico Natural Gas Pipelines primarily due to earnings from TGNH assets placed in commercial service in third quarter 2022 as well as the lateral section of the Villa de Reyes pipeline which was placed in service in August 2023, partially offset by lower equity earnings from Sur de Texas primarily due to peso-denominated financial exposure and higher interest expense
- the positive foreign exchange impact of a stronger U.S. dollar on the Canadian dollar equivalent segmented earnings (losses) in our U.S. dollar-denominated operations. U.S. dollar-denominated comparable EBITDA increased by US$87 million compared to 2022 which was translated at a rate of 1.35 in 2023 versus 1.28 in 2022. Refer to the Foreign exchange section for additional information.

Due to the flow-through treatment of certain costs including income taxes, financial charges and depreciation in our Canadian rate-regulated pipelines, changes in these costs impact our comparable EBITDA despite having no significant effect on net income.

Comparable earnings – 2023 versus 2022

Comparable earnings decreased by $33 million or $0.07 per common share for the three months ended September 30, 2023 compared to the same period in 2022 and was primarily the net effect of:

- changes in comparable EBITDA described above
- higher interest expense primarily due to long-term debt issuances, net of maturities, the foreign exchange impact of a stronger U.S. dollar in 2023 compared to 2022, partially offset by higher capitalized interest, largely due to funding related to our investment in Coastal GasLink LP
- higher depreciation and amortization on the NGTL System from expansion facilities that were placed in service
- realized losses in third quarter 2023 compared to realized gains for the same period in 2022 on derivatives used to manage our foreign exchange exposure to net liabilities in Mexico and higher net realized losses on derivatives used to manage our net exposure to foreign exchange rate fluctuation on U.S. dollar-denominated income
- increased income tax expense due to lower foreign tax rate differentials and the impact of Mexico's foreign exchange exposure
- higher AFUDC primarily due to the reactivation of AFUDC on the TGNH assets under construction following the new TSA with the CFE in third quarter 2022, including capital expenditures on the Southeast Gateway pipeline project, partially offset by lower AFUDC resulting from NGTL System expansion projects being placed in service
- higher interest income and other due to higher interest earned on short-term investments.

Comparable earnings increased by $99 million and decreased by $0.03 per common share for the nine months ended September 30, 2023 compared to the same period in 2022 primarily due to the net effect of the following:

- changes in comparable EBITDA described above
- higher interest expense primarily due to long-term debt issuances, net of maturities, the foreign exchange impact of a stronger U.S. dollar in 2023 compared to 2022 and higher interest rates on decreased levels of short-term borrowings, partially offset by higher capitalized interest, largely due to funding related to our investment in Coastal GasLink LP
- increased income tax expense due to lower foreign tax rate differentials, the impact of Mexico's foreign exchange exposure and higher comparable earnings subject to income tax
- higher depreciation and amortization due to incremental depreciation for the NGTL System and in U.S. Natural Gas Pipelines due to expansion facilities and new projects placed in service, partially offset by the discontinuance of depreciation expense on TGNH assets in Mexico accounted for as leases
- higher AFUDC primarily due to the reactivation of AFUDC on the TGNH assets under construction following the new TSA with the CFE in third quarter 2022, including capital expenditures on the Southeast Gateway pipeline project, partially offset by lower AFUDC resulting from NGTL System expansion projects being placed in service

- higher realized gains in 2023 compared to 2022 on derivatives used to manage our foreign exchange exposure to net liabilities in Mexico, partially offset by net realized losses in 2023 compared to net realized gains in 2022 on derivatives used to manage our net exposure to foreign exchange rate fluctuation on U.S. dollar-denominated income and higher foreign exchange losses on the revaluation of our peso-denominated net monetary liabilities to U.S. dollars
- higher interest income and other due to higher interest earned on short-term investments.

Comparable earnings per common share for the three and nine months ended September 30, 2023 reflect the dilutive effect of common shares issued.

Outlook

Comparable EBITDA and comparable earnings

Our overall comparable EBITDA outlook for 2023 remains unchanged from the 2022 Annual Report; however, our comparable earnings per common share outlook for 2023 was revised lower in second quarter 2023, primarily due to the sale of a 40 per cent equity interest in Columbia Gas Transmission, LLC (Columbia Gas) and Columbia Gulf Transmission, LLC (Columbia Gulf) which closed on October 4, 2023. This equity sale will result in a higher expected net income attributable to non-controlling interests, partially offset by lower interest expense due to the receipt of cash proceeds from the sale. As such, we expect our 2023 comparable earnings per common share outlook to be generally consistent with 2022. Refer to the Recent Developments – U.S. Natural Gas Pipelines and Corporate sections for further information on asset divestitures.

Consolidated capital spending and equity investments

Our total capital expenditures for 2023 are now expected to be approximately $12.0 billion to $12.5 billion. The increase from the range as outlined in our 2022 Annual Report is primarily related to shifts in timing for some of our growth projects and maintenance capital expenditures in our natural gas pipelines businesses, as well as the foreign exchange impact of a stronger U.S. dollar. We continue to work on cost mitigation strategies and assess developments in our construction projects and market conditions for changes to our overall capital program.

Capital program

We are developing quality projects under our capital program. These long-life infrastructure assets are supported by long-term commercial arrangements with creditworthy counterparties and/or regulated business models and are expected to generate significant growth in earnings and cash flows. In addition, many of these projects are expected to advance our goals to reduce our own carbon footprint as well as that of our customers.

Our capital program consists of approximately $32 billion of secured projects that represent commercially supported, committed projects that are either under construction or are in, or preparing to commence, the permitting stage.

Three years of maintenance capital expenditures for our businesses are included in the Secured projects table. Maintenance capital expenditures on our regulated Canadian and U.S. natural gas pipelines are added to rate base on which we have the opportunity to earn a return and recover these expenditures through current or future tolls, which is similar to our capacity capital projects on these pipelines. Tolling arrangements in our liquids pipelines business provide for the recovery of maintenance capital expenditures.

During the nine months ended September 30, 2023, we placed approximately $3.8 billion of projects into service, including Canadian, U.S. and Mexico natural gas as well as liquids pipeline capacity capital projects and the Bruce Power Unit 6 Major Component Replacement (MCR), which we declared commercially operational on September 14, 2023. In addition, approximately $1.6 billion of maintenance capital expenditures were incurred.

All projects are subject to cost and timing adjustments due to factors including weather, market conditions, route refinement, land acquisition, permitting conditions, scheduling and timing of regulatory permits, as well as other potential restrictions and uncertainties including inflationary pressures on labour and materials. Amounts exclude capitalized interest and AFUDC, where applicable.

In addition to our secured projects, we are pursuing a portfolio of quality projects in various stages of development across each of our business units as discussed in our 2022 Annual Report. Projects under development have greater uncertainty with respect to timing and estimated project costs and are subject to corporate and regulatory approvals, unless otherwise noted. While each business segment also has additional areas of focus for further ongoing business development activities and growth opportunities, new opportunities will be assessed within our capital allocation framework in order to fit within our annual capital expenditure parameters. As these projects advance and reach necessary milestones they will be included in the Secured projects table below. Refer to the Recent developments section for updates to our secured projects and projects under development.

Secured projects

Estimated and incurred project costs referred to in the following table include 100 per cent of the capital expenditures related to our wholly-owned projects and our share of equity contributions to fund projects within our equity investments, primarily Coastal GasLink and Bruce Power.

(billions of $)	Expected in-service date	Estimated project cost	Project costs incurred as at September 30, 2023
Canadian Natural Gas Pipelines			
NGTL System[1]	2023	3.0	2.7
	2024	0.6	0.3
	2025+	0.7	—
Coastal GasLink[2]	2023	5.5	4.1
Regulated maintenance capital expenditures	2023-2025	2.3	0.6
U.S. Natural Gas Pipelines			
Modernization and other	2023-2025	US 1.5	US 0.8
Delivery market projects	2025	US 1.5	US 0.1
Other capital	2023-2028	US 1.6	US 0.4
Regulated maintenance capital expenditures	2023-2025	US 2.4	US 0.6
Mexico Natural Gas Pipelines			
Villa de Reyes – south section[3]	2024	US 0.3	US 0.3
Tula[4]	—	US 0.4	US 0.3
Southeast Gateway	2025	US 4.5	US 2.0
Liquids Pipelines			
Recoverable maintenance capital expenditures	2023-2025	0.1	—
Power and Energy Solutions			
Bruce Power – life extension[5]	2023-2027	3.0	1.2
Other capacity capital	2023	0.1	0.1
Other			
Non-recoverable maintenance capital expenditures[6]	2023-2025	0.5	0.2
		28.0	**13.7**
Foreign exchange impact on secured projects[7]		**4.2**	**1.6**
Total secured projects (Cdn$)		**32.2**	**15.3**

1 Estimated project costs for 2023 include $0.8 billion for the Foothills portion of the West Path Delivery Program.

2 Subsequent to revised project agreements executed between Coastal GasLink LP and LNG Canada and amended agreements with our partners in Coastal GasLink LP, the estimated project cost noted above represents our share of anticipated partner equity contributions to the project. Mechanical completion has been achieved ahead of schedule and commercial in-service of the Coastal GasLink pipeline will occur after completion of commissioning activities and upon receiving notice from LNG Canada. Refer to the Recent developments – Canadian Natural Gas Pipelines section for additional information.

3 The lateral section of the Villa de Reyes pipeline was placed into commercial service in the third quarter of 2023. We are working with the CFE to complete the south section of the Villa de Reyes pipeline. Refer to the Recent developments – Mexico Natural Gas Pipelines section for additional information.

4 With the CFE, we are assessing the completion of the Tula pipeline, subject to an FID. Refer to the Recent developments – Mexico Natural Gas Pipelines section for additional information.

5 Excludes the Unit 6 MCR which was declared commercially operational on September 14, 2023. Reflects our expected share of cash contributions for the Bruce Power Unit 3 MCR program, expected to be in service in 2026, as well as amounts to be invested under the Asset Management program through 2027 and the incremental uprate initiative. Refer to the Recent developments – Power and Energy Solutions section for additional information.

6 Includes non-recoverable maintenance capital expenditures from all segments and is primarily comprised of our proportionate share of maintenance capital expenditures for Bruce Power and other Power and Energy Solutions assets.

7 Reflects U.S./Canada foreign exchange rate of 1.35 at September 30, 2023.

Canadian Natural Gas Pipelines

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (losses) (the most directly comparable GAAP measure).

(millions of $)	three months ended September 30		nine months ended September 30	
	2023	**2022**	**2023**	**2022**
NGTL System	**546**	473	**1,621**	1,351
Canadian Mainline	**199**	198	**578**	556
Other Canadian pipelines[1]	**36**	42	**102**	131
Comparable EBITDA	**781**	713	**2,301**	2,038
Depreciation and amortization	**(336)**	(304)	**(983)**	(886)
Comparable EBIT	**445**	409	**1,318**	1,152
Specific item:				
Coastal GasLink impairment charge	**(1,244)**	—	**(2,100)**	—
Segmented earnings (losses)	**(799)**	409	**(782)**	1,152

1 Includes results from Foothills, Ventures LP, Great Lakes Canada, our investments in TQM and Coastal GasLink as well as general and administrative and business development costs related to our Canadian Natural Gas Pipelines.

For the three months ended September 30, 2023, Canadian Natural Gas Pipelines segmented losses were $799 million compared to segmented earnings of $409 million for the same period in 2022. For the nine months ended September 30, 2023, Canadian Natural Gas Pipelines segmented losses were $782 million compared to segmented earnings of $1,152 million for the same period in 2022. These amounts included a pre-tax impairment charge of $1,244 million and $2,100 million for the three and nine months ended September 30, 2023, respectively (2022 – nil and nil, respectively), related to our equity investment in Coastal GasLink LP, which has been excluded from our calculation of comparable EBITDA and comparable EBIT. Refer to Note 5, Coastal GasLink, of our Condensed consolidated financial statements for additional information.

Net income and comparable EBITDA for our rate-regulated Canadian natural gas pipelines are primarily affected by our approved ROE, investment base, the level of deemed common equity and incentive earnings. Changes in depreciation, financial charges and income taxes also impact comparable EBITDA, but do not have a significant impact on net income as they are almost entirely recovered in revenues on a flow-through basis.

NET INCOME AND AVERAGE INVESTMENT BASE

(millions of $)	three months ended September 30		nine months ended September 30	
	2023	**2022**	**2023**	**2022**
Net income				
NGTL System	**191**	177	**572**	523
Canadian Mainline	**58**	58	**169**	162
Average investment base				
NGTL System			**18,843**	17,281
Canadian Mainline			**3,685**	3,712

Net income for the NGTL System increased by $14 million and $49 million for the three and nine months ended September 30, 2023 compared to the same periods in 2022 mainly due to a higher average investment base resulting from continued system expansions. The NGTL System is operating under the 2020-2024 Revenue Requirement Settlement which includes an approved ROE of 10.1 per cent on 40 per cent deemed common equity. This settlement provides the NGTL System the opportunity to increase depreciation rates if tolls fall below specified levels and an incentive mechanism for certain operating costs where variances from projected amounts are shared with our customers.

Net income for the Canadian Mainline for the three months ended September 30, 2023 was consistent with the same period in 2022. Net income for the Canadian Mainline increased by $7 million for the nine months ended September 30, 2023 compared to the same period in 2022 mainly due to higher incentive earnings. The Canadian Mainline is operating under the 2021-2026 Mainline Settlement which includes an approved ROE of 10.1 per cent on 40 per cent deemed common equity and an incentive to decrease costs and increase revenues on the pipeline under a beneficial sharing mechanism with our customers.

COMPARABLE EBITDA

Comparable EBITDA for Canadian Natural Gas Pipelines increased by $68 million and $263 million for the three and nine months ended September 30, 2023 compared to the same periods in 2022 due to the net effect of:

- higher flow-through financial charges, depreciation and income taxes as well as higher rate-base earnings on the NGTL System
- higher flow-through depreciation and financial charges as well as higher incentive earnings, partially offset by lower flow-through income taxes on the Canadian Mainline
- lower Coastal GasLink development fee revenue due to timing of revenue recognition.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by $32 million and $97 million for the three and nine months ended September 30, 2023 compared to the same periods in 2022 reflecting incremental depreciation on the NGTL System from expansion facilities that were placed in service. Depreciation increased on the Canadian Mainline due to assets placed into service on a section with higher depreciation rates per the terms of the 2021-2026 Mainline Settlement.

U.S. Natural Gas Pipelines

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (losses) (the most directly comparable GAAP measure).

	three months ended September 30		nine months ended September 30	
(millions of US$, unless otherwise noted)	**2023**	2022	**2023**	2022
Columbia Gas	**359**	352	**1,113**	1,118
ANR	**147**	128	**473**	440
Columbia Gulf	**49**	50	**157**	155
Great Lakes	**38**	37	**123**	129
GTN	**54**	42	**154**	136
Other U.S. pipelines[1]	**66**	91	**298**	293
Non-controlling interests[2]	**9**	9	**30**	29
Comparable EBITDA	**722**	709	**2,348**	2,300
Depreciation and amortization	**(167)**	(174)	**(516)**	(510)
Comparable EBIT	**555**	535	**1,832**	1,790
Foreign exchange impact	**191**	164	**635**	503
Comparable EBIT (Cdn$)	**746**	699	**2,467**	2,293
Specific items:				
Great Lakes goodwill impairment charge	**—**	—	**—**	(571)
Risk management activities	**36**	15	**109**	13
Segmented earnings (losses) (Cdn$)	**782**	714	**2,576**	1,735

1 Reflects comparable EBITDA from our ownership in our mineral rights business (CEVCO), North Baja, Tuscarora, Bison, 61.7 per cent of Portland, Crossroads and our share of equity income from Northern Border, Iroquois, Millennium and Hardy Storage, our U.S. natural gas marketing business as well as general and administrative and business development costs related to our U.S. natural gas pipelines.

2 Reflects comparable EBITDA attributable to the 38.3 per cent interest in Portland that we do not own.

U.S. Natural Gas Pipelines segmented earnings increased by $68 million and $841 million for the three and nine months ended September 30, 2023 compared to the same periods in 2022 and included the following specific items which have been excluded from our calculation of comparable EBITDA and comparable EBIT:

- a pre-tax goodwill impairment charge of $571 million related to Great Lakes in first quarter 2022
- unrealized gains and losses from changes in the fair value of derivatives related to our U.S. natural gas marketing business.

A stronger U.S. dollar for the three and nine months ended September 30, 2023 had a positive impact on the Canadian dollar equivalent segmented earnings from our U.S. operations compared to the same periods in 2022. Refer to the Foreign exchange section for additional information.

Comparable EBITDA for U.S. Natural Gas Pipelines increased by US$13 million and US$48 million for the three and nine months ended September 30, 2023 compared to the same periods in 2022 and was primarily due to the net effect of:

- a net increase in earnings from ANR following the FERC-approved settlement for higher transportation rates effective August 2022, partially offset by decreased earnings due to the sale of natural gas from certain gas storage facilities in 2022
- higher realized earnings related to our U.S. natural gas marketing business primarily due to higher margins for the nine months ended September 30, 2023
- incremental earnings from growth projects placed in service
- increased equity earnings from Iroquois and Northern Border
- decreased earnings from our mineral rights business due to lower commodity prices
- decreased earnings from higher operational costs, reflective of increased system utilization across our footprint, as well as higher property taxes related to projects in service.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization decreased by US$7 million and increased by US$6 million for the three and nine months ended September 30, 2023 compared to the same periods in 2022 due to new projects placed in service and certain adjustments in third quarter 2023.

Mexico Natural Gas Pipelines

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (losses) (the most directly comparable GAAP measure).

	three months ended September 30		nine months ended September 30	
(millions of US$, unless otherwise noted)	**2023**	2022	**2023**	2022
TGNH[1]	**58**	47	**171**	107
Topolobampo	**40**	41	**119**	121
Guadalajara	**16**	18	**49**	55
Mazatlán	**21**	15	**54**	50
Sur de Texas[2]	**38**	34	**50**	88
Comparable EBITDA	**173**	155	**443**	421
Depreciation and amortization	**(17)**	(15)	**(50)**	(59)
Comparable EBIT	**156**	140	**393**	362
Foreign exchange impact	**53**	44	**137**	104
Comparable EBIT (Cdn$)	**209**	184	**530**	466
Specific item:				
Expected credit loss provision on net investment in leases and certain contract assets in Mexico	**1**	(71)	**116**	(71)
Segmented earnings (losses) (Cdn$)	**210**	113	**646**	395

1 TGNH includes the operating sections of the Tamazunchale, Villa de Reyes and Tula pipelines.

2 Represents equity income from our 60 per cent interest and fees earned from the construction and operation of the pipeline.

Mexico Natural Gas Pipelines segmented earnings increased by $97 million and $251 million for the three and nine months ended September 30, 2023 compared to the same periods in 2022 and included a recovery of $1 million and $116 million for the three and nine months ended September 30, 2023, respectively (2022 – loss of $71 million and $71 million, respectively), related to the expected credit loss provision on the TGNH net investment in leases and certain contract assets in Mexico which has been excluded from our calculation of comparable EBITDA and comparable EBIT. Refer to our 2022 Consolidated financial statements for additional information on expected credit loss provisions and Note 12, Risk management and financial instruments, for additional information on the expected credit loss provision recognized in 2023.

A stronger U.S. dollar for the three and nine months ended September 30, 2023 had a positive impact on the Canadian dollar equivalent segmented earnings compared to the same periods in 2022. Refer to the Foreign exchange section for additional information, including the foreign exchange impacts of the Mexican peso against the U.S. dollar.

Comparable EBITDA for Mexico Natural Gas Pipelines increased by US$18 million and US$22 million for the three and nine months ended September 30, 2023 compared to the same periods in 2022 due to the net effect of:

- higher earnings in TGNH primarily related to the north section of the Villa de Reyes pipeline and the east section of the Tula pipeline that were placed in commercial service in third quarter 2022 as well as the lateral section of the Villa de Reyes pipeline which was placed in commercial service in August 2023
- lower equity earnings for the nine months ended September 30, 2023 primarily due to increased interest expense as a result of higher interest rates and foreign exchange impacts on the revaluation of peso-denominated liabilities as a result of a stronger Mexican peso. We use foreign exchange derivatives to manage this exposure, the impact of which is recognized in Foreign exchange (gains) losses, net in the Condensed consolidated statement of income. Refer to the Foreign exchange section for additional information.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by US$2 million and decreased by US$9 million for the three and nine months ended September 30, 2023 compared to the same periods in 2022. The decrease for the nine months ended September 30, 2023 is primarily due to lease accounting for Tamazunchale subsequent to execution of the new TGNH TSA with the CFE in third quarter 2022. Under sales-type lease accounting, our in-service TGNH pipeline assets are reflected on our Condensed consolidated balance sheet within net investment in leases with no depreciation expense being recognized.

Liquids Pipelines

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (losses) (the most directly comparable GAAP measure).

(millions of $)	three months ended September 30		nine months ended September 30	
	2023	**2022**	**2023**	**2022**
Keystone Pipeline System[1]	**379**	318	**1,028**	959
Intra-Alberta pipelines[2]	**18**	17	**53**	53
Other[1]	**1**	(3)	**(3)**	(10)
Comparable EBITDA	**398**	332	**1,078**	1,002
Depreciation and amortization	**(83)**	(83)	**(252)**	(244)
Comparable EBIT	**315**	249	**826**	758
Specific items:				
Keystone FERC decision	**—**	—	**(57)**	—
Keystone XL preservation and other	**(3)**	(4)	**(13)**	(15)
Risk management activities	**(59)**	23	**(54)**	58
Segmented earnings (losses)	**253**	268	**702**	801
Comparable EBITDA denominated as follows:				
Canadian dollars	**97**	98	**282**	296
U.S. dollars	**226**	179	**592**	550
Foreign exchange impact	**75**	55	**204**	156
Comparable EBITDA	**398**	332	**1,078**	1,002

1 Liquids marketing results were previously disclosed separately, but almost fully relate to marketing activities with respect to the Keystone Pipeline System. For comparative periods, liquids marketing results have been reclassified within Keystone Pipeline System.
2 Intra-Alberta pipelines include Grand Rapids and White Spruce.

Liquids Pipelines segmented earnings decreased by $15 million and $99 million for the three and nine months ended September 30, 2023 compared to the same periods in 2022 and included the following specific items which have been excluded from our calculation of comparable EBITDA and comparable EBIT:

- a $57 million pre-tax charge in first quarter 2023 as a result of the FERC Administrative Law Judge initial decision issued in February 2023 in respect of a tolling-related complaint pertaining to amounts recognized from 2018 to 2022. Refer to the Recent developments – Liquids Pipelines section for additional information
- pre-tax preservation and other costs for Keystone XL pipeline project assets of $3 million and $13 million for the three and nine months ended September 30, 2023, respectively (2022 – $4 million and $15 million, respectively), which could not be accrued as part of the Keystone XL asset impairment charge
- unrealized gains and losses from changes in the fair value of derivatives related to our liquids marketing business.

A stronger U.S. dollar in 2023 relative to 2022 had a positive impact on the Canadian dollar equivalent segmented earnings from our U.S. operations for the three and nine months ended September 30, 2023. Refer to the Foreign exchange section for additional information.

Comparable EBITDA for Liquids Pipelines increased by $66 million and $76 million for the three and nine months ended September 30, 2023 compared to the same periods in 2022 primarily due to the net effect of:

- higher long-haul contracted volumes on the Keystone Pipeline System
- higher volumes on the U.S. Gulf Coast section of the Keystone Pipeline System, partially offset by higher operating costs for the three and nine months ended September 30, 2023 and lower rates in first quarter 2023
- lower uncontracted volumes on the Keystone Pipeline System as a result of the pressure de-rate per the terms of the Corrective Action Order (CAO) and Amended Corrective Action Order (ACAO) due to the Milepost 14 incident, which occurred in December 2022
- a stronger U.S. dollar as described above.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization was consistent for the three months ended September 30, 2023 compared with the same period in 2022. Depreciation and amortization increased $8 million for the nine months ended September 30, 2023 compared to the same period in 2022 primarily as a result of a stronger U.S. dollar.

Power and Energy Solutions

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (losses) (the most directly comparable GAAP measure).

	three months ended September 30		nine months ended September 30	
(millions of $)	**2023**	2022	**2023**	2022
Bruce Power[1]	**178**	199	**512**	412
Canadian Power	**74**	115	**256**	250
Natural Gas Storage and other	**4**	(19)	**(14)**	42
Comparable EBITDA	**256**	295	**754**	704
Depreciation and amortization	**(26)**	(19)	**(66)**	(53)
Comparable EBIT	**230**	276	**688**	651
Specific items:				
Bruce Power unrealized fair value adjustments	**(8)**	3	**—**	(29)
Risk management activities	**12**	10	**53**	(87)
Segmented earnings (losses)	**234**	289	**741**	535

1 Represents our share of equity income from Bruce Power.

Power and Energy Solutions segmented earnings decreased by $55 million and increased by $206 million for the three and nine months ended September 30, 2023 compared to the same periods in 2022 and included the following specific items which have been excluded from our calculations of comparable EBITDA and comparable EBIT:

- our proportionate share of Bruce Power's unrealized gains and losses on funds invested for post-retirement benefits and risk management activities
- unrealized gains and losses from changes in the fair value of derivatives used to reduce commodity exposures.

Comparable EBITDA for Power and Energy Solutions decreased by $39 million for the three months ended September 30, 2023 compared to the same period in 2022 primarily due to the net effect of:

- lower Canadian Power financial results on reduced contributions from marketing activities, lower realized power prices, partially offset by lower natural gas fuel costs
- decreased contributions from Bruce Power primarily due to lower generation, partially offset by lower depreciation expense, higher contract price, fewer planned outage days and lower operating expenses. Refer to the Bruce Power section for additional information
- increased Natural Gas Storage and other results from higher TC Turbines contributions and higher realized Alberta natural gas storage spreads.

Comparable EBITDA for Power and Energy Solutions increased by $50 million for the nine months ended September 30, 2023 compared to the same period in 2022 primarily due to the net effect of:

- higher contributions from Bruce Power primarily due to a higher contract price, reduced outage costs with fewer planned outage days and lower depreciation expense, partially offset by lower generation and realized losses on funds invested for post-retirement benefits and risk management activities. Refer to the Bruce Power section for additional information
- increased Canadian Power financial results primarily from higher realized power prices and lower natural gas fuel costs, partially offset by reduced contributions from marketing activities
- decreased Natural Gas Storage and other results from higher business development costs across the segment and lower realized Alberta natural gas storage spreads.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by $7 million and $13 million for the three and nine months ended September 30, 2023 compared to the same periods in 2022 primarily due to the acquisitions of the Fluvanna Wind Farm on March 15, 2023 and the Blue Cloud Wind Farm on June 14, 2023.

BRUCE POWER

The following is our proportionate share of the components of comparable EBITDA and comparable EBIT.

	three months ended September 30		nine months ended September 30	
(millions of $, unless otherwise noted)	**2023**	**2022**	**2023**	**2022**
Items included in comparable EBITDA and comparable EBIT comprised of:				
Revenues[1]	**474**	518	**1,453**	1,365
Operating expenses	**(211)**	(227)	**(686)**	(684)
Depreciation and other	**(85)**	(92)	**(255)**	(269)
Comparable EBITDA and comparable EBIT[2]	**178**	199	**512**	412
Bruce Power – other information				
Plant availability[3,4]	**94%**	95%	**94%**	86%
Planned outage days[4]	**15**	28	**28**	232
Unplanned outage days	**9**	2	**47**	19
Sales volumes (GWh)[5]	**5,060**	5,684	**15,301**	15,361
Realized power price per MWh[6]	**$92**	$91	**$94**	$88

1 Net of amounts recorded to reflect operating cost efficiencies shared with the IESO, if applicable.
2 Represents our 48.3 per cent ownership interest and internal costs supporting our investment in Bruce Power. Excludes unrealized gains and losses on funds invested for post-retirement benefits and risk management activities.
3 The percentage of time the plant was available to generate power, regardless of whether it was running.
4 Excludes Unit 6 and Unit 3 MCR outage days.
5 Sales volumes include deemed generation.
6 Calculation based on actual and deemed generation. Realized power price per MWh includes realized gains and losses from contracting activities and cost flow-through items. Excludes unrealized gains and losses on contracting activities and non-electricity revenues.

The Unit 3 MCR commenced on March 1, 2023 with a return to service expected in 2026. The Unit 6 MCR, which began in 2020, was declared commercially operational on September 14, 2023, ahead of schedule and within budget.

A planned outage on Unit 4 was completed in second quarter 2023 and a scheduled outage on Unit 8 began late-third quarter 2023. The average 2023 plant availability, excluding the Unit 6 and Unit 3 MCR programs, is expected to be in the low-90 per cent range. Sales volumes in 2023 also include the impacts of the de-rating Unit 4 following the completion of its planned outage and the ramp-up period on Unit 6 following its return to service from its MCR.

Corporate

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to Corporate segmented earnings (losses) (the most directly comparable GAAP measure).

	three months ended September 30		nine months ended September 30	
(millions of $)	**2023**	**2022**	**2023**	**2022**
Comparable EBITDA and comparable EBIT	**(3)**	(9)	**(9)**	(16)
Specific items:				
Focus Project costs	**(18)**	—	**(50)**	—
Liquids separation costs	**(15)**	—	**(15)**	—
Foreign exchange gains – inter-affiliate loans[1]	**—**	—	**—**	28
Segmented earnings (losses)	**(36)**	(9)	**(74)**	12

1 Reported in Income from equity investments in the Condensed consolidated statement of income.

Corporate segmented losses increased by $27 million for the three months ended September 30, 2023 compared to the same period in 2022. For the nine months ended September 30, 2023, Corporate segmented losses were $74 million compared to segmented earnings of $12 million for the same period in 2022.

Corporate segmented earnings (losses) included the following specific items which have been excluded from our calculation of comparable EBITDA and comparable EBIT:

- a pre-tax charge of $18 million and $50 million for the three and nine months ended September 30, 2023 related to Focus Project costs. Refer to the Recent developments – Corporate section for additional information
- a pre-tax charge of $15 million due to separation costs incurred in third quarter 2023 related to the proposed spinoff of our Liquids Pipelines business. Refer to the Recent developments – Liquids Pipelines section for additional information
- foreign exchange gains in 2022 on our proportionate share of peso-denominated inter-affiliate loans to the Sur de Texas joint venture from its partners up to March 15, 2022 when the peso-denominated inter-affiliate loans were fully repaid upon maturity. These foreign exchange gains were recorded in Income from equity investments in the Corporate segment and were excluded from our calculation of comparable EBITDA and comparable EBIT as they were fully offset by corresponding foreign exchange losses on the inter-affiliate loan receivable included in Foreign exchange gains (losses), net. Refer to the Financial risks and financial instruments – Related party transactions section for additional information.

Comparable EBITDA and EBIT for Corporate increased by $6 million and $7 million for the three and nine months ended September 30, 2023 compared to the same periods in 2022 primarily due to lower legal expenses.

INTEREST EXPENSE

(millions of $)	three months ended September 30		nine months ended September 30	
	2023	**2022**	**2023**	**2022**
Interest expense on long-term debt and junior subordinated notes				
Canadian dollar-denominated	**(227)**	(203)	**(668)**	(570)
U.S. dollar-denominated	**(458)**	(321)	**(1,219)**	(944)
Foreign exchange impact	**(157)**	(98)	**(421)**	(267)
	(842)	(622)	**(2,308)**	(1,781)
Other interest and amortization expense	**(76)**	(49)	**(230)**	(96)
Capitalized interest	**53**	5	**125**	11
Interest expense included in comparable earnings	**(865)**	(666)	**(2,413)**	(1,866)
Specific item:				
Keystone FERC decision	**—**	—	**(5)**	—
Interest expense	**(865)**	(666)	**(2,418)**	(1,866)

Interest expense increased by $199 million and $552 million for the three and nine months ended September 30, 2023 compared to the same periods in 2022 and included accrued carrying charges of $5 million for the nine months ended September 30, 2023 as a result of a pre-tax charge related to the FERC Administrative Law Judge initial decision on Keystone. This decision was issued in February 2023 in respect of a tolling-related complaint pertaining to amounts recognized from 2018 to 2022 which has been removed from our calculation of Interest expense included in comparable earnings. Refer to the Recent developments – Liquids Pipelines section for additional information.

Interest expense included in comparable earnings increased by $199 million and $547 million for the three and nine months ended September 30, 2023 compared to the same periods in 2022 primarily due to the net effect of:

- long-term debt issuances, net of maturities. Refer to the Financial Condition section for additional information
- the foreign exchange impact from a stronger U.S. dollar on translation of U.S. dollar-denominated interest expense
- higher interest rates on decreased levels of short-term borrowings
- higher capitalized interest, largely due to funding related to our investment in Coastal GasLink LP. Refer to Note 5, Coastal GasLink, of our Condensed consolidated financial statements for additional information.

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

(millions of $)	three months ended September 30		nine months ended September 30	
	2023	**2022**	**2023**	**2022**
Canadian dollar-denominated	**28**	40	**81**	117
U.S. dollar-denominated	**102**	58	**269**	106
Foreign exchange impact	**34**	18	**93**	31
Allowance for funds used during construction	**164**	116	**443**	254

AFUDC increased by $48 million and $189 million for the three and nine months ended September 30, 2023 compared to the same periods in 2022. The decrease in Canadian dollar-denominated AFUDC is primarily related to NGTL System expansion projects placed in service. The increase in U.S. dollar-denominated AFUDC is mainly the result of the reactivation of AFUDC on the TGNH assets under construction following the new TSA with the CFE, including capital expenditures on the Southeast Gateway pipeline project in 2023, partially offset by projects placed in service on our U.S. natural gas pipelines.

FOREIGN EXCHANGE GAINS (LOSSES), NET

(millions of $)	three months ended September 30		nine months ended September 30	
	2023	**2022**	**2023**	**2022**
Foreign exchange gains (losses), net included in comparable earnings	**(25)**	6	**78**	32
Specific items:				
Foreign exchange gains (losses), net – intercompany loan	**20**	—	**11**	—
Foreign exchange losses – inter-affiliate loan	**—**	—	**—**	(28)
Risk management activities	**(40)**	(283)	**142**	(321)
Foreign exchange gains (losses), net	**(45)**	(277)	**231**	(317)

In the three months ended September 30, 2023, foreign exchange losses were $45 million compared to $277 million for the same period in 2022. In the nine months ended September 30, 2023, foreign exchange gains were $231 million compared to foreign exchange losses of $317 million for the same period in 2022. The following specific items have been removed from our calculation of Foreign exchange gains (losses), net included in comparable earnings:

- unrealized foreign exchange gains and losses on the peso-denominated intercompany loan between TCPL and TGNH beginning in second quarter 2023. Refer to the Non-GAAP measures section for additional information
- unrealized gains and losses from changes in the fair value of derivatives used to manage our foreign exchange risk
- foreign exchange losses on the peso-denominated inter-affiliate loan receivable from the Sur de Texas joint venture until March 15, 2022, when it was fully repaid upon maturity. The interest income and interest expense on the peso-denominated inter-affiliate loan was included in comparable earnings with all amounts offsetting and resulting in no impact on consolidated net income.

Refer to the Financial risks and financial instruments section for additional information on related party transactions and derivatives.

Foreign exchange losses included in comparable earnings were $25 million in the three months ended September 30, 2023 compared to foreign exchange gains of $6 million in the same period in 2022. The changes were primarily due to the net effect of:

- realized losses in 2023 compared to realized gains in 2022 on derivatives used to manage our foreign exchange exposure to net liabilities in Mexico
- higher net realized losses on derivatives used to manage our net exposure to foreign exchange rate fluctuation on U.S. dollar-denominated income.

Foreign exchange gains included in comparable earnings were $78 million in the nine months ended September 30, 2023 compared to $32 million in the same period in 2022. The changes were primarily due to the net effect of:

- higher realized gains on derivatives used to manage our foreign exchange exposure to net liabilities in Mexico
- net realized losses in 2023 compared to net realized gains in 2022 on derivatives used to manage our net exposure to foreign exchange rate fluctuation on U.S. dollar-denominated income
- higher foreign exchange losses on the revaluation of our peso-denominated net monetary liabilities to U.S. dollars.

INTEREST INCOME AND OTHER

(millions of $)	three months ended September 30		nine months ended September 30	
	2023	**2022**	**2023**	**2022**
Interest income and other included in comparable earnings	**63**	35	**157**	93
Specific item:				
Milepost 14 insurance expense	**—**	—	**(36)**	—
Interest income and other	**63**	35	**121**	93

Interest income and other increased by $28 million for both the three and nine months ended September 30, 2023 compared to the same periods in 2022. This includes a $36 million accrued insurance expense related to the Milepost 14 incident for the nine months ended September 30, 2023, which is an estimate of the insurance proceeds for environmental remediation that we expect to receive from our wholly-owned captive insurance subsidiary. This expense has been removed from our calculation of Interest income and other included in comparable earnings. Refer to the Non-GAAP measures section for additional information.

Interest income and other included in comparable earnings increased by $28 million and $64 million for the three and nine months ended September 30, 2023 compared to the same periods in 2022 due to higher interest earned on short-term investments and the change in fair value of other restricted investments, partially offset by lower interest income in 2023 due to the repayment of the inter-affiliate loan receivable from the Sur de Texas joint venture in July 2022.

INCOME TAX (EXPENSE) RECOVERY

(millions of $)	three months ended September 30		nine months ended September 30	
	2023	**2022**	**2023**	**2022**
Income tax (expense) recovery included in comparable earnings	**(220)**	(202)	**(749)**	(554)
Specific items:				
Coastal GasLink impairment charge	**65**	—	**83**	—
Keystone FERC decision	**—**	—	**14**	—
Focus Project costs	**4**	—	**11**	—
Liquids separation costs	**4**	—	**4**	—
Keystone XL preservation and other	**1**	1	**3**	4
Expected credit loss provision on net investment in leases and certain contract assets in Mexico	**(1)**	21	**(36)**	21
Great Lakes goodwill impairment charge	**—**	—	**—**	40
Settlement of Mexico prior years' income tax assessments	**—**	—	**—**	(195)
Bruce Power unrealized fair value adjustments	**2**	(1)	**—**	7
Risk management activities	**11**	59	**(63)**	84
Income tax (expense) recovery	**(134)**	(122)	**(733)**	(593)

Income tax expense increased by $12 million and $140 million for the three and nine months ended September 30, 2023 compared to the same periods in 2022, which included the settlement of prior years' income tax assessments related to our operations in Mexico paid in second quarter 2022. This has been removed from our calculation of Income tax expense included in comparable earnings, in addition to the income tax impacts on specified items referenced elsewhere in this MD&A.

Income tax expense included in comparable earnings increased by $18 million for the three months ended September 30, 2023 compared to the same period in 2022 primarily due to lower foreign income tax rate differentials, partially offset by a lower Mexico inflationary adjustment and lower earnings.

Income tax expense included in comparable earnings increased by $195 million for the nine months ended September 30, 2023 compared to the same period in 2022 primarily due to lower foreign income tax rate differentials, the impact of Mexico foreign exchange exposure and higher earnings. Refer to the Foreign exchange section for additional information regarding our Mexico foreign exchange exposure.

NET (INCOME) LOSS ATTRIBUTABLE TO NON-CONTROLLING INTERESTS

	three months ended September 30		nine months ended September 30	
(millions of $)	**2023**	**2022**	**2023**	**2022**
Net (income) loss attributable to non-controlling interests	**(1)**	(8)	**(18)**	(28)

Net income attributable to non-controlling interests decreased by $7 million and $10 million for the three and nine months ended September 30, 2023 compared to the same periods in 2022 primarily due to the acquisition of the wind farms in Texas. Refer to the Recent developments – Power and Energy Solutions section for additional information.

PREFERRED SHARE DIVIDENDS

	three months ended September 30		nine months ended September 30	
(millions of $)	**2023**	**2022**	**2023**	**2022**
Preferred share dividends	**(23)**	(21)	**(69)**	(85)

Preferred share dividends increased by $2 million and decreased by $16 million for the three and nine months ended September 30, 2023, respectively, compared to the same periods in 2022. The decrease for the nine months ended September 30, 2023 is primarily due to the redemption of all issued and outstanding Series 15 preferred shares on May 31, 2022, partially offset by higher floating dividend rates on certain series of preferred shares.

Foreign exchange

FOREIGN EXCHANGE RELATED TO U.S. DOLLAR-DENOMINATED OPERATIONS

Certain of our businesses generate all or most of their earnings in U.S. dollars and, since we report our financial results in Canadian dollars, changes in the value of the U.S. dollar against the Canadian dollar directly affect our comparable EBITDA and may also impact comparable earnings. As our U.S. dollar-denominated operations continue to grow, this exposure increases. A portion of the U.S. dollar-denominated comparable EBITDA exposure is naturally offset by U.S. dollar-denominated amounts below comparable EBITDA within Depreciation and amortization, Interest expense and other income statement line items. A portion of the remaining exposure is actively managed on a rolling forward basis up to three years using foreign exchange derivatives; however, the natural exposure beyond that period remains. The net impact of the U.S. dollar movements on comparable earnings during the three and nine months ended September 30, 2023 after considering natural offsets and economic hedges was not significant.

The components of our financial results denominated in U.S. dollars are set out in the table below, including our U.S. and Mexico Natural Gas Pipelines operations along with the majority of our Liquids Pipelines business. Comparable EBITDA is a non-GAAP measure.

PRE-TAX U.S. DOLLAR-DENOMINATED INCOME AND EXPENSE ITEMS

	three months ended September 30		nine months ended September 30	
(millions of US$)	**2023**	**2022**	**2023**	**2022**
Comparable EBITDA				
U.S. Natural Gas Pipelines	**722**	709	**2,348**	2,300
Mexico Natural Gas Pipelines[1]	**173**	158	**443**	446
Liquids Pipelines	**226**	179	**592**	550
	1,121	1,046	**3,383**	3,296
Depreciation and amortization	**(233)**	(238)	**(713)**	(715)
Interest expense on long-term debt and junior subordinated notes	**(458)**	(321)	**(1,219)**	(944)
Allowance for funds used during construction	**102**	58	**269**	106
Non-controlling interests and other	**(20)**	(29)	**(64)**	(57)
	512	516	**1,656**	1,686
Average exchange rate - U.S. to Canadian dollars	**1.34**	1.31	**1.35**	1.28

1 Excludes interest expense on our inter-affiliate loans with the Sur de Texas joint venture which was fully offset in Interest income and other. These inter-affiliate loans were fully repaid in 2022.

FOREIGN EXCHANGE RELATED TO MEXICO NATURAL GAS PIPELINES

Changes in the value of the Mexican peso against the U.S. dollar can affect our comparable earnings as a portion of our Mexico Natural Gas Pipelines monetary assets and liabilities are peso-denominated, while our financial results are denominated in U.S. dollars for our Mexico operations. These peso-denominated balances are revalued to U.S. dollars, creating foreign exchange gains and losses that are included in Income from equity investments and Foreign exchange (gains) losses, net in the Condensed consolidated statement of income.

In addition, foreign exchange gains or losses calculated for Mexico income tax purposes on the revaluation of U.S. dollar-denominated monetary assets and liabilities result in a peso-denominated income tax exposure for these entities, leading to fluctuations in Income from equity investments and Income tax expense. This exposure increases as our U.S. dollar-denominated net monetary liabilities grow. 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 revolving credit facility, which resulted in an additional peso-denominated income tax expense compared to 2022.

The above exposures are managed using foreign exchange derivatives, although some unhedged exposure remains. The impacts of the foreign exchange derivatives are recorded in Foreign exchange (gains) losses, net in the Condensed consolidated statement of income. Refer to the Financial risks and financial instruments section for additional information.

The period end exchange rates for one U.S. dollar to Mexican pesos were as follows:

September 30, 2023	**17.42**
September 30, 2022	20.10
December 31, 2022	19.50
December 31, 2021	20.48

A summary of the impacts of transactional foreign exchange gains and losses from changes in the value of the Mexican peso against the U.S. dollar and associated derivatives is set out in the table below:

	three months ended September 30		nine months ended September 30	
(millions of $)	**2023**	**2022**	**2023**	**2022**
Comparable EBITDA - Mexico Natural Gas Pipelines[1]	**7**	—	**(67)**	(17)
Foreign exchange gains (losses), net included in comparable earnings	**(12)**	3	**160**	20
Income tax (expense) recovery included in comparable earnings	**18**	2	**(95)**	(2)
	13	5	**(2)**	1

1 Includes the foreign exchange impacts from the Sur de Texas joint venture recorded in Income from equity investments in the Condensed consolidated statement of income.

Recent developments

CANADIAN NATURAL GAS PIPELINES

Coastal GasLink

The Coastal GasLink project has achieved mechanical completion ahead of target, including the successful hydrotesting and post-construction engineering reviews of the full 670 km length of the pipeline. Through the remainder of 2023, the project will complete pipeline commissioning activities to be ready to deliver commissioning gas to the LNG Canada facility by the end of this year. The project remains on track with the cost estimate of approximately $14.5 billion and in 2024 we will continue reclamation work. Coastal GasLink LP continues to pursue cost recoveries.

Project costs are funded by existing project-level credit facilities and equity contributions from the Coastal GasLink LP partners, including us. Beginning in 2023, the equity financing required to fund construction of the pipeline to completion will initially be provided through a subordinated loan agreement between TC Energy and Coastal GasLink LP. Draws by Coastal GasLink LP on this loan will be repaid with funds from equity contributions to the partnership by the Coastal GasLink LP partners, including us, subsequent to the in-service date of the Coastal GasLink pipeline when final project costs are known. We expect that, in accordance with contractual terms, the additional equity contributions required will be predominantly funded by us, except under certain conditions, but will not result in a change to our 35 per cent ownership. At September 30, 2023, committed capacity under this subordinated loan agreement was $3,375 million, on which $2,020 million was drawn.

The expectation that additional equity contributions will predominantly be funded by us continued to be an indicator at September 30, 2023 that a decrease in the value of our equity investment had occurred. As a result, we completed a valuation assessment and concluded that there was an other-than-temporary impairment of our investment, resulting in a pre-tax impairment charge of the full value of our investment in Coastal GasLink LP of $1,244 million ($1,179 million after tax) and $2,100 million ($2,017 million after tax) for the three and nine months ended September 30, 2023, respectively. The impairment charge reflected the net impact of $2,020 million drawn and $250 million repaid on the subordinated loan for the nine months ended September 30, 2023, along with TC Energy's proportionate share of unrealized gains and losses on interest rate derivatives in Coastal GasLink LP and other changes to the equity investment. The impairment of the subordinated loan resulted in unrealized non-taxable capital losses that are not recognized. The cumulative pre-tax impairment charge recognized to date at September 30, 2023 is $5,148 million ($4,660 million after tax). Refer to Note 5, Coastal GasLink, of our Condensed consolidated financial statements for additional information.

We will continue to assess for other-than-temporary declines in the fair value of our investment in Coastal GasLink LP, and the extent of any future impairment charges, if any, will depend on the outcome of the valuation assessment performed at the respective reporting date.

NGTL System and Foothills

In the nine months ended September 30, 2023, the NGTL System and Foothills placed approximately $1.3 billion and $0.2 billion, respectively, of capacity projects in service. The details of the significant capacity programs are listed below.

2021 NGTL System Expansion Program

The 2021 NGTL System Expansion Program consists of new pipeline and compression facilities to add incremental capacity to the NGTL System. All facilities required to declare contracts have been placed in-service and construction of remaining facilities is underway with anticipated in-service by the end of 2023.

2022 NGTL System Expansion Program

The 2022 NGTL System Expansion Program consists of new pipeline and compression facilities to meet firm-receipt and intra-basin delivery requirements. The capital cost of the program was $1.4 billion with all assets placed in service.

NGTL System/Foothills West Path Delivery Program

The NGTL System/Foothills West Path Delivery Program is a multi-year expansion of the NGTL System and Foothills to facilitate incremental contracted export capacity connecting to GTN. The capital cost of the program is $1.6 billion with substantially all assets placed in service on November 1, 2023.

Valhalla North and Berland River Project

On August 1, 2023, we filed an application with the CER to construct, own and operate the Valhalla North and Berland River (VNBR) project with an anticipated in-service date in second quarter 2026, subject to regulatory approval. The VNBR project will serve aggregate system requirements and connect migrating supply to key demand markets, providing incremental capacity on the NGTL System and is anticipated to contribute to lower GHG emission intensity for the overall system. The estimated cost of the project is $0.6 billion and consists of new pipeline, one new non-emitting electric compressor unit and associated facilities.

U.S. NATURAL GAS PIPELINES

Columbia Gas and Columbia Gulf Monetization

On October 4, 2023, we successfully completed the sale of a 40 per cent equity interest in Columbia Gas and Columbia Gulf to Global Infrastructure Partners (GIP) for proceeds of $5.3 billion (US$3.9 billion). Columbia Gas and Columbia Gulf are held by a newly formed entity with GIP. Preceding the close of the equity sale, on August 8, 2023, Columbia Pipelines Operating Company LLC and Columbia Pipelines Holding Company LLC issued US$4.6 billion and US$1.0 billion of long-term, senior unsecured debt, respectively. The net proceeds from the offerings were used to repay existing intercompany indebtedness with TC Energy entities and directed towards reducing leverage. Refer to the Financial Condition section for additional information.

We continue to have a controlling interest in Columbia Gas and Columbia Gulf and we will remain the operator of these pipelines. TC Energy and GIP will each fund their proportionate share of annual maintenance, modernization and sanctioned growth capital expenditures through internally generated cash flows, debt financing within the Columbia entities, or from proportionate contributions from TC Energy and GIP.

North Baja XPress

In June 2023, the North Baja XPress project, an expansion project designed to expand capacity and meet increased customer demand on our North Baja pipeline, was placed in service.

Virginia Electrification Project

In March 2023, the FERC provided a certificate order approving our Virginia Electrification project. The Virginia Electrification project will replace and upgrade certain facilities through conversion to electric compression and is expected to reduce emissions along portions of our Columbia Gas system. The anticipated in-service date is early 2024 with an estimated project cost of US$0.1 billion.

ANR Section 4 Rate Case

ANR reached a settlement with its customers effective August 2022 and received FERC approval on April 11, 2023. As part of the settlement, there is a moratorium on any further rate changes until November 1, 2025. ANR must file for new rates with an effective date no later than August 1, 2028. The settlement also included an additional rate step up effective August 2024 related to certain modernization projects. In second quarter 2023, previously accrued rate refund liabilities, including interest, were refunded to customers.

Columbia Gulf Rate Settlement

On July 7, 2023, Columbia Gulf filed an uncontested rate settlement which would set new recourse rates for Columbia Gulf effective March 1, 2024 and institute a rate moratorium through February 28, 2027. The revised rates are not expected to have a significant impact on our U.S. Natural Gas Pipelines segment comparable earnings. Columbia Gulf must file for new rates no later than March 1, 2029.

Bison XPress Project

In third quarter 2023, we approved the Bison XPress project, an expansion project on our Northern Border and Bison systems that will replace and upgrade certain facilities and provide much needed production egress from the Bakken basin to a delivery point at the Cheyenne Hub. The project has an anticipated in-service date in 2026. Total estimated project costs are US$0.4 billion, of which our share is US$0.2 billion, representing our 50 per cent equity investment in Northern Border and 100 per cent ownership in Bison.

Line VB Strasburg

On July 25, 2023, a natural gas pipeline rupture on Columbia Gas occurred alongside Interstate 81 in Strasburg, Virginia. Emergency response procedures were enacted and the segment of impacted pipeline was isolated shortly thereafter. There were no reported injuries involved with this incident and no significant damage to surrounding structures. The pipeline has been operated at reduced pressure in accordance with PHMSA's CAO since July 28, 2023 and we are working with PHMSA under the CAO to return the system to normal operations as soon as possible. We do not expect this event to have a material impact on our 2023 financial results.

GTN XPress Project

In October 2023, FERC provided a certificate order approving our GTN XPress project. The GTN XPress project is an expansion of the GTN system that will provide for the transport of incremental contracted export capacity facilitated by the NGTL System/Foothills West Path Delivery Program. The anticipated in-service date is in 2024 with an estimated project cost of US$0.1 billion.

MEXICO NATURAL GAS PIPELINES

TGNH Strategic Alliance with the CFE

In August 2022, we announced a strategic alliance with Mexico's state-owned electric utility, the CFE, for the development of new natural gas infrastructure in central and southeast Mexico. In connection with the strategic alliance, we reached an FID to develop and construct the Southeast Gateway pipeline, a 1.3 Bcf/d, 715 km (444 mile) offshore natural gas pipeline to serve the southeast region of Mexico with an expected in-service by mid-2025 and an estimated project cost of US$4.5 billion. The Southeast Gateway pipeline project is progressing according to planned milestones, with construction activities on all facilities and installations in Veracruz and Tabasco ongoing. We expect to begin offshore pipe installation at the end of 2023.

In third quarter 2023, we placed the lateral section of the Villa de Reyes pipeline in commercial service, serving power generation in the state of Guanajuato. Due to stakeholder issues, the south section of the Villa de Reyes pipeline is not yet completed; however, with the support of the CFE and state governments, we are targeting the south section to be in service by the second half of 2024. We are working with the CFE and state governments to achieve necessary land access and to resolve legal claims on the Tula pipeline. We expect to make an FID on completing the Tula pipeline in 2024, subject to further stakeholder engagement and technical analysis.

Subject to regulatory approvals from Mexico's Federal Economic Competition Commission (COFECE) and the Regulatory Energy Commission, the strategic alliance provides the CFE with the ability to hold an equity interest in TGNH, which is conditional upon the CFE contributing capital, acquiring land and supporting permitting on the TGNH projects. Subsequent to receiving the appropriate approvals, the CFE would receive an initial equity interest upon making a capital contribution to TGNH. Additional equity would accrue as the CFE performs its contractual obligations, and upon in-service of the Southeast Gateway pipeline, the CFE's equity interest in TGNH will equal 15 per cent and will increase to approximately 35 per cent upon expiry of the contract in 2055. On March 30, 2023, the initial submission was made to the COFECE to start the regulatory approval process, which is currently under review. Regulatory approvals related to the CFE's equity participation in TGNH could take up to 24 months.

LIQUIDS PIPELINES

Proposed Spinoff

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

Under the proposed Transaction, our shareholders will retain their current ownership in TC Energy's common shares and receive a pro-rata allocation of common shares in South Bow Corporation. The determination of the number of common shares in South Bow Corporation to be distributed to our shareholders will be determined prior to the closing of the proposed Transaction.

For the three and nine months ended September 30, 2023, we incurred pre-tax separation costs of $15 million ($11 million after tax) with respect to the Transaction, which included employee-related transaction costs, legal, tax, audit and other consulting fees. This amount has been excluded from comparable measures.

Milepost 14 Incident

In December 2022, a pipeline incident occurred in Washington County, Kansas on the Keystone Pipeline System, releasing 12,937 barrels of crude oil. In June 2023, we completed the recovery of all released volumes and in October 2023, we returned Mill Creek to its natural flowing state. Restoration activities are ongoing and expected to continue into 2024. The pipeline is operating subject to an ACAO, which was issued by PHMSA in March 2023 and includes certain operating pressure restrictions. Under the corrective order, we expect to continue to fulfill our Keystone contract commitments.

As outlined by PHMSA's ACAO, a Root Cause Failure Analysis (RCFA) was conducted by an independent third party, which was released on April 21, 2023. The RCFA revealed that a unique set of circumstances occurred at the rupture location, which likely originated during construction, with the primary cause of the rupture being a fatigue crack. A comprehensive remedial work plan is being implemented, including the RCFA's recommendations, to enhance pipeline integrity and safety performance of the system.

At June 30, 2023, we revised our environmental remediation cost estimate before insurance recoveries, fines and penalties, subject to certain assumptions, to $794 million. At September 30, 2023, the remediation cost estimate remains unchanged; however, it is reasonably possible that we may incur additional costs. Appropriate insurance policies are in place and we believe that it remains probable that the majority of environmental remediation costs will be eligible for recovery under our existing insurance coverage. For the nine months ended September 30, 2023, we have received $396 million (2022 – nil) from insurance proceeds related to the environmental remediation. Included in our cost estimate is $36 million that we expect to be recoverable from our wholly-owned captive insurance subsidiary, which was recorded in Interest income and other in the Condensed consolidated statement of income. This amount has been excluded from comparable measures.

CER and FERC Decisions

In 2019 and 2020, three Keystone customers initiated complaints before the FERC and the CER regarding certain costs within the variable toll calculation. In December 2022, the CER issued a decision in respect of the complaint that resulted in an adjustment to previously charged tolls of $38 million. In July 2023, the CER dismissed Keystone's Review and Variance application that challenged the correctness of the original decision. The CER has established a proceeding to consider Keystone's compliance filing required by the decision.

In February 2023, the FERC released its initial decision in respect of the complaint. As a result, we have recorded a one-time pre-tax charge of $57 million reflective of previously charged tolls between 2018 and 2022. This amount has been excluded from comparable measures.

Port Neches

In March 2023, the Port Neches Link Pipeline System was placed in service, connecting the Keystone Pipeline System to Motiva's Port Neches Terminal, enabling last-mile connectivity to Motiva's 630,000 Bbl/d refinery.

POWER AND ENERGY SOLUTIONS

Bruce Power Life Extension

The Unit 6 MCR, which began in January 2020, was declared commercially operational on September 14, 2023, ahead of schedule and within budget despite challenges associated with the COVID-19 pandemic.

Bruce Power intends to submit its Final Basis of Estimate for the Unit 4 MCR, the third unit of six units in the MCR program, to the IESO in fourth quarter 2023. IESO approval of the Unit 4 MCR is expected in first quarter 2024.

On March 1, 2023, Unit 3 was removed from service and began its MCR outage with a return to service expected in 2026.

Texas Wind Farms Acquisitions

On March 15, 2023, we acquired 100 per cent of the Class B Membership Interests in the 155 MW Fluvanna Wind Farm located in Scurry County, Texas for US$99 million, before post-closing adjustments. Additionally, on June 14, 2023, we acquired 100 per cent of the Class B Membership Interests in the 148 MW Blue Cloud Wind Farm located in Bailey County, Texas for US$125 million, before post-closing adjustments.

Each of these operating assets has a tax equity investor which owns 100 per cent of the Class A Membership Interests, to which a percentage of earnings, tax attributes and cash flows are allocated under the provisions of each tax equity agreement and are recorded in Net income (loss) attributable to non-controlling interests in the Condensed consolidated statement of income.

Ontario Pumped Storage Project

On July 10, 2023, the Government of Ontario announced that the Minister of Energy will conduct a final evaluation of our Ontario Pumped Storage Project (OPSP) with a decision expected by the end of 2023.

The OPSP remains subject to approval by our Board of Directors and a successful partnership agreement with the Saugeen Ojibway Nation. We are targeting an FID in 2025 with OPSP expected to be in-service in the early 2030s, subject to receipt of regulatory and corporate approvals.

Renewable Energy Contracts and/or Investment Opportunities

In first quarter 2023, we secured approximately 300 MW from wind farms in Texas. To date, we have secured approximately 900 MW in the U.S. from solar and wind projects to meet the electricity needs of internal and external customers in the industrial and oil and gas sectors.

In second quarter 2023, we finalized contracts to sell 50 MW under our 24-by-7 carbon-free power offering in the Province of Alberta. Contract terms range from 15 to 20 years and are expected to commence in 2025.

Saddlebrook Solar

On October 25, 2023, Saddlebrook Solar, an 81 MW facility located near Aldersyde, Alberta was placed in service. Total cost of the project was $146 million which was partially supported with funding from Emissions Reduction Alberta and Lockheed Martin.

OTHER ENERGY SOLUTIONS

Alberta Carbon Grid

In June 2021, we announced a partnership with Pembina Pipeline Corporation to jointly develop a world-scale carbon transportation and sequestration system which, when fully constructed, is expected to be capable of transporting up to 20 million tonnes of carbon dioxide annually. Alberta Carbon Grid continues to evaluate the suitability of our Areas Of Interest, including the advancement of well drilling and testing activities to support the development of a detailed Measurement, Monitoring and Verification plan required to apply for a sequestration permit.

CORPORATE

2016 Columbia Pipeline Acquisition Lawsuit

On June 30, 2023, the Delaware Chancery Court (the Court) issued a ruling against TC Energy and other named defendants in a class action lawsuit brought on behalf of the former shareholders of Columbia Pipeline Group Inc. (Columbia) related to the acquisition of Columbia by TC Energy in July 2016. The Court determined that Columbia's then CEO and CFO breached their fiduciary duties and made material disclosure omissions and that TC Energy was aware and took advantage of those breaches. The Court awarded shareholders damages in the amount of US$1 per share. The final award is yet to be determined but is expected to be in the range of US$400 million, plus interest at the statutory rate. Liability for this award will be allocated between Columbia's former executives and TC Energy in a subsequent proceeding before the Court that will determine proportionate responsibility and account for the prior settlement. Until this allocation is known, the amount that TC Energy is liable for cannot be reasonably estimated, therefore, we have not accrued a provision for this claim as at September 30, 2023.

TC Energy will not be responsible for the full amount of the award, but its proportionate share will not be known until the allocation hearing is completed. We strongly disagree with the ruling and intend to appeal once the final judgment is entered and the allocation is determined. The same Court had previously confirmed, after trial in an appraisal rights action filed in 2016, that the US$25.50 per share that TC Energy paid Columbia shareholders was fair value.

Focus Project

In late 2022, we launched the Focus Project to identify opportunities to improve safety, productivity and cost-effectiveness and to date have identified a broad set of opportunities expected to improve safety and financial performance over the long term. Certain initiatives have been implemented and we expect to continue designing and implementing additional initiatives beyond 2023, with benefits in the form of enhanced productivity and cost-effectiveness expected to be realized in the future.

For the three and nine months ended September 30, 2023 we have incurred pre-tax costs of $29 million and $98 million, respectively, for the Focus Project primarily related to external consulting and severance costs of which $18 million and $50 million, respectively, was recorded in Plant operating costs and other in the Condensed consolidated statement of income and was removed from comparable amounts. An additional $4 million and $19 million was recorded in Plant operating costs and other for the three and nine months ended September 30, 2023 with offsetting revenues related to costs recoverable through regulatory and commercial tolling structures, the net effect of which had no impact on net income. As at September 30, 2023, $29 million was allocated to capital projects.

Asset Divestiture Program

As part of the $5+ billion asset divestiture program announced in 2022, on October 4, 2023, TC Energy successfully completed the sale of a 40 per cent equity interest in Columbia Gas and Columbia Gulf. This has significantly accelerated our deleveraging goal and we will continue to look at future capital rotation opportunities to further strengthen our financial position.

2023 Canada Federal Budget

On March 28, 2023, the Canadian Federal Government delivered its 2023 Budget. As part of this budget, several changes were announced to interest deductibility rules, global minimum tax proposals and other tax measures. We do not expect a material impact on our financial performance and cash flows in the near term, but we will continue to monitor any developments.

Financial condition

We strive to maintain financial strength and flexibility in all parts of the economic cycle. We rely on our operating cash flows to sustain our business, pay dividends and fund a portion of our growth. In addition, we access capital markets and engage in portfolio management activities to meet our financing needs and to manage our capital structure and credit ratings.

We believe that we have the financial capacity to fund our existing capital program through predictable and growing cash flows from operations, access to capital markets, portfolio management activities, joint ventures, asset-level financing, cash on hand and substantial committed credit facilities. Annually, in the fourth quarter, we renew and extend our credit facilities as required.

At September 30, 2023, our current assets totaled $9.6 billion and current liabilities amounted to $11.1 billion, leaving us with a working capital deficit of $1.5 billion compared to $9.6 billion at December 31, 2022. Our working capital deficiency is considered to be in the normal course of business and is managed through:

- our ability to generate predictable and growing cash flows from operations
- a total of $10.4 billion of TCPL committed revolving credit facilities of which $10.2 billion of short-term borrowing capacity remains available, net of $0.2 billion backstopping outstanding commercial paper balances, arrangements for a further $2.0 billion of demand credit facilities of which $0.9 billion remained available as at September 30, 2023
- additional committed revolving credit facilities at certain of our subsidiaries and affiliates
- our access to capital markets, including through securities issuances, incremental credit facilities, portfolio management activities and DRP, if deemed appropriate.

CASH PROVIDED BY OPERATING ACTIVITIES

	three months ended September 30		nine months ended September 30	
(millions of $)	**2023**	**2022**	**2023**	**2022**
Net cash provided by operations	**1,824**	1,701	**5,408**	4,350
Increase (decrease) in operating working capital	**(102)**	(67)	**15**	511
Funds generated from operations	**1,722**	1,634	**5,423**	4,861
Specific items:				
Keystone FERC decision, net of current income tax	**—**	—	**48**	—
Milepost 14 insurance expense	**—**	—	**36**	—
Focus Project costs, net of current income tax	**15**	—	**42**	—
Liquids separation costs	**15**	—	**15**	—
Keystone XL preservation and other, net of current income tax	**3**	3	**11**	12
Settlement of Mexico prior years' income tax assessments	**—**	—	**—**	195
Comparable funds generated from operations	**1,755**	1,637	**5,575**	5,068

Net cash provided by operations

Net cash provided by operations increased by $123 million and $1,058 million for the three and nine months ended September 30, 2023, respectively, compared to the same periods in 2022 primarily due to higher funds generated from operations and timing of working capital changes.

Comparable funds generated from operations

Comparable funds generated from operations, a non-GAAP measure, helps us assess the cash generating ability of our businesses by excluding the timing effects of working capital changes as well as the cash impact of our specific items.

Comparable funds generated from operations increased by $118 million and $507 million for the three and nine months ended September 30, 2023, respectively, compared to the same periods in 2022 primarily due to increased comparable EBITDA, higher distributions from operating activities of our equity investments, partially offset by higher interest expense. Higher comparable funds generated from operations for the nine months ended September 30, 2023 also reflects the realized gains and losses on derivatives used to manage our foreign exchange exposures.

CASH (USED IN) PROVIDED BY INVESTING ACTIVITIES

	three months ended September 30		nine months ended September 30	
(millions of $)	**2023**	**2022**	**2023**	**2022**
Capital spending				
Capital expenditures	**(2,042)**	(1,837)	**(5,945)**	(4,608)
Capital projects in development	**(18)**	(11)	**(122)**	(33)
Contributions to equity investments	**(1,229)**	(746)	**(3,246)**	(1,181)
	(3,289)	(2,594)	**(9,313)**	(5,822)
Loans to affiliate (issued) repaid, net	**—**	101	**250**	(11)
Acquisitions, net of cash acquired	**—**	—	**(302)**	—
Other distributions from equity investments	**—**	1,205	**16**	1,237
Keystone XL contractual recoveries	**2**	95	**7**	568
Deferred amounts and other	**(42)**	60	**(33)**	29
Net cash (used in) provided by investing activities	**(3,329)**	(1,133)	**(9,375)**	(3,999)

Capital expenditures in 2023 have been incurred primarily for the development of the Southeast Gateway pipeline, the NGTL System and Foothills expansion programs, Columbia Gas and ANR projects, as well as maintenance capital expenditures. Higher capital expenditures in 2023 compared to 2022 reflect increased spending for the development of the Southeast Gateway pipeline and Columbia Gas projects, partially offset by reduced spending on expansion of the NGTL System.

Contributions to equity investments increased in 2023 compared to 2022 mainly due to draws of $2,020 million on the subordinated loan by Coastal GasLink LP in 2023 which are accounted for as in-substance equity contributions.

Loans to affiliate (issued) repaid, net represent issuances prior to amended agreements in 2022 and repayments on the subordinated demand revolving credit facility and the subordinated loan agreement that we entered with Coastal GasLink LP. Refer to the Financial risks and financial instruments – Related party transactions section for additional information.

As part of refinancing activities with the Sur de Texas joint venture, on March 15, 2022, our peso-denominated inter-affiliate loan was fully repaid upon maturity in the amount of $1.2 billion and was subsequently replaced with a new U.S. dollar-denominated inter-affiliate loan of an equivalent $1.2 billion. The Contributions to equity investments and Other distributions from equity investments with respect to these refinancing activities are presented above on a net basis, although they are reported on a gross basis in our Condensed consolidated statement of cash flows. Refer to the Financial risks and financial instruments – Related party transactions section for additional information.

On March 15, 2023, we acquired 100 per cent of the Class B Membership Interests in the Fluvanna Wind Farm located in Scurry County, Texas for US$99 million, before post-closing adjustments. On June 14, 2023, we acquired 100 per cent of the Class B Membership Interests in the Blue Cloud Wind Farm located in Bailey County, Texas for US$125 million, before post-closing adjustments. Refer to the Recent developments – Power and Energy Solutions section for additional information.

CASH (USED IN) PROVIDED BY FINANCING ACTIVITIES

	three months ended September 30		nine months ended September 30	
(millions of $)	**2023**	**2022**	**2023**	**2022**
Notes payable issued (repaid), net	**(2,401)**	458	**(6,055)**	672
Long-term debt issued, net of issue costs	**7,434**	(2)	**15,887**	2,508
Long-term debt repaid	**(2,150)**	(1,287)	**(2,610)**	(1,313)
Junior subordinated notes issued, net of issue costs	**—**	—	**—**	1,008
Dividends and distributions paid	**(616)**	(923)	**(1,979)**	(2,770)
Common shares issued, net of issue costs	**—**	1,742	**4**	1,900
Preferred shares redeemed	**—**	—	**—**	(1,000)
Other	**—**	6	**—**	23
Net cash (used in) provided by financing activities	**2,267**	(6)	**5,247**	1,028

Notes Payable

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

Long-term debt issued

The following table outlines significant long-term debt issuances in the nine months ended September 30, 2023:

(millions of Canadian $, unless otherwise noted) Company	Issue date	Type	Maturity date	Amount	Interest rate
TransCanada PipeLines Limited					
	May 2023	Senior Unsecured Term Loan[1]	May 2026	US 1,024	Floating
	March 2023	Senior Unsecured Notes	March 2026[2]	US 850	6.20%
	March 2023	Senior Unsecured Notes	March 2026[2]	US 400	Floating
	March 2023	Medium Term Notes	July 2030	1,250	5.28%
	March 2023	Medium Term Notes	March 2026[2]	600	5.42%
	March 2023	Medium Term Notes	March 2026[2]	400	Floating
Columbia Pipelines Operating Company LLC[3]					
	August 2023	Senior Unsecured Notes	November 2033	US 1,500	6.04%
	August 2023	Senior Unsecured Notes	November 2053	US 1,250	6.54%
	August 2023	Senior Unsecured Notes	August 2030	US 750	5.93%
	August 2023	Senior Unsecured Notes	August 2043	US 600	6.50%
	August 2023	Senior Unsecured Notes	August 2063	US 500	6.71%
Columbia Pipelines Holding Company LLC[3]					
	August 2023	Senior Unsecured Notes	August 2028	US 700	6.04%
	August 2023	Senior Unsecured Notes	August 2026	US 300	6.06%
TC Energía Mexicana, S. de R.L. de C.V.					
	January 2023	Senior Unsecured Term Loan	January 2028	US 1,800	Floating
	January 2023	Senior Unsecured Revolving Credit Facility	January 2028	US 500	Floating
Gas Transmission Northwest LLC					
	June 2023	Senior Unsecured Notes	June 2030	US 50	4.92%

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

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

3 On October 4, 2023, TC Energy completed the sale of a 40 per cent equity interest in Columbia Gas and Columbia Gulf. Refer to Note 17, Subsequent event, of our Condensed consolidated financial statements for additional information.

Long-term debt repaid/retired

The following table outlines significant long-term debt repaid in the nine months ended September 30, 2023:

(millions of Canadian $, unless otherwise noted)				
Company	**Repayment date**	**Type**	**Amount**	**Interest rate**
TransCanada PipeLines Limited				
	September 2023	Senior Unsecured Term Loan[1]	US 1,024	Floating
	July 2023	Medium Term Notes	750	3.69%
Nova Gas Transmission Ltd.				
	April 2023	Debentures	US 200	7.88%
TC Energía Mexicana, S. de R.L. de C.V.				
	Various	Senior Unsecured Revolving Credit Facility	US 120	Floating

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

On October 16, 2023, TCPL retired US$625 million of senior unsecured notes bearing interest at a fixed rate of 3.75 per cent.

DIVIDENDS

On November 7, 2023, we declared quarterly dividends on our common shares of $0.93 per share payable on January 31, 2024 to shareholders of record at the close of business on December 29, 2023.

DIVIDEND REINVESTMENT PLAN

Under the DRP, eligible holders of common and preferred shares of TC Energy can reinvest their dividends and make optional cash payments to obtain additional TC Energy common shares. From July 1, 2022 to July 31, 2023, common shares were issued from treasury at a discount of two per cent to market prices over a specified period. The participation rate by common shareholders in the DRP in 2023 was approximately 39 per cent, resulting in $737 million reinvested in common equity under the program.

Commencing with the dividends declared on July 27, 2023, common shares purchased under TC Energy's DRP will no longer be satisfied with shares issued from treasury at a discount, but rather will be acquired on the open market at 100 per cent of the weighted average purchase price.

SHARE INFORMATION

At November 2, 2023, we had approximately 1.0 billion issued and outstanding common shares and approximately 7 million outstanding options to buy common shares of which 4 million were exercisable.

CREDIT FACILITIES

At November 2, 2023, we had a total of $10.6 billion of TCPL committed revolving credit facilities of which $10.1 billion of short-term borrowing capacity remains available, net of $0.5 billion backstopping outstanding commercial paper balances. We also have arrangements in place for a further $2.0 billion of demand credit facilities of which $1.0 billion remains available.

On August 31, 2023, Columbia Pipelines Holding Company LLC entered a US$1.0 billion senior unsecured revolving credit facility that matures August 2026; no amounts were drawn as at September 30, 2023.

CONTRACTUAL OBLIGATIONS

Capital expenditure commitments at September 30, 2023 have decreased by approximately $0.3 billion from those reported at December 31, 2022, reflecting normal course fulfillment of construction contracts, partially offset by new contractual commitments entered into for the construction of the Southeast Gateway pipeline and other capital projects.

There were no material changes to our contractual obligations in third quarter 2023 or to payments due in the next five years or thereafter. Refer to our 2022 Annual Report for additional information about our contractual obligations.

Financial risks and financial instruments

We are exposed to various financial risks and have strategies, policies and limits in place to manage the impact of these risks on our earnings, cash flows and, ultimately, shareholder value.

Risk management strategies, policies and limits are designed to ensure our risks and related exposures are in line with our business objectives and risk tolerance.

Refer to our 2022 Annual Report for additional information about the risks we face in our business which have not changed materially since December 31, 2022, other than as noted within this MD&A.

INTEREST RATE RISK

We utilize both short- and long-term debt to finance our operations which exposes us to interest rate risk. We typically pay fixed rates of interest on our long-term debt and floating rates on short-term debt including our commercial paper programs and amounts drawn on our credit facilities. A small portion of our long-term debt bears interest at floating rates. In addition, we are exposed to interest rate risk on financial instruments and contractual obligations containing variable interest rate components. We actively manage our interest rate risk using interest rate derivatives. For eligible hedging relationships affected by the expected cessation of certain reference interest rates, we have applied the optional expedient permissible under U.S. GAAP allowing an entity to assume that the hedged forecasted transaction in a cash flow hedge is probable of occurring and, therefore, we expect no material impact on our consolidated financial statements.

FOREIGN EXCHANGE RISK

Certain of our businesses generate all or most of their earnings in U.S. dollars and, since we report our financial results in Canadian dollars, changes in the value of the U.S. dollar against the Canadian dollar directly affect our comparable EBITDA and may also impact comparable earnings.

A portion of our Mexico Natural Gas Pipelines monetary assets and liabilities are peso-denominated, while our Mexico operations' financial results are denominated in U.S. dollars. Therefore, changes in the value of the Mexican peso against the U.S. dollar can affect our comparable earnings. In addition, foreign exchange gains or losses calculated for Mexico income tax purposes on the revaluation of U.S. dollar-denominated monetary assets and liabilities result in a peso-denominated income tax exposure for these entities, leading to fluctuations in Income from equity investments and Income tax expense.

We manage a portion of our foreign exchange risk using foreign exchange derivatives. Refer to the Foreign Exchange section for additional information on our foreign currency exposures.

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

COUNTERPARTY CREDIT RISK

We have exposure to counterparty credit risk in a number of areas including:

- cash and cash equivalents
- accounts receivable and certain contractual recoveries
- available-for-sale assets
- fair value of derivative assets
- net investment in leases and certain contract assets in Mexico.

Market events causing disruptions in global energy demand and supply may contribute to economic uncertainties impacting a number of our customers. While the majority of our credit exposure is to large creditworthy entities, we maintain close monitoring and communication with those counterparties experiencing greater financial pressures. Refer to our 2022 Annual Report for more information about the factors that mitigate our counterparty credit risk exposure.

We review 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. We use historical credit loss and recovery data, adjusted for our 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. At September 30, 2023, we had no significant credit risk concentrations and no significant amounts past due or impaired. We recorded a pre-tax recovery of $1 million and $116 million on the expected credit loss provision before tax on the TGNH net investment in leases and certain contract assets in Mexico for the three and nine months ended September 30, 2023, respectively (2022 – loss of $71 million and $71 million, respectively). Refer to our 2022 Consolidated financial statements for additional information on expected credit loss provisions and Note 12, Risk management and financial instruments, for additional information on the expected credit loss provision recognized in 2023.

We have significant credit and performance exposure to financial institutions that hold cash deposits and provide committed credit lines and letters of credit that help manage our exposure to counterparties and provide liquidity in commodity, foreign exchange and interest rate derivative markets. Our portfolio of financial sector exposure consists primarily of highly-rated investment grade, systemically important financial institutions. We had no direct exposure to the U.S. regional bank failures in early 2023; however, we continue to monitor potential impacts on our portfolio of financial sector counterparties.

LIQUIDITY RISK

Liquidity risk is the risk that we will not be able to meet our financial obligations as they come due. We manage our liquidity risk by continuously forecasting our cash flows and ensuring we have adequate cash balances, cash flows from operations, committed and demand credit facilities and access to capital markets to meet our operating, financing and capital expenditure obligations under both normal and stressed economic conditions.

RELATED PARTY TRANSACTIONS

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

Coastal GasLink LP

We hold a 35 per cent equity interest in Coastal GasLink LP and have been contracted to develop, construct and operate the Coastal GasLink pipeline.

TC Energy Subordinated Loan Agreement

TC Energy has a subordinated loan agreement with Coastal GasLink LP under which draws by Coastal GasLink LP will fund the remaining $1.4 billion equity requirement related to the estimated capital cost to complete the Coastal GasLink pipeline. As at September 30, 2023, the total capacity committed by TC Energy under this subordinated loan agreement was $3.4 billion.

Any amounts outstanding on this loan will be repaid by Coastal GasLink LP to TC Energy, once final project costs are known, which will be determined after the pipeline is placed 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. We expect that, in accordance with contractual terms, these additional equity contributions will be predominantly funded by TC Energy but will not result in a change to our 35 per cent ownership. The total amount drawn on this loan at September 30, 2023 was $2,020 million (December 31, 2022 – $250 million). The carrying value of this loan was reduced to nil at September 30, 2023 and December 31, 2022 as part of the impairment charges recognized to date.

In October 2023, an additional $125 million was drawn on the subordinated loan and will be assessed for impairment in future reporting periods along with future draws on this loan.

Subordinated Demand Revolving Credit Facility

We have a subordinated demand revolving credit facility with Coastal GasLink LP to provide additional short-term liquidity and funding flexibility to the project. The facility bears interest at a floating market-based rate and has a capacity of $100 million with an outstanding balance of nil at September 30, 2023 (December 31, 2022 – nil). This revolver was not impacted by the impairment charges recognized to date.

Sur de Texas

We hold a 60 per cent equity interest in a joint venture with IEnova, which owns the Sur de Texas pipeline, for which we are the operator. In 2017, we entered into a MXN$21.3 billion unsecured revolving credit facility with the joint venture, which bore interest at a floating rate. On March 15, 2022, as part of refinancing activities with the Sur de Texas joint venture, the peso-denominated inter-affiliate loan was replaced with a new U.S. dollar-denominated inter-affiliate loan from us for 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.

FINANCIAL INSTRUMENTS

With the exception of Long-term debt and Junior subordinated notes, our derivative and non-derivative financial instruments are recorded on the balance sheet at fair value unless they were entered into and continue to be held for the purpose of receipt or delivery in accordance with our normal purchase and sales exemptions and are documented as such. In addition, fair value accounting is not required for other financial instruments that qualify for certain accounting exemptions.

Derivative instruments

We use derivative instruments to reduce volatility associated with fluctuations in commodity prices, interest rates and foreign exchange rates. Derivative instruments, including those that qualify and are designated for hedge accounting treatment, are recorded at fair value.

The majority of derivative instruments that are not designated or do not qualify for hedge accounting treatment have been entered into as economic hedges to manage our exposure to market risk and are classified as held-for-trading. Changes in the fair value of held-for-trading derivative instruments are recorded in net income in the period of change. This may expose us to increased variability in reported operating results since the fair value of the held-for-trading 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 us. As a result, these gains and losses are deferred as regulatory liabilities or regulatory assets and are refunded to or collected from the ratepayers in subsequent years when the derivative settles.

Balance sheet presentation of derivative instruments

The balance sheet presentation of the fair value of derivative instruments is as follows:

(millions of $)	**September 30, 2023**	**December 31, 2022**
Other current assets	**1,313**	614
Other long-term assets	**152**	91
Accounts payable and other	**(1,296)**	(871)
Other long-term liabilities	**(242)**	(151)
	(73)	(317)

Unrealized and realized gains (losses) on derivative instruments

The following summary does not include hedges of our net investment in foreign operations.

(millions of $)	three months ended September 30		nine months ended September 30	
	2023	**2022**	**2023**	**2022**
Derivative Instruments Held for Trading[1]				
Unrealized gains (losses) in the period				
Commodities	**(17)**	42	**113**	(16)
Foreign exchange	**(40)**	(283)	**142**	(321)
Realized gains (losses) in the period				
Commodities	**249**	165	**579**	561
Foreign exchange	**(29)**	(1)	**110**	27
Derivative Instruments in Hedging Relationships				
Realized gains (losses) in the period				
Commodities	**(8)**	(21)	**(20)**	(39)
Interest rate	**(13)**	2	**(29)**	—

1 Realized and unrealized gains (losses) on held-for-trading derivative instruments used to purchase and sell commodities are included on a net basis in Revenues. Realized and unrealized gains (losses) on foreign exchange held-for-trading derivative instruments are included on a net basis in Foreign exchange (gains) losses, net in the Condensed consolidated statement of income.

For further details on our non-derivative and derivative financial instruments, including classification assumptions made in the calculation of fair value and additional discussion of exposure to risks and mitigation activities, refer to Note 12, Risk management and financial instruments, of our Condensed consolidated financial statements.

Other information

CONTROLS AND PROCEDURES

Management, including our President and CEO and our CFO, evaluated the effectiveness of our disclosure controls and procedures as at September 30, 2023, as required by the Canadian securities regulatory authorities and by the SEC and concluded that our disclosure controls and procedures are effective at a reasonable assurance level.

There were no changes in third quarter 2023 that had or are likely to have a material impact on our internal control over financial reporting.

CRITICAL ACCOUNTING ESTIMATES AND ACCOUNTING POLICY CHANGES

When we prepare financial statements that conform with U.S. GAAP, we are required to make estimates and assumptions that affect the timing and amounts we record for our assets, liabilities, revenues and expenses because these items may be affected by future events. We base the estimates and assumptions on the most current information available, using our best judgment. We also regularly assess the assets and liabilities themselves. In addition to the items discussed below, refer to our 2022 Annual Report for a listing of critical accounting estimates.

Equity Investment in Coastal GasLink LP

Impairment and Maximum Exposure to Loss

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, as with any complex construction project, the final capital cost is subject to certain risks and uncertainties. The revised estimate of total project costs and our corresponding future funding requirements were indicators that a decrease in the value of our equity investment had occurred. We completed a valuation assessment and concluded that the fair value of TC Energy's investment was below its carrying value at December 31, 2022. We determined that this was an other-than-temporary impairment of our equity investment in Coastal GasLink LP, which resulted in a pre-tax impairment charge of $3.0 billion ($2.6 billion after tax) at December 31, 2022 and we disclosed that a significant portion of our future funding was expected to be impaired. Our valuation assessments in the first, second and third quarters of 2023 concluded that the carrying value of our investment was impaired and we recognized a pre-tax impairment charge of $1,244 million ($1,179 million after tax) and $2,100 million ($2,017 million after tax) for the three and nine months ended September 30, 2023, respectively, in Impairment of equity investment in the Condensed consolidated statement of income in the Canadian Natural Gas Pipelines segment. The impairment charge reflected the net impact of $2,020 million drawn and $250 million repaid on the subordinated loan for the nine months ended September 30, 2023, along with TC Energy's proportionate share of unrealized gains and losses on interest rate derivatives in Coastal GasLink LP and other changes to the equity investment. The impairment of the subordinated loan resulted in unrealized non-taxable capital losses that are not recognized. Refer to Note 5, Coastal GasLink, of our Condensed consolidated financial statements for additional information.

The fair value of TC Energy's investment in Coastal GasLink LP at September 30, 2023 was estimated using a 40-year discounted cash flow model consistent with our fair value assessment at December 31, 2022. Refer to our 2022 Consolidated financial statements for additional information.

We will continue to assess for other-than-temporary declines in the fair value of this investment and the extent of any future impairment charges, if any, will depend on the outcome of the valuation assessment performed at the respective reporting date.

The maximum exposure to loss as a result of our involvement with Coastal GasLink LP, a variable interest entity (VIE), as at September 30, 2023 was $1.4 billion. Our maximum exposure to loss is the maximum loss that could potentially be recorded through net income in future periods as a result of our variable interest in a VIE. TC Energy is contractually obligated to fund the capital costs to complete the Coastal GasLink pipeline, which is estimated to be $1.4 billion subsequent to September 30, 2023, through additional equity contributions in Coastal GasLink LP, subject to any final cost sharing between the Coastal GasLink LP partners. The determination of our maximum exposure to loss involves an estimate of capital costs to complete.

Impairment of long-lived assets and goodwill

Goodwill is tested for impairment on an annual basis, or more frequently if events or changes in circumstances indicate it might be impaired. We can initially make this assessment based on qualitative factors. If we conclude that it is not more likely than not that the fair value of the reporting unit is greater than its carrying value, we will then perform a quantitative goodwill impairment test.

In conjunction with the process leading up to the sale of a 40 per cent equity interest in Columbia Gas and Columbia Gulf, management performed a quantitative goodwill impairment test for the Columbia Pipeline Group, Inc. (Columbia) reporting unit as at June 30, 2023. Refer to the Recent Developments – U.S. Natural Gas Pipelines section for additional information on this sale transaction.

In the determination of the fair value utilized in the quantitative goodwill impairment test for the Columbia reporting unit, we performed a discounted cash flow analysis using projections of future cash flows and applied a risk-adjusted discount rate and terminal value multiple which involved significant estimates and judgments. It was determined that the fair value of the Columbia reporting unit exceeded its carrying value, including goodwill. Although goodwill was not impaired, the estimated fair value in excess of the carrying value was reduced to less than 10 per cent. There is a risk that reductions in future cash flow forecasts and adverse changes in other key assumptions could result in a future impairment of a portion of the goodwill balance relating to Columbia.

Accounting changes

Our significant accounting policies have remained unchanged since December 31, 2022 other than as described in Note 2, Accounting changes, of our Condensed consolidated financial statements. A summary of our significant accounting policies is included in our 2022 Annual Report.

Quarterly results

SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA

	2023			2022				2021
(millions of $, except per share amounts)	**Third**	**Second**	**First**	**Fourth**	**Third**	**Second**	**First**	**Fourth**
Revenues	**3,940**	3,830	3,928	4,041	3,799	3,637	3,500	3,584
Net income (loss) attributable to common shares	**(197)**	250	1,313	(1,447)	841	889	358	1,118
Comparable earnings	**1,035**	981	1,233	1,129	1,068	979	1,103	1,028
Per share statistics:								
Net income (loss) per common share – basic	**($0.19)**	$0.24	$1.29	($1.42)	$0.84	$0.90	$0.36	$1.14
Comparable earnings per common share	**$1.00**	$0.96	$1.21	$1.11	$1.07	$1.00	$1.12	$1.05
Dividends declared per common share	**$0.93**	$0.93	$0.93	$0.90	$0.90	$0.90	$0.90	$0.87

FACTORS AFFECTING QUARTERLY FINANCIAL INFORMATION BY BUSINESS SEGMENT

Quarter-over-quarter revenues and net income fluctuate for reasons that vary across our business segments. In addition to the factors below, our revenues and segmented earnings (losses) are impacted by fluctuations in foreign exchange rates, mainly related to our U.S. dollar-denominated operations and our peso-denominated exposure. Refer to the Foreign exchange section for additional information.

In our Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines and Mexico Natural Gas Pipelines segments, except for seasonal fluctuations in short-term throughput volumes on U.S. pipelines, quarter-over-quarter revenues and segmented earnings (losses) generally remain relatively stable during any fiscal year. Over the long term, however, they fluctuate because of:

- regulatory decisions
- negotiated settlements with customers
- newly constructed assets being placed in service
- acquisitions and divestitures
- natural gas marketing activities and commodity prices
- developments outside of the normal course of operations
- certain fair value adjustments and provisions for expected credit losses on net investment in leases and certain contract assets in Mexico.

In Liquids Pipelines, quarter-over-quarter revenues and segmented earnings (losses) are affected by:

- regulatory decisions
- newly constructed assets being placed in service
- acquisitions and divestitures
- demand for uncontracted transportation services
- liquids marketing activities and commodity prices
- developments outside of the normal course of operations
- contracted and uncontracted spot transportation
- certain fair value adjustments.

In Power and Energy Solutions, quarter-over-quarter revenues and segmented earnings (losses) are affected by:

- weather
- customer demand
- newly constructed assets being placed in service
- acquisitions and divestitures
- market prices for natural gas and power
- capacity prices and payments
- power marketing and trading activities
- planned and unplanned plant outages
- developments outside of the normal course of operations
- certain fair value adjustments.

FACTORS AFFECTING FINANCIAL INFORMATION BY QUARTER

We calculate comparable measures by adjusting certain GAAP measures for specific items we believe are significant but not reflective of our underlying operations in the period. Except as otherwise described herein, these comparable measures are calculated on a consistent basis from period to period and are adjusted for specific items in each period, as applicable.

We exclude from comparable measures the unrealized gains and losses from changes in the fair value of derivatives related to financial and commodity price risk management activities. These derivatives generally provide effective economic hedges but do not meet the criteria for hedge accounting. We also exclude from comparable measures our proportionate share of the unrealized gains and losses from changes in the fair value of Bruce Power's funds invested for post-retirement benefits and derivatives related to its risk management activities. These changes in fair value are recorded in net income. As these amounts do not accurately reflect the gains and losses that will be realized at settlement, we do not consider them reflective of our underlying operations.

In third quarter 2023, comparable earnings also excluded:

- an after-tax impairment charge of $1,179 million related to our equity investment in Coastal GasLink LP
- a $14 million after-tax expense related to Focus Project costs
- an $11 million after-tax expense due to separation costs related to the proposed spinoff of our Liquids Pipelines business
- preservation and other costs for Keystone XL pipeline project assets of $2 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge
- an after-tax net unrealized foreign exchange gain of $20 million on the peso-denominated intercompany loan between TCPL and TGNH.

In second quarter 2023, comparable earnings also excluded:

- an after-tax impairment charge of $809 million related to our equity investment in Coastal GasLink LP
- a $36 million after-tax accrued insurance expense related to the Milepost 14 incident
- a $25 million after-tax expense related to Focus Project costs
- an after-tax net unrealized foreign exchange loss of $9 million on the peso-denominated intercompany loan between TCPL and TGNH
- preservation and other costs for Keystone XL pipeline project assets of $4 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge
- an $8 million after-tax recovery on the expected credit loss provision related to the TGNH net investment in leases and certain contract assets in Mexico.

In first quarter 2023, comparable earnings also excluded:

- a $72 million after-tax recovery on the expected credit loss provision related to the TGNH net investment in leases and certain contract assets in Mexico
- $48 million after-tax charge as a result of the FERC Administrative Law Judge initial decision on Keystone issued in February 2023 in respect of a tolling-related complaint pertaining to amounts recognized from 2018 to 2022 which consists of a one-time pre-tax charge of $57 million and accrued pre-tax carrying charges of $5 million
- an after-tax impairment charge of $29 million related to our equity investment in Coastal GasLink LP
- preservation and other costs for Keystone XL pipeline project assets of $4 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge.

In fourth quarter 2022, comparable earnings also excluded:

- an after-tax impairment charge of $2.6 billion related to our equity investment in Coastal GasLink LP
- a $64 million after-tax expected credit loss provision related to the TGNH net investment in leases and certain contract assets in Mexico
- $20 million after-tax charge due to the CER decision on Keystone issued in December 2022 in respect of a tolling-related complaint pertaining to amounts reflected in 2021 and 2020
- preservation and other costs for Keystone XL pipeline project assets of $8 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge
- a $5 million after-tax net expense related to the 2021 Keystone XL asset impairment charge and other due to a U.S. minimum tax, partially offset by the gain on the sale of Keystone XL project assets and reduction to the estimate for contractual and legal obligations related to termination activities
- a $1 million income tax expense for the settlement related to prior years' income tax assessments in Mexico.

In third quarter 2022, comparable earnings also excluded:

- preservation and other costs for Keystone XL pipeline project assets of $3 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge.

In second quarter 2022, comparable earnings also excluded:

- preservation and other costs for Keystone XL pipeline project assets of $3 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge
- a $2 million income tax expense for the settlement related to prior years' income tax assessments in Mexico.

In first quarter 2022, comparable earnings also excluded:

- an after-tax goodwill impairment charge of $531 million related to Great Lakes
- a $193 million income tax expense for the settlement-in-principle of matters related to prior years' income tax assessments in Mexico
- preservation and other costs for Keystone XL pipeline project assets of $5 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge.

In fourth quarter 2021, comparable earnings also excluded:

- an incremental $60 million after-tax reduction to the Keystone XL asset impairment charge, net of expected contractual recoveries and other contractual and legal obligations, related to the termination of the Keystone XL pipeline project
- an after-tax gain of $19 million related to the sale of the remaining interest in Northern Courier
- preservation and other costs for Keystone XL pipeline project assets of $10 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge
- a $7 million after-tax gain related to pension adjustments as part of the Voluntary Retirement Program
- an incremental $6 million income tax expense related to the sale of our Ontario natural gas-fired power plants sold in 2020.

Condensed consolidated statement of income

	three months ended September 30		nine months ended September 30	
(unaudited - millions of Canadian $, except per share amounts)	**2023**	**2022**	**2023**	**2022**
Revenues				
Canadian Natural Gas Pipelines	**1,303**	1,234	**3,829**	3,497
U.S. Natural Gas Pipelines	**1,473**	1,449	**4,558**	4,295
Mexico Natural Gas Pipelines	**213**	179	**625**	487
Liquids Pipelines	**715**	691	**1,935**	2,051
Power and Energy Solutions	**236**	246	**751**	606
	3,940	3,799	**11,698**	10,936
Income (Loss) from Equity Investments	**305**	322	**856**	763
Impairment of Equity Investment	**(1,244)**	—	**(2,100)**	—
Operating and Other Expenses				
Plant operating costs and other	**1,271**	1,342	**3,544**	3,521
Commodity purchases resold	**178**	128	**373**	429
Property taxes	**218**	214	**667**	634
Depreciation and amortization	**690**	653	**2,061**	1,914
Goodwill impairment charge	**—**	—	**—**	571
	2,357	2,337	**6,645**	7,069
Financial Charges				
Interest expense	**865**	666	**2,418**	1,866
Allowance for funds used during construction	**(164)**	(116)	**(443)**	(254)
Foreign exchange (gains) losses, net	**45**	277	**(231)**	317
Interest income and other	**(63)**	(35)	**(121)**	(93)
	683	792	**1,623**	1,836
Income (Loss) before Income Taxes	**(39)**	992	**2,186**	2,794
Income Tax Expense (Recovery)				
Current	**97**	110	**324**	479
Deferred	**37**	12	**409**	114
	134	122	**733**	593
Net Income (Loss)	**(173)**	870	**1,453**	2,201
Net income (loss) attributable to non-controlling interests	**1**	8	**18**	28
Net Income (Loss) Attributable to Controlling Interests	**(174)**	862	**1,435**	2,173
Preferred share dividends	**23**	21	**69**	85
Net Income (Loss) Attributable to Common Shares	**(197)**	841	**1,366**	2,088
Net Income (Loss) per Common Share				
Basic and diluted	**($0.19)**	$0.84	**$1.33**	$2.11
Weighted Average Number of Common Shares (millions)				
Basic	**1,035**	1,000	**1,028**	988
Diluted	**1,035**	1,000	**1,028**	989

See accompanying Notes to the Condensed consolidated financial statements.

Condensed consolidated statement of comprehensive income

	three months ended September 30		nine months ended September 30	
(unaudited - millions of Canadian $)	**2023**	**2022**	**2023**	**2022**
Net Income (Loss)	**(173)**	870	**1,453**	2,201
Other Comprehensive Income (Loss), Net of Income Taxes				
Foreign currency translation adjustments	**430**	1,510	**(63)**	1,872
Change in fair value of net investment hedges	**(13)**	(67)	**12**	(75)
Change in fair value of cash flow hedges	**15**	(20)	**(3)**	(8)
Reclassification to net income of (gains) losses on cash flow hedges	**25**	15	**66**	30
Reclassification to net income of actuarial (gains) losses on pension and other post-retirement benefit plans	**—**	2	**—**	6
Other comprehensive income (loss) on equity investments	**142**	(2)	**135**	343
	599	1,438	**147**	2,168
Comprehensive Income (Loss)	**426**	2,308	**1,600**	4,369
Comprehensive income (loss) attributable to non-controlling interests	**8**	16	**20**	38
Comprehensive Income (Loss) Attributable to Controlling Interests	**418**	2,292	**1,580**	4,331
Preferred share dividends	**23**	21	**69**	85
Comprehensive Income (Loss) Attributable to Common Shares	**395**	2,271	**1,511**	4,246

See accompanying Notes to the Condensed consolidated financial statements.

Condensed consolidated statement of cash flows

(unaudited - millions of Canadian $)	three months ended September 30 2023	three months ended September 30 2022	nine months ended September 30 2023	nine months ended September 30 2022
Cash Generated from Operations				
Net income (loss)	**(173)**	870	**1,453**	2,201
Depreciation and amortization	**690**	653	**2,061**	1,914
Goodwill impairment charge	**—**	—	**—**	571
Deferred income taxes	**37**	12	**409**	114
(Income) loss from equity investments	**(305)**	(322)	**(856)**	(763)
Impairment of equity investment	**1,244**	—	**2,100**	—
Distributions received from operating activities of equity investments	**329**	267	**927**	709
Employee post-retirement benefits funding, net of expense	**3**	(11)	**(19)**	(22)
Equity allowance for funds used during construction	**(103)**	(78)	**(283)**	(176)
Unrealized (gains) losses on financial instruments	**57**	241	**(255)**	337
Expected credit loss provision	**(2)**	71	**(117)**	71
Other	**(55)**	(69)	**3**	(95)
(Increase) decrease in operating working capital	**102**	67	**(15)**	(511)
Net cash provided by operations	**1,824**	1,701	**5,408**	4,350
Investing Activities				
Capital expenditures	**(2,042)**	(1,837)	**(5,945)**	(4,608)
Capital projects in development	**(18)**	(11)	**(122)**	(33)
Contributions to equity investments	**(1,229)**	(746)	**(3,246)**	(2,380)
Loans to affiliate (issued) repaid, net	**—**	101	**250**	(11)
Acquisitions, net of cash acquired	**—**	—	**(302)**	—
Other distributions from equity investments	**—**	1,205	**16**	2,436
Keystone XL contractual recoveries	**2**	95	**7**	568
Deferred amounts and other	**(42)**	60	**(33)**	29
Net cash (used in) provided by investing activities	**(3,329)**	(1,133)	**(9,375)**	(3,999)
Financing Activities				
Notes payable issued (repaid), net	**(2,401)**	458	**(6,055)**	672
Long-term debt issued, net of issue costs	**7,434**	(2)	**15,887**	2,508
Long-term debt repaid	**(2,150)**	(1,287)	**(2,610)**	(1,313)
Junior subordinated notes issued, net of issue costs	**—**	—	**—**	1,008
Dividends on common shares	**(583)**	(885)	**(1,822)**	(2,623)
Dividends on preferred shares	**(22)**	(21)	**(68)**	(84)
Distributions to non-controlling interests	**(11)**	(10)	**(47)**	(33)
Distributions on Class C Interests	**—**	(7)	**(42)**	(30)
Common shares issued, net of issue costs	**—**	1,742	**4**	1,900
Preferred shares redeemed	**—**	—	**—**	(1,000)
Other	**—**	6	**—**	23
Net cash (used in) provided by financing activities	**2,267**	(6)	**5,247**	1,028
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**117**	94	**70**	108
Increase (Decrease) in Cash and Cash Equivalents	**879**	656	**1,350**	1,487
Cash and Cash Equivalents				
Beginning of period	**1,091**	1,504	**620**	673
Cash and Cash Equivalents				
End of period	**1,970**	2,160	**1,970**	2,160

See accompanying Notes to the Condensed consolidated financial statements.

Condensed consolidated balance sheet

(unaudited - millions of Canadian $)		September 30, 2023	December 31, 2022
ASSETS			
Current Assets			
Cash and cash equivalents		**1,970**	620
Accounts receivable		**3,564**	3,624
Inventories		**1,229**	936
Other current assets		**2,857**	2,152
		9,620	7,332
Plant, Property and Equipment	net of accumulated depreciation of $36,320 and $34,629, respectively	**80,410**	75,940
Net Investment in Leases		**2,388**	1,895
Equity Investments		**10,001**	9,535
Restricted Investments		**2,420**	2,108
Regulatory Assets		**2,224**	1,910
Goodwill		**12,846**	12,843
Other Long-Term Assets		**2,740**	2,785
		122,649	114,348
LIABILITIES			
Current Liabilities			
Notes payable		**244**	6,262
Accounts payable and other		**6,967**	7,149
Dividends payable		**977**	930
Accrued interest		**832**	668
Current portion of long-term debt		**2,114**	1,898
		11,134	16,907
Regulatory Liabilities		**4,733**	4,520
Other Long-Term Liabilities		**1,164**	1,017
Deferred Income Tax Liabilities		**8,427**	7,648
Long-Term Debt		**52,731**	39,645
Junior Subordinated Notes		**10,497**	10,495
		88,686	80,232
EQUITY			
Common shares, no par value		**30,002**	28,995
Issued and outstanding:	September 30, 2023 – 1,037 million shares December 31, 2022 – 1,018 million shares		
Preferred shares		**2,499**	2,499
Additional paid-in capital		**728**	722
Retained earnings (Deficit)		**(687)**	819
Accumulated other comprehensive income (loss)		**1,100**	955
Controlling Interests		**33,642**	33,990
Non-Controlling Interests		**321**	126
		33,963	34,116
		122,649	114,348

Commitments, Contingencies and Guarantees (Note 15)

Variable Interest Entities (Note 16)

Subsequent Event (Note 17)

See accompanying Notes to the Condensed consolidated financial statements.

Condensed consolidated statement of equity

	three months ended September 30		nine months ended September 30	
(unaudited - millions of Canadian $)	**2023**	**2022**	**2023**	**2022**
Common Shares				
Balance at beginning of period	**29,627**	26,891	**28,995**	26,716
Shares issued:				
Dividend reinvestment and share purchase plan	**375**	—	**1,003**	—
Exercise of stock options	**—**	2	**4**	177
Under public offering, net of issue costs	**—**	1,754	**—**	1,754
Balance at end of period	**30,002**	28,647	**30,002**	28,647
Preferred Shares				
Balance at beginning of period	**2,499**	2,499	**2,499**	3,487
Redemption of shares	**—**	—	**—**	(988)
Balance at end of period	**2,499**	2,499	**2,499**	2,499
Additional Paid-In Capital				
Balance at beginning of period	**728**	717	**722**	729
Issuance of stock options, net of exercises	**—**	3	**6**	(9)
Balance at end of period	**728**	720	**728**	720
Retained Earnings (Deficit)				
Balance at beginning of period	**476**	3,254	**819**	3,773
Net income (loss) attributable to controlling interests	**(174)**	862	**1,435**	2,173
Common share dividends	**(966)**	(912)	**(2,874)**	(2,681)
Preferred share dividends	**(23)**	(21)	**(67)**	(70)
Redemption of preferred shares	**—**	—	**—**	(12)
Balance at end of period	**(687)**	3,183	**(687)**	3,183
Accumulated Other Comprehensive Income (Loss)				
Balance at beginning of period	**508**	(706)	**955**	(1,434)
Other comprehensive income (loss) attributable to controlling interests	**592**	1,430	**145**	2,158
Balance at end of period	**1,100**	724	**1,100**	724
Equity Attributable to Controlling Interests	**33,642**	35,773	**33,642**	35,773
Equity Attributable to Non-Controlling Interests				
Balance at beginning of period	**324**	123	**126**	125
Non-controlling interests on acquisition of Texas Wind Farms	**—**	—	**222**	—
Net income (loss) attributable to non-controlling interests	**1**	8	**18**	28
Other comprehensive income (loss) attributable to non-controlling interests	**7**	8	**2**	10
Distributions declared to non-controlling interests	**(11)**	(9)	**(47)**	(33)
Balance at end of period	**321**	130	**321**	130
Total Equity	**33,963**	35,903	**33,963**	35,903

See accompanying Notes to the Condensed consolidated financial statements.

Notes to Condensed consolidated financial statements

(unaudited)

1. BASIS OF PRESENTATION

These Condensed consolidated financial statements of TC Energy Corporation (TC Energy or the Company) have been prepared by management in accordance with U.S. GAAP. The accounting policies applied are consistent with those outlined in TC Energy's annual audited Consolidated financial statements for the year ended December 31, 2022, except as described in Note 2, Accounting changes. Capitalized and abbreviated terms that are used but not otherwise defined herein are identified in the 2022 audited Consolidated financial statements included in TC Energy's 2022 Annual Report.

These Condensed consolidated financial statements reflect adjustments, all of which are normal recurring adjustments that are, in the opinion of management, necessary to reflect fairly the financial position and results of operations for the respective periods. These Condensed consolidated financial statements do not include all disclosures required in the annual financial statements and should be read in conjunction with the 2022 audited Consolidated financial statements included in TC Energy's 2022 Annual Report. Certain comparative figures have been adjusted to reflect the current period's presentation.

Earnings for interim periods may not be indicative of results for the fiscal year in certain of the Company's segments primarily due to:

- Natural gas pipelines segments – the timing of regulatory decisions and negotiated rate case settlements as well as seasonal fluctuations in short-term throughput volumes on U.S. pipelines and marketing activities
- Liquids Pipelines – fluctuations in throughput volumes on the Keystone Pipeline System and marketing activities
- Power and Energy Solutions – the impacts of seasonal weather conditions on customer demand, market supply and prices of natural gas and power as well as maintenance outages in certain of the Company's investments in electrical power generation plants and Canadian non-regulated natural gas storage facilities, and marketing activities.

In addition to the factors mentioned above, revenues and segmented earnings are impacted by fluctuations in foreign exchange rates, mainly related to the Company's U.S. dollar-denominated operations and Mexican peso-denominated exposure.

Use of Estimates and Judgments

In preparing these Condensed 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. In the opinion of management, these Condensed consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the Company's significant accounting policies included in the annual audited Consolidated financial statements for the year ended December 31, 2022, except as described in Note 2, Accounting changes.

Asset divestiture program

As part of the $5+ billion asset divestiture program announced in 2022, on October 4, 2023, TC Energy successfully completed the sale of a 40 per cent equity interest in Columbia Gas Transmission, LLC (Columbia Gas) and Columbia Gulf Transmission, LLC (Columbia Gulf). In conjunction with the process leading up to the sale, the Company performed a quantitative goodwill impairment test as at June 30, 2023. Refer to Note 17, Subsequent event, for additional information on this sale transaction.

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

2. ACCOUNTING CHANGES

Future Accounting Changes

Leases

In March 2023, the FASB issued new guidance that clarified the accounting for leasehold improvements associated with common control leases. This new guidance is effective January 1, 2024 and can be applied either prospectively or retrospectively, with early application permitted. The Company will adopt the guidance on a prospective basis starting January 1, 2024.

3. SEGMENTED INFORMATION

three months ended September 30, 2023 (unaudited - 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	**1,303**	**1,473**	**213**	**715**	**236**	**—**	**3,940**
Intersegment revenues	**—**	**25**	**—**	**—**	**—**	**(25)** [2]	**—**
	1,303	**1,498**	**213**	**715**	**236**	**(25)**	**3,940**
Income (loss) from equity investments	**5**	**63**	**48**	**17**	**172**	**—**	**305**
Impairment of equity investment	**(1,244)**	**—**	**—**	**—**	**—**	**—**	**(1,244)**
Plant operating costs and other[3]	**(454)**	**(417)**	**(28)**	**(222)**	**(139)**	**(11)** [2]	**(1,271)**
Commodity purchase resold	**—**	**(26)**	**—**	**(145)**	**(7)**	**—**	**(178)**
Property taxes	**(73)**	**(114)**	**—**	**(29)**	**(2)**	**—**	**(218)**
Depreciation and amortization	**(336)**	**(222)**	**(23)**	**(83)**	**(26)**	**—**	**(690)**
Segmented Earnings (Losses)	**(799)**	**782**	**210**	**253**	**234**	**(36)**	**644**
Interest expense							**(865)**
Allowance for funds used during construction							**164**
Foreign exchange gains (losses), net							**(45)**
Interest income and other							**63**
Income (Loss) before Income Taxes							**(39)**
Income tax (expense) recovery							**(134)**
Net Income (Loss)							**(173)**
Net (income) loss attributable to non-controlling interests							**(1)**
Net Income (Loss) Attributable to Controlling Interests							**(174)**
Preferred share dividends							**(23)**
Net Income (Loss) Attributable to Common Shares							**(197)**

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 The Mexico Natural Gas Pipelines segment includes a recovery of $2 million on the ECL provision with respect to the net investment in leases associated with the in-service TGNH pipelines.

three months ended September 30, 2022 (unaudited - 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	1,234	1,449	179	691	246	—	3,799
Intersegment revenues	—	35	—	—	—	(35) [2]	—
	1,234	1,484	179	691	246	(35)	3,799
Income (loss) from equity investments	5	61	39	14	203	—	322
Plant operating costs and other[3]	(450)	(497)	(85)	(201)	(135)	26 [2]	(1,342)
Commodity purchase resold	—	—	—	(123)	(5)	—	(128)
Property taxes	(76)	(107)	—	(30)	(1)	—	(214)
Depreciation and amortization	(304)	(227)	(20)	(83)	(19)	—	(653)
Segmented Earnings (Losses)	409	714	113	268	289	(9)	1,784
Interest expense							(666)
Allowance for funds used during construction							116
Foreign exchange gains (losses), net							(277)
Interest income and other							35
Income (Loss) before Income Taxes							992
Income tax (expense) recovery							(122)
Net Income (Loss)							870
Net (income) loss attributable to non-controlling interests							(8)
Net Income (Loss) Attributable to Controlling Interests							862
Preferred share dividends							(21)
Net Income (Loss) Attributable to Common Shares							841

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 The Mexico Natural Gas Pipelines segment includes a $71 million ECL provision with respect to the net investment in leases associated with the in-service TGNH pipelines.

nine months ended September 30, 2023 (unaudited - 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	3,829	4,558	625	1,935	751	—	11,698
Intersegment revenues	—	76	—	—	22	(98) [2]	—
	3,829	4,634	625	1,935	773	(98)	11,698
Income (loss) from equity investments	15	227	52	49	513	—	856
Impairment of equity investment	(2,100)	—	—	—	—	—	(2,100)
Plant operating costs and other[3]	(1,317)	(1,218)	36	(610)	(459)	24 [2]	(3,544)
Commodity purchase resold	—	(26)	—	(331)	(16)	—	(373)
Property taxes	(226)	(348)	—	(89)	(4)	—	(667)
Depreciation and amortization	(983)	(693)	(67)	(252)	(66)	—	(2,061)
Segmented Earnings (Losses)	(782)	2,576	646	702	741	(74)	3,809
Interest expense							(2,418)
Allowance for funds used during construction							443
Foreign exchange gains (losses), net							231
Interest income and other							121
Income (Loss) before Income Taxes							2,186
Income tax (expense) recovery							(733)
Net Income (Loss)							1,453
Net (income) loss attributable to non-controlling interests							(18)
Net Income (Loss) Attributable to Controlling Interests							1,435
Preferred share dividends							(69)
Net Income (Loss) Attributable to Common Shares							1,366

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 The Mexico Natural Gas Pipelines segment includes a recovery of $105 million on the ECL provision with respect to the net investment in leases associated with the in-service TGNH pipelines and a recovery of $12 million on the ECL provision for contract assets related to certain other Mexico natural gas pipelines.

nine months ended September 30, 2022 (unaudited - 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	3,497	4,295	487	2,051	606	—	10,936
Intersegment revenues	—	103	—	—	12	(115) [2]	—
	3,497	4,398	487	2,051	618	(115)	10,936
Income (loss) from equity investments	14	199	96	41	385	28 [3]	763
Plant operating costs and other[4]	(1,246)	(1,320)	(112)	(545)	(397)	99 [2]	(3,521)
Commodity purchase resold	—	—	—	(414)	(15)	—	(429)
Property taxes	(227)	(316)	—	(88)	(3)	—	(634)
Depreciation and amortization	(886)	(655)	(76)	(244)	(53)	—	(1,914)
Goodwill impairment charge	—	(571)	—	—	—	—	(571)
Segmented Earnings (Losses)	1,152	1,735	395	801	535	12	4,630
Interest expense							(1,866)
Allowance for funds used during construction							254
Foreign exchange gains (losses), net[3]							(317)
Interest income and other							93
Income (Loss) before Income Taxes							2,794
Income tax (expense) recovery							(593)
Net Income (Loss)							2,201
Net (income) loss attributable to non-controlling interests							(28)
Net Income (Loss) Attributable to Controlling Interests							2,173
Preferred share dividends							(85)
Net Income (Loss) Attributable to Common Shares							2,088

1 Includes intersegment eliminations.

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

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

4 The Mexico Natural Gas Pipelines segment includes a $71 million ECL provision with respect to the net investment in leases associated with the in-service TGNH pipelines.

Total Assets by Segment

(unaudited - millions of Canadian $)	September 30, 2023	December 31, 2022
Canadian Natural Gas Pipelines	**29,036**	27,456
U.S. Natural Gas Pipelines	**50,781**	50,038
Mexico Natural Gas Pipelines	**11,552**	9,231
Liquids Pipelines	**16,355**	15,587
Power and Energy Solutions	**9,577**	8,272
Corporate	**5,348**	3,764
	122,649	114,348

4. REVENUES

Disaggregation of Revenues

The following tables summarize total Revenues for the three and nine months ended September 30, 2023 and 2022:

three months ended September 30, 2023 (unaudited - 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	**1,296**	**1,206**	**113**	**555**	**—**	**3,170**
Power generation	**—**	**—**	**—**	**—**	**109**	**109**
Natural gas storage and other[1,2]	**7**	**208**	**30**	**1**	**86**	**332**
	1,303	**1,414**	**143**	**556**	**195**	**3,611**
Sales-type lease income	**—**	**—**	**70**	**—**	**—**	**70**
Other revenues[3]	**—**	**59**	**—**	**159**	**41**	**259**
	1,303	**1,473**	**213**	**715**	**236**	**3,940**

1 The Canadian Natural Gas Pipelines segment includes $7 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.

2 The Mexico Natural Gas Pipelines segment includes $24 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.

3 Other revenues include income from the Company's marketing activities and financial instruments. Refer to Note 12, Risk management and financial instruments, for additional information on financial instruments. Additionally, other revenues include $29 million of operating lease income.

three months ended September 30, 2022 (unaudited - 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	1,220	1,072	103	515	—	2,910
Power generation	—	—	—	—	140	140
Natural gas storage and other[1]	14	357	21	—	69	461
	1,234	1,429	124	515	209	3,511
Sales-type lease income	—	—	55	—	—	55
Other revenues[2]	—	20	—	176	37	233
	1,234	1,449	179	691	246	3,799

1 The Canadian Natural Gas Pipelines segment includes $14 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.

2 Other revenues include income from the Company's marketing activities and financial instruments. Refer to Note 12, Risk management and financial instruments, for additional information on financial instruments. Additionally, other revenues include $29 million of operating lease income.

nine months ended September 30, 2023 (unaudited - 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	**3,806**	**3,709**	**331**	**1,529**	**—**	**9,375**
Power generation	**—**	**—**	**—**	**—**	**342**	**342**
Natural gas storage and other[1,2]	**23**	**656**	**92**	**2**	**300**	**1,073**
	3,829	**4,365**	**423**	**1,531**	**642**	**10,790**
Sales-type lease income	**—**	**—**	**202**	**—**	**—**	**202**
Other revenues[3]	**—**	**193**	**—**	**404**	**109**	**706**
	3,829	**4,558**	**625**	**1,935**	**751**	**11,698**

1 The Canadian Natural Gas Pipelines segment includes $23 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.

2 The Mexico Natural Gas Pipelines segment includes $73 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.

3 Other revenues include income from the Company's marketing activities and financial instruments. Refer to Note 12, Risk management and financial instruments, for additional information on financial instruments. Additionally, other revenues include $91 million of operating lease income.

nine months ended September 30, 2022 (unaudited - 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	3,444	3,303	396	1,488	—	8,631
Power generation	—	—	—	—	330	330
Natural gas storage and other[1]	53	980	36	3	274	1,346
	3,497	4,283	432	1,491	604	10,307
Sales-type lease income	—	—	55	—	—	55
Other revenues[2]	—	12	—	560	2	574
	3,497	4,295	487	2,051	606	10,936

1 The Canadian Natural Gas Pipelines segment includes $53 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.

2 Other revenues include income from the Company's marketing activities and financial instruments. Refer to Note 12, Risk management and financial instruments, for additional information on financial instruments. Additionally, other revenues include $90 million of operating lease income.

Contract Balances

(unaudited - millions of Canadian $)	September 30, 2023	December 31, 2022	Affected line item on the Condensed consolidated balance sheet
Receivables from contracts with customers	**1,543**	1,907	Accounts receivable
Contract assets	**211**	155	Other current assets
Long-term contract assets	**455**	355	Other long-term assets
Contract liabilities[1]	**89**	62	Accounts payable and other
Long-term contract liabilities	**10**	32	Other long-term liabilities

1 During the nine months ended September 30, 2023, $56 million (2022 – $43 million) of revenues were recognized that were included in contract liabilities at the beginning of the period.

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.

Future Revenues from Remaining Performance Obligations

As at September 30, 2023, future revenues from long-term pipeline capacity arrangements and transportation as well as natural gas storage and other contracts extending through 2055 are approximately $22.4 billion, of which approximately $1.9 billion is expected to be recognized during the remainder of 2023.

5. COASTAL GASLINK

Subordinated Loan Agreement

Committed capacity under the subordinated loan agreement between TC Energy and Coastal GasLink LP was $1.3 billion at December 31, 2022 and increased to $3.4 billion at September 30, 2023 to align with the Company's expected funding requirements.

Any amounts outstanding on the loan will be repaid by Coastal GasLink LP to TC Energy, once final project costs are known, which will be determined after the pipeline is placed 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.

Amounts drawn on this loan subsequent to the amended agreements executed in July 2022 are accounted for as in-substance equity contributions and are presented as Contributions to equity investments on the Company's Condensed consolidated statement of cash flows. Interest and principal repayments on this loan, which are expected to be predominantly funded by TC Energy, will be accounted for as an equity investment distribution to the Company once received.

In the nine months ended September 30, 2023, $2,020 million was drawn on the loan and $250 million was repaid.

In October 2023, an additional $125 million was drawn on the subordinated loan and will be assessed for impairment in future reporting periods along with future draws on this loan.

Impairment of Equity Investment in Coastal GasLink LP

With the expectation that additional equity contributions under the subordinated loan agreement will be predominantly funded by TC Energy, the Company completed a valuation assessment and concluded that the fair value of its investment in Coastal GasLink LP was below its carrying value at September 30, 2023 and that this was an other-than-temporary impairment. As a result, a pre-tax impairment charge of $1,244 million ($1,179 million after tax) and $2,100 million ($2,017 million after tax) was recognized for the three and nine months ended September 30, 2023, respectively, in Impairment of equity investment in the Condensed consolidated statement of income in the Canadian Natural Gas Pipelines segment, which reduced the carrying values of the investment in Coastal GasLink LP and the loan receivable from affiliate to nil at September 30, 2023. The impairment charge reflected the net impact of the $2,020 million draw and the $250 million repayment on the subordinated loan for the nine months ended September 30, 2023, along with TC Energy's proportionate share of unrealized gains and losses on interest rate derivatives in Coastal GasLink LP and other changes to the equity investment. The impairment of the subordinated loan resulted in unrealized non-taxable capital losses that are not recognized.

The fair value of TC Energy's investment in Coastal GasLink LP at September 30, 2023 was estimated using a 40-year discounted cash flow model consistent with the Company's fair value assessment at December 31, 2022. Refer to TC Energy's 2022 Consolidated financial statements for additional information.

The Company will continue to assess for other-than-temporary declines in the fair value of its investment in Coastal GasLink LP, and the extent of any future impairment charges, if any, will depend on the outcome of the valuation assessment performed at the respective reporting date.

6. INCOME TAXES

Effective Tax Rates

The effective income tax rates were 34 per cent and 21 per cent for the nine months ended September 30, 2023 and 2022, respectively. The increase in effective income tax rate was mostly due to unrealized non-taxable capital losses from the impairment of TC Energy's investment in Coastal GasLink LP, partially offset by the settlement of Mexico income tax assessments and the non-tax deductible portion of the Great Lakes goodwill impairment in 2022.

7. KEYSTONE ENVIRONMENTAL PROVISION

In December 2022, a pipeline incident occurred in Washington County, Kansas on the Keystone Pipeline System. At December 31, 2022, the Company accrued an environmental remediation liability of $650 million, before expected insurance recoveries and not including potential fines and penalties which continue to be indeterminable. At June 30, 2023, the cost estimate for the incident was adjusted to $794 million based on a review of costs and commitments incurred and, at September 30, 2023, remains unchanged. The accrual reflects certain assumptions and, therefore, it is reasonably possible that the Company will incur additional costs. To the extent costs beyond the amounts accrued are incurred, they will be evaluated under the Company's existing insurance policies. For the nine months ended September 30, 2023, amounts paid for the environmental remediation liability were $584 million (2022 – nil). The remaining balance reflected in Accounts payable and other and Other long-term liabilities on the Company’s Condensed consolidated balance sheet was $216 million and $8 million, respectively at September 30, 2023 (December 31, 2022 – $650 million and nil, respectively).

At September 30, 2023, the expected recovery of the remaining estimated environmental remediation costs recorded in Other current assets and Other long-term assets were $337 million and $33 million, respectively (December 31, 2022 – $410 million and $240 million, respectively) and includes $36 million accrued during the nine months ended September 30, 2023, which is expected to be recoverable from TC Energy's wholly-owned captive insurance subsidiary. This amount was recorded in Interest income and other in the Condensed consolidated statement of income. During the nine months ended September 30, 2023, the Company received $396 million (2022 – nil) from its insurance policies related to the costs for environmental remediation. Restoration activities are ongoing and expected to continue into 2024.

8. NOTES PAYABLE AND LONG-TERM DEBT

Notes Payable

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

On August 31, 2023, Columbia Pipelines Holding Company LLC entered a US$1.0 billion senior unsecured revolving credit facility that matures August 2026. At September 30, 2023, unused capacity was US$1.0 billion.

Long-Term Debt Issued

Long-term debt issued by the Company in the nine months ended September 30, 2023 included the following:

(unaudited - millions of Canadian $, unless otherwise noted)					
Company	**Issue date**	**Type**	**Maturity date**	**Amount**	**Interest rate**
TransCanada PipeLines Limited					
	May 2023	Senior Unsecured Term Loan[1]	May 2026	US 1,024	Floating
	March 2023	Senior Unsecured Notes	March 2026[2]	US 850	6.20%
	March 2023	Senior Unsecured Notes	March 2026[2]	US 400	Floating
	March 2023	Medium Term Notes	July 2030	1,250	5.28%
	March 2023	Medium Term Notes	March 2026[2]	600	5.42%
	March 2023	Medium Term Notes	March 2026[2]	400	Floating
Columbia Pipelines Operating Company LLC[3]					
	August 2023	Senior Unsecured Notes	November 2033	US 1,500	6.04%
	August 2023	Senior Unsecured Notes	November 2053	US 1,250	6.54%
	August 2023	Senior Unsecured Notes	August 2030	US 750	5.93%
	August 2023	Senior Unsecured Notes	August 2043	US 600	6.50%
	August 2023	Senior Unsecured Notes	August 2063	US 500	6.71%
Columbia Pipelines Holding Company LLC[3]					
	August 2023	Senior Unsecured Notes	August 2028	US 700	6.04%
	August 2023	Senior Unsecured Notes	August 2026	US 300	6.06%
TC Energía Mexicana, S. de R.L. de C.V.					
	January 2023	Senior Unsecured Term Loan	January 2028	US 1,800	Floating
	January 2023	Senior Unsecured Revolving Credit Facility	January 2028	US 500	Floating
Gas Transmission Northwest LLC					
	June 2023	Senior Unsecured Notes	June 2030	US 50	4.92%

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

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

3 On October 4, 2023, TC Energy completed the sale of a 40 per cent equity interest in Columbia Gas and Columbia Gulf. Refer to Note 17, Subsequent event, for additional information.

Long-Term Debt Repaid/Retired

Long-term debt repaid by the Company in the nine months ended September 30, 2023 included the following:

(unaudited - millions of Canadian $, unless otherwise noted)				
Company	**Repayment date**	**Type**	**Amount**	**Interest rate**
TransCanada PipeLines Limited				
	September 2023	Senior Unsecured Term Loan[1]	US 1,024	Floating
	July 2023	Medium Term Notes	750	3.69%
Nova Gas Transmission Ltd.				
	April 2023	Debentures	US 200	7.88%
TC Energía Mexicana, S. de R.L. de C.V.				
	Various	Senior Unsecured Revolving Credit Facility	US 120	Floating

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

On October 16, 2023, TCPL retired US$625 million of senior unsecured notes bearing interest at a fixed rate of 3.75 per cent.

Capitalized Interest

In the three and nine months ended September 30, 2023, TC Energy capitalized interest related to capital projects of $53 million and $125 million, respectively (2022 – $5 million and $11 million, respectively).

9. COMMON SHARES AND PREFERRED SHARES

The Board of Directors of TC Energy declared quarterly dividends as follows:

	three months ended September 30		nine months ended September 30	
(unaudited - Canadian $, rounded to two decimals)	**2023**	**2022**	**2023**	**2022**
per common share	**0.93**	0.90	**2.79**	2.70
per Series 1 preferred share	**0.22**	0.22	**0.65**	0.65
per Series 2 preferred share	**0.40**	0.21	**1.19**	0.50
per Series 3 preferred share	**0.11**	0.11	**0.32**	0.32
per Series 4 preferred share	**0.36**	0.17	**1.07**	0.38
per Series 5 preferred share	**0.12**	0.12	**0.37**	0.37
per Series 6 preferred share	**0.41**	0.23	**1.14**	0.48
per Series 7 preferred share	**0.24**	0.24	**0.73**	0.73
per Series 9 preferred share	**0.24**	0.24	**0.71**	0.71
per Series 11 preferred share	**0.21**	0.21	**0.42**	0.42
per Series 15 preferred share	**—**	—	**—**	0.31

10. 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, are as follows:

three months ended September 30, 2023 (unaudited - millions of Canadian $)	Before tax amount	Income tax (expense) recovery	Net of tax amount
Foreign currency translation adjustments	**412**	**18**	**430**
Change in fair value of net investment hedges	**(17)**	**4**	**(13)**
Change in fair value of cash flow hedges	**18**	**(3)**	**15**
Reclassification to net income of (gains) losses on cash flow hedges	**32**	**(7)**	**25**
Other comprehensive income (loss) on equity investments	**190**	**(48)**	**142**
Other Comprehensive Income (Loss)	**635**	**(36)**	**599**

three months ended September 30, 2022 (unaudited - millions of Canadian $)	Before tax amount	Income tax (expense) recovery	Net of tax amount
Foreign currency translation adjustments	1,430	80	1,510
Change in fair value of net investment hedges	(89)	22	(67)
Change in fair value of cash flow hedges	(23)	3	(20)
Reclassification to net income of (gains) losses on cash flow hedges	13	2	15
Reclassification to net income of actuarial (gains) losses on pension and other post-retirement benefit plans	3	(1)	2
Other comprehensive income (loss) on equity investments	(4)	2	(2)
Other Comprehensive Income (Loss)	1,330	108	1,438

nine months ended September 30, 2023 (unaudited - millions of Canadian $)	Before tax amount	Income tax (expense) recovery	Net of tax amount
Foreign currency translation adjustments	**(72)**	**9**	**(63)**
Change in fair value of net investment hedges	**16**	**(4)**	**12**
Change in fair value of cash flow hedges	**(5)**	**2**	**(3)**
Reclassification to net income of (gains) losses on cash flow hedges	**86**	**(20)**	**66**
Other comprehensive income (loss) on equity investments	**181**	**(46)**	**135**
Other Comprehensive Income (Loss)	**206**	**(59)**	**147**

nine months ended September 30, 2022 (unaudited - millions of Canadian $)	Before tax amount	Income tax (expense) recovery	Net of tax amount
Foreign currency translation adjustments	1,770	102	1,872
Change in fair value of net investment hedges	(100)	25	(75)
Change in fair value of cash flow hedges	(6)	(2)	(8)
Reclassification to net income of (gains) losses on cash flow hedges	37	(7)	30
Reclassification to net income of actuarial (gains) losses on pension and other post-retirement benefit plans	8	(2)	6
Other comprehensive income (loss) on equity investments	455	(112)	343
Other Comprehensive Income (Loss)	2,164	4	2,168

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

three months ended September 30, 2023 (unaudited - millions of Canadian $)	**Currency translation adjustments**	**Cash flow hedges**	**Pension and other post-retirement benefit plans adjustments**	**Equity investments**	**Total**
AOCI balance at July 1, 2023	**(22)**	**(86)**	**(44)**	**660**	**508**
Other comprehensive income (loss) before reclassifications[1]	**410**	**15**	**—**	**147**	**572**
Amounts reclassified from AOCI	**—**	**25**	**—**	**(5)**	**20**
Net current period other comprehensive income (loss)	**410**	**40**	**—**	**142**	**592**
AOCI balance at September 30, 2023	**388**	**(46)**	**(44)**	**802**	**1,100**

1 Other comprehensive income (loss) before reclassifications on currency translation adjustments is net of non-controlling interest gains of $7 million.

nine months ended September 30, 2023 (unaudited - millions of Canadian $)	**Currency translation adjustments**	**Cash flow hedges**	**Pension and other post-retirement benefit plans adjustments**	**Equity investments**	**Total**
AOCI balance at January 1, 2023	**441**	**(109)**	**(44)**	**667**	**955**
Other comprehensive income (loss) before reclassifications[1]	**(53)**	**(3)**	**—**	**148**	**92**
Amounts reclassified from AOCI[2]	**—**	**66**	**—**	**(13)**	**53**
Net current period other comprehensive income (loss)	**(53)**	**63**	**—**	**135**	**145**
AOCI balance at September 30, 2023	**388**	**(46)**	**(44)**	**802**	**1,100**

1 Other comprehensive income (loss) before reclassifications on currency translation adjustments is net of non-controlling interest gains of $2 million.

2 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 $18 million ($14 million after tax) at September 30, 2023. These estimates assume constant commodity prices, interest rates and foreign exchange rates over time; however, the amounts reclassified will vary based on the actual value of these factors at the date of settlement.

Details about reclassifications out of AOCI into the Condensed consolidated statement of income are as follows:

(unaudited - millions of Canadian $)	three months ended September 30		nine months ended September 30		Affected line item in the Condensed consolidated statement of income[1]
	2023	**2022**	**2023**	**2022**	
Cash flow hedges					
Commodities	**(29)**	(10)	**(77)**	(24)	Revenues (Power and Energy Solutions)
Interest rate	**(3)**	(3)	**(9)**	(13)	Interest expense
	(32)	(13)	**(86)**	(37)	Total before tax
	7	(2)	**20**	7	Income tax (expense) recovery
	(25)	(15)	**(66)**	(30)	Net of tax
Pension and other post-retirement benefit plans					
Amortization of actuarial gains (losses)	**—**	(3)	**—**	(8)	Plant operating costs and other[2]
	—	1	**—**	2	Income tax (expense) recovery
	—	(2)	**—**	(6)	Net of tax
Equity investments					
Equity income (loss)	**6**	1	**17**	3	Income from equity investments
	(1)	(1)	**(4)**	(1)	Income tax (expense) recovery
	5	—	**13**	2	Net of tax

1 All amounts in parentheses indicate expenses to the Condensed consolidated statement of income.

2 These AOCI components are included in the computation of net benefit cost. Refer to Note 11, Employee post-retirement benefits, for additional information.

11. EMPLOYEE POST-RETIREMENT BENEFITS

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

(unaudited - millions of Canadian $)	three months ended September 30				nine months ended September 30			
	Pension benefit plans		Other post-retirement benefit plans		Pension benefit plans		Other post-retirement benefit plans	
	2023	**2022**	**2023**	**2022**	**2023**	**2022**	**2023**	**2022**
Service cost[1]	**23**	36	**1**	2	**69**	108	**2**	4
Other components of net benefit cost[1]								
Interest cost	**39**	32	**4**	4	**118**	94	**12**	10
Expected return on plan assets	**(59)**	(59)	**(4)**	(3)	**(176)**	(178)	**(12)**	(10)
Amortization of actuarial (gains) losses	**—**	3	**—**	—	**—**	8	**—**	1
Amortization of regulatory asset	**—**	3	**—**	—	**—**	9	**—**	1
	(20)	(21)	**—**	1	**(58)**	(67)	**—**	2
Net Benefit Cost	**3**	15	**1**	3	**11**	41	**2**	6

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

12. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

Risk Management Overview

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

Counterparty Credit Risk

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

Market events causing disruptions in global energy demand and supply may contribute to economic uncertainties impacting a number of TC Energy's customers. While the majority of the Company's credit exposure is to large creditworthy entities, TC Energy maintains close monitoring and communication with those counterparties experiencing greater financial pressures. Refer to TC Energy's 2022 Annual Report for more information about the factors that mitigate the Company's counterparty credit risk exposure.

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.

For the three and nine months ended September 30, 2023, the Company recorded a recovery of $2 million and $105 million, respectively (2022 – an expense of $71 million and $71 million, respectively) on the ECL provision before tax with respect to the net investment in leases associated with the in-service TGNH pipelines and a recovery of nil and $12 million, respectively (2022 – nil and nil, respectively) on the ECL provision for contract assets related to certain other Mexico natural gas pipelines. At September 30, 2023, the balance of the ECL provision was $46 million (December 31, 2022 – $149 million) with respect to the net investment in leases associated with the in-service TGNH pipelines and $1 million (December 31, 2022 – $14 million) related to certain other Mexico natural gas pipelines. The ECL provision is driven primarily by a probability of default measure for the counterparty that is published by an external third party. There was significant volatility in the probability of default during first half of 2023 which, when combined with the size and contract term of the Company's net investment in leases, resulted in a significant change in the provision in the nine months ended September 30, 2023. The Company's net investment in leases at September 30, 2023 included the lateral section of the Villa de Reyes pipeline, which was placed into service in August 2023.

At September 30, 2023, the Company had no significant credit losses, other than the ECL provisions noted above, and there were no significant credit risk concentrations or amounts past due or impaired.

TC Energy has significant credit and performance exposure to financial institutions that hold cash deposits and provide committed credit lines and letters of credit that help manage the Company's exposure to counterparties and provide liquidity in commodity, foreign exchange and interest rate derivative markets. TC Energy's portfolio of financial sector exposure consists primarily of highly-rated investment grade, systemically important financial institutions. The Company had no direct exposure to the U.S. regional bank failures in early 2023; however, it continues to monitor potential impacts on its portfolio of financial sector counterparties.

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:

	September 30, 2023		December 31, 2022	
(unaudited - 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)	**(2)**	**US 1,600**	(22)	US 3,600
U.S. dollar cross-currency interest rate swaps (maturing 2023 to 2025)	**(7)**	**US 300**	(5)	US 300
	(9)	**US 1,900**	(27)	US 3,900

1 Fair value equals carrying value.

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

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

(unaudited - millions of Canadian $, unless otherwise noted)	September 30, 2023	December 31, 2022
Notional amount	**31,100 (US 23,000)**	32,500 (US 24,000)
Fair value	**28,300 (US 20,900)**	30,800 (US 22,700)

Non-Derivative Financial Instruments

Fair value of non-derivative financial instruments

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

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:

	September 30, 2023		December 31, 2022	
(unaudited - millions of Canadian $)	Carrying amount	Fair value	Carrying amount	Fair value
Long-term debt, including current portion[1,2]	**(54,845)**	**(51,194)**	(41,543)	(39,505)
Junior subordinated notes	**(10,497)**	**(9,106)**	(10,495)	(9,415)
	(65,342)	**(60,300)**	(52,038)	(48,920)

1 Long-term debt is recorded at amortized cost, except for US$1.8 billion (December 31, 2022 – US$1.6 billion) that is attributed to hedged risk and recorded at fair value.

2 Net income (loss) for the three and nine months ended September 30, 2023 included unrealized gains of $86 million and $99 million, respectively (2022 – unrealized gains of $73 million and $71 million, respectively) for fair value adjustments attributable to the hedged interest rate risk associated with interest rate swap fair value hedging relationships on US$1.8 billion of long-term debt at September 30, 2023 (December 31, 2022 – US$1.6 billion). There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

Available-for-sale assets summary

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

	September 30, 2023		December 31, 2022	
(unaudited - millions of Canadian $)	LMCI restricted investments	Other restricted investments[1]	LMCI restricted investments	Other restricted investments[1]
Fair values of fixed income securities[2,3]				
Maturing within 1 year	**1**	**36**	—	54
Maturing within 1-5 years	**12**	**246**	—	106
Maturing within 5-10 years	**1,233**	**—**	1,153	—
Maturing after 10 years	**76**	**—**	77	—
Fair value of equity securities[2,4]	**814**	**—**	749	—
	2,136	**282**	1,979	160

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

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

3 Classified in Level II of the fair value hierarchy.

4 Classified in Level I of the fair value hierarchy.

	September 30, 2023		September 30, 2022	
(unaudited - millions of Canadian $)	LMCI restricted investments[1]	Other restricted investments[2]	LMCI restricted investments[1]	Other restricted investments[2]
Net unrealized gains (losses) in the period				
three months ended	**(87)**	**(3)**	—	(2)
nine months ended	**8**	**1**	(300)	(8)
Net realized gains (losses) in the period[3]				
three months ended	**(1)**	**—**	(10)	—
nine months ended	**(18)**	**—**	(26)	—

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

2 Unrealized and realized gains (losses) on other restricted investments are included in Interest income and other in the Condensed consolidated statement of income.

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

Derivative Instruments

Fair value of derivative instruments

The fair value of foreign exchange and interest rate derivatives has been calculated using the income approach which uses period-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 rate-regulated accounting, including those that qualify for hedge accounting treatment, are expected to be refunded or recovered through the tolls charged by the Company. As a result, these gains and losses are deferred as regulatory liabilities or regulatory assets and are refunded to or collected from the rate payers in subsequent years when the derivative settles.

Balance sheet presentation of derivative instruments

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

at September 30, 2023 (unaudited - 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					
Commodities[2]	**5**	**—**	**—**	**1,273**	**1,278**
Foreign exchange	**—**	**—**	**2**	**33**	**35**
	5	**—**	**2**	**1,306**	**1,313**
Other long-term assets					
Commodities[2]	**5**	**—**	**—**	**134**	**139**
Foreign exchange	**—**	**—**	**—**	**13**	**13**
	5	**—**	**—**	**147**	**152**
Total Derivative Assets	**10**	**—**	**2**	**1,453**	**1,465**
Accounts payable and other					
Commodities[2]	**(11)**	**—**	**—**	**(1,189)**	**(1,200)**
Foreign exchange	**—**	**—**	**(8)**	**(54)**	**(62)**
Interest rate	**—**	**(34)**	**—**	**—**	**(34)**
	(11)	**(34)**	**(8)**	**(1,243)**	**(1,296)**
Other long-term liabilities					
Commodities[2]	**—**	**—**	**—**	**(105)**	**(105)**
Foreign exchange	**—**	**—**	**(3)**	**(5)**	**(8)**
Interest rate	**—**	**(129)**	**—**	**—**	**(129)**
	—	**(129)**	**(3)**	**(110)**	**(242)**
Total Derivative Liabilities	**(11)**	**(163)**	**(11)**	**(1,353)**	**(1,538)**
Total Derivatives	**(1)**	**(163)**	**(9)**	**100**	**(73)**

1 Fair value equals carrying value.

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

at December 31, 2022 (unaudited - 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					
Commodities[2]	—	—	—	597	597
Foreign exchange	—	—	6	11	17
	—	—	6	608	614
Other long-term assets					
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					
Commodities[2]	(72)	—	—	(584)	(656)
Foreign exchange	—	—	(31)	(158)	(189)
Interest rate	—	(26)	—	—	(26)
	(72)	(26)	(31)	(742)	(871)
Other long-term liabilities					
Commodities[2]	(2)	—	—	(75)	(77)
Foreign exchange	—	—	(4)	(20)	(24)
Interest rate	—	(50)	—	—	(50)
	(2)	(50)	(4)	(95)	(151)
Total Derivative Liabilities	(74)	(76)	(35)	(837)	(1,022)
Total Derivatives	(74)	(64)	(27)	(152)	(317)

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

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

Derivatives in fair value hedging relationships

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

	Carrying amount		Fair value hedging adjustments[1]	
(unaudited - millions of Canadian $)	September 30, 2023	December 31, 2022	September 30, 2023	December 31, 2022
Long-term debt	**(2,273)**	(2,101)	**163**	64

1 At September 30, 2023 and December 31, 2022, adjustments for discontinued hedging relationships included in these balances were nil.

Notional and maturity summary

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

at September 30, 2023 (unaudited)	Power	Natural gas	Liquids	Emission credits	Foreign exchange	Interest rate
Net sales (purchases)[1,2]	**8,550**	**73**	**2**	**125**	**—**	**—**
Millions of U.S. dollars	**—**	**—**	**—**	**—**	**5,622**	**1,800**
Millions of Mexican pesos	**—**	**—**	**—**	**—**	**19,000**	**—**
Maturity dates	**2023-2044**	**2023-2029**	**2023-2024**	**2023**	**2023-2026**	**2030-2034**

1 Volumes for power, natural gas, liquids and emission credit derivatives are in GWh, Bcf, MMBbls and thousand metric tonnes CO_2, respectively.

2 In 2023, the Company entered into contracts to sell 50 MW of power commencing in 2025 with terms ranging from 15 to 20 years and provided from specified renewable sources in the Province of Alberta.

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

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

Unrealized and Realized Gains (Losses) on Derivative Instruments

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

	three months ended September 30		nine months ended September 30	
(unaudited - millions of Canadian $)	2023	2022	2023	2022
Derivative Instruments Held for Trading[1]				
Unrealized gains (losses) in the period				
Commodities	**(17)**	42	**113**	(16)
Foreign exchange	**(40)**	(283)	**142**	(321)
Realized gains (losses) in the period				
Commodities	**249**	165	**579**	561
Foreign exchange	**(29)**	(1)	**110**	27
Derivative Instruments in Hedging Relationships				
Realized gains (losses) in the period				
Commodities	**(8)**	(21)	**(20)**	(39)
Interest rate	**(13)**	2	**(29)**	—

1 Realized and unrealized gains (losses) on held-for-trading derivative instruments used to purchase and sell commodities are included on a net basis in Revenues. Realized and unrealized gains (losses) on foreign exchange held-for-trading derivative instruments are included on a net basis in Foreign exchange (gains) losses, net in the Condensed consolidated statement of income.

Derivatives in cash flow hedging relationships

The components of OCI (Note 10) 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:

	three months ended September 30		nine months ended September 30	
(unaudited - millions of Canadian $, pre-tax)	**2023**	2022	**2023**	2022
Gains (losses) in fair value of derivative instruments recognized in OCI[1]				
Commodities	**18**	(23)	**(5)**	(42)
Interest rate	**—**	—	**—**	36
	18	(23)	**(5)**	(6)

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

Effect of fair value and cash flow hedging relationships

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

	three months ended September 30		nine months ended September 30	
(unaudited - millions of Canadian $)	**2023**	2022	**2023**	2022
Fair Value Hedges				
Interest rate contracts[1]				
Hedged items	**(24)**	(10)	**(70)**	(12)
Derivatives designated as hedging instruments	**(13)**	1	**(29)**	2
Cash Flow Hedges				
Reclassification of gains (losses) on derivative instruments from AOCI to Net income (loss)[2,3]				
Commodities[4]	**(29)**	(10)	**(77)**	(24)
Interest rate[1]	**(3)**	(3)	**(9)**	(13)

1 Presented within Interest expense in the Condensed consolidated statement of income.

2 Refer to Note 10, Other comprehensive income (loss) and Accumulated other comprehensive income (loss), for the components of OCI related to derivatives in cash flow hedging relationships.

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

4 Presented within Revenues (Power and Energy Solutions) in the Condensed 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 Condensed 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 September 30, 2023 (unaudited - millions of Canadian $)	**Gross derivative instruments**	**Amounts available for offset**[1]	**Net amounts**
Derivative instrument assets			
Commodities	**1,417**	**(1,172)**	**245**
Foreign exchange	**48**	**(34)**	**14**
	1,465	**(1,206)**	**259**
Derivative instrument liabilities			
Commodities	**(1,305)**	**1,172**	**(133)**
Foreign exchange	**(70)**	**34**	**(36)**
Interest rate	**(163)**	**—**	**(163)**
	(1,538)	**1,206**	**(332)**

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

at December 31, 2022 (unaudited - millions of Canadian $)	**Gross derivative instruments**	**Amounts available for offset**[1]	**Net amounts**
Derivative instrument assets			
Commodities	659	(591)	68
Foreign exchange	34	(33)	1
Interest rate	12	(4)	8
	705	(628)	77
Derivative instrument liabilities			
Commodities	(733)	591	(142)
Foreign exchange	(213)	33	(180)
Interest rate	(76)	4	(72)
	(1,022)	628	(394)

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

With respect to the derivative instruments presented above, the Company provided cash collateral of $133 million and letters of credit of $96 million at September 30, 2023 (December 31, 2022 – $138 million and $68 million, respectively) to its counterparties. At September 30, 2023, the Company held cash collateral of less than $1 million and $31 million letters of credit (December 31, 2022 – less than $1 million and $10 million, respectively) from counterparties on asset exposures.

Credit-risk-related contingent features of derivative instruments

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

Based on contracts in place and market prices at September 30, 2023, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $4 million (December 31, 2022 – $19 million), for which the Company has provided no collateral in the normal course of business. If the credit-risk-related contingent features in these agreements were triggered on September 30, 2023, the Company would have been required to provide collateral equal to the fair value of the related derivative instruments discussed above. Collateral may also need to be provided should the fair value of derivative instruments exceed pre-defined contractual exposure limit thresholds.

The Company has sufficient liquidity in the form of cash and undrawn committed revolving credit facilities to meet these contingent obligations should they arise.

Fair Value Hierarchy

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

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

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

at September 30, 2023 (unaudited - millions of Canadian $)	**Quoted prices in active markets (Level I)**	**Significant other observable inputs (Level II)**[1]	**Significant unobservable inputs (Level III)**[1]	**Total**
Derivative instrument assets				
Commodities	**1,159**	**245**	**13**	**1,417**
Foreign exchange	**—**	**48**	**—**	**48**
Derivative instrument liabilities				
Commodities	**(1,080)**	**(201)**	**(24)**	**(1,305)**
Foreign exchange	**—**	**(70)**	**—**	**(70)**
Interest rate	**—**	**(163)**	**—**	**(163)**
	79	**(141)**	**(11)**	**(73)**

1 There were no transfers from Level II to Level III for the nine months ended September 30, 2023.

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

at December 31, 2022 (unaudited - millions of Canadian $)	Quoted prices in active markets (Level I)	Significant other observable inputs (Level II)[1]	Significant unobservable inputs (Level III)[1]	Total
Derivative instrument assets				
Commodities	515	142	2	659
Foreign exchange	—	34	—	34
Interest rate	—	12	—	12
Derivative instrument liabilities				
Commodities	(478)	(242)	(13)	(733)
Foreign exchange	—	(213)	—	(213)
Interest rate	—	(76)	—	(76)
	37	(343)	(11)	(317)

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

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

	three months ended September 30		nine months ended September 30	
(unaudited - millions of Canadian $)	**2023**	2022	**2023**	2022
Balance at beginning of period	**(16)**	(15)	**(11)**	(6)
Net gains (losses) included in Net income (loss)	**6**	(3)	**1**	(11)
Net gains (losses) included in OCI	**1**	(1)	**—**	(2)
Transfers to Level II	**(2)**	2	**(1)**	2
Settlements	**—**	1	**—**	1
Balance at End of Period[1]	**(11)**	(16)	**(11)**	(16)

1 For the three and nine months ended September 30, 2023, there were unrealized gains of $6 million and $1 million, respectively, recognized in Revenues attributed to derivatives in the Level III category that were held at September 30, 2023 (2022 – unrealized losses of $3 million and $11 million, respectively).

13. ACQUISITIONS

Texas Wind Farms

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

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

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

14. PROPOSED SPINOFF

Proposed Spinoff of Liquids Business

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

Under the proposed Transaction, TC Energy shareholders will retain their current ownership in TC Energy's common shares and receive a pro-rata allocation of common shares in South Bow Corporation. The determination of the number of common shares in South Bow Corporation to be distributed to TC Energy shareholders will be determined prior to the closing of the proposed Transaction.

For the three and nine months ended September 30, 2023, the Company incurred pre-tax separation costs of $15 million ($11 million after tax) with respect to the Transaction, which included employee-related transaction costs, legal, tax, audit and other consulting fees.

15. COMMITMENTS, CONTINGENCIES AND GUARANTEES

Commitments

Capital expenditure commitments at September 30, 2023 have decreased by approximately $0.3 billion from those reported at December 31, 2022, reflecting normal course fulfillment of construction contracts, partially offset by new contractual commitments entered into for the construction of the Southeast Gateway pipeline and other capital projects.

Contingencies

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

2016 Columbia Pipeline Acquisition Lawsuit

On June 30, 2023, the Delaware Chancery Court (the Court) issued a ruling against TC Energy and other named defendants in a class action lawsuit brought on behalf of the former shareholders of Columbia Pipeline Group Inc. (Columbia) related to the acquisition of Columbia by TC Energy in July 2016. The Court determined that Columbia's then CEO and CFO breached their fiduciary duties and made material disclosure omissions and that TC Energy was aware and took advantage of those breaches. The Court awarded shareholders damages in the amount of US$1 per share. The final award is yet to be determined but is expected to be in the range of US$400 million, plus interest at the statutory rate. Liability for this award will be allocated between Columbia's former executives and TC Energy in a subsequent proceeding before the Court that will determine proportionate responsibility and account for the prior settlement. Until this allocation is known, the amount that TC Energy is liable for cannot be reasonably estimated, therefore, the Company has not accrued a provision for this claim as at September 30, 2023.

TC Energy will not be responsible for the full amount of the award, but its proportionate share will not be known until the allocation hearing is completed. The Company strongly disagrees with the ruling and intends to appeal once the final judgment is entered and the allocation is determined. The same Court had previously confirmed, after trial in an appraisal rights action filed in 2016, that the US$25.50 per share that TC Energy paid Columbia shareholders was fair value.

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 included in Other long-term liabilities on the Condensed consolidated balance sheet. Information regarding the Company's guarantees is as follows:

		September 30, 2023		December 31, 2022	
(unaudited - millions of Canadian $)	Term	Potential exposure[1]	Carrying value	Potential exposure[1]	Carrying value
Sur de Texas	Renewable to 2053	**100**	**—**	100	—
Bruce Power	Renewable to 2065	**88**	**—**	88	—
Other jointly-owned entities	to 2043	**80**	**3**	81	3
		268	**3**	269	3

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

16. 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:

(unaudited - millions of Canadian $)	September 30, 2023	December 31, 2022
ASSETS		
Current Assets		
Cash and cash equivalents	**47**	60
Accounts receivable	**79**	98
Inventories	**34**	32
Other current assets	**11**	14
	171	204
Plant, Property and Equipment	**4,142**	3,997
Equity Investments	**703**	748
Regulatory Assets	**7**	—
Goodwill	**450**	449
	5,473	5,398
LIABILITIES		
Current Liabilities		
Accounts payable and other	**203**	234
Accrued interest	**23**	18
Current portion of long-term debt	**72**	31
	298	283
Regulatory Liabilities	**84**	78
Other Long-Term Liabilities	**9**	1
Deferred Income Tax Liabilities	**16**	16
Long-Term Debt	**2,133**	2,136
	2,540	2,514

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 are as follows:

(unaudited - millions of Canadian $)	September 30, 2023	December 31, 2022
Balance Sheet Exposure		
Equity investments		
Bruce Power	**6,274**	5,783
Other pipeline equity investments	**1,124**	1,148
Off-Balance Sheet Exposure[1]		
Bruce Power	**1,728**	2,025
Coastal GasLink[2]	**1,355**	3,300
Other pipeline equity investments	**58**	58
Maximum Exposure to Loss	**10,539**	12,314

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

2 TC Energy is contractually obligated to fund the capital costs to complete the Coastal GasLink pipeline by funding the remaining equity requirements of Coastal GasLink LP through capacity on the subordinated loan agreement with Coastal GasLink LP until final project costs are determined.
At September 30, 2023, the total capacity committed by TC Energy under this subordinated loan agreement was $3,375 million (December 31, 2022 – $1,262 million). In the nine months ended September 30, 2023, $2,020 million was drawn on the subordinated loan, reducing the Company's funding commitment under the subordinated loan agreement to $1,355 million. Refer to Note 5, Coastal GasLink, for further information.

17. SUBSEQUENT EVENT

Columbia Gas and Columbia Gulf Monetization

On October 4, 2023, TC Energy successfully completed the sale of a 40 per cent equity interest in Columbia Gas and Columbia Gulf to Global Infrastructure Partners (GIP) for proceeds of $5.3 billion (US$3.9 billion). Columbia Gas and Columbia Gulf are held by a newly formed entity with GIP. Preceding the close of the equity sale, on August 8, 2023, Columbia Pipelines Operating Company LLC and Columbia Pipelines Holding Company LLC issued US$4.6 billion and US$1.0 billion of long-term, senior unsecured debt, respectively, with all proceeds paid to TCPL. The net proceeds from the offerings were used to repay existing intercompany indebtedness with TC Energy entities and directed towards reducing leverage. Refer to Note 8, Notes payable and Long-term debt, for additional information.

The Company continues to have a controlling interest in Columbia Gas and Columbia Gulf and will remain the operator of these pipelines. TC Energy and GIP will each fund their proportionate share of annual maintenance, modernization and sanctioned growth capital expenditures through internally generated cash flows, debt financing within the Columbia entities, or from proportionate contributions from TC Energy and GIP.