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).

	three months ended September 30		nine months ended September 30	
(millions of $)	**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

	three months ended September 30		nine months ended September 30	
(millions of $)	**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).

	three months ended September 30		nine months ended September 30	
(millions of $)	**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

	three months ended September 30		nine months ended September 30	
(millions of $)	**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 2023	three months ended September 30 2022	nine months ended September 30 2023	nine months ended September 30 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 2023	three months ended September 30 2022	nine months ended September 30 2023	nine months ended September 30 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.