Quarterly report to shareholders

Third quarter 2022

Financial highlights

	three months ended September 30		nine months ended September 30	
(millions of $, except per share amounts)	**2022**	**2021**	**2022**	**2021**
Income				
Revenues	**3,799**	3,240	**10,936**	9,803
Net income attributable to common shares	**841**	779	**2,088**	697
per common share – basic	**$0.84**	$0.80	**$2.11**	$0.72
Comparable EBITDA[1]	**2,461**	2,238	**7,218**	6,973
Comparable earnings	**1,068**	970	**3,150**	3,114
per common share	**$1.07**	$0.99	**$3.19**	$3.21
Cash flows				
Net cash provided by operations	**1,701**	1,712	**4,350**	5,089
Comparable funds generated from operations	**1,637**	1,556	**5,068**	5,333
Capital spending[2]	**2,583**	1,687	**5,789**	5,011
Dividends declared				
Per common share	**$0.90**	$0.87	**$2.70**	$2.61
Basic common shares outstanding (millions)				
– weighted average for the period	**1,000**	979	**988**	970
– issued and outstanding at end of period	**1,012**	979	**1,012**	979

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

2 Includes Capital expenditures and Contributions to equity investments. Refer to the Financial conditions – Cash used in investing activities section for additional information.

Management's discussion and analysis

November 8, 2022

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, 2022, and should be read with the accompanying unaudited Condensed consolidated financial statements for the three and nine months ended September 30, 2022, which have been prepared in accordance with U.S. GAAP.

This MD&A should also be read in conjunction with our December 31, 2021 audited Consolidated financial statements and notes and the MD&A in our 2021 Annual Report. Capitalized and abbreviated terms that are used but not otherwise defined herein are defined in our 2021 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, including portfolio management
- expected dividend growth
- expected access to and cost of capital
- expected costs and schedules for planned projects, including projects under construction and in development
- expected capital expenditures, contractual obligations, commitments and contingent liabilities
- 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
- expected industry, market and economic conditions, including the impact of these on our customers
- the expected impact of COVID-19.

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 and energy transition
- regulatory decisions and outcomes
- planned and unplanned outages and the use of our pipeline, 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
- inflation rates and commodity prices
- interest, tax and foreign exchange rates
- nature and scope of hedging
- expected impact of COVID-19.

Risks and uncertainties

- realization of expected benefits from acquisitions and divestitures
- our ability to successfully implement our strategic priorities 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 pipeline, power and storage assets
- amount of capacity sold and rates achieved in our pipeline businesses
- the amount of capacity payments and revenues from our power generation assets due to plant availability
- production levels within supply basins
- construction and completion of capital projects
- cost and availability of, and inflationary pressure 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 and COVID-19
- our ability to realize the value of tangible assets and contractual recoveries, including those specific to the Keystone XL pipeline project
- 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, including COVID-19 and the unexpected 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 2021 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.sedar.com).

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, 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 net income attributable to common shares and segmented earnings, respectively, 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
- unrealized fair value adjustments related to risk management activities and Bruce Power funds invested for post-retirement benefits
- expected credit loss provisions on our net investment in leases
- legal, contractual, bankruptcy and other settlements
- impairment of goodwill, plant, property and equipment, investments and other assets
- acquisition and integration costs
- restructuring costs.

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. Beginning in first quarter 2022, with retroactive restatement of prior periods, we exclude from comparable measures our proportionate share of the unrealized gains and losses from changes in the fair value of Bruce Power's investments held 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 2022, Transportadora de Gas Natural de la Huasteca (TGNH) and the CFE executed agreements which consolidate a number of operating and in-development natural gas pipelines in central and southeast Mexico under one TSA. This TSA contains a lease; therefore, we have recognized amounts in net investment in leases on our Condensed consolidated balance sheet. In accordance with the requirements of U.S. GAAP, we have recognized an expected credit loss provision related to net investment in leases. The amount of this provision will fluctuate from period to period based on changing economic assumptions and forward-looking information. The provision is an estimate of losses that may occur over the duration of the TSA through 2055. As this provision does not reflect losses or cash outflows that were incurred under this lease arrangement in the current period or from our underlying operations, we have excluded any unrealized changes from comparable measures. Refer to the Other information – Critical accounting estimates and accounting policy changes section for additional information.

We also 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 do not accurately reflect the gains and losses that will be realized at settlement. These amounts offset within each reporting period, resulting in no impact on net income. This peso-denominated loan was fully repaid in first quarter 2022.

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

Comparable measure	GAAP measure
comparable EBITDA	segmented earnings
comparable EBIT	segmented earnings
comparable earnings	net income attributable to common shares
comparable earnings per common share	net income 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 adjusted for certain specific items, excluding non-cash 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 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.

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, Interest expense, AFUDC, Interest income and other, Income tax expense, Non-controlling interests and Preferred share dividends, adjusted for specific items. Refer to the Consolidated results section for reconciliations to Net income attributable to common shares and Net income 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 2021 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	
	2022	**2021**	**2022**	**2021**
Canadian Natural Gas Pipelines	**409**	343	**1,152**	1,060
U.S. Natural Gas Pipelines	**714**	692	**1,735**	2,253
Mexico Natural Gas Pipelines	**113**	144	**395**	434
Liquids Pipelines	**268**	285	**801**	(1,973)
Power and Storage	**289**	116	**535**	437
Corporate	**(9)**	(36)	**12**	(40)
Total segmented earnings	**1,784**	1,544	**4,630**	2,171
Interest expense	**(666)**	(596)	**(1,866)**	(1,749)
Allowance for funds used during construction	**116**	81	**254**	195
Interest income and other	**(242)**	(76)	**(224)**	113
Income before income taxes	**992**	953	**2,794**	730
Income tax (expense)/recovery	**(122)**	(135)	**(593)**	158
Net income	**870**	818	**2,201**	888
Net income attributable to non-controlling interests	**(8)**	(8)	**(28)**	(83)
Net income attributable to controlling interests	**862**	810	**2,173**	805
Preferred share dividends	**(21)**	(31)	**(85)**	(108)
Net income attributable to common shares	**841**	779	**2,088**	697
Net income per common share – basic	**$0.84**	$0.80	**$2.11**	$0.72

Net income attributable to common shares increased by $62 million or $0.04 per common share and increased by $1,391 million or $1.39 per common share for the three and nine months ended September 30, 2022 compared to the same periods in 2021. The significant increase for the nine months ended September 30, 2022 is primarily due to the net effect of specific items mentioned below. Net income per common share also reflects the impact of common shares issued for the acquisition of TC PipeLines, LP in first quarter 2021 and the common share issuance in August 2022.

The following specific items were recognized in Net income attributable to common shares and were excluded from comparable earnings:

2022 results

- an after-tax goodwill impairment charge of $531 million in first quarter 2022 related to Great Lakes. Refer to the Other information – Critical accounting estimates and accounting policy changes section for additional information
- 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. Refer to the Other information – Critical accounting estimates and accounting policy changes section for additional information
- after-tax preservation and storage costs for Keystone XL pipeline project assets of $3 million and $11 million for the three and nine months ended September 30, 2022, which could not be accrued as part of the Keystone XL asset impairment charge.

2021 results

- a $2.2 billion after-tax asset impairment charge, predominantly in first quarter 2021, net of expected contractual recoveries and other contractual and legal obligations, related to the termination of the Keystone XL pipeline project following the January 2021 revocation of the Presidential Permit
- a $55 million after-tax expense with respect to transition payments incurred as part of the Voluntary Retirement Program
- after-tax preservation and storage costs for Keystone XL pipeline project assets of $11 million and $27 million for the three and nine months ended September 30, 2021, which could not be accrued as part of the Keystone XL asset impairment charge and interest expense on the Keystone XL project-level credit facility prior to its termination
- a $13 million after-tax recovery of certain costs from the IESO in second quarter 2021 associated with the Ontario natural gas-fired power plants sold in 2020.

Net income in both periods 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 attributable to common shares to comparable earnings is shown in the following table.

RECONCILIATION OF NET INCOME ATTRIBUTABLE TO COMMON SHARES TO COMPARABLE EARNINGS

	three months ended September 30		nine months ended September 30	
(millions of $, except per share amounts)	**2022**	**2021**	**2022**	**2021**
Net income attributable to common shares	**841**	779	**2,088**	697
Specific items (net of tax):				
Great Lakes goodwill impairment charge	**—**	—	**531**	—
Settlement of Mexico prior years' income tax assessments	**—**	—	**195**	—
Expected credit loss provision for net investment in leases	**50**	—	**50**	—
Bruce Power unrealized fair value adjustments	**(2)**	(2)	**22**	(4)
Keystone XL preservation and other	**3**	11	**11**	27
Keystone XL asset impairment charge and other	**—**	—	**—**	2,194
Voluntary Retirement Program	**—**	55	**—**	55
Gain on sale of Ontario natural gas-fired power plants	**—**	—	**—**	(13)
Risk management activities[1]	**176**	127	**253**	158
Comparable earnings	**1,068**	970	**3,150**	3,114
Net income per common share	**$0.84**	$0.80	**$2.11**	$0.72
Specific items (net of tax):				
Great Lakes goodwill impairment charge	**—**	—	**0.54**	—
Settlement of Mexico prior years' income tax assessments	**—**	—	**0.20**	—
Expected credit loss provision for net investment in leases	**0.05**	—	**0.05**	—
Bruce Power unrealized fair value adjustments	**—**	—	**0.02**	—
Keystone XL preservation and other	**—**	0.01	**0.01**	0.03
Keystone XL asset impairment charge and other	**—**	—	**—**	2.27
Voluntary Retirement Program	**—**	0.05	**—**	0.05
Gain on sale of Ontario natural gas-fired power plants	**—**	—	**—**	(0.01)
Risk management activities	**0.18**	0.13	**0.26**	0.15
Comparable earnings per common share	**$1.07**	$0.99	**$3.19**	$3.21

1 Risk management activities	three months ended September 30		nine months ended September 30	
(millions of $)	**2022**	2021	**2022**	2021
U.S. Natural Gas Pipelines	**15**	(3)	**13**	(1)
Liquids Pipelines	**23**	(8)	**58**	2
Canadian Power	**2**	7	**(26)**	8
U.S. Power	**(1)**	—	**(5)**	—
Natural Gas Storage	**9**	(39)	**(56)**	(36)
Foreign exchange	**(283)**	(125)	**(321)**	(183)
Income tax attributable to risk management activities	**59**	41	**84**	52
Total unrealized losses from risk management activities	**(176)**	(127)	**(253)**	(158)

COMPARABLE EBITDA TO COMPARABLE EARNINGS

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

	three months ended September 30		nine months ended September 30	
(millions of $, except per share amounts)	**2022**	2021	**2022**	2021
Comparable EBITDA				
Canadian Natural Gas Pipelines	**713**	631	**2,038**	2,001
U.S. Natural Gas Pipelines	**926**	890	**2,948**	2,824
Mexico Natural Gas Pipelines	**204**	171	**542**	515
Liquids Pipelines	**332**	387	**1,002**	1,146
Power and Storage	**295**	166	**704**	501
Corporate	**(9)**	(7)	**(16)**	(14)
Comparable EBITDA	**2,461**	2,238	**7,218**	6,973
Depreciation and amortization	**(653)**	(610)	**(1,914)**	(1,888)
Interest expense included in comparable earnings	**(666)**	(596)	**(1,866)**	(1,743)
Allowance for funds used during construction	**116**	81	**254**	195
Interest income and other included in comparable earnings	**41**	91	**125**	341
Income tax expense included in comparable earnings	**(202)**	(195)	**(554)**	(573)
Net income attributable to non-controlling interests	**(8)**	(8)	**(28)**	(83)
Preferred share dividends	**(21)**	(31)	**(85)**	(108)
Comparable earnings	**1,068**	970	**3,150**	3,114
Comparable earnings per common share	**$1.07**	$0.99	**$3.19**	$3.21

Comparable EBITDA – 2022 versus 2021

Comparable EBITDA increased by $223 million for the three months ended September 30, 2022 compared to the same period in 2021 primarily due to the net effect of the following:

- increased Power and Storage EBITDA attributable to higher contributions from Bruce Power due to a higher contract price and greater plant output resulting from fewer planned outage days and from Canadian Power due to increased earnings from higher realized power prices and marketing activities, partially offset by decreased results from Natural Gas Storage and other
- 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
- higher EBITDA in U.S. Natural Gas Pipelines primarily reflects a stronger U.S. dollar in 2022 with otherwise consistent EBITDA in third quarter 2022 versus the same period in 2021
- increased EBITDA from Mexico Natural Gas Pipelines primarily related to the north section of the Villa de Reyes pipeline (VdR North) and the east section of the Tula pipeline (Tula East) that were placed into commercial service in third quarter 2022
- lower EBITDA from Liquids Pipelines as a result of lower rates and volumes on the U.S. Gulf Coast section of the Keystone Pipeline System and decreased contributions from liquids marketing activities attributable to lower margins, partially offset by higher long-haul contracted volumes
- the positive foreign exchange impact of a stronger U.S. dollar on the Canadian dollar equivalent segmented earnings in our U.S. dollar-denominated operations. As detailed below, U.S. dollar-denominated comparable EBITDA decreased by US$35 million compared to 2021; however, this was translated at a rate of 1.31 in 2022 versus 1.26 in 2021. Refer to the Foreign exchange discussion below for additional information.

Comparable EBITDA increased by $245 million for the nine months ended September 30, 2022 compared to the same period in 2021 primarily due to the net effect of the following:

- increased Power and Storage EBITDA primarily attributable to higher contributions from Bruce Power due to a higher contract price and greater plant output resulting from fewer planned outage days as well as increased EBITDA from Canadian Power related to higher realized power prices and marketing activities
- higher EBITDA in U.S. Natural Gas Pipelines largely due to incremental earnings from growth projects placed in service, increased earnings from our mineral rights business as well as increased earnings on Columbia Gas following the FERC-approved settlement for higher transportation rates effective February 2021, partially offset by higher property taxes
- increased EBITDA from Canadian Natural Gas Pipelines largely attributable to the impact of higher flow-through costs and increased rate-base earnings on the NGTL System, partially offset by lower flow-through depreciation on the Canadian Mainline
- higher EBITDA from Mexico Natural Gas Pipelines primarily related to the operating segments of the TGNH pipeline, VdR North and Tula East, that were placed into commercial service in third quarter 2022
- decreased EBITDA from Liquids Pipelines as a result of lower rates and volumes on contracted volumes on the U.S. Gulf Coast section of the Keystone Pipeline System as well as lower contributions from liquids marketing activities due to lower margins
- the positive foreign exchange impact of a stronger U.S. dollar on the Canadian dollar equivalent segmented earnings in our U.S. dollar-denominated operations. As detailed below, U.S. dollar-denominated comparable EBITDA decreased by US$90 million compared to 2021; however, this was translated at a rate of 1.28 in 2022 versus 1.25 in 2021. Refer to the Foreign exchange discussion below 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 – 2022 versus 2021

Comparable earnings increased by $98 million or $0.08 per common share for the three months ended September 30, 2022 compared to the same period in 2021 and was primarily the net effect of:

- changes in comparable EBITDA described above
- increased Interest expense primarily due to higher interest rates on increased levels of short-term borrowings, long-term debt and junior subordinated note issuances, net of maturities, and the foreign exchange impact of a stronger U.S. dollar in 2022
- lower Interest income and other mainly attributable to realized losses in 2022 compared to realized gains in 2021 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income and repayment of the inter-affiliate loan receivable by the Sur de Texas joint venture on July 29, 2022
- higher Depreciation and amortization on the NGTL System from expansion facilities that were placed in service and on U.S. Natural Gas Pipelines mainly due to timing of certain adjustments related to the Columbia Gas rate case settlement
- 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.

Comparable earnings increased by $36 million and decreased by $0.02 per common share for the nine months ended September 30, 2022 compared to the same period in 2021 and was primarily the net effect of:

- changes in comparable EBITDA described above
- lower Interest income and other mainly attributable to lower realized gains in 2022 compared to 2021 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income and repayment of the inter-affiliate loan receivable by the Sur de Texas joint venture on July 29, 2022
- increased Interest expense primarily due to higher interest rates on increased levels of short-term borrowings, long-term debt and junior subordinated note issuances, net of maturities, as well as the foreign exchange impact of a stronger U.S. dollar in 2022 and lower capitalized interest as a result of its cessation for the Keystone XL pipeline project following the revocation of the Presidential Permit in January 2021
- 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 and expansion projects on the NGTL System
- lower Net income attributable to non-controlling interests following the March 2021 acquisition of all outstanding common units of TC PipeLines, LP not beneficially owned by TC Energy
- lower Preferred share dividends due to the redemption of preferred shares in 2022 and 2021
- decreased Income tax expense primarily due to lower flow-through income taxes.

Comparable earnings per common share for the three and nine months ended September 30, 2022 reflect the dilutive effect of issuing 28.4 million common shares in August 2022.

Foreign exchange

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. The balance of the 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 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

(millions of US$)	three months ended September 30 2022	three months ended September 30 2021	nine months ended September 30 2022	nine months ended September 30 2021
Comparable EBITDA				
U.S. Natural Gas Pipelines	**709**	706	**2,300**	2,256
Mexico Natural Gas Pipelines[1]	**158**	152	**446**	462
Liquids Pipelines	**179**	223	**550**	668
	1,046	1,081	**3,296**	3,386
Depreciation and amortization	**(238)**	(224)	**(715)**	(666)
Interest on long-term debt and junior subordinated notes	**(321)**	(315)	**(944)**	(945)
Allowance for funds used during construction	**58**	33	**106**	73
Non-controlling interests and other	**(29)**	(7)	**(57)**	(57)
	516	568	**1,686**	1,791
Average exchange rate - U.S. to Canadian dollars	**1.31**	1.26	**1.28**	1.25

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

Outlook

Comparable EBITDA and comparable earnings

While our comparable earnings per common share outlook for 2022 remains consistent with the 2021 Annual Report, we expect our 2022 comparable EBITDA to be higher than the outlook provided previously as a result of stronger EBITDA performance to date in 2022. We continue to monitor the impact of changes in energy markets, our construction projects and regulatory proceedings as well as COVID-19 for any potential effect on our 2022 comparable EBITDA and comparable earnings per share.

Consolidated capital spending and equity investments

Our total capital expenditures for 2022 are now expected to be approximately $9.5 billion. The increase from the amount outlined in the 2021 Annual Report is primarily due to 2022 installments of approximately $1.3 billion for partner equity contributions to the Coastal GasLink Pipeline Limited Partnership (Coastal GasLink LP) in accordance with revised agreements with Coastal GasLink LP. In addition, approximately US$0.7 billion in capital expenditures are expected in 2022 related to the construction of the Southeast Gateway pipeline subsequent to the final investment decision (FID) reached with the CFE in August 2022. Refer to the Recent developments section for additional information on Coastal GasLink and the Southeast Gateway pipeline. Finally, higher project costs are expected for the NGTL System reflecting inflationary pressures on labour and materials, additional regulatory conditions and other factors. We continue to monitor developments on construction projects, focus on cost mitigation strategies and assess market conditions as well as the impact of COVID-19 for further changes to our overall 2022 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 advance our goals to reduce our own carbon footprint as well as that of our customers.

Our capital program consists of approximately $34 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, 2022, we placed approximately $4.4 billion of Canadian, U.S. and Mexico natural gas pipelines capacity capital projects into service. In addition, approximately $1.2 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, permitting conditions, scheduling and timing of regulatory permits, as well as other potential restrictions and uncertainties, including the ongoing impact of COVID-19. Amounts exclude capitalized interest and AFUDC, where applicable.

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 $)	Expected in-service date	Estimated project cost	Project costs incurred as at September 30, 2022
Canadian Natural Gas Pipelines			
NGTL System[1]	2022	3.3	3.2
	2023	2.6	0.5
	2024+	1.2	0.1
Canadian Mainline	2022	0.2	0.2
Coastal GasLink[2]	2023	2.1	0.8
Regulated maintenance capital expenditures	2022-2024	2.2	0.4
U.S. Natural Gas Pipelines			
Modernization III (Columbia Gas)	2022-2024	US 1.2	US 0.5
Delivery market projects	2025	US 1.5	—
Other capital	2022-2028	US 1.2	US 0.2
Regulated maintenance capital expenditures	2022-2024	US 2.4	US 0.5
Mexico Natural Gas Pipelines			
Villa de Reyes – lateral and south sections[3]	2023	US 0.5	US 0.4
Tula – central and west sections[4]	2024	US 0.5	US 0.3
Southeast Gateway	2025	US 4.5	US 0.4
Liquids Pipelines			
Other capacity capital	2022	US 0.1	US 0.1
Recoverable maintenance capital expenditures	2022-2024	0.3	—
Power and Storage			
Bruce Power – life extension[5]	2022-2027	4.5	2.3
Other capacity capital	2023	0.1	—
Other			
Non-recoverable maintenance capital expenditures[6]	2022-2024	0.7	0.1
		29.1	**10.0**
Foreign exchange impact on secured projects[7]		**4.5**	**0.9**
Total secured projects (Cdn$)		**33.6**	**10.9**

1 Estimated project costs for 2022 and 2023 include $0.7 billion for Foothills related to 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 in-service is expected to be reached by the end of 2023. Commercial in-service of the Coastal GasLink pipeline will occur after completion of commissioning the pipeline. Refer to the Recent developments – Canadian Natural Gas Pipelines section for additional information.

3 VdR North was placed into commercial service in third quarter 2022. We are currently working with the CFE on the remaining sections of the Villa de Reyes pipeline, expecting commercial in-service in 2023. Refer to the Recent developments – Mexico Natural Gas Pipelines section for additional information.

4 Tula East was placed into commercial service in third quarter 2022. With the CFE, we are assessing the completion of the central section of the Tula pipeline, subject to an FID. Refer to the Recent developments – Mexico Natural Gas Pipelines section for additional information.

5 Reflects our expected share of cash contributions for the Bruce Power Unit 6 Major Component Replacement (MCR) program, expected to be in service in 2023, and the Unit 3 MCR, 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 Storage 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 Storage assets.

7 Reflects U.S./Canada foreign exchange rate of 1.38 at September 30, 2022.

Projects under development

In addition to our secured projects, we have a portfolio of projects that we are currently pursuing that are in varying stages of development. 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. Each business segment has also outlined additional areas of focus for further ongoing business development activities and growth opportunities. As these projects are advanced and reach necessary milestones they will be included in the secured projects table.

Canadian Natural Gas Pipelines

We continue to focus on optimizing the utilization and value of our existing Canadian Natural Gas Pipelines assets, including in-corridor expansions, providing connectivity to LNG export terminals and connections to growing shale gas supplies. Sustainability development projects are expected to include additional compressor station electrification and waste heat capture power generation on our systems as well as other GHG abatement initiatives.

U.S. Natural Gas Pipelines

Delivery Market Projects

Projects are in development that are expected to replace, upgrade and modernize certain U.S. Natural Gas Pipelines facilities while reducing emissions along portions of our pipeline systems in principal delivery markets. The enhanced facilities are expected to improve reliability of our systems and allow for additional transportation services under long-term contracts to address growing demand in the U.S. Midwest and the Mid-Atlantic regions, while reducing direct carbon dioxide equivalent emissions. Included in our secured projects are the US$0.7 billion VR Project on Columbia Gas and the US$0.8 billion WR Project on ANR, two delivery market projects that were approved in 2021 with expected in-service dates in the second half of 2025.

Renewable Natural Gas Hub Development

In April 2022, we announced a strategic collaboration with GreenGasUSA to explore development of a network of renewable natural gas (RNG) transportation hubs. These hubs would provide centralized access to existing energy transportation infrastructure for RNG sources, such as farms, wastewater treatment facilities and landfills. We believe that this collaboration, which targets 10 transportation hubs nationally, will rapidly expand and provide incremental capability to the already existing RNG interconnects across our U.S. natural gas footprint. The development of these hubs is an important step towards the acceleration of methane capture projects and the concurrent reduction of GHG emissions.

Other Opportunities

We are currently pursuing a variety of projects, including compression replacement, while furthering the electrification of our fleet, power generation and LDCs, expanding our modernization programs and in-corridor expansion opportunities on our existing systems. These projects are expected to improve the reliability of our systems with an environmental focus on cleaner energy.

We are also developing multiple transmission projects to link gas supply to the facilities that will serve the growing global demand for North American LNG.

Mexico Natural Gas Pipelines

On August 4, 2022, we announced a strategic alliance with the CFE, Mexico’s state-owned electric utility, to accelerate the development of natural gas infrastructure in the central and southeast regions of Mexico. Along with the assets in service or currently under construction, we are assessing the completion of the central section of Tula, subject to an FID.

Liquids Pipelines

Grand Rapids Phase II

Regulatory approvals have been obtained for Phase II of Grand Rapids, which consists of completing the 36-inch pipeline for crude oil service and converting the 20-inch pipeline from crude oil to diluent service. Commercial support is being pursued with prospective customers.

Terminals Projects

We continue to pursue projects associated with our terminals in Alberta and the U.S. to expand our core business and add operational flexibility for our customers.

Other Opportunities

We remain focused on maximizing the value of our liquids assets by expanding and leveraging our existing infrastructure and enhancing connectivity and service offerings to our customers. We are pursuing selective growth opportunities to add incremental value to our business and expansions that leverage available capacity on our existing infrastructure. We remain disciplined in our approach and will position our business development activities strategically to capture opportunities within our risk preferences.

Power and Storage

Bruce Power

Life Extension Program

The continuation of Bruce Power's life extension program through to 2033 will require the investment of our proportionate share of Major Component Replacement (MCR) program costs on Units 4, 5, 7 and 8, as well as the remaining Asset Management program costs which continue beyond 2033, extending the life of Units 3 to 8 and the Bruce Power site to 2064. Preparation work for the Unit 4 MCR is well underway and work for the Unit 5, 7 and 8 MCRs has also begun. Future MCR investments will be subject to discrete decisions for each unit with specified off-ramps available to Bruce Power and the IESO. We expect to spend approximately $4.8 billion for our proportionate share of the Bruce Power MCR program costs for Units 4, 5, 7 and 8 and the remaining Asset Management program costs beyond 2027, as well as the incremental uprate initiative discussed below.

Uprate Initiative

Bruce Power's Project 2030 has a goal of achieving a site peak output of 7,000 MW by 2033 in support of climate change targets and future clean energy needs. Project 2030 is focused on continued asset optimization, innovation and leveraging new technology, which could include integration with storage and other forms of energy, to increase the site peak output. Project 2030 is arranged in three stages with the first two stages fully approved for execution. Stage 1 started in 2019 and is expected to add 150 MW of output and Stage 2, which began in early 2022, is targeting another 200 MW.

Development-Stage Projects

Ontario Pumped Storage

We continue to progress the development of the Ontario Pumped Storage project (OPSP), an energy storage facility located near Meaford, Ontario that would provide 1,000 MW of flexible, clean energy to Ontario's electricity system using a process known as pumped hydro storage.

The OPSP has been granted long-term land access to the fourth Canadian Division Training Centre for development of the project on this site from the Federal Minister of National Defence and has been included in Gate 2 of the IESO's Unsolicited Proposals Process. Once in service, this project would store emission-free energy when available and provide that energy to Ontario during periods of peak demand, thereby maximizing the value of existing emission-free generation in the province.

Canyon Creek Pumped Storage

We are utilizing the existing site infrastructure from a decommissioned coal mine, located near Hinton, Alberta, to develop a pumped hydro storage project that is expected to have an initial generating capacity of 75 MW, expandable through future development to 400 MW. The facility is expected to provide up to 37 hours of on-demand, flexible, clean energy and ancillary services to the Alberta electricity grid. The project has received the approval of the Alberta Utilities Commission and the required approval of the Government of Alberta for hydro projects under the Dunvegan Hydro Development Act (Alberta).

The Canyon Creek Pumped Storage project is part of a larger product offering by us, a 24-by-7 carbon-free power product in the Province of Alberta and includes output from other projects currently under construction or being developed, thereby positioning our customers to manage hourly power needs with cost certainty and achieve decarbonization goals by sourcing power from emission-free assets.

Renewable Energy Contracts and/or Investment Opportunities

Through a Request for Information (RFI) process conducted in 2021, we are seeking potential contracts and/or investment opportunities in wind, solar and storage energy projects to meet the electricity needs of the U.S. portion of the Keystone Pipeline System and supply renewable energy products and services to industrial and oil and gas sectors proximate to our in-corridor demand. To date in 2022, we have finalized contracts for approximately 580 MW and 240 MW from wind energy and solar projects, respectively. We continue to evaluate the proposals received through the RFI process and expect to finalize additional contracts and/or investment opportunities in 2022.

Other Opportunities

We are actively building our customer-focused origination platform across North America, providing commodity products and energy services to help customers address the challenges of energy transition. Our existing network of assets, customers and suppliers provide a mutual opportunity in which we can tailor solutions to meet their clean energy needs. Although we may adopt custom-tailored strategies, the core underpinning remains consistent, which is that every opportunity we undertake will ultimately be driven by customer needs allowing us to complement each other's capabilities, diversify risk and share learnings as we navigate the energy transition.

Other Energy Solutions

Our vision is to be the premier energy infrastructure company in North America today and in the future. That future includes embracing the energy transition that is underway and contributing to a lower-carbon energy world. As energy transition continues to evolve, we recognize a significant opportunity to reduce our emissions footprint, in addition to being a partner to our customers and other industries that are also looking for low-carbon solutions. Currently, it is uncertain how the energy mix will evolve and at what pace. We continue to observe a reliance on the existing sources of natural gas, crude oil and electricity, for which we currently provide services to our customers.

We are targeting five focus areas to reduce the emissions intensity of our operations, while also capturing growth opportunities that meet the energy needs of the future:

- modernize our existing system and assets
- decarbonize our energy consumption
- drive digital solutions and technologies
- leverage carbon credits and offsets
- invest in low-carbon energy and infrastructure, such as renewables along with emerging fuels and technology.

Alberta Carbon Grid (ACG)
In June 2021, we announced a partnership with Pembina Pipeline Corporation to jointly develop a world-scale system which, when fully constructed, is expected to be capable of transporting and sequestering more than 20 million tonnes of carbon dioxide annually. As an open-access system, ACG is intended to serve as the backbone for Alberta's emerging carbon capture utilization and storage (CCUS) industry. On October 18, 2022, ACG announced that it has entered into a carbon sequestration evaluation agreement with the Government of Alberta to further evaluate one of the largest Areas of Interest (AOI) for safely storing carbon from industrial emissions in Alberta. This agreement will allow ACG to continue evaluating the suitability of our AOI and move forward into the next phase of the province's CCUS process to provide confidence to customers, Indigenous communities, stakeholders, and the Government of Alberta in the project's carbon storage capabilities. ACG proposes to leverage existing right of ways and/or pipelines to connect the Alberta Industrial Heartland emissions region to a key sequestration location.

Irving Oil Decarbonization
We have signed an MOU to explore the joint development of a series of proposed energy projects focused on reducing GHG emissions and creating new economic opportunities in New Brunswick and Atlantic Canada. Together with Irving Oil Ltd. (Irving Oil), we have identified a series of potential projects focused on decarbonizing existing assets and deploying emerging technologies to reduce overall emissions over the medium and long term. The partnership's initial focus will consider a suite of upgrade projects at Irving Oil's refinery in Saint John, New Brunswick, with the goal of significantly reducing emissions through the production and use of low-carbon power generation.

Hydrogen Hubs
We have entered into two Joint Development Agreements (JDA) to support customer-driven hydrogen production for long-haul transportation, power generation, large industrials and heating customers across the U.S. and Canada. The first opportunity is a partnership with Nikola Corporation (Nikola), a designer and manufacturer of zero-emission battery-electric and hydrogen-electric vehicles and related equipment, where Nikola will be a long-term anchor customer for hydrogen production infrastructure supporting hydrogen-fueled, zero-emission, heavy-duty trucks. The JDA with Nikola supports co-development of large-scale green and blue hydrogen production hubs, utilizing our power and natural gas infrastructure. On April 26, 2022, we announced a plan to evaluate a hydrogen production hub on 140 acres in Crossfield, Alberta, where we currently operate a natural gas storage facility. We expect an FID by the end of 2023, subject to customary regulatory approvals.

Our second customer-driven opportunity is a partnership with Hyzon Motors Inc. (Hyzon), a leader in fuel cell electric mobility for commercial vehicles, to develop hydrogen production facilities focused on zero-to-negative carbon intensity hydrogen from renewable natural gas, biogas and other sustainable sources. The facilities would be located close to demand, supporting Hyzon's back-to-base vehicle deployments. Our significant pipeline, storage and power assets can potentially be leveraged to lower the cost and increase the speed of development of these hubs. This may include exploring the integration of pipeline assets to enable hydrogen distribution and storage via pipeline and/or to deliver carbon dioxide to permanent sequestration sites to decarbonize the hydrogen production process.

Canadian Natural Gas Pipelines

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

	three months ended September 30		nine months ended September 30	
(millions of $)	**2022**	2021	**2022**	2021
NGTL System	**473**	409	**1,351**	1,214
Canadian Mainline	**198**	183	**556**	648
Other Canadian pipelines[1]	**42**	39	**131**	139
Comparable EBITDA	**713**	631	**2,038**	2,001
Depreciation and amortization	**(304)**	(288)	**(886)**	(941)
Comparable EBIT and segmented earnings	**409**	343	**1,152**	1,060

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

Canadian Natural Gas Pipelines comparable EBIT and segmented earnings increased by $66 million and $92 million for the three and nine months ended September 30, 2022 compared to the same periods in 2021.

Net income and comparable EBITDA for our rate-regulated Canadian natural gas pipelines are primarily affected by our approved ROE, our 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 $)	**2022**	2021	**2022**	2021
Net income				
NGTL System	**177**	160	**523**	467
Canadian Mainline	**58**	52	**162**	156
Average investment base				
NGTL System			**17,281**	15,345
Canadian Mainline			**3,712**	3,700

Net income for the NGTL System increased by $17 million and $56 million for the three and nine months ended September 30, 2022 compared to the same periods in 2021 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 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 and nine months ended September 30, 2022 increased by $6 million compared to the same periods in 2021 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 $82 million and $37 million for the three and nine months ended September 30, 2022 compared to the same periods in 2021 due to the net effect of:

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

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by $16 million and decreased by $55 million for the three and nine months ended September 30, 2022 compared to the same periods in 2021. The increase in third quarter 2022 compared to the same period in 2021 reflects incremental depreciation on the NGTL System resulting from expansion facilities that were placed in service, partially offset by lower depreciation on the Canadian Mainline mainly due to one section of the Canadian Mainline being fully depreciated in third quarter 2021. The decrease for the nine months ended September 30, 2022 compared to the same period in 2021 reflects lower depreciation on the Canadian Mainline as described above, partially offset by incremental depreciation on the NGTL System from expansion facilities that were placed in service.

U.S. Natural Gas Pipelines

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

	three months ended September 30		nine months ended September 30	
(millions of US$, unless otherwise noted)	**2022**	2021	**2022**	2021
Columbia Gas	**352**	359	**1,118**	1,122
ANR	**128**	135	**440**	436
Columbia Gulf	**50**	52	**155**	161
Great Lakes[1,2]	**37**	35	**129**	112
GTN[2,3]	**42**	40	**136**	95
Other U.S. pipelines[2,4]	**91**	78	**293**	215
TC PipeLines, LP[2,5]	**—**	—	**—**	24
Non-controlling interests[5]	**9**	7	**29**	91
Comparable EBITDA	**709**	706	**2,300**	2,256
Depreciation and amortization	**(174)**	(154)	**(510)**	(455)
Comparable EBIT	**535**	552	**1,790**	1,801
Foreign exchange impact	**164**	143	**503**	453
Comparable EBIT (Cdn$)	**699**	695	**2,293**	2,254
Specific items:				
Great Lakes goodwill impairment charge	**—**	—	**(571)**	—
Risk management activities	**15**	(3)	**13**	(1)
Segmented earnings (Cdn$)	**714**	692	**1,735**	2,253

1 Results reflect our 53.55 per cent direct interest in Great Lakes until March 2021 and our 100 per cent ownership interest subsequent to the March 2021 acquisition of all outstanding common units of TC PipeLines, LP not beneficially owned by us.

2 Our ownership interest in TC PipeLines, LP was 25.5 per cent prior to the acquisition in March 2021, at which time it became 100 per cent. Prior to March 2021, results reflected TC PipeLines, LP's 46.45 per cent interest in Great Lakes, its ownership of GTN, Bison, North Baja, Portland and Tuscarora as well as its share of equity income from Northern Border and Iroquois.

3 Reflects 100 per cent of GTN's comparable EBITDA subsequent to the TC PipeLines, LP acquisition in March 2021.

4 Reflects comparable EBITDA from our ownership in our mineral rights business (CEVCO), Crossroads and our share of equity income from 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. For the period subsequent to our March 2021 acquisition of TC PipeLines, LP, results also include 100 per cent of Bison, North Baja and Tuscarora, 61.7 per cent of Portland plus our equity income from Northern Border and Iroquois.

5 Reflects comparable EBITDA attributable to portions of TC PipeLines, LP and Portland that we did not own prior to our March 2021 acquisition of TC PipeLines, LP and subsequently reflects earnings attributable to the remaining 38.3 per cent interest in Portland we do not own.

U.S. Natural Gas Pipelines segmented earnings increased by $22 million and decreased by $518 million for the three and nine months ended September 30, 2022 compared to the same periods in 2021 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. Refer to the Other information – Critical accounting estimates and accounting policy changes section for additional information
- 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, 2022 had a positive impact on the Canadian dollar equivalent segmented earnings from our U.S. operations compared to the same periods in 2021. Refer to the Consolidated results – Foreign exchange section for additional information.

Comparable EBITDA for U.S. Natural Gas Pipelines increased by US$3 million and US$44 million for the three and nine months ended September 30, 2022 compared to the same periods in 2021 and was primarily due to the net effect of:

- incremental earnings from growth projects placed in service
- increased earnings from our mineral rights business due to higher commodity prices
- consistent earnings for the nine months ended September 30, 2022 on Columbia Gas following the FERC-approved settlement for higher transportation rates effective February 2021, partially offset by higher property taxes as a result of projects placed into service
- decreased earnings in 2022 across a number of the pipelines due to the impact of cold weather events and other discrete items recognized in 2021.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by US$20 million and US$55 million for the three and nine months ended September 30, 2022 compared to the same periods in 2021 mainly due to new projects placed in service and the timing of certain depreciation adjustments related to the Columbia Gas rate case settlement.

Mexico Natural Gas Pipelines

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

	three months ended September 30		nine months ended September 30	
(millions of US$, unless otherwise noted)	**2022**	2021	**2022**	2021
Topolobampo	**41**	40	**121**	121
Sur de Texas[1]	**34**	31	**88**	92
TGNH[2]	**47**	29	**107**	91
Guadalajara	**18**	17	**55**	54
Mazatlán	**15**	18	**50**	53
Comparable EBITDA	**155**	135	**421**	411
Depreciation and amortization	**(15)**	(21)	**(59)**	(65)
Comparable EBIT	**140**	114	**362**	346
Foreign exchange impact	**44**	30	**104**	88
Comparable EBIT (Cdn$)	**184**	144	**466**	434
Specific item:				
Expected credit loss provision for net investment in leases	**(71)**	—	**(71)**	—
Segmented earnings (Cdn$)	**113**	144	**395**	434

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

2 TGNH includes the operating sections of the Tamazunchale, Villa de Reyes and Tula pipelines. Refer to the Recent Developments – Mexico Natural Gas Pipelines section for additional information.

Mexico Natural Gas Pipelines segmented earnings decreased by $31 million and $39 million for the three and nine months ended September 30, 2022 compared to the same periods in 2021. This decrease is due to the impact of an expected credit loss provision of US$53 million related to the new TSA with the CFE that commenced in third quarter 2022. In accordance with the requirements of U.S. GAAP, an expected credit loss provision must be recognized on the TGNH net investment in leases. The provision is an estimate of losses that may occur over the duration of the TSA through 2055. As this provision does not reflect losses or cash outflows that were incurred under this lease arrangement in the current period or from our underlying operations, we have excluded any unrealized changes from our calculation of comparable EBITDA and comparable EBIT. Refer to the Other information – Critical accounting estimates and accounting policy changes section for additional information.

A stronger U.S. dollar for the three and nine months ended September 30, 2022 had a positive impact on the Canadian dollar equivalent segmented earnings compared to the same periods in 2021. Refer to the Consolidated results – Foreign exchange section for additional information.

Comparable EBITDA for Mexico Natural Gas Pipelines increased by US$20 million and US$10 million for the three and nine months ended September 30, 2022 compared to the same periods in 2021. The increase is primarily due to higher revenues related to the commercial in-service of VdR North and Tula East in third quarter 2022.

DEPRECIATION AND AMORTIZATION

The decrease in depreciation and amortization of US$6 million for both the three and nine months ended September 30, 2022 compared to the same periods in 2021 is due to the change in 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 $)	**2022**	**2021**	**2022**	**2021**
Keystone Pipeline System	**292**	327	**886**	956
Intra-Alberta pipelines[1]	**17**	22	**53**	67
Liquids marketing and other	**23**	38	**63**	123
Comparable EBITDA	**332**	387	**1,002**	1,146
Depreciation and amortization	**(83)**	(80)	**(244)**	(238)
Comparable EBIT	**249**	307	**758**	908
Specific items:				
Keystone XL asset impairment charge and other	**—**	—	**—**	(2,854)
Keystone XL preservation and other	**(4)**	(14)	**(15)**	(29)
Risk management activities	**23**	(8)	**58**	2
Segmented earnings/(losses)	**268**	285	**801**	(1,973)
Comparable EBITDA denominated as follows:				
Canadian dollars	**98**	106	**296**	310
U.S. dollars	**179**	223	**550**	668
Foreign exchange impact	**55**	58	**156**	168
Comparable EBITDA	**332**	387	**1,002**	1,146

1 Intra-Alberta pipelines include Grand Rapids, White Spruce and Northern Courier. In November 2021, we sold our remaining 15 per cent interest in Northern Courier.

Liquids Pipelines segmented earnings decreased by $17 million and increased by $2.8 billion for the three and nine months ended September 30, 2022 compared to the same periods in 2021 and included the following specific items which have been excluded from our calculation of comparable EBITDA and comparable EBIT:

- a $2,854 million pre-tax asset impairment charge, net of expected contractual recoveries and other contractual and legal obligations, for the nine months ended September 30, 2021, associated with the termination of the Keystone XL pipeline project following the revocation of the Presidential Permit in January 2021
- pre-tax preservation and storage costs for Keystone XL pipeline project assets of $4 million and $15 million for the three and nine months ended September 30, 2022 ($14 million and $29 million for the three and nine months ended September 30, 2021), 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 2022 relative to 2021 had a positive impact on the Canadian dollar equivalent segmented earnings from our U.S. operations; however, comparable EBITDA from our U.S. dollar-denominated operations has decreased for the three and nine months ended September 30, 2022. Refer to the Consolidated results – Foreign exchange section for additional information.

Comparable EBITDA for Liquids Pipelines decreased by $55 million and $144 million for the three and nine months ended September 30, 2022 compared to the same periods in 2021 primarily due to the net effect of:

- lower rates and volumes on the U.S. Gulf Coast section of the Keystone Pipeline System, partially offset by higher long-haul contracted volumes as we placed approximately 20,000 Bbl/d of new contracts from the 2019 Open Season into service effective April 1, 2022 and an incremental 10,000 Bbl/d effective September 1, 2022
- Liquids marketing earnings for the three months ended September 30, 2022 decreased relative to 2021 due to lower margins. Earnings for the nine months ended September 30, 2022 decreased relative to 2021 due to steep backwardation, combined with low inventory at key supply and trading hubs in first quarter 2022, which contributed to lower margins and market volatility negatively impacting marketing margins and the timing of earnings
- a stronger U.S. dollar as described above.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by $3 million and $6 million for the three and nine months ended September 30, 2022 compared to the same periods in 2021 primarily as a result of a stronger U.S. dollar.

Power and Storage

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

	three months ended September 30		nine months ended September 30	
(millions of $)	**2022**	2021	**2022**	2021
Bruce Power[1]	**199**	110	**412**	291
Canadian Power	**115**	50	**250**	176
Natural Gas Storage and other	**(19)**	6	**42**	34
Comparable EBITDA	**295**	166	**704**	501
Depreciation and amortization	**(19)**	(20)	**(53)**	(58)
Comparable EBIT	**276**	146	**651**	443
Specific items:				
Gain on sale of Ontario natural gas-fired power plants	**—**	—	**—**	17
Bruce Power unrealized fair value adjustments	**3**	2	**(29)**	5
Risk management activities	**10**	(32)	**(87)**	(28)
Segmented earnings	**289**	116	**535**	437

1 Includes our share of equity income from Bruce Power.

Power and Storage segmented earnings increased by $173 million and $98 million for the three and nine months ended September 30, 2022 compared to the same periods in 2021 and included the following specific items which have been excluded from our calculations of comparable EBITDA and comparable EBIT:

- a $17 million pre-tax recovery of certain costs from the IESO in second quarter 2021 associated with the Ontario natural gas-fired power plants sold in 2020
- 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 in our Power and Storage business.

Comparable EBITDA for Power and Storage increased by $129 million and $203 million for the three and nine months ended September 30, 2022 compared to the same periods in 2021 primarily due to the net effect of:

- higher contributions from Bruce Power primarily due to a higher contract price and greater plant output resulting from fewer planned outage days
- improved Canadian Power earnings as a result of increased contributions from higher realized power prices and related marketing activities
- decreased Natural Gas Storage and other results in the third quarter and higher year-to-date results reflect the active management of our natural gas positions to capture favourable Alberta natural gas spreads. Gains realized in second quarter 2022 were partially offset in third quarter 2022 and are expected to be further offset in fourth quarter 2022. Both of these periods also include increased business development activities across the segment.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization for the three months ended September 30, 2022 was consistent with the same period in 2021. Lower depreciation and amortization for the nine months ended September 30, 2022 compared to the same period in 2021 was the result of certain adjustments in 2022.

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)	**2022**	2021	**2022**	2021
Items included in comparable EBITDA and EBIT comprised of:				
Revenues[1]	**518**	409	**1,365**	1,215
Operating expenses	**(227)**	(214)	**(684)**	(677)
Depreciation and other	**(92)**	(85)	**(269)**	(247)
Comparable EBITDA and comparable EBIT[2]	**199**	110	**412**	291
Bruce Power – other information				
Plant availability[3,4]	**95%**	86%	**86%**	86%
Planned outage days[4]	**28**	92	**232**	257
Unplanned outage days	**2**	—	**19**	22
Sales volumes (GWh)[5]	**5,684**	5,101	**15,361**	15,197
Realized power price per MWh[6]	**$91**	$80	**$88**	$80

1 Net of amounts recorded to reflect operating cost efficiencies shared with the IESO.

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 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 6 MCR outage, which began in January 2020, is now in the installation phase. In third quarter 2022, a second planned outage on Unit 4 began with expected completion in late 2022. The average 2022 plant availability, excluding the Unit 6 MCR, is now expected to be in the mid-80 per cent range.

Corporate

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

	three months ended September 30		nine months ended September 30	
(millions of $)	**2022**	2021	**2022**	2021
Comparable EBITDA and comparable EBIT	**(9)**	(7)	**(16)**	(14)
Specific items:				
Voluntary Retirement Program	**—**	(71)	**—**	(71)
Foreign exchange gains – inter-affiliate loans[1]	**—**	42	**28**	45
Segmented (losses)/earnings	**(9)**	(36)	**12**	(40)

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

Corporate segmented losses decreased by $27 million for the three months ended September 30, 2022, and Corporate segmented earnings increased by $52 million for the nine months ended September 30, 2022 compared to the same periods in 2021. Corporate segmented (losses)/earnings included accrued pre-tax costs for the Voluntary Retirement Program offered in mid-2021 and foreign exchange gains 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 Interest income and other. Refer to the Financial risks and financial instruments – Related party transactions section for additional information.

INTEREST EXPENSE

	three months ended September 30		nine months ended September 30	
(millions of $)	**2022**	2021	**2022**	2021
Interest on long-term debt and junior subordinated notes				
Canadian dollar-denominated	**(203)**	(183)	**(570)**	(530)
U.S. dollar-denominated	**(321)**	(315)	**(944)**	(945)
Foreign exchange impact	**(98)**	(81)	**(267)**	(238)
	(622)	(579)	**(1,781)**	(1,713)
Other interest and amortization expense	**(49)**	(19)	**(96)**	(50)
Capitalized interest	**5**	2	**11**	20
Interest expense included in comparable earnings	**(666)**	(596)	**(1,866)**	(1,743)
Specific item:				
Keystone XL preservation and other	**—**	—	**—**	(6)
Interest expense	**(666)**	(596)	**(1,866)**	(1,749)

Interest expense increased by $70 million and $117 million for the three and nine months ended September 30, 2022 compared to the same periods in 2021 and included $6 million in second quarter 2021 related to the Keystone XL project-level credit facility for the period following the January 2021 revocation of the Presidential Permit for the Keystone XL pipeline. This has been removed from our calculation of Interest expense included in comparable earnings.

Interest expense included in comparable earnings increased by $70 million and $123 million for the three and nine months ended September 30, 2022 compared to the same periods in 2021 primarily due to the net effect of:

- higher interest rates on increased levels of short-term borrowings
- long-term debt and junior subordinated note issuances, net of maturities. Refer to the Financial condition section for additional information
- reduced capitalized interest due to its cessation for the Keystone XL pipeline project following the revocation of the Presidential Permit in January 2021
- the foreign exchange impact from a stronger U.S. dollar on translation of U.S. dollar-denominated interest.

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

	three months ended September 30		nine months ended September 30	
(millions of $)	**2022**	**2021**	**2022**	**2021**
Canadian dollar-denominated	**40**	40	**117**	104
U.S. dollar-denominated	**58**	33	**106**	73
Foreign exchange impact	**18**	8	**31**	18
Allowance for funds used during construction	**116**	81	**254**	195

AFUDC increased by $35 million and $59 million for the three and nine months ended September 30, 2022 compared to the same periods in 2021. 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. Refer to the Recent developments – Mexico Natural Gas Pipelines section for additional information. The increase in Canadian dollar-denominated AFUDC for the nine months ended September 30, 2022 is primarily related to increased capital expenditures on the NGTL System.

INTEREST INCOME AND OTHER

	three months ended September 30		nine months ended September 30	
(millions of $)	**2022**	**2021**	**2022**	**2021**
Interest income and other included in comparable earnings	**41**	91	**125**	341
Specific items:				
Foreign exchange losses – inter-affiliate loan	**—**	(42)	**(28)**	(45)
Risk management activities	**(283)**	(125)	**(321)**	(183)
Interest income and other	**(242)**	(76)	**(224)**	113

Interest income and other decreased by $166 million and $337 million for the three and nine months ended September 30, 2022 compared to the same periods in 2021 and included the following specific items which have been removed from our calculation of Interest income and other included in comparable earnings:

- 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
- unrealized net losses from changes in the fair value of derivatives used to manage our foreign exchange risk. These losses increased in 2022 due to significant strengthening of the U.S. dollar. Refer to the Financial risks and financial instruments section for additional information.

Our proportionate share of the corresponding foreign exchange gains and interest expense on the peso-denominated inter-affiliate loans to the Sur de Texas joint venture from its partners were reflected in Income from equity investments in the Corporate and Mexico Natural Gas Pipelines segments, respectively. The foreign exchange gains and losses on these inter-affiliate loans were removed from comparable earnings. As part of refinancing activities with the Sur de Texas joint venture, on March 15, 2022, the peso-denominated loan discussed above was replaced with a new U.S. dollar-denominated loan of an equivalent $1.2 billion (US$938 million). On July 29, 2022, the U.S. dollar-denominated loan was fully repaid. The interest income and interest expense on both the peso-denominated and U.S. dollar-denominated loans were included in comparable earnings with all amounts offsetting and resulting in no impact in net income. Refer to the Financial risks and financial instruments – Related party transactions section for additional information.

Interest income and other included in comparable earnings decreased by $50 million for the three months ended September 30, 2022 compared to the same period in 2021 primarily due to:

- realized losses in third quarter 2022 compared to realized gains for the same period in 2021 on derivatives used to manage our net exposure to foreign exchange rate fluctuation on U.S. dollar-denominated income
- lower interest income due to the repayment of the above inter-affiliate loan receivable by the Sur de Texas joint venture on July 29, 2022.

Interest income and other included in comparable earnings decreased by $216 million for the nine months ended September 30, 2022 compared to the same period in 2021 due to:

- lower realized gains in 2022 on derivatives used to manage our net exposure to foreign exchange rate fluctuation on U.S. dollar-denominated income
- lower interest income due to the refinancing of the inter-affiliate loan receivable and subsequent repayment.

INCOME TAX (EXPENSE)/RECOVERY

	three months ended September 30		nine months ended September 30	
(millions of $)	**2022**	2021	**2022**	2021
Income tax expense included in comparable earnings	**(202)**	(195)	**(554)**	(573)
Specific items:				
Great Lakes goodwill impairment charge	**—**	—	**40**	—
Settlement of Mexico prior years' income tax assessments	**—**	—	**(195)**	—
Expected credit loss provision for net investment in leases	**21**	—	**21**	—
Bruce Power unrealized fair value adjustments	**(1)**	—	**7**	(1)
Keystone XL preservation and other	**1**	3	**4**	8
Keystone XL asset impairment charge and other	**—**	—	**—**	660
Voluntary Retirement Program	**—**	16	**—**	16
Gain on sale of Ontario natural gas-fired power plants	**—**	—	**—**	(4)
Risk management activities	**59**	41	**84**	52
Income tax (expense)/recovery	**(122)**	(135)	**(593)**	158

Income tax expense decreased by $13 million and increased by $751 million for the three and nine months ended September 30, 2022 compared to the same periods in 2021 and included the following specific items which have been removed from our calculation of Income tax expense included in comparable earnings, in addition to the income tax impacts on other specific items referenced elsewhere in this MD&A:

- settlement of prior years' income tax assessments related to our operations in Mexico. Refer to the Recent developments – Corporate section for additional information
- the income tax impact of the Keystone XL pipeline project asset impairment charge and other in 2021.

Income tax expense included in comparable earnings increased by $7 million for the three months ended September 30, 2022 compared to the same period in 2021 primarily due to higher comparable earnings and higher Mexico inflation adjustments, partially offset by favourable U.S. state rate adjustments and lower flow-through income taxes.

Income tax expense included in comparable earnings decreased by $19 million for the nine months ended September 30, 2022 compared to the same period in 2021 primarily due to lower comparable earnings and lower flow-through income taxes, partially offset by higher Mexico inflation adjustments.

NET INCOME ATTRIBUTABLE TO NON-CONTROLLING INTERESTS

	three months ended September 30		nine months ended September 30	
(millions of $)	**2022**	**2021**	**2022**	**2021**
Net income attributable to non-controlling interests	**(8)**	(8)	**(28)**	(83)

Net income attributable to non-controlling interests remained consistent for three months ended September 30, 2022 and decreased by $55 million for the nine months ended September 30, 2022 compared to the same periods in 2021. The decrease is primarily the result of the March 2021 acquisition of all outstanding common units of TC PipeLines, LP not beneficially owned by TC Energy. Subsequent to the acquisition, TC PipeLines, LP became an indirect, wholly-owned subsidiary of TC Energy.

PREFERRED SHARE DIVIDENDS

	three months ended September 30		nine months ended September 30	
(millions of $)	**2022**	**2021**	**2022**	**2021**
Preferred share dividends	**(21)**	(31)	**(85)**	(108)

Preferred share dividends decreased by $10 million and $23 million for the three and nine months ended September 30, 2022 compared to the same periods in 2021 primarily due to the redemption of preferred shares in 2022 and 2021.

Recent developments

CANADIAN NATURAL GAS PIPELINES

Coastal GasLink

On July 28, 2022, Coastal GasLink LP executed definitive agreements with LNG Canada that addressed and resolved disputes over certain incurred and anticipated costs of the Coastal GasLink pipeline project.

The revised project agreements incorporate a new cost estimate for the project of $11.2 billion, which reflects an increase from the original project cost estimate due to scope increases and the impacts of COVID-19, weather and other events outside of Coastal GasLink LP's control. Current market conditions, including inflationary impacts on labour costs, could result in final project costs that are higher than this new estimate. Mechanical in-service is expected to be reached by the end of 2023. Commercial in-service of the Coastal GasLink pipeline will occur after completion of commissioning the pipeline.

The revised $11.2 billion project cost will be funded in part by existing project-level credit facilities with a revised total capacity of $8.4 billion following an expansion of $1.6 billion. Required project equity of $2.8 billion includes an additional $1.9 billion equity contribution from TC Energy, payable in monthly installments from August 2022 to February 2023 that does not result in a change to our 35 per cent ownership. Additional equity financing required to fund construction of the pipeline will initially be financed through a subordinated loan agreement between TC Energy and Coastal GasLink LP which was originally put in place in fourth quarter 2021 and was amended on July 28, 2022. Following these amendments, draws by Coastal GasLink LP will be provided through an interest-bearing loan, subject to a floating market-based interest rate, which 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 determined. Committed capacity under this subordinated loan agreement between TC Energy and Coastal GasLink LP has been and will continue to be stepped down over time. At September 30, 2022, total available capacity under the subordinated loan agreement was $1.8 billion with an outstanding balance of $250 million. We currently estimate our portion of the equity contributions to Coastal GasLink LP over the project life to be approximately $2.1 billion, including the $1.9 billion equity contribution noted above.

On March 9, 2022, we announced the signing of option agreements to sell a 10 per cent equity interest in Coastal GasLink LP to Indigenous communities across the project corridor. The opportunity to become business partners through equity ownership was made available to all 20 Nations holding existing agreements with Coastal GasLink LP. The Nations have established two entities that together currently represent 16 Indigenous communities that have confirmed their support for the option agreements. The equity option is exercisable after commercial in-service of the pipeline, subject to customary regulatory approvals and consents, including the consent of LNG Canada.

The Coastal GasLink pipeline project is approximately 75 per cent complete. The entire route has been cleared, grading is more than 84 per cent complete and approximately 400 km of pipeline has been backfilled with reclamation activities underway in many areas.

NGTL System

In the nine months ended September 30, 2022, the NGTL System placed approximately $1.9 billion of capacity projects in service.

2021 NGTL System Expansion Program

Construction of the 2021 NGTL System Expansion Program continues and, due to current market conditions as well as regulatory and weather delays, the estimated capital cost of the program is $3.5 billion. As of September 30, 2022, $2.7 billion of facilities have been placed into service, with the remaining facilities expected to be placed in service in fourth quarter 2022 and first quarter 2023. The program consists of 344 km (214 miles) of new pipeline, three compressor units and associated facilities and will add 1.6 PJ/d (1.5 Bcf/d) of incremental capacity to the NGTL System.

2022 NGTL System Expansion Program

We continue to advance construction of the 2022 NGTL System Expansion Program. As a result of current market conditions, material prices and regulatory delays, the estimated capital cost of the program is $1.5 billion with in-service dates anticipated in fourth quarter 2022 and second quarter 2023. The program consists of approximately 166 km (103 miles) of new pipeline, one new compressor unit and associated facilities and is underpinned by approximately 773 TJ/d (722 MMcf/d) of firm-service contracts with eight-year minimum terms.

NGTL System/Foothills West Path Delivery Program

On March 2, 2022, we received further regulatory approvals related to $0.5 billion of facilities, with the remaining approval anticipated in fourth quarter 2022. As a result of terrain complexity, current market conditions, material and labour cost increases and additional permitting conditions, the Canadian portion of the West Path Delivery Program has an estimated capital cost of $1.5 billion, with the first of the facilities' in-service dates anticipated in fourth quarter 2022 and the remaining facilities throughout 2023. The program consists of approximately 107 km (66 miles) of pipelines and associated facilities and is underpinned by 275 TJ/d (258 MMcf/d) of new firm-service contracts with terms that exceed 30 years.

Valhalla North and Berland River Project (VNBR)

In November 2022, we sanctioned the VNBR project which will serve aggregate system requirements and connect migrating supply to key demand markets, providing incremental capacity on the NGTL System of approximately 527 TJ/d (500 MMcf/d) and contribute to lower GHG emission intensity for the overall system. With an estimated capital cost of $0.6 billion, the project consists of approximately 33 km (21 miles) of new pipeline, one new non-emitting electric compressor unit and associated facilities. An application for the project is expected to be submitted to CER in third quarter 2023, with an anticipated in-service date in 2026 subject to regulatory approval.

U.S. NATURAL GAS PIPELINES

Columbia Gas Section 4 Rate Case

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

ANR Section 4 Rate Case

ANR filed a Section 4 rate case with FERC on January 28, 2022 requesting an increase to ANR's maximum transportation rates effective August 1, 2022, subject to refund upon completion of the rate proceeding. The rate case is progressing and we continue to pursue a collaborative process to find a mutually beneficial outcome with our customers, FERC and other stakeholders through settlement negotiations.

Great Lakes Rate Settlement

On April 26, 2022, FERC approved Great Lakes' unopposed rate case settlement with its customers by which Great Lakes and the settling parties agreed to maintain existing recourse rates through October 31, 2025.

While the settlement created short-term rate certainty, it prompted a re-evaluation of Great Lakes' long-term free cash flows which resulted in a US$451 million goodwill impairment charge being recorded in first quarter 2022. Refer to the Other information – Critical accounting estimates and accounting policy changes section for additional information.

KO Transmission Enhancement Acquisition

On April 28, 2022, we approved the approximately US$80 million acquisition of KO Transmission assets to be integrated into our Columbia Gas pipeline. After filing for and receiving FERC approval of Columbia Gas' acquisition of KO Transmission assets, which is expected by the end of 2022, this expanded footprint is expected to provide additional last-mile connectivity of Columbia Gas into northern Kentucky and southern Ohio to growing LDC markets. It is also expected to provide a platform for future capital investments including future conversions of coal-fueled power plants in the region.

Renewable Natural Gas Hub Development

In April 2022, we announced a strategic collaboration with GreenGasUSA to explore development of a network of RNG transportation hubs. These hubs would provide centralized access to existing energy transportation infrastructure for RNG sources, such as farms, wastewater treatment facilities and landfills. We believe that this collaboration, which targets 10 transportation hubs nationally, will rapidly expand and provide incremental capability to the already existing RNG interconnects across our U.S. natural gas footprint. The development of these hubs is an important step towards the acceleration of methane capture projects and the concurrent reduction of GHG emissions.

Alberta XPress and North Baja XPress Projects

In April 2022, FERC provided certificate orders approving our Alberta XPress and North Baja XPress projects. The Alberta XPress project is an expansion of ANR that utilizes existing capacity on Great Lakes and the Canadian Mainline to connect growing supply from the WCSB to U.S. Gulf Coast LNG export markets. The anticipated in-service date is late 2022 or early 2023 with an estimated project cost of US$0.3 billion. The North Baja XPress project is designed to expand capacity on North Baja to meet increased customer demand by upgrading one existing compressor station and two existing meter stations in Arizona and California with a mid-2023 expected in-service date and total anticipated cost of US$0.1 billion. All the upgrades required for North Baja XPress will occur on property and within facilities currently owned and/or operated by North Baja.

Louisiana XPress Project

The Louisiana XPress project, a Columbia Gulf project designed to connect natural gas supply to U.S. Gulf Coast LNG export facilities, was phased into service over the course of third quarter 2022.

Elwood Power and Wisconsin Access Projects

The Elwood Power and Wisconsin Access projects, both including upgrade and reliability components, while reducing emissions along portions of the ANR pipeline system, were placed into commercial service on November 1, 2022.

Gillis Access Project

In November 2022, we sanctioned development of the Gillis Access project, a 1.5 Bcf/d greenfield pipeline system that will connect supplies from the Haynesville basin at Gillis to markets elsewhere in Louisiana. The 42 mile Louisiana header system will also enable the rapidly growing Louisiana LNG export market to access Haynesville-sourced gas production as well as create a platform for further growth into the southeast Louisiana markets. The project has an anticipated in-service date in 2024 and a total estimated cost of US$0.4 billion.

MEXICO NATURAL GAS PIPELINES

Strategic Alliance with the CFE

On August 4, 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. This alliance consolidates previous TSAs executed between TC Energy's Mexico-based subsidiary TGNH and the CFE in connection with our natural gas pipeline assets in central Mexico (including the Tamazunchale, Villa de Reyes and Tula pipelines) under a single, U.S. dollar-denominated take-or-pay contract that extends through 2055. This agreement also resolves and terminates previous international arbitrations with the CFE related to the Villa de Reyes and Tula pipelines.

In connection with the strategic alliance, we reached an FID to proceed and build the Southeast Gateway pipeline, a 1.3 Bcf/d, 715 km 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 lateral section of the Villa de Reyes pipeline was mechanically completed in second quarter 2022, while VdR North and Tula East were placed into commercial service in third quarter 2022. We are working with the CFE, and expect the lateral and the south sections of the Villa de Reyes pipeline to begin commercial service in 2023. Additionally, we have agreed to jointly develop and complete the central segment of the Tula pipeline, subject to an FID.

Subject to regulatory approvals from Mexico's economic competition commission 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. Upon in-service of the Southeast Gateway pipeline, the CFE's equity interest in TGNH would equal 15 per cent, which would increase to approximately 35 per cent upon expiry of the contract in 2055. Regulatory approvals related to the CFE's equity participation in TGNH are expected to take up to 24 months.

POWER AND STORAGE

Bruce Power Life Extension

On March 7, 2022, the IESO verified Bruce Power's Unit 3 MCR program final cost and schedule duration estimate submitted in December 2021. The Unit 3 MCR program is scheduled to begin in first quarter 2023 with expected completion in 2026.

Bruce Power's contract price increased by approximately $10 per MWh on April 1, 2022, in accordance with contract terms, reflecting capital to be invested under the Unit 3 MCR program and the 2022 to 2024 Asset Management program plus normal annual inflation adjustments.

Bruce Power's Unit 4 is the third unit in their MCR program. The Unit 4 MCR definition phase was completed in June 2022 and is now in the preparation phase leading up to an FID expected in fourth quarter 2023. A preliminary basis of estimate (including an initial cost and schedule duration estimate) is expected to be submitted to the IESO in fourth quarter 2022.

Renewable Energy Contracts and/or Investment Opportunities

Through an RFI process conducted in 2021, we are seeking potential contracts and/or investment opportunities in wind, solar and energy storage projects to meet the electricity needs of the U.S. portion of the Keystone Pipeline System and supply renewable energy products and services to industrial and oil and gas sectors proximate to our in-corridor demand. To date in 2022, we have finalized contracts for approximately 580 MW and 240 MW from wind energy and solar projects, respectively. We continue to evaluate the proposals received through the RFI process and expect to finalize additional contracts and/or investment opportunities in 2022.

Saddlebrook Solar Project

On October 4, 2022, we announced that we have begun pre-construction activities on the Saddlebrook Solar project located near Aldersyde, Alberta. The expected capital cost of this 81 MW project is $146 million with the project partially supported by $10 million from Emissions Reduction Alberta. Construction is expected to be completed in 2023.

OTHER ENERGY SOLUTIONS

Hydrogen Hubs

As part of our JDA with Nikola, on April 26, 2022, we announced a plan to evaluate a hydrogen production hub on 140 acres in Crossfield, Alberta, where we currently operate our natural gas storage facility. We expect an FID by the end of 2023, subject to customary regulatory approvals.

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, will be capable of transporting more than 20 million tonnes of carbon dioxide annually. On October 18, 2022, ACG announced that it has entered into a carbon sequestration evaluation agreement with the Government of Alberta to further evaluate one of the largest AOI for safely storing carbon from industrial emissions in Alberta. This agreement will allow ACG to continue evaluating the suitability of our AOI and move forward into the next stage of the province's CCUS process to provide confidence to customers, Indigenous communities, stakeholders and the Government of Alberta in the project's carbon storage capabilities. Designed to be an open-access system, ACG proposes to leverage existing right of ways and/or pipelines to connect the Alberta Industrial Heartland emissions region to a key sequestration location.

Lynchburg Renewable Fuels

On October 17, 2022, we announced a US$29 million investment for 30 per cent ownership in the Lynchburg Renewable Fuels project, a renewable natural gas production facility in Lynchburg, Tennessee being developed by 3 Rivers Energy Partners, LLC. Along with our ownership interest, we will market all RNG and environmental attributes generated from the facility once operational in 2024. We also have the option to jointly develop future RNG projects with 3 Rivers Energy Partners, LLC.

CORPORATE

Mexico Tax Audit

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

On April 27, 2022, we settled with the SAT on all of the above matters for the tax years 2013 through 2021. In the nine months ended September 30, 2022, we recorded US$152 million of income tax expense (inclusive of withholding taxes, interest, penalties and other financial charges).

Dividend Reinvestment Plan

To prudently fund our growth program that includes increased project costs on the NGTL System and following our obligation to make an equity contribution of $1.9 billion to Coastal GasLink LP, we reinstated the issuance of common shares from treasury at a two per cent discount under our Dividend Reinvestment Plan (DRP) commencing with the dividends declared on July 27, 2022. With respect to the common share dividends declared on July 27, 2022, subsequently paid on October 31, 2022, the DRP participation rate amongst common shareholders was approximately 38 per cent resulting in $342 million reinvested in common equity. The discounted DRP is expected to be in place through the dividend declarations for the quarter ending June 30, 2023.

Common Shares Issued Under Public Offering

On August 10, 2022 we issued 28.4 million common shares at a price of $63.50 each for gross proceeds of approximately $1.8 billion. We will use the proceeds of the offering, directly or indirectly, together with other financing sources and cash on hand, to fund costs associated with the construction of the Southeast Gateway pipeline.

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 to meet our financing needs, manage our capital structure and to preserve our credit ratings.

We believe 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, joint ventures, asset-level financing, cash on hand and substantial committed credit facilities. Annually, in fourth quarter, we renew and extend our credit facilities as required.

At September 30, 2022, our current assets totaled $8.9 billion and current liabilities amounted to $16.8 billion, leaving us with a working capital deficit of $7.9 billion compared to $5.6 billion at December 31, 2021. 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 $10.6 billion of committed revolving credit facilities, of which $4.6 billion of short-term borrowing capacity remains available, net of $6.0 billion backstopping outstanding commercial paper balances. We also have arrangements in place for a further $2.4 billion of demand credit facilities of which $1.1 billion remained available as at September 30, 2022
- our access to capital markets, including through securities issuances, incremental credit facilities, portfolio management activities, DRP and Corporate ATM programs, if deemed appropriate.

CASH PROVIDED BY OPERATING ACTIVITIES

	three months ended September 30		nine months ended September 30	
(millions of $)	**2022**	2021	**2022**	2021
Net cash provided by operations	**1,701**	1,712	**4,350**	5,089
(Decrease)/increase in operating working capital	**(67)**	(227)	**511**	32
Funds generated from operations	**1,634**	1,485	**4,861**	5,121
Specific items:				
Settlement of Mexico prior years' income tax assessments	**—**	—	**195**	—
Keystone XL preservation and other	**4**	14	**15**	35
Current income tax (recovery)/expense on Keystone XL asset impairment charge, preservation and other	**(1)**	—	**(3)**	120
Voluntary Retirement Program	**—**	71	**—**	71
Current income tax recovery on Voluntary Retirement Program	**—**	(14)	**—**	(14)
Comparable funds generated from operations	**1,637**	1,556	**5,068**	5,333

Net cash provided by operations

Net cash provided by operations decreased by $11 million for the three months ended September 30, 2022 compared to the same period in 2021 primarily due to the amount and timing of working capital changes, partially offset by higher funds generated from operations. Net cash provided by operations decreased $739 million for the nine months ended September 30, 2022 compared to the same period in 2021 primarily due to the amount and timing of working capital changes as well as lower funds generated from operations.

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 $81 million for the three months ended September 30, 2022 compared to the same period in 2021 primarily due to increased EBITDA. This was partially offset by higher interest expense, the impact of derivatives used to manage our net exposure to foreign exchange fluctuations on U.S. dollar-denominated income and the refinancing of the inter-affiliate loan receivable and its subsequent repayment in 2022. Comparable funds generated from operations decreased by $265 million for the nine months ended September 30, 2022 compared to the same period in 2021 as a result of the items listed above, partially offset by increased EBITDA.

CASH USED IN INVESTING ACTIVITIES

	three months ended September 30		nine months ended September 30	
(millions of $)	**2022**	**2021**	**2022**	**2021**
Capital spending				
Capital expenditures	**(1,837)**	(1,446)	**(4,608)**	(4,305)
Contributions to equity investments	**(746)**	(241)	**(1,181)**	(706)
	(2,583)	(1,687)	**(5,789)**	(5,011)
Keystone XL contractual recoveries	**95**	—	**568**	—
Loans to affiliate repaid/(issued), net	**101**	(620)	**(11)**	(840)
Other distributions from equity investments	**1,205**	—	**1,237**	—
Deferred amounts and other	**49**	(66)	**(4)**	(470)
Net cash used in investing activities	**(1,133)**	(2,373)	**(3,999)**	(6,321)

Capital expenditures in 2022 were incurred primarily for the expansion of the NGTL System, Columbia Gas and ANR projects, and development of the Southeast Gateway pipeline, as well as maintenance capital expenditures. Higher capital expenditures in 2022 compared to 2021 reflected spending for the development of the Southeast Gateway pipeline and expansion of the NGTL System, partially offset by the termination of the Keystone XL pipeline project following the revocation of the Presidential Permit in January 2021 as well as reduced spending on ANR projects.

Contributions to equity investments increased in 2022 compared to 2021 mainly due to equity contributions to Coastal GasLink LP, in accordance with the July 2022 definitive agreements, partially offset by reduced cash calls from Bruce Power. 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 loan was fully repaid upon maturity in the amount of $1.2 billion and was subsequently replaced with a new U.S. dollar-denominated loan of an equivalent $1.2 billion. 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. The Contributions to equity investments and Other distributions from equity investments with respect to the 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.

For the three and nine months ended September 30, 2022, we received $95 million and $568 million, respectively, of contractual recoveries related to the Keystone XL pipeline project termination in 2021.

Loans to affiliate represent issuances and repayments on the subordinated demand revolving credit facility and the subordinated loan agreement that we entered into with Coastal GasLink LP to provide additional liquidity and funding to the project. Refer to the Financial risks and financial instruments – Related party transactions section for additional information.

CASH (USED IN)/PROVIDED BY FINANCING ACTIVITIES

	three months ended September 30		nine months ended September 30	
(millions of $)	**2022**	**2021**	**2022**	**2021**
Notes payable issued/(repaid), net	**458**	1,448	**672**	(1,012)
Long-term debt issued, net of issue costs	**(2)**	47	**2,508**	7,798
Long-term debt repaid	**(1,287)**	—	**(1,313)**	(980)
Junior subordinated notes issued, net of issue costs	**—**	—	**1,008**	495
Redeemable non-controlling interest repurchased	**—**	—	**—**	(633)
Dividends and distributions paid	**(923)**	(903)	**(2,770)**	(2,652)
Common shares issued, net of issue costs	**1,742**	4	**1,900**	64
Preferred shares redeemed	**—**	—	**(1,000)**	(500)
Other	**6**	—	**23**	(15)
Net cash (used in)/provided by financing activities	**(6)**	596	**1,028**	2,565

Long-term debt issued

The following table outlines significant long-term debt issuances in the nine months ended September 30, 2022:

(millions of Canadian $, unless otherwise noted)					
Company	**Issue date**	**Type**	**Maturity date**	**Amount**	**Interest rate**
TRANSCANADA PIPELINES LIMITED					
	May 2022	Medium Term Notes	May 2032	800	5.33%
	May 2022	Medium Term Notes	May 2026	400	4.35%
	May 2022	Medium Term Notes	May 2052	300	5.92%
ANR PIPELINE COMPANY					
	May 2022	Senior Unsecured Notes	May 2032	US 300	3.43%
	May 2022	Senior Unsecured Notes	May 2034	US 200	3.58%
	May 2022	Senior Unsecured Notes	May 2037	US 200	3.73%
	May 2022	Senior Unsecured Notes	May 2029	US 100	3.26%

Long-term debt retired

On August 1, 2022, TCPL retired US$1.0 billion of senior unsecured notes bearing interest at a fixed rate of 2.50 per cent.

Junior subordinated notes issued

In March 2022, we issued US$800 million of junior subordinated notes through TransCanada Trust, a wholly-owned financing trust subsidiary of TCPL. We used the proceeds from the issuance to redeem all issued and outstanding TC Energy Series 15 preferred shares on May 31, 2022 pursuant to their terms. Refer to Note 10, Junior subordinated notes issued, of our Condensed consolidated financial statements for additional information.

DIVIDENDS

On November 8, 2022, we declared quarterly dividends on our common shares of $0.90 per share payable on January 31, 2023 to shareholders of record at the close of business on December 30, 2022.

DIVIDEND REINVESTMENT PLAN

To prudently fund our growth program that includes increased project costs on the NGTL System and following our obligation to make an equity contribution of $1.9 billion to Coastal GasLink LP, we reinstated the issuance of common shares from treasury at a two per cent discount under our DRP commencing with the dividends declared on July 27, 2022. With respect to the common share dividends declared on July 27, 2022, subsequently paid on October 31, 2022, the DRP participation rate amongst common shareholders was approximately 38 per cent resulting in $342 million reinvested in common equity. The discounted DRP is expected to be in place through the dividend declarations for the quarter ending June 30, 2023.

SHARE INFORMATION

At November 3, 2022, we had 1.0 billion issued and outstanding common shares and 6 million outstanding options to buy common shares, of which 3 million were exercisable.

On August 10, 2022 we issued 28.4 million common shares at a price of $63.50 each for gross proceeds of approximately $1.8 billion. We will use the proceeds of the issuance, directly or indirectly, together with other financing sources and cash on hand, to fund costs associated with the construction of the Southeast Gateway pipeline.

On May 31, 2022, we redeemed all of the 40 million issued and outstanding Series 15 preferred shares at a redemption price of $25.00 per share and paid the final quarterly dividend of $0.30625 per Series 15 preferred share for the period up to but excluding May 31, 2022, as previously announced on April 1, 2022.

CREDIT FACILITIES

At November 3, 2022, we had a total of $10.5 billion of committed revolving credit facilities of which $3.6 billion of short-term borrowing capacity remains available, net of $6.9 billion backstopping outstanding commercial paper balances. We also have arrangements in place for a further $2.4 billion of demand credit facilities of which $1.1 billion remains available.

Refer to the Financial risks and financial instruments section for more information about liquidity, market and other risks.

CONTRACTUAL OBLIGATIONS

Capital expenditure commitments are largely consistent with December 31, 2021, reflecting the net effect of normal course fulfillment of commitments related to construction, partially offset by new commitments on capital projects.

There were no material changes to our contractual obligations in third quarter 2022 or to payments due in the next five years or after. Refer to our 2021 Annual Report for more information about our contractual obligations.

Financial risks and financial instruments

We are exposed to market risk and counterparty credit risk 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 2021 Annual Report for more information about the risks we face in our business which have not changed substantially since December 31, 2021, 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.

Many of our financial instruments and contractual obligations with variable rate components reference U.S. dollar London Interbank Offered Rate (LIBOR), of which certain rate settings have ceased to be published at the end of 2021 with full cessation by mid-2023. We expect to use practical expedients available in the guidance to treat contract modifications as events that do not require contract remeasurement or reassessment of previous accounting determinations. As such, these changes are not expected to have a material impact on our consolidated financial statements. In the nine months ended September 30, 2022, we have not identified any applicable contract modifications as a result of reference rate reform. We continue to monitor any new developments with respect to this guidance.

On May 16, 2022, Refinitiv Benchmark Services (UK) Limited, the administrator of the Canadian Dollar Offered Rate (CDOR), announced that the calculation and publication of all tenors of CDOR will permanently cease following a final publication on June 28, 2024. We are currently evaluating the impact of this guidance on contracts and financial instruments with variable rate components that reference CDOR and have not yet determined the effect 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 can affect our comparable EBITDA and comparable earnings. Refer to the Consolidated results – Foreign exchange section for additional information.

A small portion of our Mexico Natural Gas Pipelines monetary assets and liabilities are peso-denominated, while the functional currency for our Mexico operations is U.S. dollars. These peso-denominated balances are revalued to U.S. dollars and, as a result, changes in the value of the Mexican peso against the U.S. dollar can affect our net income. In addition, foreign exchange gains or losses calculated for Mexico income tax purposes on the revaluation of the Sur de Texas U.S. dollar-denominated loans payable result in peso-denominated deferred income tax expense or recovery for Sur de Texas, leading to fluctuations in comparable EBITDA. These exposures are managed using foreign exchange derivatives, with the hedging gains and losses recorded in Interest income and other.

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
- loans receivable
- net investment in leases.

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 2021 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, 2022, we had no significant credit risk concentrations and no significant amounts past due or impaired. As discussed in Note 8, TGNH strategic alliance with the CFE, a $71 million (US$53 million) expected credit loss provision before tax was recognized on the TGNH net investment in leases, as required by U.S. GAAP.

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.

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.

Sur de Texas

We hold a 60 per cent equity interest in a joint venture with IEnova to own 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 and was fully repaid upon maturity on March 15, 2022 in the amount of approximately $1.2 billion.

Our Condensed consolidated statement of income reflected the related interest income and foreign exchange impact on this loan which were fully offset upon consolidation with corresponding amounts included in our proportionate share of Sur de Texas' equity earnings as follows:

	three months ended September 30		nine months ended September 30		Affected line item in the Condensed consolidated statement of income
(millions of $)	**2022**	**2021**	**2022**	**2021**	
Interest income[1]	**—**	22	**19**	64	Interest income and other
Interest expense[2]	**—**	(22)	**(19)**	(64)	Income from equity investments
Foreign exchange losses[1]	**—**	(42)	**(28)**	(45)	Interest income and other
Foreign exchange gains[1]	**—**	42	**28**	45	Income from equity investments

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

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

Coastal GasLink LP

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

TC Energy Equity Contributions and Subordinated Loan Agreement

In July 2022, in accordance with definitive agreements with the Coastal GasLink LP partners, we entered into an obligation to make an equity contribution to Coastal GasLink LP of $1.9 billion, payable in monthly installments from August 2022 to February 2023, with no resulting change to our 35 per cent ownership. At September 30, 2022, the remaining $1.3 billion of the equity contribution had been accrued and was reflected in Accounts payable and other on our Condensed consolidated balance sheet.

In 2021, we entered into a subordinated loan agreement with Coastal GasLink LP to provide interim temporary financing to fund incremental project costs as a bridge to a required increase in project-level financing. Under this agreement, financing was provided through a combination of interest-bearing loans subject to floating market-based interest rates and non-interest-bearing loans. Following amendments to this loan agreement on July 28, 2022, draws on this loan by Coastal GasLink LP will be provided through an interest-bearing loan, subject to a floating market-based interest rate, which will be repaid by the Coastal GasLink LP partners, including us, subsequent to the in-service date of the Coastal GasLink pipeline when final project costs are determined. The total capacity committed under this subordinated loan agreement was $2.1 billion of which $1.3 billion reflects the accrued equity contribution described above. An outstanding balance of $250 million as at September 30, 2022 (December 31, 2021 – $238 million) is reflected in Long-term loans receivable from affiliate on our Condensed consolidated balance sheet.

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 had a capacity of $100 million with an outstanding balance of nil at September 30, 2022 (December 31, 2021 – $1 million) reflected in Loans receivable from affiliates under Current assets on our Condensed consolidated balance sheet.

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 recovered or refunded through the tolls charged by us. As a result, these gains and losses are deferred as regulatory assets or regulatory liabilities and are collected from or refunded to 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, 2022**	**December 31, 2021**
Other current assets	**702**	169
Other long-term assets	**69**	48
Accounts payable and other	**(1,080)**	(221)
Other long-term liabilities	**(239)**	(47)
	(548)	(51)

Unrealized and realized gains and 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	
	2022	**2021**	**2022**	**2021**
Derivative Instruments Held-for-Trading[1]				
Amount of unrealized gains/(losses) in the period				
Commodities	**42**	(43)	**(16)**	(27)
Foreign exchange	**(283)**	(125)	**(321)**	(183)
Amount of realized gains/(losses) in the period				
Commodities	**165**	58	**561**	167
Foreign exchange	**(1)**	37	**27**	195
Derivative Instruments in Hedging Relationships				
Amount of realized (losses)/gains in the period				
Commodities	**(21)**	(9)	**(39)**	(32)
Interest rate	**2**	(6)	**—**	(18)

1 Realized and unrealized gains and losses on held-for-trading derivative instruments used to purchase and sell commodities are included on a net basis in Revenues. Realized and unrealized gains and losses on foreign exchange held-for-trading derivative instruments are included on a net basis in Interest income and other.

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 14, 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, 2022, 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 2022 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 2021 Annual Report for a listing of critical accounting estimates.

Strategic alliance with the CFE

On August 4, 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. This alliance consolidates previous TSAs executed between TC Energy's Mexico-based subsidiary TGNH and the CFE in connection with our natural gas pipeline assets in central Mexico (including the Tamazunchale, Villa de Reyes and Tula pipelines) under a single, U.S. dollar-denominated take-or-pay contract that extends through 2055. This agreement also resolves and terminates previous international arbitrations with the CFE related to the Villa de Reyes and Tula pipelines.

Lease accounting policy

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

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

We consider non-lease components as distinct elements of a contract that are not related to the use of the leased asset. A good or service that is promised to a customer is distinct if: 1) the customer can benefit from the good or service either on its own or together with other resources that are readily available to the customer and 2) the entity's promise to transfer the good or service to the customer is separately identifiable from other promises in the contract.

The TSA executed between TC Energy and the CFE contains a lease under U.S. GAAP with multiple lease and non-lease components. The lease components represent the capacity available to the CFE provided by the pipelines in service which, at September 30, 2022, included the Tamazunchale, VdR North and Tula East pipelines. The non-lease components represent our services with respect to operation and maintenance of the TGNH pipelines in service.

The contract consideration consisting of fixed toll payments is allocated to lease and non-lease components based on the standalone selling price for each distinct good or service within the contract using a combination of expected cost plus a margin and residual approach. In order to establish the expected cost plus a margin approach, we applied judgment to determine reasonable estimates of the expected future cost of satisfying the non-lease performance obligations.

The TGNH pipelines are regulated and tolls are designed to recover the cost of providing service. On this basis, we applied judgment to determine that, at the inception of the lease arrangement, the fair value of the underlying assets approximates the carrying value and the residual value approximates the remaining carrying value at the end of the lease term. There is no guaranteed residual value for the underlying assets; however, TC Energy expects to continue to operate the TGNH pipelines following the lease term expiration as long as there is supply and demand for natural gas in Mexico. At the inception of the lease arrangement, we determined that the present value of the sum of the future lease payments over the lease term exceeds substantially all of the fair value of the underlying TGNH pipelines in service and as such are classified as sales-type leases.

Sales-type leases and expected credit loss provision

At September 30, 2022, we recognized an aggregate net investment in sales-type leases amounting to $2,393 million with no gains or losses recorded upon derecognition of the respective Plant, property and equipment on our Condensed consolidated balance sheet.

The net investment in leases arising from sales-type leases is a financial asset subject to impairment using a lifetime expected loss approach at initial recognition and throughout the life of the financial asset. Expected credit losses are calculated using a model and methodology based on assumptions and judgment considering historical data, current counterparty information as well as reasonable and supportable forecasts of future economic conditions. As required under U.S. GAAP, our methodology includes consideration of the probability of default (the probability that the lessee will default during the lease term), the loss given default (the economic loss as a proportion of the net investment in leases balance in the event of a default) and the exposure at default (the net investment in leases balance at the time of a hypothetical default) with one-year forward-looking information that includes assumptions for future macroeconomic conditions under three probability-weighted future scenarios. The macroeconomic factors considered most relevant to the lessee's ability to settle the net investment in leases include Mexico's GDP, government debt to GDP and inflation.

The expected credit loss amount is updated at each reporting date to reflect changes in assumptions and forecasts for future economic conditions. With respect to net investment in leases, for the three and nine months ended September 30, 2022, we recorded a $71 million (US$53 million) expected credit loss provision before tax in Plant operating costs and other in the Condensed consolidated statement of income.

Equity investment in Coastal GasLink LP

Our non-consolidated Variable Interest Entities (VIEs) consist of legal entities where TC Energy is not the primary beneficiary as it does not have the power to direct the activities that most significantly impact the economic performance of these VIEs or where this power is shared with third parties. The assessment of whether an entity is a VIE and, if so, whether TC Energy is the primary beneficiary, is completed at the inception of the entity or at a reconsideration event. We examine specific criteria and use judgment when determining if we are the primary beneficiary of a VIE.

In third quarter 2022, there was a reconsideration event for our investment in Coastal GasLink LP as a result of revised project agreements and a further $1.9 billion equity contribution from TC Energy. We exercised judgment in performing the primary beneficiary analysis and determined that power continues to be shared with our partners; therefore, TC Energy is not the primary beneficiary. In addition, we evaluated our investment in Coastal GasLink LP and concluded there was no indication of impairment as at September 30, 2022.

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 more likely than not that the fair value of the reporting unit is less than its carrying value, we will then perform a quantitative goodwill impairment test.

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

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

Management performed a quantitative impairment test that evaluated a range of assumptions through a discounted cash flow analysis using a risk-adjusted discount rate. It was determined that the estimated fair value of the Great Lakes reporting unit no longer exceeded its carrying value, including goodwill, and that an impairment charge was necessary. As a result, we recorded a pre-tax goodwill impairment charge of $571 million ($531 million after tax) within the U.S. Natural Gas Pipelines segment that is included in Goodwill and asset impairment charges and other in the Condensed consolidated statement of income and was excluded from comparable earnings. The remaining goodwill balance related to Great Lakes is US$122 million at September 30, 2022 (December 31, 2021 – US$573 million). There is a risk that continued reductions in future cash flow forecasts and adverse changes in other key assumptions could result in a future impairment of the goodwill balance relating to Great Lakes.

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

Accounting changes

Our significant accounting policies have remained unchanged since December 31, 2021 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 2021 Annual Report.

Quarterly results

SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA

	2022			2021				2020
(millions of $, except per share amounts)	Third	Second	First	Fourth	Third	Second	First	Fourth
Revenues	**3,799**	3,637	3,500	3,584	3,240	3,182	3,381	3,297
Net income/(loss) attributable to common shares	**841**	889	358	1,118	779	975	(1,057)	1,124
Comparable earnings	**1,068**	979	1,103	1,028	970	1,038	1,106	1,069
Per share statistics:								
Net income/(loss) per common share – basic	**$0.84**	$0.90	$0.36	$1.14	$0.80	$1.00	($1.11)	$1.20
Comparable earnings per common share	**$1.07**	$1.00	$1.12	$1.05	$0.99	$1.06	$1.16	$1.14
Dividends declared per common share	**$0.90**	$0.90	$0.90	$0.87	$0.87	$0.87	$0.87	$0.81

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 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 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
- developments outside of the normal course of operations
- certain fair value adjustments, and provisions for expected credit losses on net investment in leases.

In Liquids Pipelines, annual revenues and segmented earnings are based on contracted and uncontracted spot transportation, as well as liquids marketing activities. Quarter-over-quarter revenues and segmented earnings 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
- certain fair value adjustments.

In Power and Storage, quarter-over-quarter revenues and segmented earnings 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
- 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 and non-GAAP measures for specific items we believe are significant but not reflective of our underlying operations in the period.

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. Beginning in first quarter 2022, with retroactive restatement of prior periods, we exclude from comparable measures our proportionate share of the unrealized gains and losses from changes in the fair value of Bruce Power's investments held 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 2022, TGNH and the CFE executed agreements which consolidate a number of operating and in-development natural gas pipelines in central and southeast Mexico under one TSA. This TSA contains a lease; therefore, we have recognized amounts in net investment in leases on our Condensed consolidated balance sheet. In accordance with the requirements of U.S. GAAP, we have recognized an expected credit loss provision related to net investment in leases. The amount of this provision will fluctuate from period to period based on changing economic assumptions and forward-looking information. The provision is an estimate of losses that may occur over the duration of the TSA through 2055. As this provision does not reflect losses or cash outflows that were incurred under this lease arrangement in the current period or from our underlying operations, we have excluded any unrealized changes from comparable measures. Refer to the Other information – Critical accounting estimates and accounting policy changes section for additional information.

We also exclude 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 do not accurately reflect the gains and losses that will be realized at settlement. These amounts offset within each reporting period, resulting in no impact on net income. This peso-denominated loan was fully repaid in first quarter 2022.

In third quarter 2022, comparable earnings also excluded:

- preservation and storage 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 storage 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 storage 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 storage 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.

In third quarter 2021, comparable earnings also excluded:

- a $55 million after-tax expense with respect to transition payments incurred as part of the Voluntary Retirement Program
- preservation and other costs of $11 million after tax primarily related to the preservation and storage of Keystone XL pipeline project assets.

In second quarter 2021, comparable earnings also excluded:

- preservation and other costs of $16 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge and interest expense on the Keystone XL project-level credit facility prior to its termination
- a $13 million after-tax recovery of certain costs from the IESO associated with the Ontario natural gas-fired power plants sold in 2020
- an incremental $2 million after-tax asset impairment charge, net of expected contractual recoveries and other contractual and legal obligations, related to the termination of the Keystone XL pipeline project.

In first quarter 2021, comparable earnings also excluded:

- an after-tax asset impairment charge, net of expected contractual recoveries and other contractual and legal obligations, of $2.2 billion related to the formal suspension of the Keystone XL pipeline project following the January 2021 revocation of the Presidential Permit.

In fourth quarter 2020, comparable earnings also excluded:

- an incremental after-tax loss of $81 million related to the sale of our Ontario natural gas-fired power plants
- an income tax valuation allowance release of $18 million related to certain prior years' U.S. income tax losses resulting from our reassessment of deferred tax assets that are more likely than not to be realized
- an additional $18 million income tax recovery related to state income taxes on the sale of certain Columbia Midstream assets in 2019.