Quarterly report to shareholders

Third quarter 2021

Financial highlights

	three months ended September 30		nine months ended September 30	
(millions of $, except per share amounts)	**2021**	**2020**	**2021**	**2020**
Income				
Revenues	**3,240**	3,195	**9,803**	9,702
Net income attributable to common shares	**779**	904	**697**	3,333
per common share – basic	**$0.80**	$0.96	**$0.72**	$3.55
Comparable EBITDA	**2,240**	2,294	**6,978**	7,028
Comparable earnings	**972**	893	**3,118**	2,865
per common share	**$0.99**	$0.95	**$3.21**	$3.05
Cash flows				
Net cash provided by operations	**1,712**	1,783	**5,089**	5,119
Comparable funds generated from operations	**1,556**	1,663	**5,333**	5,306
Capital spending[1]	**1,687**	2,250	**5,011**	6,669
Dividends declared				
Per common share	**$0.87**	$0.81	**$2.61**	$2.43
Basic common shares outstanding (millions)				
– weighted average for the period	**979**	940	**970**	940
– issued and outstanding at end of period	**979**	940	**979**	940

1 Includes capacity capital expenditures, maintenance capital expenditures, capital projects in development and contributions to equity investments.

Management’s discussion and analysis

November 4, 2021

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, 2021, and should be read with the accompanying unaudited Condensed consolidated financial statements for the three and nine months ended September 30, 2021, which have been prepared in accordance with U.S. GAAP.

This MD&A should also be read in conjunction with our December 31, 2020 audited Consolidated financial statements and notes and the MD&A in our 2020 Annual Report. Capitalized abbreviated terms that are used but not otherwise defined herein are defined in our 2020 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
- 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
- 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
- the expected impacts 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

- 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
- inflation rates and commodity prices
- interest, tax and foreign exchange rates
- nature and scope of hedging
- expected impact of COVID-19.

Risks and uncertainties

- 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 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
- 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 2020 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 (AIF) 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.

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 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
- certain fair value adjustments relating to risk management activities
- legal, contractual and bankruptcy settlements
- impairment of goodwill, plant, property and equipment, investments and other assets
- acquisition and integration costs
- restructuring costs.

We exclude the unrealized gains and losses from changes in the fair value of derivatives used to reduce our exposure to certain financial and commodity price risks. These derivatives generally provide effective economic hedges but do not meet the criteria for hedge accounting. As a result, the 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. We also exclude the unrealized foreign exchange gains and losses on the Loan receivable from affiliate as well as the corresponding proportionate share of Sur de Texas foreign exchange gains and losses, as these 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.

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 (comparable earnings before interest, taxes, depreciation and amortization) 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 (comparable earnings before interest and taxes) represents segmented earnings adjusted for specific items and is an effective tool for evaluating trends in each segment. Refer to each business segment section for a reconciliation to segmented earnings.

Comparable earnings and comparable earnings per common share

Comparable earnings represents earnings or losses attributable to common shareholders on a consolidated basis, adjusted for specific items. Comparable earnings is comprised of segmented earnings, Interest expense, Allowance for funds used during construction (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. We believe it 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 performance of our assets. 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.

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.

Our capital program consists of approximately $22 billion of secured projects which include commercially supported, committed projects that are either under construction or are in or preparing to commence the permitting stage. An additional $7 billion of projects under development are commercially supported (except where noted) but have greater uncertainty with respect to timing and estimated project costs and are subject to certain key approvals.

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.

In the nine months ended September 30, 2021, we placed approximately $0.9 billion of Canadian and U.S. Natural Gas Pipelines capacity capital projects into service. In addition, approximately $1.3 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 the additional restrictions and uncertainty presented by the ongoing impact of COVID-19. Amounts exclude capitalized interest and AFUDC.

Secured projects

(billions of $)	Expected in-service date	Estimated project cost[1]	Carrying value at September 30, 2021
Canadian Natural Gas Pipelines			
Canadian Mainline	2021-2024	0.3	0.2
NGTL System[2]	2021	1.2	1.1
	2022	3.3	1.2
	2023	1.8	0.1
	2024+	0.5	—
Coastal GasLink[3]	2023	0.2	0.2
Regulated maintenance capital expenditures	2021-2023	2.1	0.4
U.S. Natural Gas Pipelines			
Other capacity capital	2021-2025	US 3.5	US 1.2
Regulated maintenance capital expenditures	2021-2023	US 2.1	US 0.5
Mexico Natural Gas Pipelines			
Villa de Reyes	2022	US 1.0	US 0.9
Tula[4]	—	US 0.8	US 0.6
Liquids Pipelines			
Other capacity capital	2022	US 0.1	—
Recoverable maintenance capital expenditures	2021-2023	0.1	—
Power and Storage			
Bruce Power – life extension[5]	2021-2024	2.7	1.6
Other			
Non-recoverable maintenance capital expenditures[6]	2021-2023	0.7	0.2
		20.4	**8.2**
Foreign exchange impact on secured projects[7]		**2.0**	**0.9**
Total secured projects (Cdn$)		**22.4**	**9.1**

1 Amounts reflect 100 per cent of costs related to wholly-owned assets as well as cash contributions to our joint venture investments.

2 Estimated project costs for 2022 and 2023 include $0.5 billion for Foothills related to the West Path Expansion Program.

3 The estimated project cost represents our share of anticipated partner equity contributions to the project, with the expected in-service date and estimated project cost reflecting the last project update. Refer to the Recent developments – Canadian Natural Gas Pipelines section for additional information on the status of Coastal GasLink's dispute with LNG Canada regarding the recognition of certain costs and schedule changes, as well as our commitment to provide additional temporary financing, if necessary, to Coastal GasLink under certain circumstances.

4 Construction of the central segment of the Tula project has been delayed due to a lack of progress to successfully complete Indigenous consultation by the Secretary of Energy. Project completion is expected approximately two years after the consultation process is successfully concluded. The East Section of the Tula pipeline is available for interruptible transportation services.

5 Reflects our expected share of cash contributions for the Bruce Power Unit 6 MCR program, expected to be in service in 2023, amounts to be invested under the Asset Management program through 2024 as well as 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 1.27 at September 30, 2021.

Projects under development

The costs provided in the table below reflect the most recent estimates for each project as filed with the various regulatory authorities or otherwise determined by management.

(billions of $)	Estimated project cost[1]	Carrying value at September 30, 2021
U.S. Natural Gas Pipelines		
Other capacity capital[2]	US 0.3	—
Liquids Pipelines		
Grand Rapids Phase II[3]	0.7	—
Power and Storage		
Bruce Power – life extension[4]	6.3	0.3
	7.3	0.3
Foreign exchange impact on projects under development[5]	0.1	—
Total projects under development (Cdn$)	**7.4**	**0.3**

1 Amounts reflect our proportionate share of joint venture costs where applicable and 100 per cent of costs related to wholly-owned assets.

2 Includes projects subject to a positive customer FID.

3 Regulatory approvals have been obtained and additional commercial support is being pursued.

4 Reflects our proportionate share of the Bruce Power MCR program costs for Units 3, 4, 5, 7 and 8, the remaining Asset Management program costs beyond 2024, as well as the incremental uprate initiative. Refer to the Recent developments – Power and Storage section for additional information.

5 Reflects U.S./Canada foreign exchange rate of 1.27 at September 30, 2021.

Consolidated results – third quarter 2021

	three months ended September 30		nine months ended September 30	
(millions of $, except per share amounts)	**2021**	**2020**	**2021**	**2020**
Canadian Natural Gas Pipelines	**343**	334	**1,060**	1,307
U.S. Natural Gas Pipelines	**692**	644	**2,253**	2,107
Mexico Natural Gas Pipelines	**144**	142	**434**	532
Liquids Pipelines	**285**	342	**(1,973)**	1,059
Power and Storage	**116**	105	**437**	138
Corporate	**(36)**	(61)	**(40)**	220
Total segmented earnings	**1,544**	1,506	**2,171**	5,363
Interest expense	**(596)**	(559)	**(1,749)**	(1,698)
Allowance for funds used during construction	**81**	91	**195**	254
Interest income and other	**(76)**	164	**113**	(160)
Income before income taxes	**953**	1,202	**730**	3,759
Income tax (expense)/recovery	**(135)**	(190)	**158**	(78)
Net income	**818**	1,012	**888**	3,681
Net income attributable to non-controlling interests	**(8)**	(69)	**(83)**	(228)
Net income attributable to controlling interests	**810**	943	**805**	3,453
Preferred share dividends	**(31)**	(39)	**(108)**	(120)
Net income attributable to common shares	**779**	904	**697**	3,333
Net income per common share – basic	**$0.80**	$0.96	**$0.72**	$3.55

Net income attributable to common shares decreased by $125 million and $2.6 billion or $0.16 and $2.83 per common share for the three and nine months ended September 30, 2021 compared to the same periods in 2020. These decreases were primarily due to the $2.2 billion after-tax asset impairment of the Keystone XL pipeline project, net of expected contractual recoveries and other contractual and legal obligations, as well as unrealized net losses on risk management activities in third quarter 2021 compared to unrealized gains in third quarter 2020. The decreases in Net income per common share also reflected the impact of common shares issued for the acquisition of the remaining ownership interests in TC PipeLines, LP in first quarter 2021.

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

2021 results included:

- 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 20, 2021 revocation of the Presidential Permit. Refer to the Recent developments – Liquids Pipelines section for additional information
- preservation and other costs of $11 million and $27 million after tax for the three and nine months ended September 30, 2021 primarily related to the preservation and storage of Keystone XL pipeline project assets which could not be accrued as part of the Keystone XL impairment charge, as well as interest expense in second quarter 2021 on the Keystone XL project-level credit facility prior to its termination
- a $55 million after-tax expense with respect to transition payments incurred as part of the Voluntary Retirement Program (VRP)
- 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 April 2020.

The Keystone XL pipeline project asset impairment charge does not reflect offsetting amounts with respect to the Government of Alberta's related investment in Keystone XL nor their repayment of the project's guaranteed credit facility without recourse to TC Energy, both of which were accounted for within the Condensed consolidated statement of equity in second quarter 2021 and served to reduce our net financial impact from the Keystone XL pipeline project termination. Refer to the Recent developments – Liquids Pipelines section for additional information.

2020 results included:

- a $6 million reduction to the after-tax gain in third quarter 2020 related to the sale of a 65 per cent equity interest in Coastal GasLink Pipeline Limited Partnership (Coastal GasLink LP) in May 2020, resulting in an after-tax gain of $402 million for the nine months ended September 30, 2020
- an income tax valuation allowance release of $281 million following our reassessment of deferred income tax assets that were deemed more likely than not to be realized in first quarter 2020
- an incremental after-tax loss of $45 million in third quarter 2020 related to the Ontario natural-gas fired power plants sold in April 2020, which resulted in a year-to-date after-tax loss of $202 million at September 30, 2020.

Net income in both periods included unrealized gains and losses from changes in risk management activities 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 TO COMPARABLE EARNINGS

	three months ended September 30		nine months ended September 30	
(millions of $, except per share amounts)	**2021**	**2020**	**2021**	**2020**
Net income attributable to common shares	**779**	904	**697**	3,333
Specific items (net of tax):				
Keystone XL asset impairment charge and other	**—**	—	**2,194**	—
Keystone XL preservation and other	**11**	—	**27**	—
Voluntary Retirement Program	**55**	—	**55**	—
Gain on partial sale of Coastal GasLink LP	**—**	6	**—**	(402)
Income tax valuation allowance release	**—**	—	**—**	(281)
Loss/(gain) on sale of Ontario natural gas-fired power plants	**—**	45	**(13)**	202
Risk management activities[1]	**127**	(62)	**158**	13
Comparable earnings	**972**	893	**3,118**	2,865
Net income per common share	**$0.80**	$0.96	**$0.72**	$3.55
Specific items (net of tax):				
Keystone XL asset impairment charge and other	**—**	—	**2.27**	—
Keystone XL preservation and other	**0.01**	—	**0.03**	—
Voluntary Retirement Program	**0.05**	—	**0.05**	—
Gain on partial sale of Coastal GasLink LP	**—**	0.01	**—**	(0.43)
Income tax valuation allowance release	**—**	—	**—**	(0.30)
Loss/(gain) on sale of Ontario natural gas-fired power plants	**—**	0.05	**(0.01)**	0.21
Risk management activities	**0.13**	(0.07)	**0.15**	0.02
Comparable earnings per common share	**$0.99**	$0.95	**$3.21**	$3.05

1 Risk management activities	three months ended September 30		nine months ended September 30	
(millions of $)	**2021**	2020	**2021**	2020
U.S. Natural Gas marketing	**(3)**	—	**(1)**	—
Liquids marketing	**(8)**	9	**2**	16
Canadian Power	**7**	—	**8**	(1)
Natural Gas Storage	**(39)**	(4)	**(36)**	(8)
Foreign exchange	**(125)**	78	**(183)**	(24)
Income tax attributable to risk management activities	**41**	(21)	**52**	4
Total unrealized (losses)/gains from risk management activities	**(127)**	62	**(158)**	(13)

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)	**2021**	2020	**2021**	2020
Comparable EBITDA				
Canadian Natural Gas Pipelines	**631**	666	**2,001**	1,884
U.S. Natural Gas Pipelines	**890**	863	**2,824**	2,719
Mexico Natural Gas Pipelines	**171**	170	**515**	620
Liquids Pipelines	**387**	415	**1,146**	1,292
Power and Storage	**168**	187	**506**	516
Corporate	**(7)**	(7)	**(14)**	(3)
Comparable EBITDA	**2,240**	2,294	**6,978**	7,028
Depreciation and amortization	**(610)**	(673)	**(1,888)**	(1,938)
Interest expense included in comparable earnings	**(596)**	(559)	**(1,743)**	(1,698)
Allowance for funds used during construction	**81**	91	**195**	254
Interest income and other included in comparable earnings	**91**	32	**341**	87
Income tax expense included in comparable earnings	**(195)**	(184)	**(574)**	(520)
Net income attributable to non-controlling interests	**(8)**	(69)	**(83)**	(228)
Preferred share dividends	**(31)**	(39)	**(108)**	(120)
Comparable earnings	**972**	893	**3,118**	2,865
Comparable earnings per common share	**$0.99**	$0.95	**$3.21**	$3.05

Comparable EBITDA – 2021 versus 2020

Comparable EBITDA decreased by $54 million for the three months ended September 30, 2021 compared to the same period in 2020 primarily due to the net effect of the following:

- lower EBITDA from Canadian Natural Gas Pipelines largely attributable to the impact of lower flow-through depreciation and financial charges on the Canadian Mainline, partially offset by increased flow-through depreciation and income taxes along with higher rate-base earnings on the NGTL System
- decreased earnings from Liquids Pipelines as a result of lower contributions from liquids marketing activities, mainly attributable to lower margins
- lower Power and Storage results attributable to decreased earnings at Bruce Power in 2021 due to lower volumes resulting from greater planned outage days and higher operating expenses, partially offset by higher realized power prices
- increased earnings in U.S. Natural Gas Pipelines from Columbia Gas following the application for higher transportation rates effective February 1, 2021 and the settlement-in-principle that was reached on July 28, 2021, subject to refund upon completion of the current rate proceeding
- foreign exchange impact of a weaker 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 increased by US$53 million to US$1.1 billion compared to 2020, however, this was translated at a rate of 1.26 in 2021 versus 1.33 in 2020. Refer to the Foreign exchange discussion below for additional information.

Comparable EBITDA decreased by $50 million for the nine months ended September 30, 2021 compared to the same period in 2020 primarily due to the net effect of the following:

- decreased earnings from Liquids Pipelines attributable to lower volumes on the U.S. Gulf Coast section of the Keystone Pipeline System, partially offset by increased contributions from liquids marketing activities reflecting higher margins and volumes
- lower contribution from Mexico Natural Gas Pipelines mainly due to US$55 million of fees recognized in 2020 associated with the successful completion of the Sur de Texas pipeline
- lower Power and Storage results attributable to decreased earnings at Bruce Power in 2021 due to lower volumes resulting from greater planned outage days and higher operating expenses, partially offset by higher realized power prices, increased Natural Gas Storage and Other earnings reflecting higher realized Alberta natural gas spreads and the impact of the November 2020 acquisition of the remaining 50 per cent ownership interest in TC Turbines
- higher EBITDA from Canadian Natural Gas Pipelines largely as a result of the impact of increased flow-through depreciation and income taxes along with higher rate-base earnings on the NGTL System, as well as higher Coastal GasLink development fees and Canadian Mainline incentive earnings and flow-through income taxes, partially offset by lower flow-through depreciation and financial charges on the Canadian Mainline
- increased earnings in U.S. Natural Gas Pipelines from Columbia Gas following the application for higher transportation rates effective February 1, 2021 and the settlement-in-principle that was reached on July 28, 2021, subject to refund upon completion of the current rate proceeding, and improved earnings across our U.S. Natural Gas Pipelines assets following the cold weather events of 2021 impacting many of the U.S. markets in which we operate, partially offset by higher property taxes
- foreign exchange impact of a weaker 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 increased by US$134 million to US$3.4 billion compared to 2020, however, this was translated at a rate of 1.25 in 2021 versus 1.35 in 2020.

While the weakening of the U.S. dollar in 2021 compared to the same periods in 2020 had a considerable negative impact on 2021 comparable EBITDA, the corresponding impact on comparable earnings was not significant due to offsetting natural and economic hedges. Refer to the Foreign exchange discussion below for additional information.

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

Comparable earnings – 2021 versus 2020

Comparable earnings increased by $79 million or $0.04 per common share for the three months ended September 30, 2021 compared to the same period in 2020 and was primarily the net effect of:

- changes in comparable EBITDA described above
- lower Depreciation and amortization primarily in Canadian Natural Gas Pipelines on the Canadian Mainline, partially offset by higher depreciation on the NGTL System from expansion facilities that were placed in service
- decreased Non-controlling interests following the March 3, 2021 acquisition of all outstanding common units of TC PipeLines, LP not beneficially owned by TC Energy
- higher Interest income and other mainly attributable to realized gains in 2021 compared to realized losses in 2020 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- higher Interest expense primarily due to 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, partially offset by the foreign exchange impact from a weaker U.S. dollar on translation of U.S. dollar-denominated interest.

Comparable earnings increased by $253 million or $0.16 per common share for the nine months ended September 30, 2021 compared to the same period in 2020 and was primarily the net effect of:

- changes in comparable EBITDA described above
- higher Interest income and other mainly attributable to realized gains in 2021 compared to realized losses in 2020 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- decreased Non-controlling interests following the March 3, 2021 acquisition of all outstanding common units of TC PipeLines, LP not beneficially owned by TC Energy
- lower Depreciation and amortization on our U.S. dollar-denominated assets primarily as a result of the weaker U.S. dollar
- lower AFUDC, predominantly due to the suspension of recording AFUDC on the Villa de Reyes project effective January 1, 2021 as a result of ongoing project delays, partially offset by higher AFUDC related to the NGTL System and U.S. natural gas pipeline expansion projects
- higher Income tax expense primarily as a result of higher pre-tax earnings and increased flow-through income taxes on our Canadian rate-regulated pipelines, partially offset by higher foreign tax rate differentials
- higher Interest expense primarily due to 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, the change to equity accounting for our Coastal GasLink investment upon the sale of a 65 per cent interest in Coastal GasLink LP in second quarter 2020 and the completion of the Napanee power plant in first quarter 2020, partially offset by long-term debt issuances, net of maturities and the foreign exchange impact from a weaker U.S. dollar on translation of U.S. dollar-denominated interest.

Comparable earnings per share also reflected the impact of common shares issued for the acquisition of the remaining ownership interests in TC PipeLines, LP in first quarter 2021. Refer to the Financial condition section of this MD&A for further information on common share issuances.

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 two-year forward basis using foreign exchange derivatives, however, the natural exposure beyond that period remains. As noted previously, the net impact of the U.S. dollar movements on comparable earnings for the three and nine months ended September 30, 2021 compared to 2020, after considering natural offsets and economic hedges, was not significant.

Average exchange rate — U.S. to Canadian dollars

The average exchange rate for one U.S. dollar converted into Canadian dollars was as follows:

three months ended September 30, 2021	**1.26**
three months ended September 30, 2020	1.33
nine months ended September 30, 2021	**1.25**
nine months ended September 30, 2020	1.35

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

Pre-tax U.S. dollar-denominated income and expense items	**three months ended September 30**		**nine months ended September 30**	
(millions of US$)	**2021**	**2020**	**2021**	**2020**
Comparable EBITDA				
U.S. Natural Gas Pipelines	**706**	647	**2,256**	2,008
Mexico Natural Gas Pipelines[1]	**152**	146	**462**	520
U.S. Liquids Pipelines	**223**	235	**668**	724
	1,081	1,028	**3,386**	3,252
Depreciation and amortization	**(224)**	(233)	**(666)**	(661)
Interest on long-term debt and junior subordinated notes	**(315)**	(324)	**(945)**	(987)
Capitalized interest	**—**	38	**10**	89
Allowance for funds used during construction	**33**	51	**73**	126
Non-controlling interests and other	**(7)**	(56)	**(67)**	(178)
	568	504	**1,791**	1,641

1 Excludes interest expense on our inter-affiliate loan with Sur de Texas which is fully offset in Interest income and other.

Outlook

Consolidated comparable earnings

Our overall comparable earnings per common share outlook for 2021 is expected to be modestly higher than reported in the 2020 Annual Report. This is primarily due to incremental U.S. Natural Gas Pipelines' earnings in 2021 and higher realized margins in Canadian Power.

We continue to monitor developments in energy markets, our construction projects and regulatory proceedings for any impact on our 2021 comparable earnings per common share. We do not expect COVID-19 to have a material impact on our 2021 comparable earnings.

Consolidated capital spending

Our expected total capital expenditures for 2021 as outlined in the 2020 Annual Report remain materially unchanged. Although we have observed some slowdown on certain of our construction activities and capital expenditures, we do not believe disruptions related to COVID-19 will be material to our overall 2021 capital program.

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 $)	**2021**	2020	**2021**	2020
NGTL System	**409**	390	**1,214**	1,103
Canadian Mainline	**183**	229	**648**	677
Other Canadian pipelines[1]	**39**	47	**139**	104
Comparable EBITDA	**631**	666	**2,001**	1,884
Depreciation and amortization	**(288)**	(326)	**(941)**	(941)
Comparable EBIT	**343**	340	**1,060**	943
Specific item:				
Gain on partial sale of Coastal GasLink LP	**—**	(6)	**—**	364
Segmented earnings	**343**	334	**1,060**	1,307

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 segmented earnings increased by $9 million and decreased by $247 million for the three and nine months ended September 30, 2021 compared to the same periods in 2020. Third quarter 2020 results included a $6 million reduction to the pre-tax gain on the May 2020 sale of a 65 per cent equity interest in Coastal GasLink LP, resulting in a pre-tax gain of $364 million for the nine months ended September 30, 2020. These amounts have been excluded from our calculation of comparable EBIT.

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 affect 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 $)	**2021**	2020	**2021**	2020
Net income				
NGTL System	**160**	145	**467**	419
Canadian Mainline	**52**	40	**156**	118
Average investment base				
NGTL System			**15,345**	13,890
Canadian Mainline			**3,700**	3,649

Net income for the NGTL System increased by $15 million and $48 million for the three and nine months ended September 30, 2021 compared to the same periods in 2020 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, 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 increased by $12 million and $38 million for the three and nine months ended September 30, 2021 compared to the same periods in 2020 largely due to higher incentive earnings and the elimination of a $20 million after-tax annual TC Energy contribution included in the previous NEB 2014 Decision. Beginning January 1, 2021, 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 decreased by $35 million and increased by $117 million for the three and nine months ended September 30, 2021 compared to the same periods in 2020 due to the net effect of:

- higher flow-through depreciation and income taxes as well as increased rate-base earnings on the NGTL System
- lower flow-through depreciation and financial charges, partially offset by higher flow-through income taxes, increased incentive earnings and elimination of the TC Energy contribution on the Canadian Mainline
- Coastal GasLink development fee revenue commenced in second quarter 2020 and resulted in increased earnings for the nine months ended September 30, 2021, with lower earnings for the three months ended September 30, 2021 due to the timing of revenue recognition, compared to the same periods in 2020.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization decreased by $38 million for the three months ended September 30, 2021 compared to the same period in 2020 mainly due to one section of the Canadian Mainline being fully depreciated, partially offset by higher depreciation on the NGTL System from expansion facilities that were placed in service. Depreciation and amortization was consistent for the nine months ended September 30, 2021 with the same period in 2020.

U.S. Natural Gas Pipelines

On March 3, 2021, we acquired all the outstanding common units of TC PipeLines, LP not beneficially owned by TC Energy or our affiliates in exchange for TC Energy common shares (the TC PipeLines, LP acquisition). Refer to the Recent developments – U.S. Natural Gas Pipelines section for additional information. TC PipeLines, LP results reflect our ownership interests in eight natural gas pipelines prior to the acquisition.

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$, unless otherwise noted)	**2021**	**2020**	**2021**	**2020**
Columbia Gas	**359**	308	**1,122**	968
ANR	**135**	120	**436**	381
Columbia Gulf	**52**	46	**161**	143
Great Lakes[1,4]	**35**	18	**112**	65
GTN[2,4]	**40**	—	**95**	—
Other U.S. pipelines[3,4]	**78**	36	**215**	86
TC PipeLines, LP[4,5]	**—**	28	**24**	88
Non-controlling interests[5]	**7**	91	**91**	277
Comparable EBITDA	**706**	647	**2,256**	2,008
Depreciation and amortization	**(154)**	(164)	**(455)**	(452)
Comparable EBIT	**552**	483	**1,801**	1,556
Foreign exchange impact	**143**	161	**453**	551
Comparable EBIT (Cdn$)	**695**	644	**2,254**	2,107
Specific item:				
Risk management activities	**(3)**	—	**(1)**	—
Segmented earnings (Cdn$)	**692**	644	**2,253**	2,107

1 Results reflect our 53.55 per cent direct interest in Great Lakes until March 3, 2021 and our 100 per cent ownership interest subsequent to the TC PipeLines, LP acquisition.

2 Reflects 100 per cent of GTN's earnings subsequent to the TC PipeLines, LP acquisition on March 3, 2021.

3 Reflects earnings from our ownership in our mineral rights business (CEVCO), Crossroads, and our share of equity income from Millennium and Hardy Storage, as well as general and administrative and business development costs related to our U.S. natural gas pipelines. For the period subsequent to the TC PipeLines, LP acquisition on March 3, 2021, 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.

4 Our ownership interest in TC PipeLines, LP was 25.5 per cent prior to the acquisition on March 3, 2021, at which time it became 100 per cent. Prior to March 3, 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.

5 Reflects earnings attributable to portions of TC PipeLines, LP and Portland that we did not own prior to the TC PipeLines, LP acquisition on March 3, 2021, 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 $48 million and $146 million for the three and nine months ended September 30, 2021 compared to the same periods in 2020 and included unrealized losses from changes in the fair value of derivatives related to our U.S. Natural Gas marketing business in 2021 which have been excluded from our calculation of comparable EBIT. A weaker U.S. dollar in 2021 had a negative impact on the Canadian dollar equivalent segmented earnings from our U.S. operations compared to the same period in 2020. Refer to the Consolidated results – Foreign exchange section for additional information.

Comparable EBITDA for U.S. Natural Gas Pipelines increased by US$59 million and US$248 million for the three and nine months ended September 30, 2021 compared to the same periods in 2020 and was primarily due to the net effect of:

- a net increase in earnings from Columbia Gas following the application for higher transportation rates effective February 1, 2021 and the settlement-in-principle that was reached on July 28, 2021, subject to refund upon completion of the rate proceeding, partially offset by higher property taxes. For the nine months ended September 30, 2021, earnings also increased due to greater capitalized pipeline integrity costs in 2021 compared to 2020. Refer to the Recent developments – U.S. Natural Gas Pipelines section for additional information
- increased earnings across our U.S. Natural Gas Pipelines assets, which includes the impact of cold weather events in first quarter 2021 affecting many of the U.S. markets in which we operate.

The positive impact on comparable earnings following the TC PipeLines, LP acquisition noted above is reflected through a reduction in Non-controlling interests. Refer to the Corporate – Net income attributable to non-controlling interests section for additional information.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization decreased by US$10 million for the three months ended September 30, 2021 compared to the same period in 2020 mainly due to certain third quarter 2020 adjustments and increased by US$3 million for the nine months ended September 30, 2021 compared to the same period in 2020 mainly due to new projects placed in service.

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$, unless otherwise noted)	**2021**	2020	**2021**	2020
Topolobampo	**40**	40	**121**	120
Sur de Texas[1]	**31**	23	**92**	145
Tamazunchale	**29**	31	**91**	91
Guadalajara	**17**	16	**54**	47
Mazatlán	**18**	18	**53**	53
Comparable EBITDA	**135**	128	**411**	456
Depreciation and amortization	**(21)**	(21)	**(65)**	(65)
Comparable EBIT	**114**	107	**346**	391
Foreign exchange impact	**30**	35	**88**	141
Comparable EBIT and segmented earnings (Cdn$)	**144**	142	**434**	532

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

Mexico Natural Gas Pipelines comparable EBIT and segmented earnings increased by $2 million and decreased by $98 million for the three and nine months ended September 30, 2021, compared to the same periods in 2020. A weaker U.S. dollar for the three and nine months ended September 30, 2021 had a negative impact on the Canadian dollar equivalent segmented earnings compared to the same periods in 2020. Refer to the Consolidated results – Foreign exchange section for additional information.

Comparable EBITDA for Mexico Natural Gas Pipelines increased by US$7 million for the three months ended September 30, 2021 compared to the same period in 2020 primarily as a result of increased Sur de Texas earnings reflecting lower interest and deferred income tax expenses. Comparable EBITDA decreased by US$45 million for the nine months ended September 30, 2021 compared to the same period in 2020 mainly attributable to US$55 million of fees recognized in first quarter 2020 associated with the successful completion of the Sur de Texas pipeline, partially offset by additional earnings from Guadalajara following the implementation of a flow reversal completed in 2020.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization for the three and nine months ended September 30, 2021 was consistent with the same periods in 2020.

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 $)	**2021**	**2020**	**2021**	**2020**
Keystone Pipeline System	**327**	345	**956**	1,113
Intra-Alberta pipelines[1]	**22**	22	**67**	69
Liquids marketing and other	**38**	48	**123**	110
Comparable EBITDA	**387**	415	**1,146**	1,292
Depreciation and amortization	**(80)**	(82)	**(238)**	(249)
Comparable EBIT	**307**	333	**908**	1,043
Specific items:				
Keystone XL asset impairment charge and other	**—**	—	**(2,854)**	—
Keystone XL preservation and other	**(14)**	—	**(29)**	—
Risk management activities	**(8)**	9	**2**	16
Segmented earnings/(losses)	**285**	342	**(1,973)**	1,059
Comparable EBITDA denominated as follows:				
Canadian dollars	**106**	102	**310**	311
U.S. dollars	**223**	235	**668**	724
Foreign exchange impact	**58**	78	**168**	257
Comparable EBITDA	**387**	415	**1,146**	1,292

1 Intra-Alberta pipelines include Grand Rapids, White Spruce and Northern Courier.

Liquids Pipelines segmented earnings decreased by $57 million and $3.0 billion for the three and nine months ended September 30, 2021 compared to the same periods in 2020 and included the following specific items which have been excluded from our calculation of comparable EBIT and comparable earnings:

- a $2.8 billion 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 and related projects following the January 20, 2021 revocation of the Presidential Permit. Refer to the Recent developments – Liquids Pipelines section for additional information
- pre-tax preservation and other costs of $14 million and $29 million for the three and nine months ended September 30, 2021 primarily related to the preservation and storage of the Keystone XL pipeline project assets which could not be accrued as part of the Keystone XL impairment charge
- unrealized losses and gains from changes in the fair value of derivatives related to our liquids marketing business.

A weaker U.S. dollar in 2021 had a negative impact on the Canadian dollar equivalent segmented earnings from our U.S. operations compared to the same periods in 2020. Refer to the Consolidated results – Foreign exchange section for additional information.

Comparable EBITDA for Liquids Pipelines decreased by $28 million and $146 million for the three and nine months ended September 30, 2021 compared to the same periods in 2020 and was primarily due to the net effect of:

- lower volumes on the U.S. Gulf Coast section of the Keystone Pipeline System for the nine months ended September 30, 2021
- lower contributions from liquids marketing activities for the three months ended September 30, 2021 mainly attributable to lower margins. Earnings for the nine months ended September 30, 2021 from liquids marketing increased due to higher margins and volumes.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization decreased by $2 million and $11 million for the three and nine months ended September 30, 2021 compared to the same periods in 2020 primarily as a result of a weaker 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 $)	**2021**	**2020**	**2021**	**2020**
Bruce Power[1]	**112**	140	**296**	339
Canadian Power[2]	**50**	39	**176**	164
Natural Gas Storage and other	**6**	8	**34**	13
Comparable EBITDA	**168**	187	**506**	516
Depreciation and amortization	**(20)**	(18)	**(58)**	(48)
Comparable EBIT	**148**	169	**448**	468
Specific items:				
(Loss)/gain on sale of Ontario natural gas-fired power plants	**—**	(60)	**17**	(321)
Risk management activities	**(32)**	(4)	**(28)**	(9)
Segmented earnings	**116**	105	**437**	138

1 Represents our share of equity income from Bruce Power.

2 Includes Napanee from in-service in March 2020 and our other Ontario natural gas-fired power plants until sold in April 2020.

Power and Storage segmented earnings increased by $11 million and $299 million for the three and nine months ended September 30, 2021 compared to the same periods in 2020 and included the following specific items which have been excluded from 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 April 2020. Pre-tax losses on the sale of $60 million and $321 million were recorded in the three and nine months ended September 30, 2020
- unrealized 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 decreased by $19 million and $10 million for the three and nine months ended September 30, 2021 compared to the same periods in 2020 primarily due to the net effect of:

- decreased contributions from Bruce Power due to lower volumes resulting from greater planned outage days and increased operating expenses, partially offset by higher realized power prices. Earnings for the nine months ended September 30, 2021 also included increased gains on funds invested for post-retirement benefits. Additional financial and operating information on Bruce Power is provided below
- Natural Gas Storage and other results reflecting higher realized Alberta natural gas storage spreads in 2021 and the November 2020 acquisition of the remaining 50 per cent ownership interest in TC Turbines. Results for the three months ended September 30, 2021 also included higher business development activities across the segment
- increased Canadian Power results primarily due to higher realized margins in 2021 and earnings from our MacKay River cogeneration facility following its return to service in May 2020, partially offset by the sale of our Ontario natural gas-fired power plants in April 2020.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by $2 million and $10 million for the three and nine months ended September 30, 2021 compared to the same periods in 2020 and includes incremental TC Turbines depreciation following the November 2020 acquisition of the remaining 50 per cent ownership interest as well as other adjustments in second quarter 2020.

BRUCE POWER

The following reflects 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)	2021	2020	2021	2020
Equity income included in comparable EBITDA and EBIT comprised of:				
Revenues[1]	**411**	432	**1,220**	1,270
Operating expenses	**(214)**	(206)	**(677)**	(653)
Depreciation and other	**(85)**	(86)	**(247)**	(278)
Comparable EBITDA and EBIT[2]	**112**	140	**296**	339
Bruce Power – other information				
Plant availability[3,4]	**86%**	93%	**86%**	88%
Planned outage days[4]	**92**	26	**257**	195
Unplanned outage days	**—**	16	**22**	28
Sales volumes (GWh)[2]	**5,101**	5,510	**15,197**	15,818
Realized power price per MWh[5]	**$80**	$78	**$80**	$80

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

2 Represents our 48.4 per cent ownership interest in Bruce Power. Sales volumes include deemed generation and Unit 6 output until January 2020 when its MCR program commenced.

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 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 commenced in January 2020. Planned maintenance was completed on Unit 1 in first quarter 2021 and on Unit 3 on October 9, 2021. Refer to the Recent developments – Power and Storage section for additional information. Planned maintenance is still expected to occur on Unit 7 in fourth quarter 2021. The average 2021 plant availability, excluding the Unit 6 MCR, is 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 $)	**2021**	2020	**2021**	2020
Comparable EBITDA and EBIT	**(7)**	(7)	**(14)**	(3)
Specific items:				
Voluntary Retirement Program (VRP)	**(71)**	—	**(71)**	—
Foreign exchange gain/(loss) – inter-affiliate loans[1]	**42**	(54)	**45**	223
Segmented (losses)/earnings	**(36)**	(61)	**(40)**	220

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

Corporate segmented losses decreased by $25 million for the three months ended September 30, 2021 while Corporate segmented earnings decreased by $260 million for the nine months ended September 30, 2021 compared to the same periods in 2020. Corporate segmented losses included accrued pre-tax costs for the VRP offered in mid-2021 as well as foreign exchange gains and losses on our proportionate share of peso-denominated inter-affiliate loans to the Sur de Texas joint venture from its partners. These foreign exchange gains and losses are recorded in Income from equity investments in the Corporate segment and have been excluded from our calculation of comparable EBITDA and EBIT as they are fully offset by corresponding foreign exchange losses and gains on the inter-affiliate loan receivable included in Interest income and other. Refer to the Recent developments – Corporate section for additional information on the VRP and Financial risks and financial instruments – Related party transactions section for additional information on our peso-denominated inter-affiliate loans.

Comparable EBITDA and EBIT for Corporate for the three months ended September 30, 2021 was consistent with the same period in 2020 and decreased by $11 million for the nine months ended September 30, 2021 compared to the same period in 2020 primarily due to a U.S. capital tax adjustment recorded in second quarter 2020.

Interest expense

	three months ended September 30		nine months ended September 30	
(millions of $)	**2021**	2020	**2021**	2020
Interest on long-term debt and junior subordinated notes				
Canadian dollar-denominated	**(183)**	(178)	**(530)**	(511)
U.S. dollar-denominated	**(315)**	(324)	**(945)**	(987)
Foreign exchange impact	**(81)**	(108)	**(238)**	(350)
	(579)	(610)	**(1,713)**	(1,848)
Other interest and amortization expense	**(19)**	(17)	**(50)**	(69)
Capitalized interest	**2**	68	**20**	219
Interest expense included in comparable earnings	**(596)**	(559)	**(1,743)**	(1,698)
Specific item:				
Keystone XL preservation and other	**—**	—	**(6)**	—
Interest expense	**(596)**	(559)	**(1,749)**	(1,698)

Interest expense increased by $37 million and $51 million for the three and nine months ended September 30, 2021 compared to the same periods in 2020 and included $6 million for the nine months ended September 30, 2021 related to the Keystone XL project-level credit facility for the period following the 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 $37 million and $45 million for the three and nine months ended September 30, 2021 compared to the same periods in 2020 primarily due to the net effect of:

- lower capitalized interest due to its cessation for the Keystone XL pipeline project following the revocation of the Presidential Permit in January 2021, the change to equity accounting for our Coastal GasLink investment upon the sale of a 65 per cent interest in Coastal GasLink LP in second quarter 2020 and the completion of the Napanee power plant in first quarter 2020
- long-term debt issuances, net of maturities. Refer to the Financial condition section for additional information
- lower interest rates on short-term borrowings
- the foreign exchange impact from a weaker 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 $)	**2021**	2020	**2021**	2020
Canadian dollar-denominated	**40**	23	**104**	83
U.S. dollar-denominated	**33**	51	**73**	126
Foreign exchange impact	**8**	17	**18**	45
Allowance for funds used during construction	**81**	91	**195**	254

AFUDC decreased by $10 million and $59 million for the three and nine months ended September 30, 2021 compared to the same periods in 2020. The increases in Canadian dollar-denominated AFUDC are primarily related to a higher balance of NGTL System expansion projects under construction. The decreases in U.S. dollar-denominated AFUDC are mainly the result of the suspension of recording AFUDC on the Villa de Reyes project effective January 1, 2021 due to ongoing delays on the project and the Columbia Gas BXP project which went into service on January 1, 2021, partially offset by increased capital expenditures on our U.S. natural gas pipeline projects.

Interest income and other

	three months ended September 30		nine months ended September 30	
(millions of $)	**2021**	2020	**2021**	2020
Interest income and other included in comparable earnings	**91**	32	**341**	87
Specific items:				
Foreign exchange (losses)/gains – inter-affiliate loan	**(42)**	54	**(45)**	(223)
Risk management activities	**(125)**	78	**(183)**	(24)
Interest income and other	**(76)**	164	**113**	(160)

Interest income and other decreased by $240 million and increased by $273 million for the three and nine months ended September 30, 2021 compared to the same periods in 2020 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 and gains on the peso-denominated inter-affiliate loan receivable from the Sur de Texas joint venture
- unrealized losses and gains from changes in the fair value of derivatives used to manage our foreign exchange risk.

Our proportionate share of the corresponding foreign exchange gains and losses and interest expense on the peso-denominated inter-affiliate loans to the Sur de Texas joint venture from its partners are reflected in Income from equity investments in the Corporate and Mexico Natural Gas Pipelines segments, respectively. The foreign exchange losses and gains on these inter-affiliate loans are removed from comparable earnings while the interest income and interest expense are included in comparable earnings with all amounts offsetting and resulting in no impact on 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 increased by $59 million and $254 million for the three and nine months ended September 30, 2021 compared to the same periods in 2020 mainly due to realized gains in 2021 compared to realized losses in 2020 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income.

Income tax expense

	three months ended September 30		nine months ended September 30	
(millions of $)	**2021**	2020	**2021**	2020
Income tax expense included in comparable earnings	**(195)**	(184)	**(574)**	(520)
Specific items:				
Keystone XL asset impairment charge and other[1]	**—**	—	**660**	—
Keystone XL preservation and other[1]	**3**	—	**8**	—
Voluntary Retirement Program	**16**	—	**16**	—
Income tax valuation allowance release	**—**	—	**—**	281
Loss/(gain) on sale of Ontario natural gas-fired power plants	**—**	15	**(4)**	119
Gain on partial sale of Coastal GasLink LP	**—**	—	**—**	38
Risk management activities	**41**	(21)	**52**	4
Income tax (expense)/recovery	**(135)**	(190)	**158**	(78)

1 Includes $3 million of deferred income tax recovery and $nil of current income tax expense for the three months ended September 30, 2021 and $788 million of deferred income tax recovery and $120 million of current income tax expense for the nine months ended September 30, 2021.

Income tax expense decreased by $55 million for the three months ended September 30, 2021 compared to the same period in 2020 primarily due to reduced earnings in 2021.

Income tax expense decreased by $236 million for the nine months ended September 30, 2021 to a recovery of $158 million compared to the same period in 2020 primarily due to the net effect of:
- the income tax impact of the Keystone XL pipeline project asset impairment charge in 2021
- the income tax valuation allowance release of $281 million which was recorded in first quarter 2020 following our reassessment of deferred income tax assets that were deemed more likely than not to be realized
- an income tax valuation allowance release related to the Ontario natural gas-fired power plants and Coastal GasLink LP sale transactions in 2020
- the non-taxable portion of capital gains recognized in second quarter 2020.

These items were removed from Income tax expense included in comparable earnings in addition to the income tax impacts of the specific items referenced elsewhere in this MD&A.

Income tax expense included in comparable earnings increased by $11 million for the three months ended September 30, 2021 compared to the same period in 2020 primarily due to higher income subject to tax in 2021, partially offset by higher foreign tax rate differentials. Income tax expense included in comparable earnings increased by $54 million for the nine months ended September 30, 2021 compared to the same period in 2020 primarily due to higher earnings subject to tax and higher flow-through income taxes on Canadian rate-regulated pipelines, partially offset by higher foreign tax rate differentials.

Net income attributable to non-controlling interests

	three months ended September 30		nine months ended September 30	
(millions of $)	**2021**	**2020**	**2021**	**2020**
Net income attributable to non-controlling interests	**(8)**	(69)	**(83)**	(228)

Net income attributable to non-controlling interests for the three and nine months ended September 30, 2021 decreased by $61 million and $145 million compared to the same periods in 2020 primarily as a result of the March 3, 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. Refer to the U.S. Natural Gas Pipelines section and Note 10, Non-controlling interests, of our Condensed consolidated financial statements for additional information.

Preferred share dividends

	three months ended September 30		nine months ended September 30	
(millions of $)	**2021**	**2020**	**2021**	**2020**
Preferred share dividends	**(31)**	(39)	**(108)**	(120)

Preferred share dividends decreased by $8 million and $12 million for the three and nine months ended September 30, 2021 compared to the same periods in 2020 primarily due to the redemption of all issued and outstanding Series 13 preferred shares on May 31, 2021.

Recent developments

COVID-19

Amid the ongoing adaptations and restrictions in place as a result of the COVID-19 pandemic, we continue to effectively operate our assets, conduct commercial activities and execute on projects with a focus on health, safety and reliability. While it remains premature to ascertain any long-term impact that COVID-19 may have on our capital program, directionally we have observed some slowdown on certain of our construction activities and capital expenditures largely due to permitting delays as regulators have been unable to process permits and conduct consultations within timeframes that were originally anticipated. In addition, supply chain impacts are manifesting with rising costs for certain commodities and labour shortages in some areas which can cause cost increases and slower progress than anticipated. Further details for capital projects more significantly impacted by COVID-19 are provided below.

The degree to which COVID-19 has a more pronounced longer-term impact on our operations and growth projects will depend on future developments, policies and actions, all of which remain somewhat uncertain. Additional information regarding the risks, uncertainties and impact on our business from COVID-19 can be found throughout this MD&A including the Capital program, Outlook and the Financial risks and financial instruments sections.

CANADIAN NATURAL GAS PIPELINES

Coastal GasLink

From late December 2020 until April 13, 2021, in response to the COVID-19 pandemic, an order of the British Columbia Provincial Health Officer restricted the number of workers on industrial sites across northern British Columbia, including Coastal GasLink, and, as a result, only critical construction activities continued during this time. Major erosion and sediment control work was required in the absence of continued pipeline construction during the winter period. On April 13, 2021, the provincial health order was lifted allowing the project to finalize remobilization plans for the summer construction program.

As a result of scope changes, previous permit delays compared to the original construction schedule and the impacts from COVID-19, including the provincial health order, we continue to expect project costs to increase significantly along with a delay to project completion compared to the original project cost and schedule. Coastal GasLink has sought and will continue to mitigate cost increases and schedule delays. Coastal GasLink expects incremental costs will be included in the final pipeline tolls, subject to certain conditions.

Coastal GasLink is in dispute with LNG Canada with respect to the recognition of certain costs and the impacts on schedule. Construction activities continue and, at this time, we do not expect any suspension of these activities while the parties work toward a resolution. During this time, construction is being funded in part by a subordinated demand revolving facility with TC Energy which provides the project with additional short-term funding and financial flexibility and, on which, $840 million was drawn at September 30, 2021. In October 2021, this amount was fully repaid and further draws were made which resulted in an outstanding balance of $175 million at October 29, 2021. As a further interim measure, TC Energy has committed to providing additional temporary financing to the project, if necessary, of up to $3.3 billion as a bridge to a required increase in project-level financing to fund incremental costs. This financing is expected to be provided at market-based returns. While we do not anticipate our future equity contributions will increase significantly, the portion of this temporary financing that will ultimately be required to be contributed as equity by Coastal GasLink LP partners, including us, will be determined by the substance of a resolution with LNG Canada.

NGTL System

In the nine months ended September 30, 2021, the NGTL System placed approximately $0.5 billion of capacity projects in service.

2022 NGTL System Expansion Program

In second quarter 2021, we received federal approval for the 2022 NGTL System Expansion Program. With an estimated capital cost of $1.1 billion, the 2022 NGTL System Expansion Program will provide incremental capacity to meet firm-receipt and intra-basin delivery requirements and consist of approximately 166 km (103 miles) of new pipeline, one new compressor unit and associated facilities. Construction activities began in September 2021 with anticipated in-service dates commencing in fourth quarter 2022.

2023 NGTL System Intra-Basin Expansion

In May 2021, we received CER approval to construct and operate $0.3 billion of the NGTL System Intra-Basin Expansion Program. An application for the remaining facilities was submitted to the CER in June 2021 with a decision anticipated in late 2021. Based on the outcome of the 2021 Capacity Optimization Open Season, changes in expected supply have reduced the scope of the program which now has an estimated capital cost of $0.6 billion, consisting of 23 km (14 miles) of new pipeline and two new compressor stations and is underpinned by approximately 255 TJ/d (238 MMcf/d) of new firm-service contracts with 15-year terms. The Intra-Basin Expansion is expected to be placed in service commencing in 2023.

NGTL System/Foothills West Path Delivery Program

In November 2019, we announced our West Path Delivery Program which is an expansion of the NGTL System and Foothills for contracted incremental export capacity on GTN. The Canadian portion of the expansion program has an estimated capital cost of $1.2 billion and consists of approximately 108 km (67 miles) of pipeline and associated facilities with in-service dates in fourth quarter 2022 and fourth quarter 2023. The program is underpinned by approximately 275 TJ/d (258 MMcf/d) of new firm-service contracts with terms that exceed 30 years. Applications to construct and operate $0.2 billion of the facilities received CER approval in April 2021 and applications for the remaining facilities have been submitted, with federal approvals anticipated in fourth quarter 2022.

U.S. NATURAL GAS PIPELINES

Columbia Gas Section 4 Rate Case

Columbia Gas filed a Section 4 Rate Case with FERC in July 2020 requesting an increase to its maximum transportation rates effective February 1, 2021, subject to refund upon completion of the rate proceeding. On July 28, 2021, Columbia Gas notified FERC that it reached a settlement-in-principle with its customers addressing all remaining issues in the case, including but not limited to the resolution of rates and continuation of Columbia Gas's modernization program. On October 29, 2021, Columbia Gas filed its settlement with FERC, and is now awaiting Commission approval, with 2021 revenues expected to be generally consistent with estimates recorded to date. We expect FERC approval of the settlement in early 2022.

GTN Rate Case Settlement

On September 29, 2021, GTN filed an uncontested rate settlement which would set new recourse rates for GTN effective January 1, 2022 and institute a rate moratorium through December 31, 2023. The revised rates are not expected to have a significant impact on our U.S. Natural Gas Pipelines segment comparable earnings. In addition, GTN must file for new rates no later than April 1, 2024.

Acquisition of TC PipeLines, LP

On March 3, 2021, we completed the previously announced acquisition pursuant to the agreement dated December 14, 2020. Refer to the Recent developments – Corporate section for additional information.

Grand Chenier XPress

Phase I of Grand Chenier XPress, an expansion project on ANR connecting supply directly to U.S. Gulf Coast LNG export facilities, went into service in April 2021. Phase II is expected to be placed in service in early 2022.

Delivery Market Projects

We are actively developing projects that will replace and upgrade certain facilities while reducing emissions along portions of our pipeline systems in principal delivery markets. The enhanced facilities will improve reliability of the systems and allow for additional transportation services to address growing demand under long-term contracts while reducing direct carbon dioxide equivalent (CO_2e) emissions. Consistent with this initiative, the VR project on Columbia Gas has been sanctioned, subject to customary conditions precedent and normal-course regulatory approvals. This project represents an approximate US$0.7 billion capital investment and is targeted to be placed in service during the second half of 2025. In addition, the WR project on ANR has also been sanctioned and will serve markets in the midwestern U.S. This project has an estimated capital cost of approximately US$0.8 billion and is expected to be placed in service in fourth quarter 2025.

MEXICO NATURAL GAS PIPELINES

Tula and Villa de Reyes

The CFE initiated arbitration in June 2019 for the Tula and Villa de Reyes projects, disputing fixed capacity payments due to force majeure events. Arbitration proceedings are currently suspended through December 31, 2021 while management advances settlement discussions with the CFE.

Villa de Reyes construction is ongoing but completion has been delayed due to COVID-19 contingency measures and challenges gaining access to land in certain local communities. Management is working closely with state and local governments to complete negotiations and achieve access to land so that construction can be completed. We expect to reach partial in-service by the end of 2021, with the remainder of the construction of Villa de Reyes completed in the first half of 2022.

LIQUIDS PIPELINES

Keystone XL

On June 9, 2021, following the revocation of the Presidential Permit for the Keystone XL pipeline project on January 20, 2021, and after a comprehensive review of options in consultation with our partner, the Government of Alberta, we terminated the Keystone XL pipeline project.

The Keystone XL investment was evaluated for impairment in first quarter 2021 along with our investments in related capital projects including Heartland Pipeline, TC Terminals and Keystone Hardisty Terminal. We determined that the carrying amount of these assets was no longer fully recoverable. As a result, we recognized an asset impairment charge, net of expected contractual recoveries and other contractual and legal obligations related to termination activities, of $2.8 billion ($2.2 billion after tax) for the nine months ended September 30, 2021, which was excluded from comparable earnings. The asset impairment charge was based on the excess of the carrying value of $3.3 billion over the estimated fair value of $0.2 billion. Termination activities and related costs will continue through 2022 with any adjustments to the estimated fair value and future contractual and legal obligations expensed as determined and excluded from comparable earnings. Refer to Note 5, Keystone XL, of our Condensed consolidated financial statements for additional information.

Although we recorded a $2.2 billion after-tax asset impairment charge, net of expected contractual recoveries and other contractual and legal obligations related to the Keystone XL pipeline project termination activities, a significant portion of this amount was shared with the Government of Alberta, thereby reducing the net financial impact to TC Energy. In June 2021, Class A Interests previously issued to the Government of Alberta totaling $394 million were repurchased for a nominal amount, the $1.0 billion (US$849 million) balance on the credit facility was guaranteed and fully paid by the Government of Alberta and $91 million of Class C Interests were issued to the Government of Alberta entitling them to future liquidation proceeds from specified Keystone XL project assets. After considering these transactions, including the income tax impact thereon, the net financial impact to us as a result of the termination of Keystone XL and related projects at September 30, 2021 was $1.1 billion determined as follows:

(millions of $)	**September 30, 2021**
Asset impairment charge and other (after tax)[1]	**2,194**
Government of Alberta Class A Interests repurchased for a nominal amount[2]	**(394)**
Credit facility balance – guaranteed and paid by the Government of Alberta (net)[2,3]	**(737)**
Net financial impact of the termination of the Keystone XL pipeline project	**1,063**

1 Refer to Note 5, Keystone XL, of our Condensed consolidated financial statements for additional information.
2 Recognized through the Condensed consolidated statement of equity.
3 Net of income taxes and Class C Interests issued.

After the Presidential Permit was revoked, construction activities ceased except for certain activities required to clean up and reclaim worksites in adherence to our commitment to safety, the environment, and our regulatory requirements. We will continue to coordinate with regulators, stakeholders and Indigenous groups to meet our environmental and regulatory commitments and ensure a safe exit from the Keystone XL pipeline project. The majority of these associated costs were funded through a final drawdown on the project-level credit facility which occurred in June 2021, subsequent to which the credit facility was fully repaid by the Government of Alberta and terminated.

We continue to manage legacy challenges to the 2019 Presidential Permit and the Bureau of Land Management Grant of Right-of-Way, which remain pending before the federal district court in Montana, in a manner consistent with the termination of the project.

On July 2, 2021, TC Energy filed a Notice of Intent to initiate a legacy North American Free Trade Agreement (NAFTA) claim to recover economic damages resulting from the revocation of the Presidential Permit for the Keystone XL pipeline. We will be seeking to recover more than US$15 billion in damages as a result of the U.S. Government's breach of its NAFTA obligations. This claim is in a preliminary stage and the timing of outcome is unknown at present.

Northern Courier

On September 16, 2021, we announced the sale of our remaining 15 per cent equity interest in Northern Courier Pipeline to Astisiy Limited Partnership, comprised of Suncor and eight Indigenous communities in the Regional Municipality of Wood Buffalo, for gross proceeds of approximately $30 million before post-closing adjustments. The transaction is anticipated to close in fourth quarter 2021, subject to customary closing conditions and the receipt of the required regulatory approvals.

Port Neches

On March 8, 2021, we entered a joint venture with Motiva Enterprises (Motiva) to construct the US$152 million Port Neches Link pipeline system which will connect the Keystone Pipeline System to Motiva's Port Neches Terminal which supplies 630,000 Bbl/d to their Port Arthur refinery. This common carrier pipeline system will also include facilities to tie in additional liquids terminals to the Keystone Pipeline System with other downstream infrastructure and is expected to be in service in the second half of 2022.

POWER AND STORAGE

Sharp Hills Wind Power Purchase Agreement

On September 20, 2021, we executed a 15-year PPA for 100 per cent of the power produced and the rights to all environmental attributes from the 297 MW Sharp Hills Wind Farm located in eastern Alberta. The Sharp Hills Wind Farm is anticipated to be operational in 2023, subject to customary regulatory approvals and conditions.

Bruce Power Outage

As part of the planned inspections, testing, analysis and maintenance activities at Bruce Power during the current Unit 6 MCR outage and the recently completed Unit 3 planned outage, higher than anticipated readings of hydrogen concentration in pressure tubes were detected. These readings were limited to a very small area of the respective pressure tubes and did not impact safety nor pressure tube integrity as concluded following an assessment of all of the Bruce Power units. On October 9, 2021, Unit 3 returned to service after the Canadian Nuclear Safety Commission approved Bruce Power's restart request following extensive inspections which demonstrated that safety and pressure tube integrity continued to meet regulatory requirements. Bruce Power will be incorporating additional inspections as part of their normal surveillance programs to address the new findings while progressing further programs that demonstrate fitness for service at elevated hydrogen concentration levels.

Bruce Power Life Extension

The Unit 6 MCR program continues on budget and on schedule. The program is nearing the end of the Inspection Phase and is about to enter the Installation Phase. Preparation of the Unit 3 MCR program, which is the next scheduled MCR outage, continues and Bruce Power expects to submit its final cost and schedule duration estimate to the IESO in fourth quarter 2021.

Bruce Power Uprate Initiative

Bruce Power recently launched Project 2030 with the goal of achieving a site peak output of 7,000 MW by 2030 in support of climate change targets and future clean energy needs. Project 2030 will focus 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 at Bruce Power.

Ontario Pumped Storage Project

As part of our strategy to capture opportunities that capitalize on the transition to a less carbon-intensive energy mix, we are developing a 1,000 MW pumped hydro storage project in Meaford, Ontario near Bruce Power. Once complete, this facility is designed to provide emission-free electricity to the province while reducing greenhouse gas emissions by an expected 490,000 tonnes and delivering more than $250 million in annual electricity savings to Ontario ratepayers. On July 28, 2021, we reached an agreement with the Department of National Defence that, subject to conditions and regulatory approval, allows for the development of this project on the Meaford base. We will continue to consult with the Saugeen Ojibway Nation, other Indigenous Rightsholders and communities along with other local stakeholders as we continue to advance this project, which remains subject to a number of conditions and approvals, including approval of our Board of Directors.

Renewable Energy Requests for Information (RFI)

Through an RFI process in second quarter 2021, we announced that we were seeking to identify potential contracts and/or investment opportunities in up to 620 MW of wind energy projects, 300 MW of solar projects and 100 MW of energy storage projects to meet the electricity needs of a portion of our U.S. pipeline assets. The project team is currently evaluating proposals, has commenced negotiations and expects to finalize contracts by the end of the year.

OTHER ENERGY TRANSITION DEVELOPMENTS

Alberta Carbon Grid

On June 17, 2021, we announced a partnership with Pembina Pipeline Corporation to jointly develop a carbon transportation and sequestration system which, when fully constructed, would be capable of transporting more than 20 million tonnes of CO_2 annually. By leveraging existing pipelines and a newly developed sequestration hub, the Alberta Carbon Grid (ACG) is expected to provide an infrastructure platform for Alberta-based industries to manage their emissions and contribute to a lower-carbon economy. Designed to be an open-access system, the ACG would connect the Fort McMurray, Alberta Industrial Heartland and Drayton Valley regions to key sequestration locations and delivery points across the province.

Irving Oil Decarbonization

On August 12, 2021, we signed a memorandum of understanding to explore the joint development of a series of proposed energy projects focused on reducing greenhouse gas emissions and creating new economic opportunities in New Brunswick and Atlantic Canada. Together with Irving Oil, we have identified a series of potential projects for exploration focused on decarbonizing current assets and deploying emerging technologies to reduce overall emissions. 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

On October 7, 2021, we announced a partnership with Nikola Corporation to collaborate on developing, constructing, operating and owning large-scale hydrogen production facilities (hubs) in the United States and Canada. We are actively collaborating to identify and develop projects to establish the infrastructure required to deliver low-cost and low-carbon hydrogen at scale in line with each company's core objectives. Both parties desire to accelerate the adoption of heavy-duty zero-emission fuel cell electric vehicles (FCEVs) and hydrogen across industrial sectors by establishing hubs in key geographic locations.

A key objective of the collaboration is to establish hubs producing 150 tonnes or more of hydrogen per day near highly traveled truck corridors to serve Nikola's planned need for hydrogen to fuel its Class 8 FCEVs within the next five years. Our significant pipeline, storage and power assets can potentially be leveraged to lower the cost and increase the speed of delivery of these hubs. This may include exploring the integration of midstream 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.

CORPORATE

Voluntary Retirement Program

In mid-2021, we offered a one-time VRP to eligible employees. Participants in the program will retire by December 31, 2021 and receive a transition payment in addition to existing retirement benefits. For the three and nine months ended September 30, 2021, we have expensed a total of $89 million before tax, mainly related to the VRP transition payments, which was included in Plant operating costs and other. Of the total program costs, $71 million was excluded from comparable earnings and $18 million was recorded in Revenues related to costs that are recoverable through regulatory and tolling structures on a flow-through basis.

Retirement and Appointment of our Executive Vice-President and CFO

On May 17, 2021, we announced that Don Marchand, Executive Vice-President and Chief Financial Officer (CFO), will retire from TC Energy on November 1, 2021. Mr. Marchand stepped down as CFO on July 31, 2021 and Joel Hunter, previously Senior Vice-President, Capital Markets, succeeded Mr. Marchand as Executive Vice-President and CFO as of August 1, 2021.

Acquisition of TC PipeLines, LP

On March 3, 2021, we completed the acquisition of all of the outstanding common units of TC PipeLines, LP not beneficially owned by TC Energy, resulting in TC PipeLines, LP becoming an indirect, wholly-owned subsidiary of TC Energy. Upon close of the transaction and in accordance with the acquisition terms, TC PipeLines, LP common unitholders received 0.70 common shares of TC Energy for each issued and outstanding publicly-held TC PipeLines, LP common unit resulting in the issuance of 38 million TC Energy common shares valued at approximately $2.1 billion, net of transaction costs. Refer to Note 10, Non-controlling interests, of our Condensed consolidated financial statements for additional information.

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, 2021, our current assets totaled $8.7 billion and current liabilities amounted to $17.0 billion, leaving us with a working capital deficit of $8.3 billion compared to $6.8 billion at December 31, 2020. 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 $10.0 billion of committed revolving credit facilities, of which $7.0 billion of short-term borrowing capacity remains available, net of $3.0 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, 2021
- 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 $)	**2021**	**2020**	**2021**	**2020**
Net cash provided by operations	**1,712**	1,783	**5,089**	5,119
(Decrease)/increase in operating working capital	**(227)**	(120)	**32**	187
Funds generated from operations	**1,485**	1,663	**5,121**	5,306
Specific items:				
Current income tax expense on Keystone XL asset impairment charge, preservation and other	**—**	—	**120**	—
Keystone XL preservation and other	**14**	—	**35**	—
Voluntary Retirement Program	**71**	—	**71**	—
Current income tax recovery on Voluntary Retirement Program	**(14)**	—	**(14)**	—
Comparable funds generated from operations	**1,556**	1,663	**5,333**	5,306

Net Cash Provided by Operations

Net cash provided by operations decreased by $71 million and $30 million for the three and nine months ended September 30, 2021 compared to the same periods in 2020 primarily due to lower funds generated from operations, partially offset by the amount and timing of working capital changes.

Comparable Funds Generated From Operations

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

Comparable funds generated from operations decreased by $107 million for the three months ended September 30, 2021 compared to the same period in 2020 primarily due to lower comparable EBITDA, higher current income taxes and lower distributions from the operating activities of our equity investments, partially offset by realized gains in 2021 compared to realized losses in 2020 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income.

Comparable funds generated from operations increased by $27 million for the nine months ended September 30, 2021 compared to the same period in 2020 primarily due to higher comparable earnings, including realized gains in 2021 compared to realized losses in 2020 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income. This increase was partially offset by fees collected in 2020 associated with the successful completion of the Sur de Texas pipeline and lower distributions from the operating activities of our equity investments in 2021.

CASH USED IN INVESTING ACTIVITIES

	three months ended September 30		nine months ended September 30	
(millions of $)	**2021**	**2020**	**2021**	**2020**
Capital spending				
Capital expenditures	**(1,446)**	(2,063)	**(4,305)**	(6,049)
Capital projects in development	**—**	—	**—**	(122)
Contributions to equity investments	**(241)**	(187)	**(706)**	(498)
	(1,687)	(2,250)	**(5,011)**	(6,669)
Proceeds from sale of assets, net of transaction costs	**—**	—	**—**	3,407
Loan to affiliate	**(620)**	(250)	**(840)**	(250)
Deferred amounts and other	**(66)**	(137)	**(470)**	(359)
Net cash used in investing activities	**(2,373)**	(2,637)	**(6,321)**	(3,871)

Capital expenditures in 2021 were incurred primarily for the expansion of the NGTL System, ANR and Columbia Gas projects as well as maintenance capital expenditures. Lower capital spending in 2021 compared to 2020 reflected reduced spending on Columbia Gas projects, the sale of a 65 per cent equity interest in and subsequent equity accounting for Coastal GasLink LP in second quarter 2020, along with the termination of the Keystone XL pipeline project following the January 20, 2021 revocation of the Presidential Permit, partially offset by higher capital spending on ANR.

Costs incurred on capital projects in development in 2020 were mostly attributable to spending on the Keystone XL pipeline project prior to its reclassification to Plant, property and equipment upon reaching a positive final investment decision in March 2020.

Contributions to equity investments increased in 2021 compared to 2020 mainly due to higher investment in Bruce Power.

In second quarter 2020, we closed the sale of our Ontario natural gas-fired power plants for net proceeds of approximately $2.8 billion and the sale of a 65 per cent equity interest in Coastal GasLink LP for net proceeds of $656 million.

TC Energy entered into a subordinated demand revolving credit facility with Coastal GasLink LP to provide additional short-term liquidity and funding flexibility to the project. During the nine months ended September 30, 2021, $840 million was drawn on this facility. In October 2021, this amount was fully repaid and further draws were made which resulted in an outstanding balance of $175 million at October 29, 2021. Refer to Note 7, Loans receivable from affiliates, of our Condensed consolidated financial statements for additional information.

CASH PROVIDED BY FINANCING ACTIVITIES

	three months ended September 30		nine months ended September 30	
(millions of $)	**2021**	**2020**	**2021**	**2020**
Notes payable issued/(repaid), net	**1,448**	338	**(1,012)**	(2,765)
Long-term debt issued, net of issue costs	**47**	35	**7,798**	5,571
Long-term debt repaid	**—**	—	**(980)**	(2,241)
Junior subordinated notes issued, net of issue costs	**—**	—	**495**	—
Loss on settlement of financial instruments	**—**	—	**—**	(130)
Redeemable non-controlling interest repurchased	**—**	—	**(633)**	—
Contributions from redeemable non-controlling interest	**—**	524	**—**	578
Dividends and distributions paid	**(903)**	(854)	**(2,652)**	(2,514)
Common shares issued	**4**	3	**64**	86
Preferred shares redeemed	**—**	—	**(500)**	—
Acquisition of TC PipeLines, LP transaction costs	**—**	—	**(15)**	—
Net cash provided by/(used in) financing activities	**596**	46	**2,565**	(1,415)

Long-term debt issued

On October 12, 2021, TCPL issued US$1.25 billion of Senior Unsecured Notes due in October 2024 bearing interest at a fixed rate of 1.00 per cent, and US$1.0 billion of Senior Unsecured Notes due in October 2031 bearing interest at a fixed rate of 2.50 per cent.

On June 9, 2021, TCPL issued $750 million of Medium Term Notes due in June 2024 bearing interest at a floating rate, $500 million of Medium Term Notes due in June 2031 bearing interest at a fixed rate of 2.97 per cent and $250 million of Medium Term Notes due in September 2047 bearing interest at a fixed rate of 4.33 per cent.

On January 4, 2021, we established a US$4.1 billion project-level credit facility to support the construction of the Keystone XL pipeline project, which was fully guaranteed by the Government of Alberta and non-recourse to us. The availability of this credit facility was subsequently reduced to US$1.6 billion, on which we drew a total of US$849 million, with full repayment by the Government of Alberta of the amount outstanding in June 2021. Refer to Note 5, Keystone XL, of our Condensed consolidated financial statements for additional information.

In December 2020, our subsidiary, Columbia Pipeline Group, Inc., entered into a US$4.2 billion Term Loan due in June 2022 bearing interest at a floating rate. In January 2021, US$4.0 billion was drawn on the Term Loan and the total availability under the loan agreement was reduced accordingly.

Long-term debt repaid/retired

In January 2021, TCPL repaid US$400 million of Debentures bearing interest at a fixed rate of 9.875 per cent.

In March 2021, our subsidiary, TC PipeLines, LP, redeemed US$350 million of Senior Unsecured Notes bearing interest at a fixed rate of 4.65 per cent.

As noted above, in June 2021, the Government of Alberta repaid the US$849 million ($1.0 billion) outstanding balance under the Keystone XL project-level credit facility, with no cash impact to us, and the facility was subsequently terminated. Refer to Note 5, Keystone XL, of our Condensed consolidated financial statements for additional information.

Junior subordinated notes issued

In March 2021, we issued $500 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 13 preferred shares on May 31, 2021 pursuant to their terms. Refer to Note 9, Junior subordinated notes issued, of our Condensed consolidated financial statements for additional information.

Redeemable non-controlling interest repurchased

On January 8, 2021, we exercised our call right in accordance with contractual terms and paid US$497 million to repurchase the Government of Alberta Class A Interests which were classified as Current liabilities on the Consolidated balance sheet at December 31, 2020. This transaction was funded by draws on the Keystone XL project-level credit facility which was guaranteed by the Government of Alberta as discussed above.

DIVIDENDS

On November 4, 2021, we declared quarterly dividends on our common shares of $0.87 per share payable on January 31, 2022 to shareholders of record at the close of business on December 31, 2021.

SHARE INFORMATION

At October 29, 2021, we had 981 million issued and outstanding common shares and 8 million outstanding options to buy common shares, of which 4 million were exercisable.

On May 31, 2021, we redeemed all of the 20 million issued and outstanding Series 13 preferred shares at a redemption price of $25.00 per share and paid the final quarterly dividend of $0.34375 per Series 13 preferred share for the period up to but excluding May 31, 2021 as previously declared on May 6, 2021.

On March 3, 2021, we issued 37,955,093 TC Energy common shares to acquire all the outstanding common units of TC PipeLines, LP, valued at approximately $2.1 billion, net of transaction costs. Refer to the Recent developments – Corporate section for additional information on the acquisition.

On February 1, 2021, 818,876 Series 5 preferred shares were converted, on a one-for-one basis, into Series 6 preferred shares and 175,208 Series 6 preferred shares were converted, on a one-for-one basis, into Series 5 preferred shares.

CREDIT FACILITIES

At October 29, 2021, we had a total of $9.8 billion of committed revolving credit facilities of which $7.3 billion of short-term borrowing capacity remains available, net of $2.5 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.

On March 4, 2021, our subsidiary, TC PipeLines, LP, terminated a US$500 million unsecured revolving credit facility bearing interest at a floating rate on which no amount was outstanding.

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

CONTRACTUAL OBLIGATIONS

Capital expenditure commitments at September 30, 2021 are largely consistent with December 31, 2020, reflecting the net effect of an approximate $0.9 billion reduction related to the termination of the Keystone XL pipeline project and an increase in new capital commitments primarily related to NGTL System expansions and U.S. natural gas pipeline projects.

There were no other material changes to our contractual obligations in third quarter 2021 or to payments due in the next five years or after. Refer to our 2020 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 2020 Annual Report for more information about the risks we face in our business which have not changed substantially since December 31, 2020, other than as noted within this MD&A. Refer to the Recent developments – COVID-19 section of this MD&A for further information regarding the impact of COVID-19 on our financial risks.

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 LIBOR, of which certain rate settings will cease to be published at the end of 2021 with full cessation by mid-2023. We continue to monitor developments and are addressing necessary system and contractual changes while assessing the adoption of the standard market proposed reference rates. This includes testing system solutions and analyzing existing agreements to determine the effect of reference rate reform on our consolidated financial statements. These changes are not expected to have a material impact on our consolidated financial statements.

FOREIGN EXCHANGE RISK

Certain of our businesses generate all or most of their earnings in U.S. dollars and, since we report our financial results in Canadian dollars, changes in the value of the U.S. dollar against the Canadian dollar can affect our comparable EBITDA and net income. 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. This exposure is managed using foreign exchange derivatives.

Net investment hedges

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.

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 due to significant market events. Although the effects of the COVID-19 pandemic and other market disruptions on our customers are difficult to predict, similar to 2020, we are not expecting a material negative impact to our 2021 earnings or cash flows. Refer to our 2020 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 supportable forecasts to determine any impairment, which is recognized in Plant operating costs and other. At September 30, 2021, we had no significant credit losses, no significant credit risk concentration and no significant amounts past due or impaired.

We have significant credit and performance exposure to financial institutions because they 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

Loans Receivable from Affiliates

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

Sur de Texas

At September 30, 2021 and December 31, 2020, the Loan receivable from affiliate on our Condensed consolidated balance sheet of MXN$20.9 billion or $1.3 billion, represented our 60 per cent proportionate share of long-term debt financing to the Sur de Texas joint venture. Our Condensed consolidated statement of income reflects the related interest income and foreign exchange impact on this loan receivable which were fully offset upon consolidation with corresponding amounts included in our 60 per cent 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 $)	**2021**	2020	**2021**	2020	
Interest income[1]	**22**	25	**64**	87	Interest income and other
Interest expense[2]	**(22)**	(25)	**(64)**	(87)	Income from equity investments
Foreign exchange (losses)/gains[1]	**(42)**	54	**(45)**	(223)	Interest income and other
Foreign exchange gains/(losses)[1]	**42**	(54)	**45**	223	Income from equity investments

1 Included in our Corporate segment.

2 Included in our Mexico Natural Gas Pipelines segment.

Coastal GasLink Pipeline Limited Partnership

We hold a 35 per cent equity interest in Coastal GasLink LP which has contracted us to construct and operate the Coastal GasLink pipeline. In 2020, we entered into 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 $850 million at September 30, 2021 with an outstanding balance of $840 million (December 31, 2020 – nil) reflected in Other current assets on our Condensed consolidated balance sheet. In October 2021, this amount was fully repaid and further draws were made which resulted in an outstanding balance of $175 million at October 29, 2021.

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 refunded to or collected from the ratepayers in subsequent years when the derivative settles.

Balance sheet presentation of derivative instruments

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

(millions of $)	September 30, 2021	December 31, 2020
Other current assets	**207**	235
Other long-term assets	**44**	41
Accounts payable and other	**(272)**	(72)
Other long-term liabilities	**(63)**	(59)
	(84)	145

Unrealized and realized (losses)/gains 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	
	2021	2020	2021	2020
Derivative Instruments Held for Trading[1]				
Amount of unrealized (losses)/gains in the period				
Commodities	**(43)**	(2)	**(27)**	14
Foreign exchange	**(125)**	78	**(183)**	(24)
Amount of realized gains/(losses) in the period				
Commodities	**58**	68	**167**	146
Foreign exchange	**37**	(11)	**195**	(62)
Derivative Instruments in Hedging Relationships[2]				
Amount of realized (losses)/gains in the period				
Commodities	**(9)**	2	**(32)**	4
Interest rate	**(6)**	(6)	**(18)**	(10)

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

2 In the three and nine months ended September 30, 2021 and 2020, there were no gains or losses included in Net income relating to discontinued cash flow hedges where it was probable that the anticipated transaction would not occur.

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, 2021, 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 2021 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. A summary of our critical accounting estimates is included in our 2020 Annual Report.

Accounting Changes

Our significant accounting policies have remained unchanged since December 31, 2020 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 2020 Annual Report.

Quarterly results

SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA

	2021			2020				2019
(millions of $, except per share amounts)	Third	Second	First	Fourth	Third	Second	First	Fourth
Revenues	**3,240**	3,182	3,381	3,297	3,195	3,089	3,418	3,263
Net income/(loss) attributable to common shares	**779**	975	(1,057)	1,124	904	1,281	1,148	1,108
Comparable earnings	**972**	1,038	1,108	1,080	893	863	1,109	970
Per share statistics:								
Net income/(loss) per common share – basic	**$0.80**	$1.00	($1.11)	$1.20	$0.96	$1.36	$1.22	$1.18
Comparable earnings per common share	**$0.99**	$1.06	$1.16	$1.15	$0.95	$0.92	$1.18	$1.03
Dividends declared per common share	**$0.87**	$0.87	$0.87	$0.81	$0.81	$0.81	$0.81	$0.75

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 shippers
- newly constructed assets being placed in service
- acquisitions and divestitures
- developments outside of the normal course of operations.

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.

Comparable earnings exclude the unrealized gains and losses from changes in the fair value of certain derivatives used to reduce our exposure to specific financial and commodity price risks. These derivatives generally provide effective economic hedges but do not meet the criteria for hedge accounting. As a result, the 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 part of our underlying operations. We also exclude the unrealized foreign exchange gains and losses on the Loan receivable from affiliate as well as the corresponding proportionate share of Sur de Texas foreign exchange gains and losses, as these 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.

In third quarter 2021, comparable earnings also excluded:

- a $55 million after-tax expense with respect to transition payments incurred as part of the VRP
- 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:

- 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
- preservation and other costs of $16 million after tax primarily related to the preservation and storage of Keystone XL pipeline project assets 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.

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 20, 2021 revocation of the Presidential Permit.

In fourth quarter 2020, comparable earnings also excluded:

- 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 income 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
- an incremental after-tax loss of $81 million for the three months ended December 31, 2020 related to the sale of our Ontario natural gas-fired power plants.

In third quarter 2020, comparable earnings also excluded:

- an incremental after-tax loss of $45 million related to the sale of the Ontario natural gas-fired power plants
- a $6 million reduction in the after-tax gain related to the sale of a 65 per cent equity interest in Coastal GasLink LP.

In second quarter 2020, comparable earnings also excluded:

- an after-tax gain of $408 million related to the sale of a 65 per cent equity interest in Coastal GasLink LP
- an incremental after-tax loss of $80 million related to the sale of the Ontario natural gas-fired power plants.

In first quarter 2020, comparable earnings also excluded:

- an income tax valuation allowance release of $281 million following our reassessment of deferred income tax assets that are deemed more likely than not to be realized
- an incremental after-tax loss of $77 million related to the Ontario natural gas-fired power plant assets held for sale.

In fourth quarter 2019, comparable earnings also excluded:

- an income tax valuation allowance release of $195 million related to certain prior years' U.S. income tax losses resulting from our reassessment of deferred income tax assets that are more likely than not to be realized
- an incremental after-tax loss of $61 million related to the Ontario natural gas-fired power plant assets held for sale
- an additional $19 million expense related to state income taxes on the sale of certain Columbia Midstream assets.