Management's discussion and analysis

February 14, 2022

This management's discussion and analysis (MD&A) contains information to help the reader make investment decisions about TC Energy Corporation (TC Energy). It discusses our business, operations, financial position, risks and other factors for the year ended December 31, 2021.

This MD&A should also be read in conjunction with our December 31, 2021 audited Consolidated financial statements and notes for the same period, which have been prepared in accordance with U.S. GAAP.

Contents

About this document

Throughout this MD&A, the terms we, us, our and TC Energy mean TC Energy Corporation and its subsidiaries. Abbreviations and acronyms that are not defined in the document are defined in the glossary on page 120. All information is as of February 14, 2022 and all amounts are in Canadian dollars, unless noted otherwise.

FORWARD-LOOKING INFORMATION

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

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

Forward-looking statements in this MD&A include information about the following, among other things:

- our financial and operational performance, including the performance of our subsidiaries
- expectations about strategies and goals for growth and expansion, including acquisitions
- expected cash flows and future financing options available, including portfolio management
- expected dividend growth
- expected access to and cost of capital
- expected costs and schedules for planned projects, including projects under construction and in development
- expected capital expenditures, contractual obligations, commitments and contingent liabilities
- expected regulatory processes and outcomes
- statements related to our GHG emissions reduction goals
- expected outcomes with respect to legal proceedings, including arbitration and insurance claims
- the expected impact of future tax and accounting changes
- expected industry, market and economic conditions
- the expected impact of COVID-19.

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

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

Assumptions

- realization of expected benefits from acquisitions, divestitures and energy transition
- regulatory decisions and outcomes
- planned and unplanned outages and the use of our pipeline, power and storage assets
- integrity and reliability of our assets
- anticipated construction costs, schedules and completion dates
- access to capital markets, including portfolio management
- expected industry, market and economic conditions
- inflation rates and commodity prices
- interest, tax and foreign exchange rates
- nature and scope of hedging
- expected impact of COVID-19.

Risks and uncertainties

- realization of expected benefits from acquisitions and divestitures
- our ability to successfully implement our strategic priorities and whether they will yield the expected benefits
- our ability to implement a capital allocation strategy aligned with maximizing shareholder value
- the operating performance of our pipeline, power and storage assets
- amount of capacity sold and rates achieved in our pipeline businesses
- the amount of capacity payments and revenues from our power generation assets due to plant availability
- production levels within supply basins
- construction and completion of capital projects
- cost and availability of labour, equipment and materials
- the availability and market prices of commodities
- access to capital markets on competitive terms
- interest, tax and foreign exchange rates
- performance and credit risk of our counterparties
- regulatory decisions and outcomes of legal proceedings, including arbitration and insurance claims
- our ability to effectively anticipate and assess changes to government policies and regulations, including those related to the environment and COVID-19
- our ability to realize the value of tangible assets and contractual recoveries, including those specific to the Keystone XL pipeline project
- competition in the businesses in which we operate
- unexpected or unusual weather
- acts of civil disobedience
- cyber security and technological developments
- ESG related risks
- impact of energy transition on our business
- economic conditions in North America as well as globally
- global health crises, such as pandemics and epidemics, including COVID-19 and the unexpected impacts related thereto.

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

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

FOR MORE INFORMATION

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

NON-GAAP MEASURES

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

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

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

Comparable measures

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

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

- gains or losses on sales of assets or assets held for sale
- income tax refunds, valuation allowances and adjustments resulting from changes in legislation and enacted tax rates
- 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 from comparable measures the unrealized gains and losses from changes in the fair value of derivatives related to financial and commodity price risk management activities. These derivatives generally provide effective economic hedges, but do not meet the criteria for hedge accounting. 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 from comparable measures 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

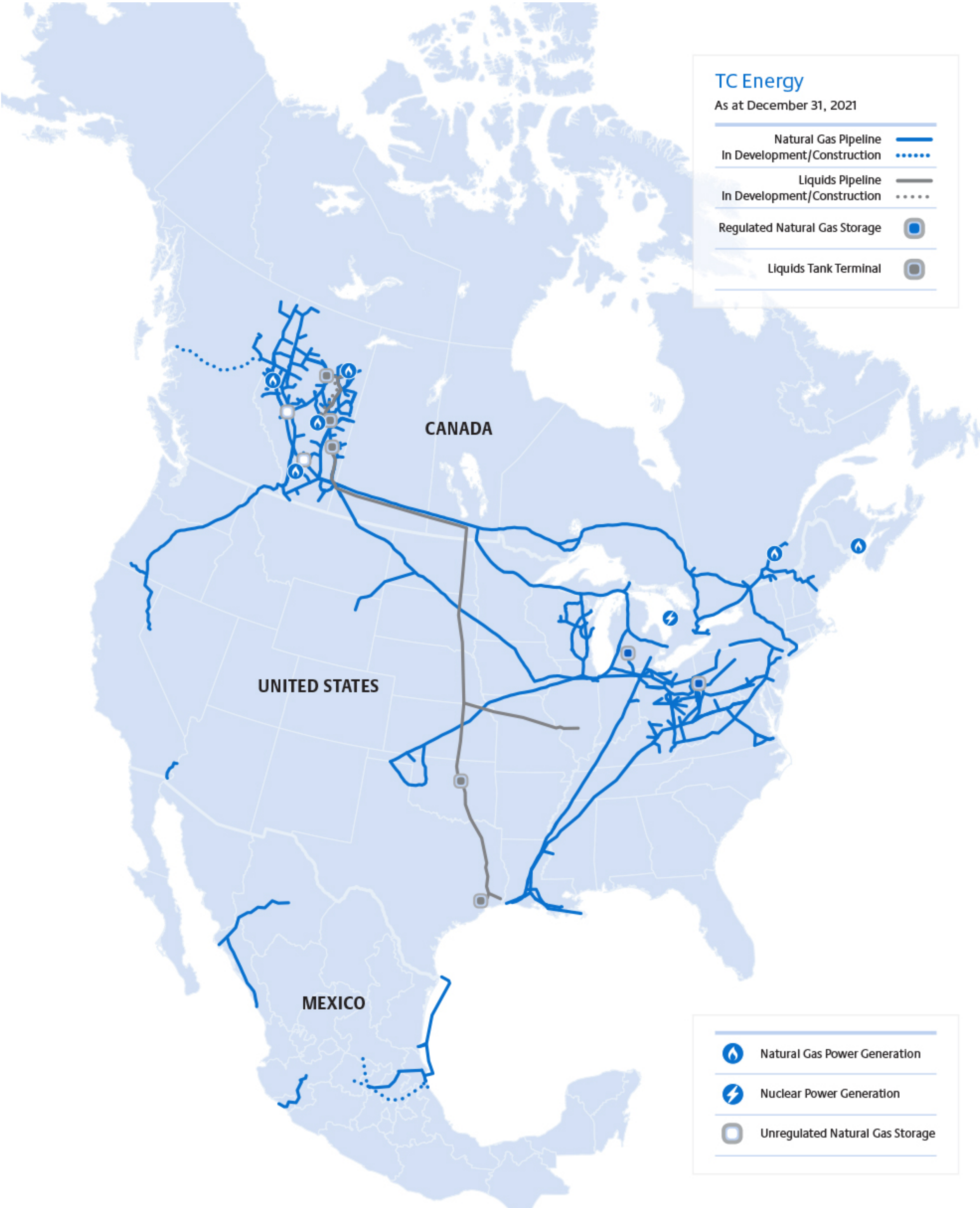
Comparable EBITDA represents segmented earnings adjusted for certain specific items, excluding non-cash charges for depreciation and amortization. We use comparable EBITDA as a measure of our earnings from ongoing operations as it is a useful indicator of our performance and is also presented on a consolidated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

Comparable earnings and comparable earnings per common share
Comparable earnings represents earnings attributable to common shareholders on a consolidated basis, adjusted for specific items. Comparable earnings is comprised of segmented earnings, Interest expense, AFUDC, Interest income and other, Income tax expense, Non-controlling interests and Preferred share dividends, adjusted for specific items. Refer to the Financial highlights 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 (working capital). The components of changes in working capital are disclosed in Note 27, Changes in operating working capital, of our 2021 Consolidated financial statements. We believe funds generated from operations is a useful measure of our consolidated operating cash flows because it excludes fluctuations from working capital balances, which do not necessarily reflect underlying operations in the same period and is used to provide a consistent measure of the cash-generating ability of our businesses. Comparable funds generated from operations is adjusted for the cash impact of specific items noted above. Refer to the Financial condition section for a reconciliation to Net cash provided by operations.

About our business

With over 70 years of experience, TC Energy is a leader in the responsible development and reliable operation of North American energy infrastructure including natural gas and liquids pipelines, power generation and natural gas storage facilities.



THREE CORE BUSINESSES

We operate in three core businesses – Natural Gas Pipelines, Liquids Pipelines and Power and Storage. In order to provide information that is aligned with how management decisions about our businesses are made and how performance of our businesses is assessed, our results are reflected in five operating segments: Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines, Mexico Natural Gas Pipelines, Liquids Pipelines and Power and Storage. We also have a Corporate segment consisting of corporate and administrative functions that provide governance, financing and other support to TC Energy's business segments.

Year at-a-glance

at December 31 (millions of $)	2021	2020
Total assets by segment		
Canadian Natural Gas Pipelines	**25,213**	22,852
U.S. Natural Gas Pipelines	**45,502**	43,217
Mexico Natural Gas Pipelines	**7,547**	7,215
Liquids Pipelines	**14,951**	16,744
Power and Storage	**6,563**	5,062
Corporate	**4,442**	5,210
	104,218	100,300

year ended December 31 (millions of $)	2021	2020
Total revenues by segment		
Canadian Natural Gas Pipelines	**4,519**	4,469
U.S. Natural Gas Pipelines	**5,233**	5,031
Mexico Natural Gas Pipelines	**605**	716
Liquids Pipelines	**2,306**	2,371
Power and Storage	**724**	412
	13,387	12,999

year ended December 31 (millions of $)	2021	2020
Comparable EBITDA by segment[1]		
Canadian Natural Gas Pipelines	**2,675**	2,566
U.S. Natural Gas Pipelines	**3,856**	3,638
Mexico Natural Gas Pipelines	**666**	786
Liquids Pipelines	**1,526**	1,700
Power and Storage	**683**	677
Corporate	**(24)**	(16)
	9,382	9,351

1 For further information on the reconciliation of segmented earnings to comparable EBITDA, refer to the Financial results sections for each business segment.

OUR STRATEGY

Our vision is to be the premier energy infrastructure company in North America today and in the future, focused on transporting and delivering the energy people need every day. Our goal is to develop and build a portfolio of infrastructure assets that will enable us to prosper irrespective of the pace and direction of energy transition.

Our business consists of natural gas and crude oil transportation, storage and delivery systems in addition to power generation assets that produce electricity. These long-life infrastructure assets cover strategic North American corridors and are supported by long-term commercial arrangements and/or rate regulation, generating predictable and sustainable cash flows and earnings, the cornerstones of our low-risk business model. Our long-term strategy is driven by several key beliefs:

- natural gas will continue to play a pivotal role in North America's energy future
- crude oil will remain an important part of the fuel mix
- the need for renewables along with reliable, on-demand energy sources to support grid stability will grow significantly
- the value of existing infrastructure assets will become more valuable given the challenges to develop new greenfield, linear-energy infrastructure, in particular, pipelines.

These beliefs drive our capital allocation framework and we will seek to intentionally migrate our portfolio composition over time.

Allocation of comparable EBITDA[1]

year ended December 31	2021
Comparable EBITDA by segment	
Canadian Natural Gas Pipelines	**29%**
U.S. Natural Gas Pipelines	**41%**
Mexico Natural Gas Pipelines	**7%**
Liquids Pipelines	**16%**
Power and Storage	**7%**
	100%

1 Refer to Note 4, Segmented information, of our 2021 Consolidated financial statements for an allocation of segmented earnings by business segment.

Future investments will alter our business mix as energy transition unfolds with the following anticipated shifts in capital allocation:

- Power and Storage weighting in our portfolio is expected to grow
- Natural Gas Pipelines will continue to attract capital
- Liquids Pipelines investment will be targeted and tied to maximizing the value of our asset base
- Measured investment in new technology without taking significant commodity price or volumetric risk.

Key components of our strategy, set out below, support our ability to be competitive, responsible and innovative, enhance the value proposition for our shareholders and safely deliver the energy people need today and in the future.

Key components of our strategy

1 Maximize the full-life value of our infrastructure assets and commercial positions

- Maintaining safe, reliable operations and ensuring asset integrity, while minimizing environmental impacts, continues to be the foundation of our business
- Our pipeline assets include large-scale natural gas and crude oil pipelines and associated storage facilities that connect long-life, low cost supply basins with premium North American and export markets, generating predictable and sustainable cash flows and earnings
- Our power and non-regulated storage assets are primarily under long-term contracts that provide stable cash flows and earnings.

2 Commercially develop and build new asset investment programs

- We are developing high quality, long-life assets under our current capital program, comprised of approximately $24 billion in secured projects. As well, our noted projects under development are, or are expected to be, largely commercially supported. These investments will contribute to incremental earnings and cash flows as they are placed in service
- Our existing extensive footprint offers significant in-corridor growth opportunities. This includes possible future opportunities to deploy low-emissions infrastructure technologies such as renewables, hydrogen and carbon capture, which will help reduce our and our customers' carbon footprint and also supports extending the longevity of our existing assets
- We continue to develop projects and manage construction risk in a disciplined manner that maximizes capital efficiency and returns to shareholders
- As part of our growth strategy, we rely on our experience and our regulatory, commercial, financial, legal and operational expertise to successfully permit, fund, build and integrate new pipeline and other energy facilities
- Safety, executability, profitability and responsible ESG performance are fundamental to our investments.

3 Cultivate a focused portfolio of high-quality development and investment options

- We assess opportunities to develop and acquire energy infrastructure that complements our existing portfolio, enhances future resilience under a changing energy mix, and diversifies access to attractive supply and market regions within our risk preferences. Refer to the Enterprise risk management section for an overview of our enterprise risks
- We focus on commercially regulated and/or long-term contracted growth initiatives in core regions of North America and prudently manage development costs, minimizing capital at risk in a project's early stages
- We will advance selected opportunities, including energy transition growth initiatives, to full development and construction when market conditions are appropriate and project risks and returns are acceptable
- We monitor trends specific to energy supply and demand fundamentals, in addition to analyzing how our portfolio performs under different energy mix scenarios considering the recommendations of the Financial Stability Board's Task Force on Climate-related Financial Disclosures. This enables the identification of opportunities that contribute to our resilience, strengthen our asset base or improve diversification.

4 Maximize our competitive strengths

- We continually seek to enhance our core competencies in safety, operational excellence, investment opportunity origination, project execution and stakeholder relations as well as key sustainability and ESG areas to ensure we deliver shareholder value. The use of a disciplined approach to capital allocation supports our ability to maximize value over the short, medium and long term. A strong focus on talent management ensures that we have the necessary capabilities to execute and deliver on our strategy.

Our competitive advantage

Decades of experience in the energy infrastructure business, a disciplined approach to project management and a proven capital allocation model result in a solid competitive position as we remain focused on our purpose; to deliver the energy people need today and in the future, safely, responsibly, collaboratively and with integrity through:

- strong leadership and governance: we maintain rigorous governance over our approach to business ethics, enterprise risk management, competitive behaviour, operating capabilities and strategy development as well as regulatory, legal, commercial, stakeholder and financing support
- a high-quality portfolio: our low-risk and enduring business model offers the scale and presence to provide essential and highly competitive infrastructure services that enable us to maximize the full-life value of our long-life assets and commercial positions throughout all points of the business cycle. Our portfolio of assets support transporting both molecules and electrons, providing us flexibility to allocate capital towards electrification or other emerging low-carbon technologies in support of any energy transition scenario

- disciplined operations: our values-centred workforce is highly skilled in designing, building and operating energy infrastructure with a focus on operational excellence and a commitment to health, safety, sustainability and the environment that is suited to both today's environment as well as an evolving energy industry
- financial positioning: we exhibit consistently strong financial performance, long-term stability and profitability, along with a disciplined approach to capital investment. We can access sizable amounts of competitively-priced capital to support new investment balanced with common share dividend growth while preserving financial flexibility to fund our operations in all market conditions. In addition, we continue to maintain the simplicity and understandability of our business and corporate structure
- proven ability to adapt: we have a long track record of turning policy and technology changes into opportunities – for example, re-entering Mexico when the country shifted from fuel oil to natural gas, reversing pipeline flows in response to the shale gas revolution and re-purposing the underutilized Canadian Mainline pipeline capacity from natural gas to crude oil service
- commitment to sustainability and ESG: we take a long-term view to managing our interactions with the environment, Indigenous groups, community members and landowners. We aim to communicate transparently on sustainability-related topics with all stakeholders. The 2021 Report on Sustainability builds on our commitment to establishing clear metrics and targets for 10 sustainability commitments from last year. We have also committed to reduce GHG emissions intensity from our operations by 30 per cent by 2030 and position us to achieve zero emissions from our operations, on a net basis, by 2050
- open communication: we carefully manage relationships with our customers and stakeholders and offer clear, candid communication of our prospects to investors in order to build trust and support.

Our risk preferences

The following is an overview of our risk philosophy:

Financial strength and flexibility
• Rely on internally-generated cash flows, existing debt capacity, partnerships and portfolio management to finance new initiatives. Reserve common equity issuances for transformational opportunities.
Known and acceptable project risks
• Select investments with known, acceptable and manageable project execution risk, including stakeholder considerations.
Business underpinned by strong fundamentals
• Invest in assets that are investment-grade on a stand-alone basis with stable cash flows supported by strong underlying macroeconomic fundamentals, conducive regulation and/or long-term contracts with creditworthy counterparties.
Manage credit metrics to ensure "top-end" sector ratings
• Solid investment-grade ratings are an important competitive advantage and TC Energy will seek to ensure our credit profile remains at the top end of our sector while balancing the interests of equity and fixed income investors.
Prudent management of counterparty exposure
• Limit counterparty concentration and sovereign risk; seek diversification and solid commercial arrangements underpinned by strong fundamentals.

2021 FINANCIAL HIGHLIGHTS

We use certain financial measures that do not have a standardized meaning under GAAP because we believe they improve our ability to compare results between reporting periods and enhance understanding of our operating performance. Known as non-GAAP measures, they may not be comparable to similar measures provided by other companies.

Comparable EBITDA, comparable earnings, comparable earnings per common share and comparable funds generated from operations are all non-GAAP measures. Refer to page 11 for more information about the non-GAAP measures we use and pages 22 and 82 as well as the business segment Financial results sections for reconciliations to the most directly comparable GAAP measures.

year ended December 31 (millions of $, except per share amounts)	**2021**	**2020**	**2019**
Income			
Revenues	**13,387**	12,999	13,255
Net income attributable to common shares	**1,815**	4,457	3,976
per common share – basic	**$1.87**	$4.74	$4.28
Comparable EBITDA[1]	**9,382**	9,351	9,366
Comparable earnings	**4,153**	3,945	3,851
per common share	**$4.27**	$4.20	$4.14
Cash flows			
Net cash provided by operations	**6,890**	7,058	7,082
Comparable funds generated from operations	**7,406**	7,385	7,117
Capital spending[2]	**7,134**	8,900	8,784
Proceeds from sales of assets, net of transaction costs	**35**	3,407	2,398
Balance sheet[3]			
Total assets	**104,218**	100,300	99,279
Long-term debt, including current portion	**38,661**	36,885	36,985
Junior subordinated notes	**8,939**	8,498	8,614
Redeemable non-controlling interest[4]	**—**	393	—
Preferred shares	**3,487**	3,980	3,980
Non-controlling interests	**125**	1,682	1,634
Common shareholders' equity	**29,784**	27,418	26,783
Dividends declared			
per common share	**$3.48**	$3.24	$3.00
Basic common shares (millions)			
– weighted average for the year	**973**	940	929
– issued and outstanding at end of year	**981**	940	938

1 Additional information on Segmented earnings, the most directly comparable GAAP measure, can be found on page 20.

2 Includes Capital expenditures, Capital projects in development and Contributions to equity investments. Refer to Note 4, Segmented information, of our 2021 Consolidated financial statements for the financial statement line items that comprise total capital spending.

3 As at December 31.

4 At December 31, 2020, redeemable non-controlling interest was classified in mezzanine equity and subsequently repurchased in 2021.

Consolidated results

year ended December 31 (millions of $, except per share amounts)	2021	2020	2019
Canadian Natural Gas Pipelines	**1,449**	1,657	1,115
U.S. Natural Gas Pipelines	**3,071**	2,837	2,747
Mexico Natural Gas Pipelines	**557**	669	490
Liquids Pipelines	**(1,600)**	1,359	1,848
Power and Storage	**628**	181	455
Corporate	**(46)**	70	(70)
Total segmented earnings	**4,059**	6,773	6,585
Interest expense	**(2,360)**	(2,228)	(2,333)
Allowance for funds used during construction	**267**	349	475
Interest income and other	**200**	213	460
Income before income taxes	**2,166**	5,107	5,187
Income tax expense	**(120)**	(194)	(754)
Net income	**2,046**	4,913	4,433
Net income attributable to non-controlling interests	**(91)**	(297)	(293)
Net income attributable to controlling interests	**1,955**	4,616	4,140
Preferred share dividends	**(140)**	(159)	(164)
Net income attributable to common shares	**1,815**	4,457	3,976
Net income per common share – basic	**$1.87**	$4.74	$4.28

Net income attributable to common shares in 2021 was $1.8 billion or $1.87 per share (2020 – $4.5 billion or $4.74 per share; 2019 – $4.0 billion or $4.28 per share), a decrease of $2.6 billion or $2.87 per share compared to the same period in 2020 primarily due to the $2.1 billion after-tax asset impairment of the Keystone XL pipeline project, net of expected contractual recoveries and other contractual and legal obligations recorded in 2021. The decrease in Net income per common share in 2021 also reflects the impact of common shares issued for the acquisition of the remaining ownership interests in TC PipeLines, LP. The increase in Net income per common share in 2020 of $0.46 per share compared to 2019 reflected higher net income in 2020 and the dilutive impact of common shares issued under our DRP in 2019.

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

2021

- a $2.1 billion 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 following the January 20, 2021 revocation of the Presidential Permit. Refer to the Liquids Pipelines – Significant events section for additional information
- a $48 million after-tax expense with respect to transition payments incurred as part of the Voluntary Retirement Program (VRP)
- preservation and storage costs for Keystone XL pipeline project assets of $37 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge, as well as interest expense on the Keystone XL project-level credit facility prior to its termination
- an after-tax gain of $19 million related to the sale of the remaining interest in Northern Courier
- a $7 million after-tax recovery primarily related to certain costs from the IESO 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 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 Consolidated statement of equity in 2021 and served to reduce our net financial impact from the Keystone XL pipeline project termination. Refer to the Liquids Pipelines – Significant events section for additional information.

2020

- an after-tax loss of $283 million related to the Ontario natural gas-fired power plants sold in April 2020. The total after-tax loss on this transaction to the end of 2020 was $477 million including losses accrued in 2019 upon classification of the assets as held for sale
- an after-tax gain of $402 million related to the sale of a 65 per cent equity interest in Coastal GasLink Pipeline Limited Partnership (Coastal GasLink LP)
- an income tax valuation allowance release of $299 million following our reassessment of deferred tax assets that were deemed more likely than not to be realized in 2020
- an additional $18 million income tax recovery related to state income taxes on the sale of certain Columbia Midstream assets.

2019

- an after-tax gain of $115 million related to the sale of an 85 per cent equity interest in Northern Courier
- an after-tax loss of $194 million related to the Ontario natural gas-fired power plant assets held for sale
- 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 tax assets that were deemed more likely than not to be realized
- an after-tax loss of $152 million related to the sale of certain Columbia Midstream assets in 2019
- an after-tax gain of $54 million related to the sale of the Coolidge generating station
- a deferred income tax benefit of $32 million related to the impact of an Alberta corporate income tax rate reduction on our Canadian businesses not subject to RRA
- an after-tax loss of $6 million related to the sale of the remainder of our U.S. Northeast power marketing contracts.

Refer to the Financial results sections in each business segment and the Financial condition section of this MD&A for further discussion of these highlights.

Net income in all 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

year ended December 31 (millions of $, except per share amounts)	2021	2020	2019
Net income attributable to common shares	**1,815**	4,457	3,976
Specific items (net of tax):			
Keystone XL asset impairment charge and other	**2,134**	—	—
Voluntary Retirement Program	**48**	—	—
Keystone XL preservation and other	**37**	—	—
Gain on sale of Northern Courier	**(19)**	—	(115)
(Gain)/loss on sale of Ontario natural gas-fired power plants	**(7)**	283	194
Gain on partial sale of Coastal GasLink LP	**—**	(402)	—
Income tax valuation allowance releases	**—**	(299)	(195)
(Gain)/loss on sale of Columbia Midstream assets	**—**	(18)	152
Gain on sale of Coolidge generating station	**—**	—	(54)
Alberta corporate income tax rate reduction	**—**	—	(32)
U.S. Northeast power marketing contracts	**—**	—	6
Risk management activities[1]	**145**	(76)	(81)
Comparable earnings	**4,153**	3,945	3,851
Net income per common share	**$1.87**	$4.74	$4.28
Keystone XL asset impairment charge and other	**2.19**	—	—
Voluntary Retirement Program	**0.05**	—	—
Keystone XL preservation and other	**0.04**	—	—
Gain on sale of Northern Courier	**(0.02)**	—	(0.12)
(Gain)/loss on sale of Ontario natural gas-fired power plants	**(0.01)**	0.30	0.21
Gain on partial sale of Coastal GasLink LP	**—**	(0.43)	—
Income tax valuation allowance releases	**—**	(0.32)	(0.21)
(Gain)/loss on sale of Columbia Midstream assets	**—**	(0.02)	0.16
Gain on sale of Coolidge generating station	**—**	—	(0.06)
Alberta corporate income tax rate reduction	**—**	—	(0.03)
U.S. Northeast power marketing contracts	**—**	—	0.01
Risk management activities	**0.15**	(0.07)	(0.10)
Comparable earnings per common share	**$4.27**	$4.20	$4.14

1

year ended December 31 (millions of $)	2021	2020	2019
U.S. Natural Gas Pipelines	**6**	—	—
Liquids Pipelines	**(3)**	(9)	(72)
Canadian Power	**12**	(2)	—
U.S. Power	**—**	—	(52)
Natural Gas Storage	**(6)**	(13)	(11)
Foreign exchange	**(203)**	126	245
Income taxes attributable to risk management activities	**49**	(26)	(29)
Total unrealized (losses)/gains from risk management activities	**(145)**	76	81

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 Financial results sections for each business segment.

year ended December 31 (millions of $, except per share amounts)	2021	2020	2019
Comparable EBITDA			
Canadian Natural Gas Pipelines	**2,675**	2,566	2,274
U.S. Natural Gas Pipelines	**3,856**	3,638	3,480
Mexico Natural Gas Pipelines	**666**	786	605
Liquids Pipelines	**1,526**	1,700	2,192
Power and Storage	**683**	677	832
Corporate	**(24)**	(16)	(17)
Comparable EBITDA	**9,382**	9,351	9,366
Depreciation and amortization	**(2,522)**	(2,590)	(2,464)
Interest expense included in comparable earnings	**(2,354)**	(2,228)	(2,333)
Allowance for funds used during construction	**267**	349	475
Interest income and other included in comparable earnings	**444**	173	162
Income tax expense included in comparable earnings	**(833)**	(654)	(898)
Net income attributable to non-controlling interests	**(91)**	(297)	(293)
Preferred share dividends	**(140)**	(159)	(164)
Comparable earnings	**4,153**	3,945	3,851
Comparable earnings per common share	**$4.27**	$4.20	$4.14

Comparable EBITDA – 2021 versus 2020

Comparable EBITDA in 2021 increased by $31 million compared to 2020 primarily due to the net result of the following:

- increased earnings in U.S. Natural Gas Pipelines from higher Columbia Gas transportation rates effective February 1, 2021 as a result of the subsequently uncontested rate case settlement, 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, increased earnings from our mineral rights business and increased capitalization of pipeline integrity costs, partially offset by higher property taxes
- higher comparable 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, full-year recognition of Coastal GasLink development fee revenue and higher Canadian Mainline incentive earnings and flow-through income taxes, partially offset by lower flow-through depreciation and financial charges
- consistent Power and Storage results mainly attributable to increased Canadian Power earnings primarily due to higher realized margins in 2021, contributions from trading activities and a full of year of 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 and decreased earnings at Bruce Power in 2021 due to lower volumes resulting from greater planned outage days and higher operating expenses
- 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
- 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 on page 25, U.S. dollar-denominated comparable EBITDA of US$4.6 billion increased by US$226 million compared to 2020; however, this was translated at 1.25 in 2021 versus 1.34 in 2020. Refer to the Foreign exchange discussion below for additional information.

While the weakening of the U.S. dollar in 2021 compared to 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.

Comparable EBITDA – 2020 versus 2019

Comparable EBITDA in 2020 decreased by $15 million compared to 2019 primarily due to the net result of the following:

- decreased earnings from Liquids Pipelines as a result of lower volumes on the Keystone Pipeline System, reduced contributions from liquids marketing activities and the July 2019 sale of an 85 per cent equity interest in Northern Courier
- lower Power and Storage results mainly attributable to decreased Bruce Power results in 2020 primarily due to the net impact of lower overall plant generation with the commencement of the Unit 6 MCR program in January 2020, partially offset by fewer outage days on the remaining units and a higher realized power price. As well, reduced earnings in Canadian Power in 2020 were largely as a result of the sale of our Ontario natural gas-fired power plants in April 2020 and the May 2019 sale of our Coolidge generating station
- higher comparable EBITDA from Canadian Natural Gas Pipelines primarily due to the impact of increased rate-base earnings and flow-through depreciation from additional facilities placed in service as well as higher flow-through financial charges on the NGTL System, plus Coastal GasLink development fee revenue recognized in 2020, partially offset by lower flow-through income taxes on the NGTL System and the Canadian Mainline
- increased contribution from Mexico Natural Gas Pipelines mainly due to higher earnings from our investment in the Sur de Texas pipeline following its September 2019 in-service. This includes revenues of US$55 million recognized in 2020 related to fees associated with our successful completion of the Sur de Texas pipeline
- incremental earnings in U.S. Natural Gas Pipelines from Columbia Gas and Columbia Gulf growth projects placed in service and from ANR due to the sale of natural gas from certain gas storage facilities, partially offset by decreased earnings as a result of the sale of certain Columbia Midstream assets in August 2019
- foreign exchange impact of a stronger U.S. dollar on the Canadian dollar equivalent segmented earnings in our U.S. dollar-denominated operations. As detailed on page 25, U.S. dollar-denominated comparable EBITDA of US$4.3 billion decreased by US$174 million compared to 2019; however, this was translated at 1.34 in 2020 versus 1.33 in 2019. 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 in 2021 were $208 million or $0.07 per common share higher than in 2020, and were primarily the net result 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 and in Canadian Natural Gas Pipelines due to one section of the Canadian Mainline being fully depreciated in 2021
- higher Income tax expense mainly due to increased pre-tax earnings and higher flow-through income taxes on our Canadian rate-regulated pipelines
- 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 on January 20, 2021, the change to equity accounting for our Coastal GasLink investment upon the sale of a 65 per cent interest in Coastal GasLink LP and the completion of the Napanee power plant in 2020, partially offset by the foreign exchange impact from a weaker U.S. dollar on translation of U.S. dollar-denominated interest
- 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 the NGTL System and U.S. natural gas pipeline expansion projects.

Comparable earnings – 2020 versus 2019

Comparable earnings in 2020 were $94 million or $0.06 per common share higher than in 2019, and were primarily the net result of:

- changes in comparable EBITDA described above
- a decrease in Income tax expense mainly due to lower flow-through income taxes on Canadian rate-regulated pipelines and the impact of higher foreign tax rate differentials
- lower Interest expense as a result of higher capitalized interest largely related to Keystone XL, net of the impact of Napanee completing construction in 2020 and lower interest rates on reduced levels of short-term borrowings. These were partially offset by the effect of long-term debt issuances, net of maturities, as well as the foreign exchange impact from a stronger U.S. dollar on the translation of U.S. dollar-denominated interest
- a decrease in AFUDC predominantly due to NGTL System expansion projects placed in service and the suspension of recording AFUDC on the Tula project resulting from continued construction delays, partially offset by further construction of the Villa de Reyes pipeline
- higher Depreciation and amortization largely in Canadian Natural Gas Pipelines and U.S. Natural Gas Pipelines reflecting new assets placed in service. In Canadian Natural Gas Pipelines, as it is fully recovered in tolls on a flow-through basis, it has no significant impact on comparable earnings.

Comparable earnings per share reflects the impact of common shares issued for the acquisition of the remaining ownership interests in TC PipeLines, LP on March 3, 2021 and under our DRP in 2019. Refer to the Financial condition section 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 forward basis up to three years using foreign exchange derivatives; however, the natural exposure beyond that period remains. Despite the significant change in the average exchange rate in 2021 compared to 2020, the net impact of U.S. dollar movements on comparable earnings over this period, after considering natural offsets and economic hedges, was not significant.

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

Pre-tax U.S. dollar-denominated income and expense items

year ended December 31 (millions of US$)	2021	2020	2019
Comparable EBITDA			
U.S. Natural Gas Pipelines	**3,075**	2,714	2,623
Mexico Natural Gas Pipelines[1]	**602**	666	568
U.S. Liquids Pipelines	**884**	955	1,318
	4,561	4,335	4,509
Depreciation and amortization	**(911)**	(877)	(847)
Interest on long-term debt and junior subordinated notes	**(1,259)**	(1,302)	(1,326)
Capitalized interest on capital expenditures	**10**	131	34
Allowance for funds used during construction	**101**	182	205
Non-controlling interests and other	**(76)**	(248)	(233)
	2,426	2,221	2,342
Average exchange rate – U.S. to Canadian dollars	**1.25**	1.34	1.33

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

Cash flows

Net cash provided by operations of $6.9 billion in 2021 was two per cent lower than 2020 due to lower funds generated from operations, partially offset by the amount and timing of working capital changes. Comparable funds generated from operations of $7.4 billion in 2021 was consistent with 2020 and reflected higher comparable earnings, partially offset by fees collected in 2020 associated with the construction of the Sur de Texas pipeline, as well as lower distributions from the operating activities of our equity investments.

Funds used in investing activities

Capital spending[1]

year ended December 31 (millions of $)	2021	2020	2019
Canadian Natural Gas Pipelines	**2,737**	3,608	3,906
U.S. Natural Gas Pipelines	**2,820**	2,785	2,516
Mexico Natural Gas Pipelines	**129**	173	357
Liquids Pipelines	**571**	1,442	954
Power and Storage	**842**	834	1,019
Corporate	**35**	58	32
	7,134	8,900	8,784

1 Capital spending includes Capital expenditures, Capital projects in development and Contributions to equity investments. Refer to Note 4, Segmented information, of our 2021 Consolidated financial statements for the financial statement line items that comprise total capital spending.

In 2021 and 2020, we invested $7.1 billion and $8.9 billion, respectively, in capital projects to maintain and optimize the value of our existing assets and to develop new, complementary assets in high-demand areas. Our total capital spending in 2021 and 2020 included contributions of $1.2 billion and $0.8 billion, respectively, to our equity investments, predominantly related to Bruce Power and Iroquois.

Proceeds from sales of assets

In 2021, we completed the sale of our remaining 15 per cent equity interest in Northern Courier for gross proceeds of $35 million.

In 2020, we completed the following portfolio management transactions. All cash proceeds amounts are prior to income tax and post-closing adjustments:

- the sale of a 65 per cent equity interest in Coastal GasLink LP for proceeds of $656 million
- the sale of our Ontario natural gas-fired power plants for net proceeds of approximately $2.8 billion.

In addition to the proceeds from the above transactions, in 2020, we received $1.5 billion from the initial draw by Coastal GasLink LP on the project-level credit facility which preceded the equity sale.

Balance sheet

We continue to maintain a solid financial position while growing our total assets by $3.9 billion in 2021. At December 31, 2021, common shareholders' equity, including non-controlling interests, represented 35 per cent (2020 – 35 per cent) of our capital structure, while other subordinated capital, in the form of junior subordinated notes, redeemable non-controlling interest and preferred shares, represented an additional 15 per cent (2020 – 16 per cent). Refer to the Financial condition section for more information about our capital structure.

Dividends

We increased the quarterly dividend on our outstanding common shares by 3.4 per cent to $0.90 per common share for the quarter ending March 31, 2022 which equates to an annual dividend of $3.60 per common share. This was the 22nd consecutive year we have increased the dividend on our common shares and is consistent with our goal of growing our common share dividend at an average annual rate of three to five per cent.

Dividend reinvestment plan

Under the DRP, eligible holders of common and preferred shares of TC Energy can reinvest their dividends and make optional cash payments to obtain additional TC Energy common shares. Commencing with the dividends declared October 31, 2019, common shares purchased under TC Energy's DRP are acquired on the open market at 100 per cent of the weighted average purchase price. From January 1, 2019 to October 31, 2019, common shares were issued from treasury at a discount of two per cent to market prices over a specified period.

Cash dividends paid

year ended December 31 (millions of $)	2021	2020	2019
Common shares	**3,317**	2,987	1,798
Preferred shares	**141**	159	160

OUTLOOK

Comparable EBITDA and comparable earnings

We expect our 2022 comparable EBITDA to be modestly higher than 2021; however, our 2022 comparable earnings per common share are expected to be consistent with 2021 largely due to the impact of a lower average foreign exchange hedge rate on our 2022 U.S. dollar-denominated earnings, as well as the following:

- growth in the NGTL System
- contributions from the Villa de Reyes pipeline expected to be placed in service
- higher AFUDC related to our Mexico natural gas pipeline projects subject to a successful resolution of the current contract dispute
- full-year impact from assets placed in service in 2021 and new projects anticipated to be placed in service in 2022, net of incremental depreciation expense
- lower contributions from the Keystone Pipeline System and reduced margins in the liquids marketing business
- higher Interest expense as a result of long-term debt issuances, net of maturities.

We continue to monitor developments in energy markets, our construction projects and regulatory proceedings as well as COVID-19 for any potential impacts on the above outlook.

Consolidated capital spending and equity investments

We expect to spend approximately $6.5 billion in 2022 on growth projects, maintenance capital expenditures and contributions to equity investments. The majority of the 2022 capital program is focused on NGTL System expansions, U.S. natural gas pipeline projects, the Bruce Power life extension program and normal course maintenance capital expenditures. We recognize that continued uncertainty exists on the duration of COVID-19 and the impact it could have on our construction activities and capital expenditures; however, we do not believe such disruptions will be material to our overall 2022 capital program.

Refer to the relevant business segment and Financial condition outlook sections for additional details on expected earnings and capital spending for 2022.

CAPITAL PROGRAM

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

Our capital program consists of approximately $24 billion of secured projects which represent commercially supported, committed projects that are either under construction or are in or preparing to commence the permitting stage.

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

During the year ended December 31, 2021, we placed approximately $2.3 billion of Canadian and U.S. natural gas pipelines capacity capital projects into service. In addition, approximately $1.8 billion of maintenance capital expenditures were incurred.

All projects are subject to cost and timing adjustments due to factors including weather, market conditions, route refinement, permitting conditions, scheduling and timing of regulatory permits, as well as other potential restrictions and uncertainties, including the ongoing impact of COVID-19. Amounts exclude capitalized interest and AFUDC, where applicable.

Secured projects

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

(billions of $)	Expected in-service date	Estimated project cost[1]	Project costs incurred as at December 31, 2021
Canadian Natural Gas Pipelines			
NGTL System[2]	2022	3.3	1.8
	2023	1.8	0.2
	2024+	0.5	—
Canadian Mainline	2022	0.2	0.1
Coastal GasLink[3]	2023	0.2	0.2
Regulated maintenance capital expenditures	2022-2024	2.1	—
U.S. Natural Gas Pipelines			
Modernization III (Columbia Gas)[4]	2022-2024	US 1.2	US 0.2
Delivery market projects	2025	US 1.5	—
Other capacity capital	2022-2025	US 1.5	US 0.9
Regulated maintenance capital expenditures	2022-2024	US 2.0	—
Mexico Natural Gas Pipelines			
Villa de Reyes	2022	US 1.0	US 0.9
Tula[5]	—	US 0.8	US 0.6
Liquids Pipelines			
Other capacity capital	2022-2023	US 0.2	US 0.1
Recoverable maintenance capital expenditures	2022-2024	0.1	—
Power and Storage			
Bruce Power – life extension[6]	2022-2027	4.4	1.9
Other			
Non-recoverable maintenance capital expenditures[7]	2022-2024	0.6	—
		21.4	6.9
Foreign exchange impact on secured projects[8]		2.2	0.7
Total secured projects (Cdn$)		23.6	7.6

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 a total of $0.6 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 Canadian Natural Gas Pipelines – Significant events section for additional information on the status of Coastal GasLink's dispute with LNG Canada regarding the recognition of certain costs and schedule changes. Refer to Note 11, Loans receivable from affiliates, of our 2021 Consolidated financial statements for information regarding our commitment to provide additional temporary financing, if necessary, to Coastal GasLink under certain circumstances.
4 Subject to FERC approval of the Columbia Gas uncontested rate case settlement. Refer to the U.S. Natural Gas Pipelines – Significant events section for additional information.
5 The East Section of the Tula pipeline is available for interruptible transportation services. We are working to procure necessary land access on the west section of the Tula pipeline to finalize its construction. The central segment construction has been delayed due to pending Indigenous consultation processes under the responsibility of the Secretary of Energy. Refer to the Mexico Pipelines – Significant events section for additional information.
6 Reflects our expected share of cash contributions for the Bruce Power Unit 6 Major Component Replacement (MCR) program, expected to be in service in 2023, amounts to be invested under the Asset Management program through 2027 as well as the incremental uprate initiative. In addition, it includes our expected share of cash contributions for the Unit 3 MCR, subject to IESO approval of the basis of estimate. Refer to the Power and Storage – Significant events section for additional information.
7 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.
8 Reflects U.S./Canada foreign exchange rate of 1.27 at December 31, 2021.

Projects under development

In addition to our secured projects, we have a portfolio of projects that we are currently pursuing which are in varying stages of development. Projects under development have greater uncertainty with respect to timing and estimated project costs and are subject to corporate and regulatory approvals, unless otherwise noted. Each business segment has also outlined additional areas of focus for further ongoing business development activities and growth opportunities. As these projects are advanced, reaching necessary milestones, they will be included in the secured projects table.

Canadian Natural Gas Pipelines

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

U.S. Natural Gas Pipelines

Delivery Market Projects

Projects are in development that will replace, upgrade and modernize certain U.S. Natural Gas Pipelines facilities while reducing emissions along portions of our pipeline systems' principal delivery markets. The enhanced facilities are expected to improve reliability of our systems and allow for additional contracted transportation services to address growing demand in the U.S. Midwest and the Mid-Atlantic regions under long-term contracts while reducing direct carbon dioxide equivalent (CO_2e) emissions. Included in our secured projects are the US$0.7 billion VR Project on Columbia Gas and the US$0.8 billion WR Project on ANR, two delivery market projects that were approved in 2021 with expected in-service dates in the second half of 2025.

Other Opportunities

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

Refer to the U.S. Natural Gas Pipelines – Significant events section for additional information.

Mexico Natural Gas Pipelines

We are currently evaluating new growth projects driven by Mexico's economic expansion and the need to connect natural gas to new regions of the country to serve power plants, industrial demand and LNG exports and, in doing so, reduce reliance on costly, carbon intensive fuel oil. Potential projects include a re-route of the central segment of Tula as well as a new offshore pipeline that would connect additional natural gas supply to Southeast Mexico and capacity expansions on existing assets.

Liquids Pipelines

Grand Rapids Phase II

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

Terminals Projects

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

Other Opportunities

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

Power and Storage

Bruce Power

Life Extension Program

The continuation of Bruce Power's life extension program through to 2033 will require the investment of our proportionate share of Major Component Replacement (MCR) program costs on Units 3, 4, 5, 7 and 8, as well as the remaining Asset Management program costs which continue beyond 2033. This program will extend the life of Units 3 to 8 and the Bruce Power site to 2064. The basis of estimate for the Unit 3 MCR was submitted to the IESO in December 2021 for a refurbishment outage expected to begin in first quarter 2023. Preparation work for the Unit 4 MCR is well underway and work for Unit 5, 7 and 8 MCRs have also begun. Future MCR investments will be subject to discrete decisions for each unit with specified off-ramps available to Bruce Power and the IESO. We expect to spend approximately $4.8 billion for our proportionate share of the Bruce Power MCR program costs for Units 4, 5, 7 and 8, the remaining Asset Management program costs beyond 2027, as well as the incremental uprate initiative discussed below.

Uprate Initiative

Bruce Power recently launched Project 2030 with the goal of achieving a site peak output of 7,000 MW by 2033 in support of climate change targets and future clean energy needs. Project 2030 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. Project 2030 is arranged in three stages with the first two stages fully approved for execution. Stage 1 started in 2019 and is expected to add 150 MW of output and Stage 2, beginning in early 2022, is targeting another 200 MW. Both stages are expected to increase output in multiple steps ending in 2033. Stage 3 requires Stage 1 and 2 to be complete and would enable an increase to the reactor power limit.

Development-Stage Projects

Ontario Pumped Storage

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

Two key milestones on the Ontario Pumped Storage project were reached in 2021. On July 28, 2021, the Federal Minister of National Defence granted long-term land access to the fourth Canadian Division Training Centre for development of the project on this site. On November 11, 2021, Ontario's Minister of Energy instructed the IESO to progress the project to Gate 2 of the Unsolicited Proposals Process. Once in service, this project will store emission-free energy when available and provide that energy to Ontario during periods of peak demand, thereby maximizing the value of existing emissions-free generation in the province.

Saddlebrook Solar and Storage

We are proposing to construct and operate the Saddlebrook Solar and Storage project, a solar and energy storage solution, which consists of a solar-generating facility located in Aldersyde, Alberta that will operate in conjunction with a battery energy storage system.

The proposed generating facility will produce approximately 81 MW of power and the battery storage system will provide up to 40 MWh of energy storage capacity and is expected to reduce GHG emissions by approximately 115,000 tonnes per year. The proposed project is partially funded through Emissions Reduction Alberta's Biotechnology, Electricity and Sustainable Transportation Challenge. We expect to make a final investment decision on the project in 2022 with the first phases of commissioning beginning towards the end of 2022.

Canyon Creek Pumped Storage

We acquired 100 per cent ownership of the Canyon Creek pumped storage development project in 2021. Once in service, the facility will have initial generating capacity of 75 MW, expandable through future development to 400 MW, and will utilize existing site infrastructure from a decommissioned coal mine. The facility will provide up to 37 hours of on-demand, flexible, clean energy and ancillary services to the Alberta electricity grid. The project has received the approval of the Alberta Utilities Commission and the required approval of the Alberta Government for hydro projects under the Hydro Development Act.

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

Renewable Energy Request for Information (RFI)

In 2021, we announced that we were seeking to identify potential contracts and/or investment opportunities in wind, solar and power storage renewable energy projects. We requested 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 the U.S. portion of the Keystone Pipeline System assets. We also identified meaningful origination opportunities to supply renewable energy products and services to industrial and oil and gas sectors proximate to our in-corridor demand. We received a significant number of responses to our RFI and are currently evaluating proposals and expect to finalize contracts during the first half of 2022.

Other Opportunities

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

Refer to the Power and Storage – Significant events section for additional information.

Other Energy Transition Developments

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

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

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

Alberta Carbon Grid (ACG)

On June 17, 2021, we announced a partnership with Pembina Pipeline Corporation to jointly develop a world-scale carbon transportation and sequestration system which, when fully constructed, will be capable of transporting more than 20 million tonnes of carbon dioxide annually, thereby providing opportunities to retrofit existing assets and reduce our carbon footprint. By leveraging existing pipelines and a newly developed sequestration hub, the 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. We are also pursuing opportunities to leverage our existing systems in support of hydrogen production and transportation.

Irving Oil Decarbonization

On August 12, 2021, we signed an MOU to explore the joint development of a series of proposed energy projects focused on reducing GHG emissions and creating new economic opportunities in New Brunswick and Atlantic Canada. Together with Irving Oil, we have identified a series of potential projects focused on decarbonizing existing assets and deploying emerging technologies to reduce overall emissions over the medium and long term. The partnership's initial focus will consider a suite of upgrade projects at Irving Oil's refinery in Saint John, New Brunswick, with the goal of significantly reducing emissions through the production and use of low-carbon power generation.

Hydrogen Hubs

We have entered into two Joint Development Agreements (JDA), to support customer-driven hydrogen production for long-haul transportation, power generation, large industrials and heating customers across the United States and Canada. The first opportunity is a partnership with Nikola Corporation, a designer and manufacturer of zero-emission battery-electric and hydrogen-electric vehicles and related equipment, where Nikola will be a long-term anchor customer for hydrogen production infrastructure supporting hydrogen fueled zero-emission heavy-duty trucks. The JDA with Nikola supports co-development of large-scale green and blue hydrogen production hubs, utilizing our power and natural gas infrastructure.

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

NATURAL GAS PIPELINES BUSINESS

Our natural gas pipeline network transports natural gas from supply basins to local distribution companies, power generation plants, industrial facilities, interconnecting pipelines, LNG export terminals and other businesses across Canada, the U.S. and Mexico. Our network of pipelines taps into most major supply basins and transports over 25 per cent of continental daily natural gas needs through:

- wholly-owned natural gas pipelines – 88,110 km (54,748 miles)
- partially-owned natural gas pipelines – 5,184 km (3,221 miles).

In addition to our natural gas pipelines, we have regulated natural gas storage facilities in the U.S. with a total working gas capacity of 535 Bcf, making us one of the largest providers of natural gas storage and related services to key markets in North America.

Our Natural Gas Pipelines business is split into three operating segments representing its geographic diversity: Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines and Mexico Natural Gas Pipelines.

Strategy

Optimize the value of our existing natural gas pipeline systems in a safe and reliable manner, while responding to the changing flow patterns of natural gas in North America. We also pursue new pipeline opportunities to add incremental value to our business.

Our key areas of focus include:

- primarily in-corridor expansion and extension of our existing significant North American natural gas pipeline footprint
- connections to new and growing industrial and electric power generation markets and LDCs
- expanding our systems in key locations and developing new projects to provide connectivity to LNG export terminals, both operating and proposed, in Canada, the U.S. and Mexico
- connections to growing Canadian and U.S. shale gas and other supplies
- decarbonizing our energy consumption, thereby reducing overall GHG intensity.

Each of these areas plays a critical role in meeting the transportation requirements for supply of and demand for natural gas in North America.

Our natural gas pipeline systems are enabling energy transition. Natural gas is a reliable, high-efficiency energy source that is displacing coal-fired power while backstopping the intermittency of renewable power sources across North America. In support of our GHG intensity reduction targets, we continue to improve operational efficiencies and factor sustainability into our decision making around new projects, modernization, maintenance, electrification and enhanced leak detection. Further, a growing number of renewable natural gas customers are connecting to our system. Our business provides socioeconomic benefits as we work closely with Indigenous communities, community-based organizations, landowners and other stakeholders in alignment with our values and sustainability commitments.

Recent highlights

Canadian Natural Gas Pipelines

- approximately $1.2 billion of projects placed into service in 2021
- received federal approval for the 2022 NGTL System Expansion Program with in-service dates anticipated in 2022
- CER approved the 2023 NGTL System Intra-Basin Expansion Program
- advanced construction of the Coastal GasLink pipeline project.

U.S. Natural Gas Pipelines

- placed approximately US$2.4 billion of capital projects into service including BXP on Columbia Gas and Grand Chenier XPress on ANR
- originated an additional US$2.9 billion of growth projects including the GHG emissions-reducing Delivery Market projects on Columbia Gas and ANR, as well as the Columbia Gas Modernization III program
- Columbia Gas uncontested rate settlement filed with FERC and GTN rate settlement approved by FERC
- ANR filed a Section 4 rate case with FERC on January 28, 2022 requesting an increase to maximum transportation rates effective August 1, 2022, subject to refund. As the rate process progresses, we expect to engage in a collaborative process to achieve settlement with our customers, FERC and other stakeholders
- achieved record throughput volumes on certain pipelines.

Mexico Natural Gas Pipelines

- advanced resolution of the arbitration with the CFE on the Tula and Villa de Reyes pipeline projects with the signing of an MOU on July 30, 2021
- commenced feasibility assessments with the CFE under the MOU to jointly evaluate potential alternatives to complete the Tula pipeline and a new offshore pipeline to connect natural gas to southeast Mexico
- continued construction of the Villa de Reyes pipeline project with phased commissioning and in-service expected in 2022 subject to timely receipt of pending authorizations and land access to critical pipeline sections
- assets performed with 100 per cent reliability and asset utilization continued to increase.

UNDERSTANDING OUR NATURAL GAS PIPELINES BUSINESS

Natural gas pipelines move natural gas from major sources of supply to locations or markets that use natural gas to meet their energy needs.

Our natural gas pipelines business builds, owns and operates a network of natural gas pipelines across North America that connects gas production to interconnects, end-use markets and LNG export terminals. The network includes underground pipelines that transport natural gas predominantly under high pressure, compressor stations that act like pumps to move large volumes of natural gas along the pipeline, meter stations that record the amount of natural gas coming on the network at receipt locations and leaving the network at delivery locations and regulated natural gas storage facilities that provide services to customers and help maintain the overall balance of the pipeline systems.

Our major pipeline systems

The Natural Gas Pipelines map on page 38 shows our extensive pipeline network in North America that connects major supply sources and markets. The highlights shown on the map include:

Canadian Natural Gas Pipelines

NGTL System: This is our natural gas gathering and transportation system for the WCSB, connecting most of the natural gas production in western Canada to domestic and export markets. We are well positioned to connect growing supply in northeast British Columbia and northwest Alberta. Our capital program for new pipeline facilities is driven by these two supply areas, along with growing demand for intra-Alberta firm transportation for electric power generation conversion from coal, oil sands development and petro-chemical feedstock as well as to our major export points at the Empress and Alberta/British Columbia delivery locations. The NGTL System is also well positioned to connect WCSB supply to LNG export facilities on the Canadian west coast, through future extensions of the system or future connections to other pipelines serving that area.

Canadian Mainline: This pipeline supplies markets in Ontario, Québec, the Canadian Maritimes as well as the Midwest and Northeast U.S. from the WCSB and, through interconnects, from the Appalachian basin.

U.S. Natural Gas Pipelines

Columbia Gas: This is our natural gas transportation system for the Appalachian basin, which contains the Marcellus and Utica shale plays, two of the largest natural gas shale plays in North America. Similar to our footprint in the WCSB, our Columbia Gas assets are well positioned to connect growing supply to markets in this area. This system also interconnects with other pipelines that provide access to key markets in the U.S. Northeast, the Midwest, the Atlantic coast and south to the Gulf of Mexico and its growing demand for natural gas to serve LNG exports.

ANR: This pipeline system connects supply basins and markets throughout the U.S. Midwest and south to the Gulf of Mexico. This includes connecting supply in Texas, Oklahoma, the Appalachian basin and the Gulf of Mexico to markets in Wisconsin, Michigan, Illinois and Ohio. In addition, ANR has bidirectional capability on its Southeast Mainline and delivers gas produced from the Appalachian basin to customers throughout the U.S. Gulf Coast region.

Columbia Gulf: This pipeline system transports growing Appalachian basin supplies to various U.S. Gulf Coast markets and LNG export terminals from its interconnections with Columbia Gas and other pipelines.

Other U.S. Natural Gas Pipelines: We have ownership interests in eight wholly-owned or partially-owned natural gas pipelines serving major markets in the U.S. that were previously held by our subsidiary, 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, in exchange for TC Energy common shares, resulting in TC PipeLines, LP becoming an indirect, wholly-owned subsidiary of TC Energy, thereby increasing our effective ownership in the TC PipeLines, LP assets. Refer to the Corporate – Significant events section for additional information.

Mexico Natural Gas Pipelines

Sur de Texas: This offshore pipeline transports natural gas from Texas to power and industrial markets in the eastern and central regions of Mexico. The average volumes transported by this pipeline in 2021 supplied approximately 15 per cent of Mexico's total natural gas imports via pipelines. We own a 60 per cent interest in and are the operator of this pipeline.

Northwest System: The Topolobampo and Mazatlán pipelines make up our Mexico northwest system. The system runs through the states of Chihuahua and Sinaloa, supplying power plants and industrial facilities, bringing natural gas to a region of the country that previously did not have access to it.

TGNH System: This system is located in the central region of Mexico and is comprised of the existing Tamazunchale pipeline and the Tula and Villa de Reyes pipelines currently under construction. This system supplies, or will supply, several power plants and industrial facilities in Veracruz, San Luis Potosí, Querétaro and Hidalgo. It has interconnects with upstream pipelines that bring in supply from the Agua Dulce and Waha basins in Texas.

Guadalajara: This bidirectional pipeline connects imported LNG supply near Manzanillo and continental gas supply near Guadalajara to power plants and industrial customers in the states of Colima and Jalisco.

Regulation of tolls and cost recovery

Our natural gas pipelines are generally regulated by the CER in Canada, FERC in the U.S. and CRE in Mexico. These entities regulate the construction, operation and requested abandonment of pipeline infrastructure.

Regulators in Canada, the U.S. and Mexico allow us to recover costs to operate the network by collecting tolls for services. These tolls generally include a return on our capital invested in the assets or rate base as well as recovery of the rate base over time through depreciation. Other costs generally recovered through tolls include OM&A, taxes and interest on debt. The regulators review our costs to ensure they are reasonable and prudently incurred and approve tolls that provide a reasonable opportunity to recover those costs.

Business environment and strategic priorities

The North American natural gas pipeline network has been developed to connect diverse supply regions to domestic markets and to meet demand from LNG export facilities. Use and growth of this infrastructure is affected by changes in the location and relative cost of natural gas supplies as well as changes in the location of markets and level of demand.

We have significant pipeline footprints that serve two of the most prolific supply regions of North America – the WCSB and the Appalachian basin. Our pipelines also source natural gas from other significant basins including the Rockies, Williston, Haynesville, Fayetteville and Anadarko basins as well as the Gulf of Mexico. We expect continued growth in North American natural gas production to meet demand within growing domestic markets, particularly in the electric generation and industrial sectors which benefit from a relatively low natural gas price. In addition, North American supply is expected to benefit from increased natural gas demand in Mexico and growing access to international markets via LNG exports. We expect North American natural gas demand, including LNG exports, of approximately 121 Bcf/d by 2026, reflecting an increase of approximately 18 Bcf/d from 2021 levels.

As the world shifts toward lower-emission fuel sources, further retirements of coal-fired power generation and export demand growth over the next five to 10 years will offer growth opportunities for base-load power from natural gas-fired generation. This expected growth in demand for natural gas, coupled with the anticipated production increases in key producing areas like WCSB, onshore Gulf Coast, Appalachia and the Permian basin, will provide investment opportunities for pipeline infrastructure companies to build new facilities or increase utilization of the existing footprint. Modernizing and decarbonizing our natural gas pipeline systems will provide ongoing additional capital investment opportunities that will meet our risk preferences while supporting our GHG intensity reduction goals.

Changing demand

The abundant supply of natural gas has supported increased demand, particularly in the following areas:

- natural gas-fired power generation
- petrochemical and industrial facilities
- Alberta oil sands.

Natural gas producers continue to progress opportunities to sell natural gas to global markets which involves connecting natural gas supplies to LNG export terminals, both operating and proposed, along the U.S. Gulf Coast, the west coast of Canada, the U.S. and Mexico and the east coast of Canada. The increasing supply of natural gas in Mexico is driven by the CFE's need to serve existing markets by connecting natural gas plants to supply and building pipelines to serve new regions. They are forecasting significant gas demand growth in the future to support economic expansion and conversion to lower carbon fuels for industrial and power generation use. The demand created by the addition of these new markets provides additional opportunities for us to build new pipeline infrastructure and to increase throughput on our existing pipelines. The growing focus on ESG is expected to result in shifting market dynamics, as both energy demand and pressure for accelerated climate action increase simultaneously.

Commodity prices

In general, the profitability of our natural gas pipelines business is not directly tied to commodity prices given we are a transporter of the commodity and the transportation tolls are not tied to the price of natural gas. However, the cyclical supply and demand nature of commodities and related pricing can have an indirect impact on our business where producers may choose to accelerate or delay development of gas reserves or, similarly on the demand side, projects requiring natural gas may be accelerated or delayed depending on market or price conditions.

More competition

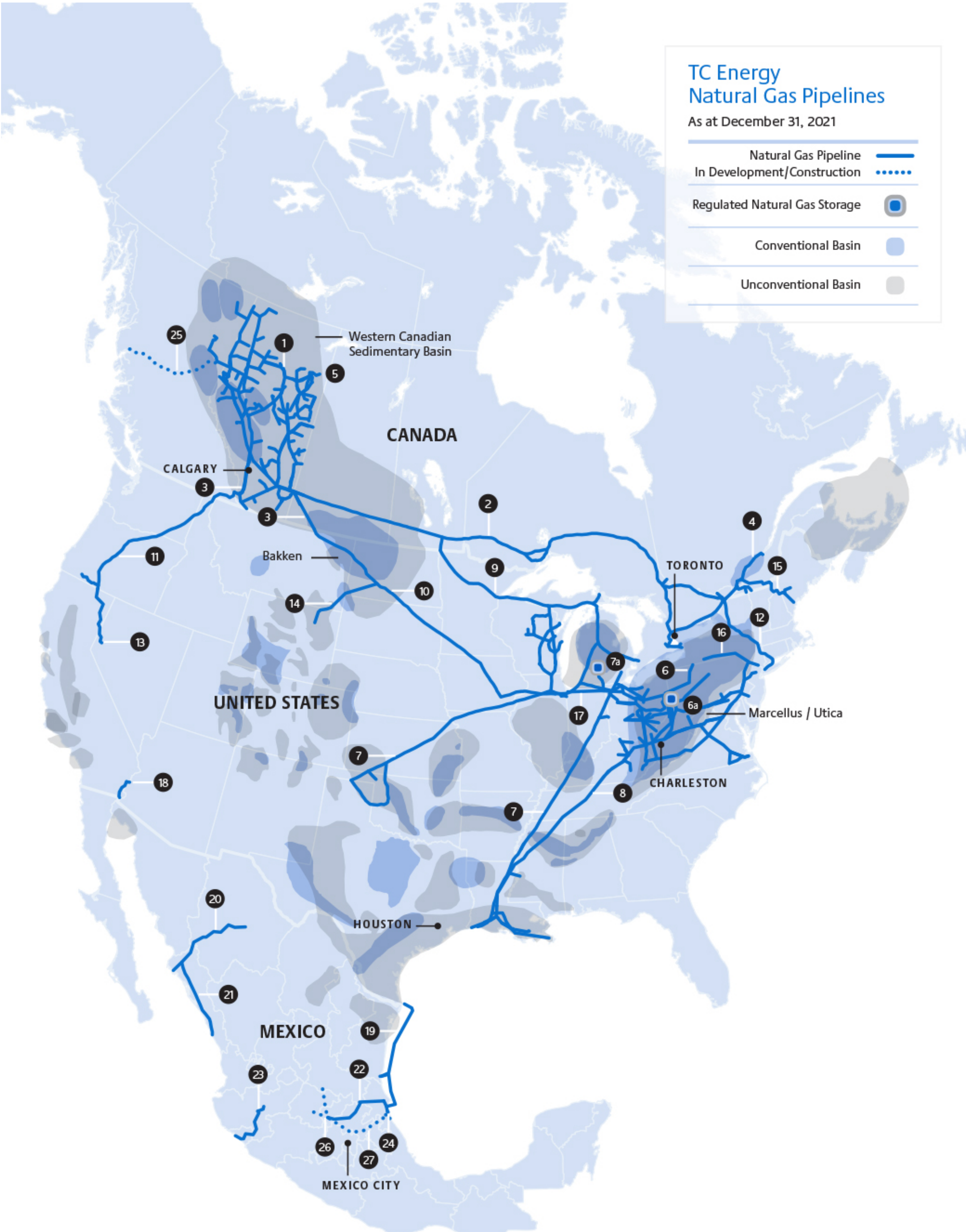
Changes in supply and demand levels and locations have resulted in increased competition to provide transportation services throughout North America. Our well-distributed footprint of natural gas pipelines, particularly in the liquids-rich and low-cost WCSB and the Appalachian basin, both of which are connected to North American demand centres, has placed us in a strong competitive position. Incumbent pipelines benefit from the connectivity and economies of scale afforded by the base infrastructure as well as existing right-of-way and operational synergies given the increasing challenges of siting and permitting new pipeline construction and expansions. We have and will continue to offer competitive services to capture growing supply and North American demand that now includes access to global markets through LNG exports.

Strategic priorities

Our pipelines deliver the natural gas that millions of individuals and businesses across North America rely on for their energy needs. We are focused on capturing opportunities resulting from growing natural gas supply and connecting new markets while satisfying increasing demand for natural gas within existing markets. We are also focused on adapting our existing assets to changing natural gas flow dynamics and supporting our corporate-level sustainability goals and ESG targets, including GHG intensity reduction.

In 2022, some of our key focus areas will be the continued execution of our existing capital program that includes further investment in the NGTL System, continued construction of Coastal GasLink as well as the completion and initiation of new pipeline projects in the U.S. and Mexico. We will also continue to pursue the next wave of growth opportunities. Our goal is to place all of our projects into service on time and on budget while ensuring the safety of our people, of the environment and general public impacted by the construction and operation of these facilities.

Our natural gas marketing entities will complement our pipeline operations and generate non-regulated revenues by managing the procurement of natural gas supply and pipeline transportation capacity for natural gas customers within our pipeline corridors.



TC Energy
Natural Gas Pipelines
As at December 31, 2021
Natural Gas Pipeline
In Development/Construction
Regulated Natural Gas Storage
Conventional Basin
Unconventional Basin
Western Canadian Sedimentary Basin
CANADA
CALGARY
Bakken
UNITED STATES
TORONTO
Marcellus / Utica
CHARLESTON
HOUSTON
MEXICO
MEXICO CITY
1
2
3
4
5
6
6a
7
7a
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27

We are the operator of all of the following natural gas pipelines and regulated natural gas storage assets except for Iroquois.

		Length	Description	Ownership
	Canadian pipelines			
1	NGTL System	24,494 km (15,220 miles)	Receives, transports and delivers natural gas within Alberta and British Columbia, and connects with Canadian Mainline, Foothills and third-party pipelines.	100%
2	Canadian Mainline	14,082 km (8,750 miles)	Transports natural gas from the Alberta/Saskatchewan border and the Ontario/U.S. border to serve eastern Canada and interconnects to the U.S.	100%
3	Foothills	1,237 km (769 miles)	Transports natural gas from central Alberta to the U.S. border for export to the U.S. Midwest, Pacific Northwest, California and Nevada.	100%
4	Trans Québec & Maritimes (TQM)	574 km (357 miles)	Connects with the Canadian Mainline near the Ontario/Québec border to transport natural gas to the Montréal to Québec City corridor, and interconnects with Portland.	50%
5	Ventures LP	133 km (83 miles)	Transports natural gas to the oil sands region near Fort McMurray, Alberta.	100%
	Great Lakes Canada[1]	60 km (37 miles)	Transports natural gas from the Great Lakes system in the U.S. to a point near Dawn, Ontario through a connection at the U.S. border underneath the St. Clair River.	100%
	U.S. pipelines and gas storage assets			
6	Columbia Gas	18,815 km (11,691 miles)	Transports natural gas primarily from the Appalachian basin to markets and pipeline interconnects throughout the U.S. Northeast, Midwest and Atlantic regions.	100%
6a	Columbia Storage	285 Bcf	Provides regulated underground natural gas storage service from several facilities (not all shown) to customers in key eastern markets. We also own a 50 per cent interest in the 12 Bcf Hardy Storage facility.	100%
7	ANR	15,075 km (9,367 miles)	Transports natural gas from various supply basins to markets throughout the U.S. Midwest and U.S. Gulf Coast.	100%
7a	ANR Storage	250 Bcf	Provides regulated underground natural gas storage service from several facilities (not all shown) to customers in key mid-western markets.	
8	Columbia Gulf	5,419 km (3,367 miles)	Transports natural gas to various markets and pipeline interconnects in the southern U.S. and U.S. Gulf Coast.	100%
9	Great Lakes	3,404 km (2,115 miles)	Connects with the Canadian Mainline near Emerson, Manitoba and to Great Lakes Canada near St Clair, Ontario, plus interconnects with ANR at Crystal Falls and Farwell in Michigan, to transport natural gas to eastern Canada and the U.S. Midwest.	100%
10	Northern Border	2,272 km (1,412 miles)	Transports WCSB, Bakken and Rockies natural gas from connections with Foothills and Bison to U.S. Midwest markets.	50%
11	Gas Transmission Northwest (GTN)	2,216 km (1,377 miles)	Transports WCSB and Rockies natural gas to Washington, Oregon and California. Connects with Tuscarora and Foothills.	100%
12	Iroquois	669 km (416 miles)	Connects with the Canadian Mainline and serves markets in New York.	50%
13	Tuscarora	491 km (305 miles)	Transports natural gas from GTN at Malin, Oregon to markets in northeastern California and northwestern Nevada.	100%
14	Bison	488 km (303 miles)	Transports natural gas from the Powder River basin in Wyoming to Northern Border in North Dakota.	100%
15	Portland	475 km (295 miles)	Connects with TQM near East Hereford, Québec to deliver natural gas to customers in the U.S. Northeast and Canadian Maritimes.	61.7%

		Length	Description	Ownership
16	Millennium	424 km (263 miles)	Transports natural gas primarily sourced from the Marcellus shale play to markets across southern New York and the lower Hudson Valley as well as to New York City through its pipeline interconnections.	47.5%
17	Crossroads	325 km (202 miles)	Interstate natural gas pipeline operating in Indiana and Ohio with multiple interconnects to other pipelines.	100%
18	North Baja	138 km (86 miles)	Transports natural gas between Arizona and California and connects with a third-party pipeline on the California/Mexico border.	100%
	Mexico pipelines			
19	Sur de Texas	770 km (478 miles)	Offshore pipeline that transports natural gas from the U.S./Mexican border near Brownsville, Texas, to Mexican power plants in Altamira, Tamaulipas and Tuxpan, Veracruz, where it interconnects with the Tamazunchale and Tula pipelines and other third-party facilities.	60%
20	Topolobampo	572 km (355 miles)	Transports natural gas to El Oro and Topolobampo, Sinaloa, from interconnects with third-party pipelines in El Encino, Chihuahua and El Oro.	100%
21	Mazatlán	430 km (267 miles)	Transports natural gas from El Oro to Mazatlán, Sinaloa and connects to the Topolobampo Pipeline at El Oro.	100%
22	Tamazunchale	370 km (230 miles)	Transports natural gas from Naranjos, Veracruz to Tamazunchale, San Luis Potosi and on to El Sauz, Querétaro in central Mexico.	100%
23	Guadalajara	313 km (194 miles)	Bidirectional pipeline that connects imported LNG supply near Manzanillo and continental gas supply near Guadalajara to power plants and industrial customers in the states of Colima and Jalisco.	100%
24	Tula – East Section	48 km (30 miles)	The East Section of the Tula pipeline is available to transport natural gas from Sur de Texas to power plants in Tuxpan, Veracruz.	100%
	Under construction			
	Canadian pipelines			
25	Coastal GasLink	670 km (416 miles)	A greenfield project to deliver natural gas from the Montney gas producing region to LNG Canada's liquefaction facility under construction near Kitimat, British Columbia	35%
	NGTL System 2022 Facilities[1,2]	415 km (258 miles)	Multiple components of the 2021 NGTL System Expansion Program, 2022 NGTL System Expansion Program and 2023 NGTL System/Foothills West Path Delivery Program, along with other facilities, with expected in-service dates in 2022.	100%

	Under construction (continued)	Length	Description	Ownership
	U.S. pipelines			
	Elwood Power/ANR Horsepower Replacement[3]	n/a	A reliability project on ANR that will replace and upgrade certain facilities with expected in-service in 2022.	100%
	Wisconsin Access[3]	n/a	A reliability project on ANR that will replace and upgrade certain facilities with expected in-service in 2022.	100%
	Alberta XPress[3]	n/a	An expansion project of ANR through compressor station modifications and additions with expected in-service commencing in 2022.	100%
	Mexico pipelines			
26	Villa de Reyes	420 km (261 miles)	This bidirectional pipeline will transport natural gas to Tula, Hidalgo and Villa de Reyes, San Luis Potosí, connecting to the Tamazunchale and Tula pipelines as well as other pipeline systems, and the Salamanca industrial complex in the state of Guanajuato.	100%
27	Tula (excluding the East Section)	276 km (171 miles)	The pipeline will interconnect the completed east segment with Villa de Reyes near Tula, Hidalgo to supply natural gas to CFE combined-cycle power generating facilities in central Mexico.	100%
	Permitting and pre-construction phase			
	NGTL System 2023/2024 Facilities[1,2]	199 km (124 miles)	Multiple components of the 2022 NGTL System Expansion Program, 2023 NGTL System/Foothills West Path Delivery Program and 2023 NGTL System Intra-Basin Expansion, along with other facilities, with expected in-service dates commencing in 2023.	100%
	U.S. pipelines			
	VR Project[3]	n/a	A delivery market project on Columbia Gas that will replace and upgrade certain facilities while improving reliability and reducing emissions with expected in-service in 2025.	100%
	WR Project[3]	n/a	A delivery market project on ANR that will replace and upgrade certain facilities while improving reliability and reducing emissions with expected in-service in 2025.	100%

1 Facilities and some pipelines are not shown on the map.
2 Final pipe lengths are subject to change during construction and/or final design considerations.
3 Project includes compressor station modifications and additions with no additional pipe length.

Canadian Natural Gas Pipelines

UNDERSTANDING OUR CANADIAN NATURAL GAS PIPELINES SEGMENT

The Canadian natural gas pipeline business is subject to regulation by various federal and provincial governmental agencies. The CER has jurisdiction over our regulated Canadian natural gas interprovincial pipeline systems, while provincial regulators have jurisdiction over pipeline systems operating entirely within a single province. All of our major Canadian natural gas pipeline assets are regulated by the CER with the exception of Coastal GasLink, which is currently under construction.

For the interprovincial natural gas pipelines it regulates, the CER approves tolls and services that are in the public interest and provide a reasonable opportunity for a pipeline to recover its costs to operate the pipeline. Included in the overall toll is a return on the investment we have made in the assets, referred to as the return on equity. Equity is generally 40 per cent of the deemed capital structure, with the remaining 60 per cent debt. Typically, tolls are based on the cost of providing service, including the cost of financing, divided by a forecast of throughput volumes. Any variance in either costs or the actual volumes transported can result in an over-collection or under-collection of revenues that is normally trued up the following year in the calculation of the tolls for that period. The return on equity, however, would continue to be earned at the rate approved by the CER.

We and our shippers can also establish settlement arrangements, subject to approval by the CER, that may have elements that vary from the typical toll-setting process. Settlements can include longer terms and mechanisms such as incentive agreements that can have an impact on the actual return on equity achieved. Examples include fixing the OM&A component in determining revenue requirements, where variances are to the pipeline's account or shared between the pipeline and shippers.

The NGTL System is operating under a five-year revenue requirement settlement for 2020-2024 which includes an incentive mechanism for certain operating costs and the opportunity to increase depreciation rates if tolls fall below specified levels. Beginning January 1, 2021, the Canadian Mainline is operating under the 2021-2026 Mainline settlement which includes an incentive to decrease costs and increase revenues.

SIGNIFICANT EVENTS

Coastal GasLink Pipeline Project

Coastal GasLink is a pipeline under construction that will have an initial capacity of approximately 2.2 PJ/d (2.1 Bcf/d) and will deliver natural gas from the Dawson Creek area to a natural gas liquefaction facility near Kitimat, British Columbia. The LNG facility, which is owned by LNG Canada, is currently under construction. Transportation service on the pipeline is underpinned by 25-year TSAs (with additional renewal provisions) with each of the five LNG Canada participants. We currently hold a 35 per cent ownership interest in Coastal GasLink LP and have been contracted to develop and operate the pipeline.

The project is currently more than 59 per cent complete. The entire route has been cleared, grading is more than 70 per cent complete and more than 240 km (149 miles) of pipeline has been installed, with reclamation activities underway in many areas.

As a result of scope changes, previous permit delays compared to the original construction schedule and the impacts from COVID-19, including a health order issued by the British Columbia Provincial Health Officer restricting the number of workers on site from late December 2020 until mid-April 2021, 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 to mitigate cost increases and schedule delays and will continue to do so.

Coastal GasLink is in dispute with LNG Canada with respect to the recognition of certain costs and the impacts on schedule; however, the parties are in active and constructive discussions toward a resolution of this matter. We do not expect any suspension of construction activities while discussions continue. The ultimate level of debt financing and the amounts to be contributed as equity by Coastal GasLink LP partners, including us, will be determined by the substance of a resolution with LNG Canada.

During this time, in addition to using funds from its $6.8 billion project-level credit facility and the recovery of construction carrying costs from LNG Canada, construction is also being funded in part by a subordinated demand revolving facility with TC Energy which has a current capacity of $500 million and provides the project with additional short-term funding and financial flexibility. At December 31, 2021, $1 million was outstanding on this revolving facility.

In fourth quarter 2021, as a further interim measure, TC Energy executed a subordinated loan agreement to provide additional temporary financing to the project, if necessary, of up to $3.3 billion as a bridge to a required increase in the $6.8 billion project-level financing to fund incremental costs. This financing will be provided through a combination of interest-bearing loans and loans that are subject to a return to TC Energy under certain conditions at the time the final cost of the project is determined. At December 31, 2021, $238 million was outstanding on these loans.

NGTL System

In the year ended December 31, 2021, the NGTL System placed approximately $1.1 billion of capacity projects in service.

2022 NGTL System Expansion Program

In 2021, we received regulatory approval for the 2022 NGTL System Expansion Program. With an estimated capital cost of $1.2 billion, the 2022 NGTL System Expansion Program consists of approximately 166 km (103 miles) of new pipeline, one new compressor unit and associated facilities and will provide incremental capacity of approximately 773 TJ/d (722 MMcf/d) to meet firm-receipt and intra-basin delivery requirements with eight-year terms. Construction activities began in September 2021 with anticipated in-service dates commencing in fourth quarter 2022.

2023 NGTL System Intra-Basin Expansion

In 2021, we received regulatory approval to construct and operate the NGTL System Intra-Basin Expansion Program, 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. 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. The NGTL System Intra-Basin Expansion is expected to be placed in service commencing in 2023.

NGTL System/Foothills West Path Delivery Program

In 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 as a result of refined cost estimates and increased construction costs and consists of approximately 107 km (66 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. Regulatory approvals to construct and operate $0.4 billion of the facilities have been received and applications for the remaining facilities have been submitted with approvals anticipated in first and fourth quarter 2022.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure). Refer to page 11 for more information on non-GAAP measures we use.

year ended December 31			
(millions of $)	**2021**	**2020**	**2019**
NGTL System	**1,649**	1,509	1,210
Canadian Mainline	**838**	911	952
Other Canadian pipelines[1]	**188**	146	112
Comparable EBITDA	**2,675**	2,566	2,274
Depreciation and amortization	**(1,226)**	(1,273)	(1,159)
Comparable EBIT	**1,449**	1,293	1,115
Specific item:			
Gain on partial sale of Coastal GasLink LP	**—**	364	—
Segmented earnings	**1,449**	1,657	1,115

1 Includes results from Foothills, Ventures LP, Great Lakes Canada and 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 decreased by $208 million in 2021 compared to 2020 and increased by $542 million in 2020 compared to 2019. Segmented earnings in 2020 include a pre-tax gain of $364 million related to the sale of a 65 per cent equity interest in Coastal GasLink LP which has been excluded from our calculation of comparable EBITDA and 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 also impact comparable EBITDA, but do not have a significant impact on net income as they are almost entirely recovered in revenues on a flow-through basis.

Net income and average investment base

year ended December 31 (millions of $)	2021	2020	2019
Net income			
NGTL System	**631**	565	484
Canadian Mainline	**213**	160	173
Average investment base			
NGTL System	**15,560**	14,070	11,959
Canadian Mainline	**3,724**	3,673	3,690

Net income for the NGTL System increased by $66 million in 2021 compared to 2020 and $81 million in 2020 compared to 2019 mainly due to a higher average investment base resulting from continued system expansions. Effective January 1, 2020, the NGTL System is operating under the 2020-2024 Revenue Requirement Settlement which includes an ROE of 10.1 per cent on 40 per cent deemed common equity. This settlement provides the NGTL System the opportunity to increase depreciation rates if tolls fall below specified levels and an incentive mechanism for certain operating costs where variances from projected amounts are shared with our customers. The NGTL System's 2019 results reflected the 2018-2019 Revenue Requirement Settlement that expired on December 31, 2019 and included an ROE of 10.1 per cent on 40 per cent deemed common equity, a mechanism for sharing variances above and below a fixed annual OM&A amount and flow-through treatment of all other costs.

Net income for the Canadian Mainline increased by $53 million in 2021 compared to 2020 mainly as a result of higher incentive earnings and the elimination of a $20 million after-tax annual TC Energy contribution included in the previous settlement. Net income in 2020 decreased by $13 million compared to 2019 mainly as a result of lower incentive earnings. Effective 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. In 2020 and 2019, the Canadian Mainline operated under the terms of the 2015-2030 Tolls Application approved in 2014. The terms of the previous settlement included an ROE of 10.1 per cent on deemed common equity of 40 per cent, an incentive mechanism with both upside and downside risk and a $20 million after-tax annual TC Energy contribution to reduce the revenue requirement.

Comparable EBITDA

Comparable EBITDA for Canadian Natural Gas Pipelines was $109 million higher in 2021 compared to 2020 primarily due to the net effect of:

- higher flow-through depreciation and income taxes as well as increased rate-base earnings on the NGTL System
- Coastal GasLink development fee revenue which commenced in second quarter 2020
- 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.

Comparable EBITDA for Canadian Natural Gas Pipelines in 2020 was $292 million higher than 2019 primarily due to the net effect of:

- increased rate-base earnings and flow-through depreciation due to additional facilities placed in service as well as higher flow-through financial charges on the NGTL System
- lower flow-through income taxes and reduced incentive earnings on the Canadian Mainline and the NGTL System
- Coastal GasLink development fee revenue which commenced in 2020.

Depreciation and amortization

Depreciation and amortization was $47 million lower in 2021 compared to 2020 mainly due to one section of the Canadian Mainline being fully depreciated in 2021, partially offset by higher depreciation on the NGTL System from expansion facilities that were placed in service in 2021 and 2020. Depreciation and amortization was $114 million higher in 2020 compared to 2019 due to additional NGTL System facilities placed in service in 2020 and 2019.

OUTLOOK

Comparable EBITDA and comparable earnings

Net income for Canadian rate-regulated pipelines is affected by changes in investment base, ROE and deemed capital structure as well as by the terms of toll settlements approved by the CER. Under the current regulatory model, earnings from Canadian rate-regulated natural gas pipelines are not materially affected by short-term fluctuations in the commodity price of natural gas, changes in throughput volumes or changes in contracted capacity levels.

Canadian Natural Gas Pipelines comparable EBITDA is expected to be higher in 2022 driven by continued NGTL System expansion and recovery of flow-through items, partially offset by the reduction of flow-through depreciation in the Canadian Mainline as one segment was fully depreciated in 2021. Due to the flow-through treatment of certain expenses on our Canadian regulated pipelines, changes in these amounts can impact our comparable EBITDA despite having no significant effect on comparable earnings.

Canadian Natural Gas Pipelines comparable earnings in 2022 are expected to be higher than 2021 mainly due to continued growth of the NGTL System as we advance expansion programs which extend and expand supply facilities, enhance delivery facilities in Alberta and provide incremental service at our major border delivery locations in response to requests for firm service on the system.

Capital spending

We spent a total of $2.7 billion in 2021 in our Canadian natural gas pipelines business on growth projects and maintenance capital expenditures. We expect to spend approximately $3.5 billion in 2022, primarily on NGTL System expansion projects and maintenance capital expenditures, all of which are immediately reflected in investment base and related earnings.

U.S. Natural Gas Pipelines

UNDERSTANDING OUR U.S. NATURAL GAS PIPELINES SEGMENT

The U.S. interstate natural gas pipeline business is subject to regulation by various federal, state and local governmental agencies. FERC, however, has comprehensive jurisdiction over our U.S. natural gas business. FERC approves maximum transportation rates that are cost-based and are designed to recover the pipeline's investment, operating expenses and a reasonable return for our investors. In the U.S., we have the ability to contract for negotiated or discounted rates with shippers.

FERC does not require U.S. interstate pipelines to calculate rates annually, nor do they generally allow for the collection or refund of the variance between actual and expected revenues and costs into future years. This difference in U.S. regulation from the Canadian regulatory environment puts our U.S. pipelines at risk for the difference in expected and actual costs and revenues between rate cases. If revenues no longer provide a reasonable opportunity to recover our costs, we can file with FERC for a new determination of rates, subject to any moratorium in effect. Similarly, FERC or our shippers may institute proceedings to lower rates if they consider the return on capital invested to be unjust or unreasonable.

Similar to Canada, we can also establish settlement arrangements with our U.S. shippers that are ultimately subject to approval by FERC. Rate case moratoriums for a period of time, before either we or the shippers can file for a rate review, are common for a settlement in that they provide some certainty for shippers in terms of rates, eliminate the costs associated with frequent rate proceedings for all parties and can provide an incentive for pipelines to lower costs.

PHMSA compliance regulation

Most of our U.S. natural gas pipeline systems are subject to federal pipeline safety statutes and regulations enacted and administered by PHMSA. PHMSA has disseminated regulations governing, among other things, maximum operating pressures, pipeline patrols and leak surveys, public awareness, operation and maintenance procedures, operator qualification, minimum depth requirements and emergency procedures. Additionally, PHMSA has put into place regulations requiring pipeline operators to develop and implement integrity management programs for certain natural gas pipelines that, in the event of a pipeline leak or rupture, could affect high-consequence areas, which are areas where a release could have the most significant adverse consequences, including high-population areas.

During 2016, PHMSA proposed new rules to revise the U.S. Federal Pipeline Safety Regulations and issued a Notice of Public Rulemaking (NPRM) for natural gas transmission and gathering lines that would, if adopted, impose more stringent inspection, reporting and integrity management requirements on operators. However, PHMSA has since decided to split its 2016 proposed rule, which has become known as the Gas Mega Rule, into three separate rulemakings focusing on (1) maximum allowable operating pressure and integrity assessments on non-high consequence areas known as moderate consequence areas; (2) repair criteria, inspections and corrosion control; and (3) gathering lines. The first of these three rulemakings, for onshore natural gas transmission pipelines, was published as a final rule in October 2019 and the gathering line rule (part three) was issued in November 2021. We continue to assess the operational and financial impact related to this final rule over its 15-year implementation window that began in July 2020 and seek to optimize recovery of those costs. The remaining rulemaking comprising the Gas Mega Rule is currently expected to be issued in April 2022.

In addition to the rulemakings noted above, new pipeline safety legislation was signed into law in December 2020 that reauthorized PHMSA pipeline safety programs that expired under the 2016 Pipeline Safety Act at the end of September 2019. We are in the process of assessing the impacts associated with this new legislation which include self-directed mandates to natural gas transmission operations requiring targeted reduction of methane releases.

The Pipeline Rupture Detection and Mitigation for Onshore Populated and High Consequence Areas (HCAs) rulemaking is expected to be published as a final rule in March 2022. The rupture detection and mitigation rule will define when the installation of automatic shutoff valves, remote-controlled valves or manual valves is required on newly constructed pipelines or replacements six inches and larger in diameter. The rule primarily targets Class 3 and 4 locations and HCAs but also includes more stringent mandates on the timeliness of response and the ability for the Supervisory Control and Data Acquisition System to detect and alert operations controllers of potential large-scale leaks with a 40-minute requirement to have a release fully isolated. We have provided initial comments on the NPRM and will perform a full assessment when the rule is issued as final.

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. TC PipeLines, LP has ownership interests in the GTN, Northern Border, Bison, Great Lakes, North Baja, Tuscarora, Iroquois and Portland pipeline systems. Our overall ownership for each of these assets is provided in the asset listing of our major pipelines starting on page 39. Refer to the Corporate – Significant events section for additional information regarding the acquisition of all outstanding common units of TC PipeLines, LP not beneficially owned by TC Energy.

SIGNIFICANT EVENTS

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 approval, with 2021 revenues expected to be generally consistent with estimates recorded to date. On December 17, 2021, the presiding Administrative Law Judge recommended the settlement for approval and certified it as uncontested to FERC for its review and approval. While there is no timeframe in which FERC must act on the settlement, in line with other recent rate case settlement approval timelines, we expect to receive approval of the settlement in early 2022.

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 was placed in service in January 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 are expected to improve reliability of the systems and allow for additional transportation services to address growing demand under long-term contracts while reducing direct CO_2e emissions. Consistent with this initiative, the VR project on Columbia Gas was sanctioned in 2021, 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. Similarly, the WR project on ANR was also sanctioned in 2021 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.

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 uncontested rate settlement was approved by FERC on November 18, 2021. 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.

GTN XPress

The GTN XPress expansion project filed its FERC certificate application in fourth quarter 2021 and is expected to be placed in service in the second half of 2023.

Modernization III

Subject to FERC approval as part of the Columbia Gas uncontested rate settlement, Columbia Gas and its customers entered into a settlement arrangement (Modernization III) which provides recovery and return on investment to modernize its system, improve system safety, integrity, compliance and reliability. The Modernization III program includes, among other things, replacement of aging pipeline and compressor facilities, enhancements to system inspection capabilities and improvements in control systems as well as projects designed to increase energy efficiency and reduce emissions. The program was approved for up to US$1.2 billion of work starting in 2021 and is to be completed through 2024. As per the terms of the arrangement, facilities in service by November 30 of each year collect revenues effective April 1 of the following year until the arrangement is terminated. New rates will become effective once Columbia Gas files a subsequent Section 4 rate case under the Natural Gas Act.

ANR Section 4 Rate Case

ANR filed a Section 4 rate case with FERC on January 28, 2022 requesting an increase to ANR's maximum transportation rates effective August 1, 2022, subject to refund upon completion of the rate proceeding. As the rate case process progresses, we expect to engage in a collaborative process to achieve settlement with our customers, FERC and other stakeholders.

FINANCIAL RESULTS

On March 3, 2021, we acquired all the outstanding common units of TC PipeLines, LP not beneficially owned by TC Energy in exchange for TC Energy common shares (TC PipeLines, LP acquisition). TC PipeLines, LP results for the year ended December 31, 2021 and comparative results for 2020 and 2019 reflect our ownership interests in eight natural gas pipelines prior to the acquisition.

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure). Refer to page 11 for more information on non-GAAP measures we use.

year ended December 31 (millions of US$, unless otherwise noted)	**2021**	**2020**	**2019**
Columbia Gas	**1,529**	1,305	1,222
ANR	**592**	512	492
Columbia Gulf	**220**	195	164
Great Lakes[1,2]	**158**	91	86
GTN[2,3]	**139**	—	—
Other U.S. pipelines[2,5]	**313**	117	172
TC PipeLines, LP[2,4]	**24**	119	119
Non-controlling interests[4]	**100**	375	368
Comparable EBITDA	**3,075**	2,714	2,623
Depreciation and amortization	**(630)**	(597)	(568)
Comparable EBIT	**2,445**	2,117	2,055
Foreign exchange impact	**620**	720	671
Comparable EBIT (Cdn$)	**3,065**	2,837	2,726
Specific items:			
Gain on sale of Columbia Midstream assets	**—**	—	21
Risk management activities	**6**	—	—
Segmented earnings (Cdn$)	**3,071**	2,837	2,747

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 Our ownership interest in TC PipeLines, LP was 25.5 per cent prior to our acquisition on March 3, 2021, at which time it became 100 per cent. Prior to March 3, 2021, TC PipeLines, LP's results reflected a 46.45 per cent ownership interest in Great Lakes, its ownership of GTN, Bison, North Baja, Portland and Tuscarora as well as its share of equity income from Northern Border and Iroquois.

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

4 Reflects comparable EBITDA attributable to portions of TC PipeLines, LP and Portland that we did not own prior to our acquisition of TC PipeLines, LP on March 3, 2021, and subsequently reflects earnings attributable to the remaining 38.3 per cent interest in Portland we do not own.

5 Reflects comparable EBITDA from our ownership in our mineral rights business, 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 our acquisition of TC PipeLines, LP 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.

U.S. Natural Gas Pipelines segmented earnings in 2021 increased by $234 million compared to 2020 and increased by $90 million in 2020 compared to 2019 and included the following specific items which have been excluded from our calculation of comparable EBIT and comparable earnings:

- unrealized gains from changes in the fair value of derivatives related to our U.S. natural gas marketing business in 2021
- a pre-tax gain of $21 million related to the sale of certain Columbia Midstream assets in August 2019.

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, while a stronger U.S. dollar in 2020 had a positive impact on the Canadian dollar equivalent segmented earnings from our U.S. operations compared to the same period in 2019.

Earnings from our U.S. Natural Gas Pipelines operations are generally affected by contracted volume levels, volumes delivered and the rates charged as well as by the cost of providing services. Columbia and ANR results are also affected by the contracting and pricing of their natural gas storage capacity and incidental commodity sales. Natural gas pipeline and storage volumes and revenues are generally higher in the winter months because of the seasonal nature of the business.

Comparable EBITDA for U.S. Natural Gas Pipelines was US$361 million higher in 2021 than 2020 primarily due to the net effect of:

- a net increase in earnings from Columbia Gas as a result of the higher transportation rates effective February 1, 2021, pursuant to the Columbia Gas uncontested rate case settlement. Refer to the U.S. Natural Gas Pipelines – Significant events section for additional information
- increased earnings across our U.S. Natural Gas Pipelines assets which includes the impact of cold weather events in 2021 impacting many of the U.S. markets in which we operate
- increased earnings from our mineral rights business due to higher commodity prices
- incremental earnings resulting from increased capitalization of pipeline integrity costs and the contribution from growth projects placed in service primarily on Columbia Gas and ANR, partially offset by higher property taxes.

Comparable EBITDA for U.S. Natural Gas Pipelines was US$91 million higher in 2020 than 2019 primarily due to the net effect of:

- incremental earnings from Columbia Gas and Columbia Gulf growth projects placed in service as well as lower operating costs in 2020
- increased earnings from ANR due to the sale of natural gas from certain gas storage facilities
- decreased earnings as a result of the sale of certain Columbia Midstream assets in August 2019.

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 – Financial results section for additional information.

Depreciation and amortization

Depreciation and amortization was US$33 million higher in 2021 compared to 2020 mainly due to new projects placed in service, net of certain fourth quarter 2021 adjustments related to the Columbia Gas uncontested rate case settlement and was US$29 million higher in 2020 compared to 2019 mainly due to new projects placed in service.

OUTLOOK

Comparable EBITDA

Our U.S. natural gas pipelines are largely backed by long-term take-or-pay contracts that are expected to deliver stable and consistent financial performance. Our ability to retain customers and recontract or sell capacity at favourable rates is influenced by prevailing market conditions and competitive factors, including alternatives available to end-use customers in the form of competing natural gas pipelines and supply sources as well as broader conditions that impact demand from certain customers or market segments. Comparable EBITDA is also affected by operational and other costs, which can be impacted by safety, environmental and other regulators' decisions, as well as customer credit risk.

U.S. Natural Gas Pipelines comparable EBITDA in 2022 is expected to be consistent with 2021. This is due to, among other factors, an expected increase in transportation rates on ANR subject to the outcome of the Section 4 rate case filed with FERC, completion of expansion projects in 2021 and 2022 on the ANR and Columbia Gulf systems as well as higher revenues on Columbia Gas due to the full-year implementation of higher transportation rates as part of the uncontested Section 4 rate case settlement filed with FERC. Our pipeline systems continue to see historically strong demand for service and we anticipate our assets will maintain the high utilization levels experienced in 2021. These positive results are expected to be partially offset by higher operational costs and an anticipated increase in property taxes from capital projects placed in service.

Capital spending

We spent a total of US$2.2 billion in 2021 on our U.S. natural gas pipelines and expect to spend approximately US$1.6 billion in 2022 primarily on ANR expansion projects and our Columbia Gas Modernization III program, as well as Columbia Gas and ANR maintenance capital expenditures, the return on and recovery of which is expected to be reflected in future tolls.

Mexico Natural Gas Pipelines

UNDERSTANDING OUR MEXICO NATURAL GAS PIPELINES SEGMENT

For over a decade, Mexico has been undergoing a significant transition from fuel oil and diesel as its primary energy sources for electric generation to using natural gas. As a result, new natural gas pipeline infrastructure has been and continues to be required to meet the growing demand for natural gas. The CFE, Mexico's state-owned electric utility, is the counterparty on all of our existing pipelines under long-term contracts, which are predominately denominated in U.S. dollars. These fixed-rate contracts are generally designed to recover the cost of service and provide a return on and of invested capital. As the pipeline developer and operator, we are generally at risk for operating and construction costs and in-service delay penalties, excluding force majeure events which provide schedule relief. Our Mexico pipelines have approved tariffs, services and related rates for other potential users.

SIGNIFICANT EVENTS

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 while management holds settlement discussions with the CFE. In 2021, we advanced the resolution of disputed contract terms with the signing of an MOU on July 30, 2021 outlining main settlement principles.

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 complete the construction of Villa de Reyes in phases during 2022.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure). Refer to page 11 for more information on non-GAAP measures we use.

year ended December 31 (millions of US$, unless otherwise noted)	**2021**	**2020**	**2019**
Topolobampo	**161**	159	159
Sur de Texas[1]	**113**	171	43
Tamazunchale	**118**	120	120
Guadalajara	**71**	64	65
Mazatlán	**70**	70	70
Comparable EBITDA	**533**	584	457
Depreciation and amortization	**(86)**	(87)	(87)
Comparable EBIT	**447**	497	370
Foreign exchange impact	**110**	172	120
Comparable EBIT and segmented earnings (Cdn$)	**557**	669	490

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 segmented earnings in 2021 decreased by $112 million compared to 2020 and increased by $179 million in 2020 compared to 2019. A weaker U.S. dollar in 2021 had a negative impact on the Canadian dollar equivalent segmented earnings from our Mexico operations compared to the same period in 2020, while a stronger U.S. dollar in 2020 had a positive impact on the Canadian dollar equivalent segmented earnings from our Mexico operations compared to the same period in 2019.

Comparable EBITDA for Mexico Natural Gas Pipelines decreased by US$51 million in 2021 compared to 2020 mainly due to:

- decreased Sur de Texas equity income due to one-time fees of US$55 million recognized in 2020 associated with the construction of the project
- higher earnings from Guadalajara following the implementation of a flow reversal project completed in 2020.

Comparable EBITDA for Mexico Natural Gas Pipelines increased by US$127 million in 2020 compared to 2019 mainly due to:

- increased Sur de Texas equity income from the commencement of transportation services in September 2019
- revenues of US$55 million recognized in 2020 from fees associated with the construction of the Sur de Texas pipeline as well as ongoing fees earned from operating the pipeline.

Prior to in-service, Sur de Texas equity income primarily reflected AFUDC during construction, net of our proportionate share of interest expense on peso-denominated inter-affiliate loans. These inter-affiliate loans remain in place and our share of related interest expense in Sur de Texas continues to be fully offset by corresponding interest income recorded in Interest income and other in the Corporate segment.

Depreciation and amortization

Depreciation and amortization in 2021 was consistent with the same periods in 2020 and 2019.

OUTLOOK

Comparable EBITDA

Mexico Natural Gas Pipelines comparable EBITDA reflects long-term, stable, principally U.S. dollar-denominated transportation contracts that are affected by the cost of providing service and includes our share of equity income from our 60 per cent interest in the Sur de Texas pipeline. Due to the long-term nature of the underlying transportation contracts, comparable EBITDA is generally consistent year-over-year except when new assets are placed into service. Comparable EBITDA for 2022 is expected to be higher than 2021 due to the anticipated settlement of the disputed contract terms with the CFE and the expected in-service of Villa de Reyes during 2022.

Capital spending

We spent a total of US$0.1 billion in 2021 primarily related to the construction of the Villa de Reyes pipeline, maintenance of constructed Tula segments and life-cycle enhancements to existing assets. Capital spending in 2022 to complete construction of Villa de Reyes and additional life-cycle asset investments is expected to be US$0.1 billion.

NATURAL GAS PIPELINES – BUSINESS RISKS

The following are risks specific to our Natural Gas Pipelines business. Refer to page 93 for information about general risks related to TC Energy as a whole, including other operational, safety and financial risks as well as our approach to risk management.

Production levels within supply basins

The NGTL System and our pipelines downstream depend largely on supply from the WCSB. Columbia Gas and its connecting pipelines largely depend on Appalachian supply. We continue to monitor any changes in our customers' natural gas production plans and how these may impact our existing assets and new project schedules. There is competition amongst pipelines to connect to major basins. An overall decrease in production and/or increased competition for supply could reduce throughput on our connected pipelines that, in turn, could negatively impact overall revenues generated. The WCSB and Appalachian basins are two of the most prolific and cost-competitive basins in North America and have considerable natural gas reserves. However, the amount actually produced depends on many variables including the price of natural gas and natural gas liquids, basin-on-basin competition, pipeline and gas-processing tolls, demand within the basin, changes in policy and regulations and the overall value of the reserves, including liquids content.

Market access

We compete for market share with other natural gas pipelines. New supply basins are being developed closer to markets we have historically served and may reduce the throughput and/or distance of haul on our existing pipelines and impact revenues. New markets, including those created by LNG export facilities developed to access global natural gas demand, can lead to increased revenues through higher utilization of existing facilities and/or demand for new infrastructure. The long-term competitiveness of our pipeline systems and the avoidance of bypass pipelines will depend on our ability to adapt to changing flow patterns by offering competitive transportation services to the market.

Competition for greenfield pipeline expansion

We face competition from other pipeline companies seeking to invest in greenfield natural gas pipeline development opportunities. This competition could result in fewer available projects that meet our investment hurdles or projects that proceed with lower overall financial returns. While renewable deployments are expected to garner an increasing portion of future energy needs, including in the power generation sector, natural gas demand is still projected to grow under the most aggressive renewable deployment forecasts. The reliability of natural gas is an important factor in the successful wide-scale deployment of renewables with more intermittent capabilities.

Demand for pipeline capacity

Demand for pipeline capacity ultimately drives the sale of pipeline transportation services and is impacted by supply and market competition, variations in economic activity, weather variability, natural gas pipeline and storage competition, energy conservation as well as demand for and prices of alternative sources of energy. Renewal of expiring contracts and the opportunity to charge a competitive toll depends on the overall demand for transportation service. A decrease in the level of demand for our pipeline transportation services could adversely impact revenues, although overall utilization of our pipeline capacity continues to grow and warrant further investment and expansion.

Commodity prices

The cyclical supply and demand nature of commodities and related pricing can have a secondary impact on our business where our shippers may choose to accelerate or delay certain projects. This can impact the timing of demand for transportation services and/or new natural gas pipeline infrastructure. Disruptions in the energy supply chain can result in price volatility and a decline in natural gas prices that could impact our shippers' financial condition and their ability to meet their transportation service cost obligations.

Regulatory risk

Decisions and evolving policies by regulators and other government authorities, including changes in regulation, can impact the approval, timing, construction, operation and financial performance of our natural gas pipelines. There is a risk that decisions are delayed or are not favourable and could therefore adversely impact construction costs, in-service dates, anticipated revenues and the opportunity to further invest in our systems. There is also risk of a regulator disallowing a portion of our prudently incurred costs, now or at some point in the future.

The regulatory approval process for larger infrastructure projects, including the time it takes to receive a decision, could be delayed or lead to an unfavourable decision due to evolving public opinion and government policy related to natural gas pipeline infrastructure development. If regulatory decisions are subsequently challenged in courts, this could result in further impacts to project costs and schedule delays.

Increased scrutiny of construction and operations processes by the regulator or other enforcing agencies has the potential to delay construction, increase operating costs or require additional capital investment. There is a risk of an adverse impact to income if these costs are not fully recoverable and/or reduce the competitiveness of tolls charged to customers.

We continuously manage these risks by monitoring legislative and regulatory developments and decisions to determine the possible impact on our natural gas pipelines business and the development of rate, facility and tariff applications that account for and mitigate the risks where possible.

Governmental risk

Shifts in government policy or changes in government can impact our ability to grow our business. More complex regulatory processes, broader consultation requirements, more restrictive emissions policies and changes to environmental regulations can impact our opportunities for continued growth. We are committed to working with all levels of government to ensure our business benefits and risks are understood and mitigation strategies are implemented.

Construction and operations

Constructing and operating our pipelines to ensure transportation services are provided safely and reliably is essential to the success of our business. Interruptions in our pipeline operations impacting throughput capacity may result in reduced revenues and can affect corporate reputation as well as customer and public confidence in our operations. We manage this by investing in a highly skilled workforce, hiring third-party inspectors during construction, operating prudently, monitoring our pipeline systems continuously, using risk-based preventive maintenance programs and making effective capital investments. We use pipeline inspection equipment to regularly check the integrity of our pipelines, and repair or replace sections when necessary. We also calibrate meters regularly to ensure accuracy and employ robust reliability and integrity programs to maintain compression equipment and ensure safe and reliable operations.

Liquids Pipelines

Our existing liquids pipelines infrastructure connects Alberta crude oil supplies to U.S. refining markets in Illinois, Oklahoma and the U.S. Gulf Coast as well as U.S. crude oil supplies from the key market hub at Cushing, Oklahoma to the U.S. Gulf Coast. We also provide intra-Alberta liquids transportation.

Our Liquids Pipelines business includes:
- wholly-owned liquids pipelines – approximately 4,400 km (2,700 miles)
- wholly-owned operational and term storage – approximately 7 million barrels
- partially-owned liquids pipelines – over 460 km (290 miles).

Strategy

Optimize the value of our existing Liquids Pipelines assets, while operating safely and reliably. We also pursue emerging growth opportunities to add incremental value to our business. In support of our GHG emissions reduction targets, we are taking significant steps to source renewable power for our operations. The strategy addresses scope two emissions, which are primarily generated by the consumption of electricity used to power our liquids pipelines.

Recent highlights

- U.S. President Biden revoked the existing Presidential Permit for the Keystone XL pipeline project on January 20, 2021. As a result, we terminated the Keystone XL pipeline project
- submitted a Request for Arbitration to formally 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 project
- received $35 million in proceeds from the monetization of our remaining interest in Northern Courier
- entered into a joint venture with Motiva Enterprises (Motiva) to construct the US$152 million Port Neches Link pipeline system. Construction has commenced and is expected to be in service in mid-2022.


TC Energy
Liquids Pipelines
As at December 31, 2021
Liquids Pipeline
In Development/Construction
Liquids Tank Terminal
Production Basin
Western Canadian
Sedimentary Basin
Oil Sands
4
3
5
CANADA
CALGARY
Williston
TORONTO
1
Powder River
Denver-Julesburg
UNITED STATES
CHARLESTON
Anadarko
2
Permian
HOUSTON
Eagle Ford
MEXICO
MEXICO CITY

We are the operator and developer of the following:

		Length	Description	Ownership
	Liquids pipelines			
1	Keystone Pipeline System	4,324 km (2,687 miles)	Transports crude oil from Hardisty, Alberta to U.S. markets at Wood River and Patoka, Illinois, Cushing, Oklahoma and the U.S. Gulf Coast.	100%
2	Marketlink		Transports crude oil from Cushing, Oklahoma to the U.S. Gulf Coast on facilities that form part of the Keystone Pipeline System.	100%
3	Grand Rapids	460 km (287 miles)	Transports crude oil from the producing area northwest of Fort McMurray, Alberta to the Edmonton/Heartland, Alberta market region.	50%
4	White Spruce	72 km (45 miles)	Transports crude oil from Canadian Natural Resources Limited's Horizon facility in northeast Alberta to the Grand Rapids pipeline.	100%
	In development			
5	Grand Rapids Phase II	460 km (287 miles)	Expansion of Grand Rapids to transport additional crude oil from the producing area northwest of Fort McMurray, Alberta to the Edmonton/Heartland, Alberta market region.	50%

UNDERSTANDING OUR LIQUIDS PIPELINES BUSINESS

Our Liquids Pipelines segment consists of crude oil and liquids/petroleum products pipelines, complemented by a liquids marketing business. We efficiently transport crude oil from major supply sources to markets where crude oil can be refined into various petroleum products, and offer ancillary services such as short- and long-term storage of liquids at key terminal locations to offer our customers delivery flexibility while optimizing the value of our pipeline assets.

We provide pipeline transportation capacity to customers predominantly supported by long-term contracts with fixed monthly payments that are not linked to actual throughput volumes or to the price of the commodity, generating stable earnings over the contract term. The terms of service and fixed monthly payments are determined by contracts negotiated with customers which provide for the recovery of costs we incur to construct the asset. Generally, the costs to operate and maintain the system are flowed through to customers via a variable-toll mechanism. Uncontracted pipeline capacity is offered to the market to secure additional volumes on a monthly spot basis which provides opportunities to generate incremental earnings. Term storage of liquids at terminals is offered to our customers in return for fixed fee payments which are not linked to actual storage volumes or to the price of the commodity.

The Keystone Pipeline System, our largest liquids pipeline asset, transports approximately 20 per cent of the U.S. Midwest and the U.S. Gulf Coast refiners' demand for Canadian crude oil. It also provides significant capacity between Cushing, Oklahoma and the U.S. Gulf Coast market, primarily transporting U.S. crude oil. Our two intra-Alberta liquids pipelines – Grand Rapids and White Spruce – provide crude oil transportation for producers in northern Alberta.

Our liquids marketing business provides customers with a variety of crude oil marketing services including transportation, storage and crude oil management, largely through the purchase and sale of physical crude oil. This business contracts for capacity on our pipelines as well as third-party owned pipelines and tank terminals.

Business environment

Global crude oil and liquids demand continues to be impacted by the COVID-19 pandemic as containment measures imposed by most countries around the world continue to reduce transportation, commercial and non-essential activities. Demand is expected to gradually recover to pre-COVID-19 levels through 2022.

Global crude oil and liquids demand is projected to increase from 97 million Bbl/d in 2021 to 107 million Bbl/d in 2035, driven primarily by the transportation and industrial sectors which account for 80 per cent of total crude oil and liquids demand. Global supply of crude oil necessary to meet this demand is expected to be sourced from countries with significant crude oil reserves, mainly in North America, South America and the Middle East. To meet this demand requirement, a strong crude oil price environment is needed to support continuing investment in the energy sector.

Crude oil prices have recovered from 2020 lows, due to crude oil supply management efforts, primarily by OPEC+, capital discipline of North American producers and global demand growth. The ongoing COVID-19 pandemic, combined with uncertainty over the ability for OPEC+ to manage and meet market requirements, continues to drive crude oil price volatility.

Supply outlook

Canada

Canada has the world’s third largest crude oil reserves with over 160 billion barrels of economically and technically recoverable conventional and oil sands reserves, primarily in Alberta. Total 2021 WCSB crude oil production was approximately 4.4 million Bbl/d and is expected to increase to approximately 5.2 million Bbl/d by 2035, subject to the resolution of current ex-Alberta pipeline capacity constraints. Oil sands production comprises the majority of western Canadian crude oil supply at approximately 3.2 million Bbl/d and is a favourable supply source given its decades-long reserve life, steady production and rapidly improving cost and environmental performance.

U.S.

The U.S. is one of the largest crude oil producing countries in the world at approximately 11 million Bbl/d in 2021. The majority of continental U.S. crude oil production is in the form of light tight oil from the Permian, Williston, Eagle Ford and Niobrara basins. In recent years, the Permian basin has become the most dominant producing region accounting for approximately 30 per cent of total U.S. crude oil production and is expected to grow to greater than 6 million Bbl/d by 2035.

With light oil processing capacity fully utilized in the U.S., exports to offshore markets are the only outlets for incremental light tight oil production. U.S. crude oil exports have remained strong at close to 3 million Bbl/d in 2021, despite the global demand impact from the COVID-19 pandemic. By 2035, the U.S. is expected to export approximately 4.9 million Bbl/d of predominantly light crude oil and import approximately 4.8 million Bbl/d of heavy crude oil.

Demand outlook

Canada's proximity to the U.S., which is the world's largest consumer of crude oil at greater than 16 million Bbl/d, and Canada's significant heavy crude oil production are of strategic importance to the U.S. refining industry. Many refiners in the U.S. Midwest and U.S. Gulf Coast process a wide variety of crude oil, including significant amounts of heavy crude oil. This flexibility, access to an abundance of low-cost natural gas, proximity to light and heavy crude oil supply, economies of scale and ready access to markets have positioned these refineries to be among the most profitable in the world.

The U.S. Midwest and U.S. Gulf Coast refining markets have a strong reliance on heavy crude oil imports, with total imports of approximately 4 million Bbl/d in 2021. The U.S. Midwest refiners have total refining capacity of approximately 4 million Bbl/d, which requires approximately 1.5 million Bbl/d of heavy crude oil. The U.S. Gulf Coast is the largest regional refining centre in the world with a total capacity close to 10 million Bbl/d, representing more than half of the total U.S. refining capacity. The U.S. Gulf Coast imported over 2 million Bbl/d of primarily heavy crude oil in 2021 to meet demand.

Canada is currently the largest exporter of crude oil to the U.S. at nearly 4 million Bbl/d. Demand for heavy crude oil in the U.S. has been resilient and is expected to remain strong for the foreseeable future. While Canada, Venezuela and Mexico are the top suppliers of heavy crude oil to the U.S., the latter two countries are experiencing declining production. U.S. sanctions, along with the market impacts of the COVID-19 pandemic, have reduced demand for Venezuela's heavy crude oil production. Mexico expects the export of Maya, its flagship heavy crude oil, to continue to fall due to the continued declines in its production and new domestic demand. Approximately 36 per cent of U.S. Gulf Coast heavy crude oil imports are currently met by Mexico which presents a significant opportunity for Canada to become a more prominent supplier of crude oil to the U.S.

Strategic priorities

Our intra-Alberta liquids pipelines and the Keystone Pipeline System strategically position us to provide competitive transportation solutions for growing supplies of Alberta heavy crude oil and U.S. light tight oil to the U.S. Midwest and the U.S. Gulf Coast.

Within our established risk preferences, we remain committed to:
- optimizing the value and competitiveness of our existing assets
- expanding and leveraging our existing infrastructure
- expanding the transportation services that we offer and extending into adjacent geographies
- extending into emerging growth opportunities.

COVID-19 has had a material impact on energy markets by disrupting and delaying industry growth. The long-term contract profile supporting our business model provides stability for our existing businesses but growth will likely be challenged until energy markets normalize. The cyclical nature of commodity prices may influence the pace at which our customers expand their operations. This can impact the rate of project growth in our industry, the value of our services as contracts expire and the timing for the demand of transportation services and/or new liquids infrastructure.

Within Alberta, we continue to position ourselves to capture WCSB production growth. Declining Latin American crude oil production has increased the demand for WCSB heavy crude oil in the U.S. Gulf Coast, which has historically relied on offshore imports.

With the fast-paced growth of U.S. light tight oil production and fully satisfied demand for light oil in North America, we will examine opportunities to expand our transportation services and extend our pipeline platform to include terminals with storage and marine export capabilities. Terminal connections and storage facilities encourage flows into and out of our pipeline systems, which we expect will help to secure long-term contracts and incremental spot volumes. We will also focus on leveraging our existing assets and development of projects to reach emerging growth regions such as the Williston and Denver-Julesburg basins.

We believe our liquids pipelines business is well positioned to endure the impact of short-term commodity price fluctuations and supply/demand responses. Our existing operations and development projects are supported by long-term contracts where we provide pipeline capacity to our customers in exchange for fixed monthly payments which are not affected by commodity prices or throughput. We continually work with existing and potential customers to provide pipeline transportation and terminal services. The combination of the scale and location of our assets assists us in attracting additional volumes and in growing our business.

We closely monitor the marketplace for strategic asset acquisitions or joint venture opportunities to enhance our system connectivity or expand our footprint within North America. We remain disciplined in our approach and will position our business development activities strategically to capture opportunities within our risk preferences.

ESG considerations form an important part of our strategy. Our Liquids Pipelines assets can underpin our de-carbonization goals and present opportunities to create partnerships with Indigenous communities. Our GHG reduction strategy in Liquids Pipelines is to competitively source renewable energy to power our base operating systems and reduce our carbon footprint with a goal of reducing 99 per cent of our liquids pipelines' scope two GHG emissions from our operations by 2025 and achieving net-zero emissions by 2030. We also seek to develop partnerships with Indigenous communities that will create value and further enable participation in energy infrastructure by those partners.

SIGNIFICANT EVENTS

Keystone XL

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, on June 9, 2021, we terminated the Keystone XL pipeline project.

The Keystone XL investment was evaluated for impairment in 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 ($2.1 billion after tax) for the year ended December 31, 2021 which was excluded from comparable earnings. The asset impairment charge was based on the excess of the carrying value of the asset of $3.3 billion over the estimated fair value of $175 million, net of contractual recoveries of $693 million and contractual and legal obligations related to termination activities of $342 million.

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 6, Keystone XL, of our 2021 Consolidated financial statements for additional information.

Although we recorded a $2.1 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 us. 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 project-level credit facility was 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 December 31, 2021 was $1.0 billion determined as follows:

(millions of $)	**2021**
Asset impairment charge and other (after tax)[1]	**2,134**
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	**1,003**

1 Refer to Note 6, Keystone XL, of our 2021 Consolidated financial statements for additional information.
2 Recognized through the 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. Right-of-way clean up and restoration is substantially complete while termination activities will continue through 2022. We will 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 project-level credit facility was fully repaid by the Government of Alberta and terminated.

We continue to manage legacy challenges to the 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 November 22, 2021, we filed a Request for Arbitration to formally initiate a legacy NAFTA claim to recover economic damages resulting from the revocation of the Presidential Permit for the Keystone XL pipeline project. 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 with the timing and ultimate outcome unknown at present.

Northern Courier

On November 30, 2021, we received $35 million in proceeds from the monetization of our remaining 15 per cent equity interest in Northern Courier to Astisiy Limited Partnership, a partnership comprised of Suncor Energy Inc. and eight Indigenous communities in the Regional Municipality of Wood Buffalo. As a result, we recorded a pre-tax gain on sale of $13 million ($19 million after tax). The pre-tax gain was included in Net gain/(loss) on assets sold/held for sale in the Consolidated statement of income.

Port Neches

On March 8, 2021, we entered a joint venture with 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.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented (losses)/earnings (the most directly comparable GAAP measure). Refer to page 11 for more information on non-GAAP measures we use.

year ended December 31 (millions of $)	2021	2020	2019
Keystone Pipeline System	**1,281**	1,474	1,654
Intra-Alberta pipelines[1]	**87**	92	137
Liquids marketing and other	**158**	134	401
Comparable EBITDA	**1,526**	1,700	2,192
Depreciation and amortization	**(318)**	(332)	(341)
Comparable EBIT	**1,208**	1,368	1,851
Specific items:			
Keystone XL asset impairment charge and other	**(2,775)**	—	—
Keystone XL preservation and other	**(43)**	—	—
Gain on sale of Northern Courier	**13**	—	69
Risk management activities	**(3)**	(9)	(72)
Segmented (losses)/earnings	**(1,600)**	1,359	1,848
Comparable EBITDA denominated as follows:			
Canadian dollars	**417**	418	442
U.S. dollars	**884**	955	1,318
Foreign exchange impact	**225**	327	432
Comparable EBITDA	**1,526**	1,700	2,192

1 Intra-Alberta pipelines included Grand Rapids, White Spruce and Northern Courier. In July 2019, we sold an 85 per cent interest in Northern Courier, subsequent to which we applied equity accounting to our remaining 15 per cent investment. In November 2021, we sold the remaining 15 per cent interest in Northern Courier.

Liquids Pipelines segmented earnings decreased by $3.0 billion in 2021 compared to 2020 and decreased by $489 million in 2020 compared to 2019 and included the following specified items which have been excluded from our calculation of comparable EBIT:

- a $2.8 billion pre-tax asset impairment charge, net of expected contractual recoveries and other contractual and legal obligations, in 2021 associated with the termination of the Keystone XL pipeline project and related projects following the January 20, 2021 revocation of the Presidential Permit. Refer to the Liquids Pipelines – Significant events section for additional information
- pre-tax preservation and other costs in 2021 of $43 million related to the preservation and storage of the Keystone XL pipeline project assets which could not be accrued as part of the Keystone XL asset impairment charge
- pre-tax gain of $13 million related to the sale of the remaining 15 per cent interest in Northern Courier in 2021 and $69 million related to the sale of an 85 per cent interest in Northern Courier in 2019
- unrealized gains and losses 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 period in 2020, while a stronger U.S. dollar in 2020 had a positive impact on the Canadian dollar equivalent segmented earnings from our U.S. operations compared to the same period in 2019.

Comparable EBITDA for Liquids Pipelines was $174 million lower in 2021 compared to 2020 primarily due to the net effect of:

- lower volumes on the U.S. Gulf Coast section of the Keystone Pipeline System
- increased contributions from liquids marketing activities mainly attributable to higher margins and volumes.

Comparable EBITDA for Liquids Pipelines was $492 million lower in 2020 compared to 2019 primarily due to:

- lower volumes on the Keystone Pipeline System and lower contribution from liquids marketing activities driven by a global reduction in crude oil demand and prices due to the significant impact of the COVID-19 pandemic in 2020 and disruption to energy markets
- decreased earnings as a result of the sale of an 85 per cent equity interest in Northern Courier in July 2019.

Depreciation and amortization

Depreciation and amortization was $14 million lower in 2021 compared to 2020 primarily as a result of a weaker U.S. dollar. Depreciation and amortization was $9 million lower in 2020 compared to 2019 reflecting the sale of an 85 per cent equity interest in Northern Courier, partially offset by a stronger U.S. dollar.

OUTLOOK

Comparable EBITDA

Comparable EBITDA in 2022 is expected to be lower than 2021 for both the Keystone Pipeline System and liquids marketing business as a result of continuing lower volumes on the U.S. Gulf Coast section of the Keystone Pipeline System and decreased margins, respectively. As discussed in the Understanding our Liquids Pipelines business section, global crude oil demand continues to be impacted by the COVID-19 pandemic but is expected to gradually recover to pre-COVID-19 levels through 2022.

Capital spending

We spent a total of $0.2 billion in 2021 primarily related to capital projects in the U.S. Gulf Coast and on our operating pipelines and expect to spend approximately $0.2 billion in 2022.

BUSINESS RISKS

The following are risks specific to our Liquids Pipelines business. Refer to page 93 for information about general risks related to TC Energy as a whole, including other operational, safety and financial risks as well as our approach to risk management.

Operations

Operating our liquids pipelines to ensure transportation services are provided safely and reliably as well as optimizing and maintaining their availability are essential to the success of our business. Interruptions in our pipeline operations may impact our throughput capacity and result in reduced fixed payment revenues and spot volume opportunities. We manage these risks and any possible impact to the local communities and environment by investing in a highly skilled workforce and operating prudently using risk-based preventive maintenance programs and making effective capital investments. We use internal inspection equipment to check our pipelines regularly and repair them whenever necessary.

Regulatory and government

Decisions by Canadian and U.S. regulators can have a significant impact on the approval, construction, operation, commercial and financial performance of our liquids pipelines. Shifts in government policy by existing bodies or following changes in government can impact our ability to grow our business. Public opinion about crude oil development and production, particularly in light of climate change concerns, may also have an adverse impact on the regulatory process. In conjunction with this, there are individuals and special interest groups that are expressing opposition to crude oil production by lobbying against the construction and operation of liquids pipelines. Changing environmental requirements or revisions to the current regulatory process may adversely impact the timing or ability to obtain approvals for our liquids pipelines. We manage these risks by continuously monitoring regulatory and government developments and decisions to determine their possible impact on our liquids pipelines business by building scenario analysis into our strategic outlook and by working closely with our stakeholders in the development and operation of our assets.

Crude oil supply and demand for pipeline capacity

A decrease in demand for refined crude oil products could adversely impact the price that crude oil producers receive for their product. In the long term, lower crude oil prices could mean producers may curtail their investment in the further development of crude oil supplies. Depending on the severity, these factors could negatively impact opportunities to expand our liquids pipelines infrastructure and, in the longer term, to re-contract with customers as current agreements expire.

Competition

As we continue to further develop our competitive position in the North American liquids transportation market to connect growing crude oil supplies between key North American producing regions and refining and export markets, we face competition from other midstream companies which also seek to transport these crude oil and diluent supplies to the same markets. Our success is dependent on our ability to offer and contract transportation services on terms that are market competitive.

Liquids marketing

Our liquids marketing business provides customers with a variety of crude oil marketing services including transportation, storage and crude oil management, primarily through the purchase and sale of physical crude oil. Changing market conditions could adversely impact the value of the underlying capacity contracts and margins realized. Availability of alternative pipeline systems that can deliver into the same areas can also impact contract value. The liquids marketing business complies with our risk management policies which are described in the Other information – Enterprise risk management section.

Shifting political trends and ESG requirements

North American governments are attempting to improve their environmental standards and position climate action as a key priority. Meanwhile, the business environment is also evolving quickly as investors demand greater ESG commitments. While there is downside risk to policies that shift support away from our traditional services, there are also opportunities to reduce GHG emissions and generate associated renewable energy and carbon credits for TC Energy.

Power and Storage

Our power business includes approximately 4,300 MW of generation capacity located in Alberta, Ontario, Québec and New Brunswick, using natural gas and nuclear fuel sources and is generally supported by long-term contracts. Additionally, we are pursuing generation assets and PPA opportunities in Canada and the United States.

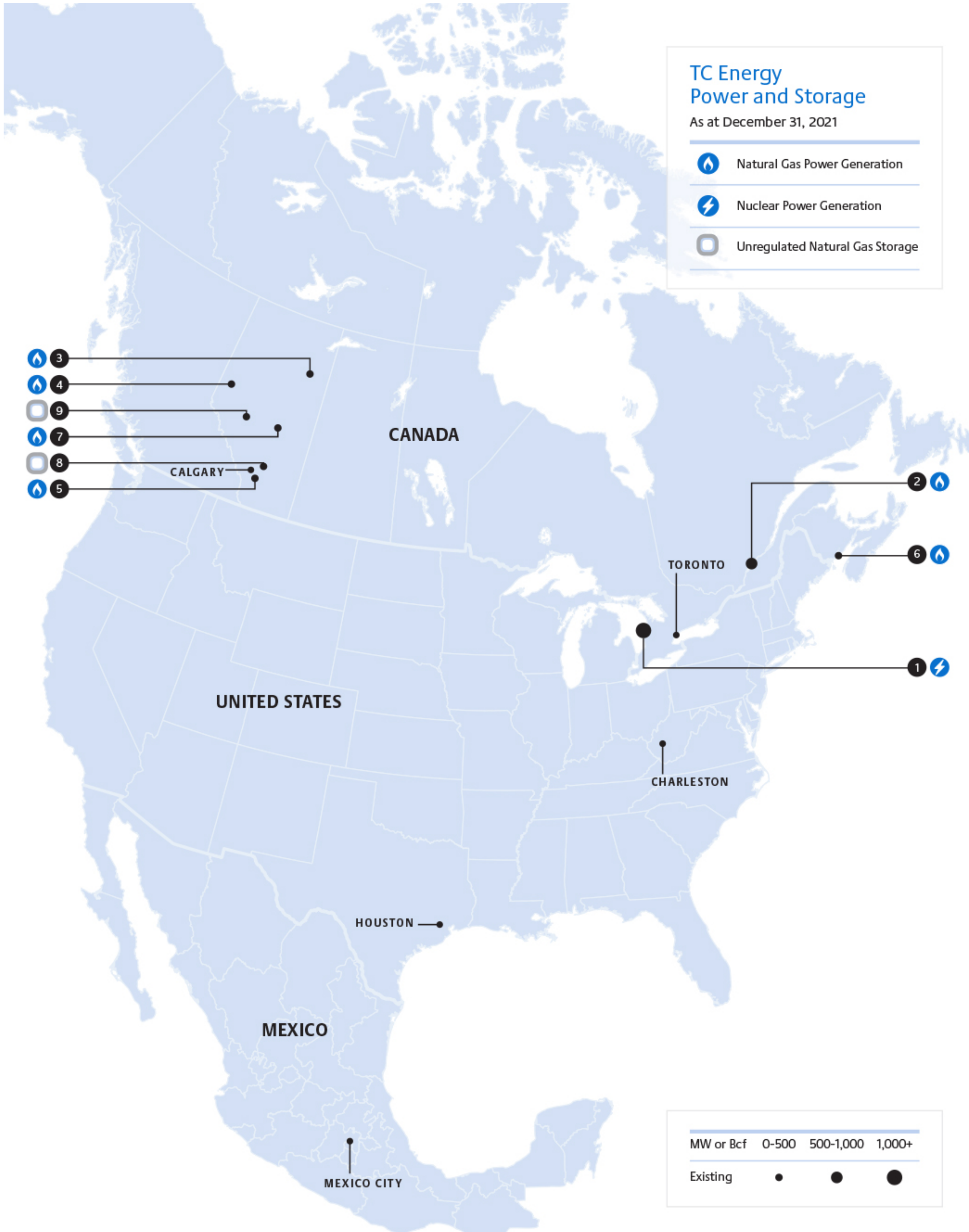
We own and operate approximately 118 Bcf of non-regulated natural gas storage capacity in Alberta.

Strategy

Our strategy is to leverage TC Energy's competitive footprint as a platform to grow our power business and enhance the life cycle and reliability of our assets, all driven by internal and external customer needs. Long term, we believe there will be a growing need for a reliable supply of resources as the energy transition unfolds. We can play a vital role in the energy transition by sourcing zero-carbon growth opportunities, new technologies and markets while decarbonizing our existing assets.

Recent highlights

- further advanced the Bruce Power life extension program with the submission of the final cost and schedule duration estimate to the IESO for the Unit 3 MCR while the Unit 6 MCR project proceeded on budget and schedule
- executed a 15-year PPA for 100 per cent of the power produced and associated environmental attributes from the 297 MW Sharp Hills Wind Farm located in Alberta, which is anticipated to begin operation in 2023
- continued to progress the development of the 1,000 MW clean energy Ontario Pumped Storage Project on federal lands, subject to conditions and regulatory approval
- the Claresholm Solar facility came into service commencing our eight-year PPA and adding 74 MW to our portfolio
- completed the purchase of the remaining interests in the Canyon Creek Pumped Storage project giving us full ownership.



TC Energy
Power and Storage
As at December 31, 2021
Natural Gas Power Generation
Nuclear Power Generation
Unregulated Natural Gas Storage
CANADA
UNITED STATES
MEXICO
CALGARY
TORONTO
CHARLESTON
HOUSTON
MEXICO CITY
1
2
3
4
5
6
7
8
9
MW or Bcf
0-500
500-1,000
1,000+
Existing

Power and Storage assets currently have a combined power generation capacity, net to TC Energy, of 4,258 MW and we operate each facility except for Bruce Power.

		Generating capacity (MW)	Type of fuel	Description	Ownership
1	Bruce Power[1]	3,170	nuclear	Eight operating reactors in Tiverton, Ontario. Bruce Power leases the nuclear facilities from OPG.	48.4%
2	Bécancour	550	natural gas	Cogeneration plant in Trois-Rivières, Québec. Power generation has been suspended since 2008 although we continue to receive PPA capacity payments while generation is suspended.	100%
3	Mackay River	207	natural gas	Cogeneration plant in Fort McMurray, Alberta	100%
4	Bear Creek	100	natural gas	Cogeneration plant in Grande Prairie, Alberta.	100%
5	Carseland	95	natural gas	Cogeneration plant in Carseland, Alberta.	100%
6	Grandview	90	natural gas	Cogeneration plant in Saint John, New Brunswick.	100%
7	Redwater	46	natural gas	Cogeneration plant in Redwater, Alberta.	100%
	Canadian non-regulated natural gas storage				
8	Crossfield	68 Bcf		Underground facility connected to the NGTL System near Crossfield, Alberta.	100%
9	Edson	50 Bcf		Underground facility connected to the NGTL System near Edson, Alberta.	100%

1 Our share of power generation capacity.

UNDERSTANDING OUR POWER AND STORAGE BUSINESS

Our Power and Storage business is made up of two groups:

- Power
- Natural Gas Storage (Canadian, non-regulated).

Power

Canadian Power

We own or have the rights to approximately 1,100 MW of power supply in Canada, excluding our investment in Bruce Power. In Alberta we own four natural gas-fired cogeneration facilities and exercise a disciplined operating strategy to maximize revenues. Our marketing group sells uncommitted power while also buying and selling power and natural gas to maximize earnings. To reduce commodity price exposure associated with uncontracted power, we sell a portion of this output in forward sales markets when acceptable contract terms are available while the remainder is retained to be sold in the spot market or under short-term forward arrangements. The objective of this strategy is to maintain adequate power supply to fulfill our sales obligations if we have unexpected plant outages and also enables us to capture opportunities to increase earnings in periods of high spot prices. Our two eastern Canadian natural gas-fired cogeneration assets are supported by long-term contracts.

Bruce Power

Bruce Power is a nuclear power generation facility located near Tiverton, Ontario and is comprised of eight nuclear units with a combined capacity of approximately 6,550 MW. Bruce Power leases the facilities from OPG, has no spent fuel risk and will return the facilities to OPG for decommissioning at the end of the lease. We hold a 48.4 per cent ownership interest in Bruce Power.

Results from Bruce Power will fluctuate primarily due to units being offline for the MCR program and the frequency, scope and duration of planned and unplanned maintenance outages. Bruce Power also markets and trades power in Ontario and neighbouring jurisdictions under strict risk controls.

Through a long-term agreement with the IESO, Bruce Power has begun to progress a series of incremental life-extension investments to extend the operating life of the facility to 2064. This agreement represents an extension and material amendment to the earlier agreement that led to the refurbishment of Units 1 and 2 at the site. Under the amended agreement, which took economic effect in January 2016, Bruce Power began investing in life extension activities for Units 3 through 8 to support the long-term refurbishment programs. Investment in the Asset Management program is designed to result in near-term life extensions of each of the six units up to the planned major refurbishment outages and beyond. The Asset Management program includes the one-time refurbishment or replacement of systems, structures or components that are not within the scope of the MCR program which focuses on the actual replacement of the key, life-limiting reactor components. The MCR program is designed to add 30 to 35 years of operational life to each of the six units.

The Unit 6 MCR is the first of the six-unit MCR life extension program. This outage commenced in January 2020 and is expected to be completed on schedule and on budget. The second unit in the MCR program is Unit 3 and the final cost and schedule duration estimate for Unit 3 was submitted to the IESO in December 2021. The Unit 3 MCR is scheduled to proceed in 2023 and has an expected completion in 2026. Investments in the remaining four units' MCR programs are expected to continue through 2033. Future MCR investments will be subject to discrete decisions for each unit with specified off-ramps available for Bruce Power and the IESO. In 2021, Bruce Power launched Project 2030 with a goal of achieving a site peak output of 7,000 MW by 2033 in support of climate change targets and future clean energy needs. Project 2030 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.

As part of the life extension and refurbishment agreement, Bruce Power receives a uniform contract price for all units which includes certain flow-through items such as fuel and lease expense recovery. The contract also provides for payment if the IESO requests a reduction in Bruce Power’s generation to balance the supply of, and demand for, electricity and/or manage other operating conditions of the Ontario power grid. The amount of the reduction is considered deemed generation, for which Bruce Power is paid the contract price.

The contract price is subject to adjustments for the return of and on capital invested at Bruce Power under the Asset Management and MCR programs, along with various other pricing adjustments that allow for a better matching of revenues and costs over the long term. As part of the amended agreement, Bruce Power is also required to share operating cost efficiencies with the IESO for better than planned performance. These efficiencies are reviewed every three years and paid out on a monthly basis over the subsequent three-year period. Approximately $200 million was paid to the IESO from 2019 to 2021 in respect to the operating and cost efficiencies realized in the 2016 to 2018 period, with our share being approximately $100 million. No operating and cost efficiencies were realized for the 2019 to 2021 period.

Bruce Power is a global supplier of Cobalt-60, a medical isotope used in the sterilization of medical equipment and to treat certain types of cancer. Cobalt-60 is produced during Bruce Power's generation of electricity, harvested during certain planned maintenance outages and provided for medical use in the treatment of brain tumours and breast cancer. In addition, Bruce Power continues to advance a project to expand isotope production from its reactors with a focus on Lutetium-177, another medical isotope used in the treatment of prostate cancer and neuroendocrine tumors. This project is being undertaken with a Canadian-based nuclear medicine partnership and the Saugeen Ojibway Nation, on whose traditional territory the Bruce Power facilities are located.

U.S. Power

Our U.S. power and emissions commercial trading and marketing business provides our customers with various physical and financial products with a measured approach to our risk management and a focus on financial discipline, compliance and operational excellence.

Power Purchase Agreements

We have secured approximately 400 MW of wind and solar generation PPAs and associated environmental attributes in Alberta as of December 31, 2021. These PPAs allow us to generate incremental earnings while also contributing to the reduction of our operational GHG intensity and allowing us to offer renewable power products to our customers.

Canadian Natural Gas Storage

We own and operate 118 Bcf of non-regulated natural gas storage capacity in Alberta. This business operates independently from our regulated natural gas transmission and U.S. storage businesses.

Our Canadian natural gas storage business helps balance seasonal and short-term supply and demand while also adding flexibility to the delivery of natural gas to markets in Alberta and the rest of North America. Market volatility creates arbitrage opportunities and our natural gas storage facilities also give us and our customers the ability to capture value from short-term price movements. The natural gas storage business is affected by changes in seasonal natural gas price spreads which are generally determined by the differential in natural gas prices between the traditional summer injection and winter withdrawal seasons. In addition, the business may be affected by pipeline restrictions in Alberta which limit the ability to capture price differentials.

Our natural gas storage business contracts with third parties, typically participants in the Alberta and interconnected gas markets, for a fixed fee to provide natural gas storage services on a short, medium and/or long-term basis.

We also enter into proprietary natural gas storage transactions which include a forward purchase of our own natural gas to be injected into storage and a simultaneous forward sale of natural gas for withdrawal at a later period, typically during the winter withdrawal season. By matching purchase and sales volumes on a back-to-back basis, we lock in future positive margins, effectively eliminating our exposure to changes in natural gas prices for these transactions.

SIGNIFICANT EVENTS

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

In mid-2021, as part of the planned inspections, testing, analysis and maintenance activities at Bruce Power during the current Unit 6 MCR outage and the 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. These inspections were added to the Unit 7 planned outage which returned to service on January 23, 2022.

Bruce Power Life Extension

The Unit 6 MCR program continues on schedule and on budget; however, COVID-19 may have an impact on cost and schedule contingency. As applicable, Bruce Power will seek recovery of any impacts in accordance with the force majeure provisions of the IESO contract. The program is nearing the end of the Inspection Phase and has entered the Installation Phase. Preparation of the Unit 3 MCR program, which is the next scheduled MCR outage, continues and Bruce Power submitted its final cost and schedule duration estimate to the IESO in December 2021. As well, Bruce Power submitted its initial preliminary cost and schedule duration estimate for the Unit 4 MCR program, which is the next unit scheduled after Unit 3.

Bruce Power Uprate Initiative

In 2021, Bruce Power launched Project 2030 with the goal of achieving a site peak output of 7,000 MW by 2033 in support of climate change targets and future clean energy needs. Project 2030 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 continue to progress the development of the Ontario Pumped Storage project, an energy storage facility located near Meaford, Ontario that would provide 1,000 MW of flexible, clean energy to Ontario's electricity system using a process known as pumped hydro storage.

Two key milestones on the Ontario Pumped Storage project were reached in 2021. On July 28, 2021, the Federal Minister of National Defence granted long-term land access to the fourth Canadian Division Training Centre for development of the project on this site. On November 11, 2021, Ontario’s Minister of Energy instructed the IESO to progress the project to Gate 2 of the Unsolicited Proposals Process. Once in service, this project will store emission-free energy when available and provide it to Ontario during periods of peak demand, thereby maximizing the value of existing emissions-free generation in the province.

We also continue to consult with the Saugeen Ojibway Nation and other Indigenous groups 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 Request for Information

Through an RFI process in 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 the U.S. portion of the Keystone Pipeline System assets. We also identified meaningful origination opportunities to supply renewable energy products and services to industrial and oil and gas sectors proximate to our in-corridor demand. We received a significant number of responses to our RFI and are currently evaluating proposals and expect to finalize contracts during the first half of 2022.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure). Refer to page 11 for more information on non-GAAP measures we use.

year ended December 31 (millions of $)	2021	2020	2019
Bruce Power[1]	**411**	439	527
Canadian Power[2]	**253**	213	285
Natural Gas Storage and other	**19**	25	20
Comparable EBITDA	**683**	677	832
Depreciation and amortization	**(78)**	(67)	(95)
Comparable EBIT	**605**	610	737
Specific items:			
Gain/(loss) on sale of Ontario natural gas-fired power plants	**17**	(414)	(279)
Gain on sale of Coolidge generating station	**—**	—	68
U.S. Northeast power marketing contracts	**—**	—	(8)
Risk management activities	**6**	(15)	(63)
Segmented earnings	**628**	181	455

1 Includes our share of equity income from Bruce Power.
2 Includes our Ontario natural gas-fired power plants until sold in April 2020 and Coolidge generating station until sold in May 2019.

Power and Storage segmented earnings increased by $447 million in 2021 compared to 2020 and decreased by $274 million in 2020 compared to 2019 and included the following specific items which have been excluded from our calculation of comparable EBIT and comparable earnings:

- a $17 million pre-tax recovery of certain costs from the IESO in 2021 associated with the Ontario natural gas-fired power plants sold in April 2020 (pre-tax loss 2020 – $414 million; 2019 – $279 million)
- a pre-tax gain of $68 million related to the sale of the Coolidge generating station in May 2019
- a pre-tax loss in 2019 of $8 million related to our remaining U.S. Northeast power marketing contracts which were sold in May 2019
- unrealized gains and losses from changes in the fair value of derivatives used to reduce our exposure to certain commodity price risks.

Comparable EBITDA for Power and Storage increased by $6 million in 2021 compared to 2020 primarily due to the net effect of:

- increased Canadian Power earnings primarily due to higher realized margins in 2021, contributions from trading activities and a full of year of 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
- decreased Bruce Power contribution as a result of increased operating expenses and lower volumes resulting from greater planned outage days, partially offset by higher realized prices and gains on funds invested for post-retirement benefits as well as lower financial charges. Additional financial and operating information on Bruce Power is provided below
- decreased Natural Gas Storage and other earnings as a result of increased business development activities across the segment, partially offset by higher realized Alberta natural gas storage spreads in 2021.

Comparable EBITDA for Power and Storage decreased by $155 million in 2020 compared to 2019 primarily due to the net effect of:

- the planned removal from service of Bruce Power Unit 6 in January 2020 for its MCR program, partially offset by fewer planned and unplanned outage days on the remaining units as well as the effects of a higher realized power price. Additional financial and operating information on Bruce Power is provided below
- lower Canadian Power earnings largely as a result of the sale of our Ontario natural gas-fired power plants in April 2020. In addition, we sold our Coolidge generating station in May 2019.

Depreciation and amortization

Depreciation and amortization increased by $11 million in 2021 compared to 2020 primarily due to incremental TC Turbines depreciation following the November 2020 acquisition of the remaining 50 per cent ownership interest as well as other adjustments in 2020. Depreciation was $28 million lower in 2020 compared to 2019 primarily due to the cessation of depreciation on our Halton Hills power plant in July 2019.

Bruce Power results

Bruce Power results reflect our proportionate share. Comparable EBITDA and comparable EBIT are non-GAAP measures. Refer to page 11 for more information on non-GAAP measures we use. The following is our proportionate share of the components of comparable EBITDA and comparable EBIT.

year ended December 31 (millions of $, unless otherwise noted)	**2021**	**2020**	**2019**
Equity income included in comparable EBITDA and EBIT comprised of:			
Revenues[1]	**1,656**	1,681	1,746
Operating expenses	**(922)**	(884)	(883)
Depreciation and other	**(323)**	(358)	(336)
Comparable EBITDA and EBIT[2]	**411**	439	527
Bruce Power – other information			
Plant availability[3,4]	**86%**	88%	84%
Planned outage days[4]	**321**	276	393
Unplanned outage days	**22**	36	58
Sales volumes (GWh)[2]	**20,542**	20,956	22,669
Realized power price per MWh[5]	**$80**	$80	$76

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.

Plant availability in 2021, excluding the Unit 6 MCR, was 86 per cent as planned maintenance on Units 1 and 3 was completed in 2021 while planned maintenance on Unit 7 commenced in fourth quarter 2021 and returned to service on January 23, 2022.

Excluding the Unit 6 MCR which commenced in January 2020, plant availability in 2020 was 88 per cent as planned maintenance was completed on Units 3, 4, 5 and 8. Plant availability in 2019 was 84 per cent as planned maintenance was completed on Units 2, 3, 5 and 7.

OUTLOOK

Comparable EBITDA

Power and Storage comparable EBITDA in 2022 is expected to be generally consistent with 2021. Bruce Power equity income in 2022 is expected to be similar to 2021 as the impact of its contract price increase for the Unit 3 MCR program is expected to be offset by greater non-MCR planned outage days and operating costs in 2022. Planned maintenance is currently scheduled for Units 1 to 5 in the first half of 2022 and for Unit 4 in the second half of 2022 while the planned outage on Unit 7, which began in fourth quarter 2021, was completed on January 23, 2022. The average 2022 plant availability percentage, excluding Unit 6 which continues its MCR program, is expected to be in the low-80 per cent range.

Capital spending

We invested $0.8 billion in 2021 for our share of Bruce Power's life extension and other maintenance capital projects across the segment and expect to invest approximately $0.9 billion in 2022.

BUSINESS RISKS

The following are risks specific to our Power and Storage business. Refer to page 93 for information about general risks related to TC Energy as a whole, including other operational, safety and financial risks. The Power and Storage marketing business complies with our risk management policies which are described in the Other information – Enterprise risk management section.

Fluctuating power and natural gas market prices

Much of the physical power generation and fuel used in our Alberta power operations is currently exposed to commodity price volatility. These exposures are partially mitigated through long-term contracts and hedging activities including selling and purchasing power and natural gas in forward markets. As contracts expire, new contracts are entered into at prevailing market prices.

Our two eastern Canadian natural gas-fired assets are fully contracted and not materially impacted by fluctuating spot power and natural gas prices. As the contracts on these assets expire it is uncertain if we will be able to re-contract on similar terms and may face future commodity exposure.

Our natural gas storage business is subject to fluctuating seasonal natural gas price spreads which are generally determined by the differential in natural gas prices between the traditional summer injection and winter withdrawal seasons. In addition, the business may be affected by pipeline restrictions in Alberta which limit the ability to capture price differentials.

Plant availability

Operating our plants to ensure services are provided safely and reliably as well as optimizing and maintaining their availability are essential to the continued success of our power and storage business. Unexpected outages or extended planned outages at our power plants can increase maintenance costs, lower plant output and sales revenues and lower capacity payments and margins. We may also have to buy power or natural gas on the spot market to meet our delivery obligations. We manage this risk by investing in a highly skilled workforce, operating prudently, running comprehensive risk-based preventive maintenance programs and making effective capital investments.

Regulatory

We operate in both regulated and deregulated power markets in both Canada and the United States. These markets are subject to various federal, provincial and state regulations. As power markets evolve, there is the potential for regulatory bodies to implement new rules that could negatively affect us as a generator and marketer of electricity. These may be in the form of market rule or market design changes, changes in the interpretation and application of market rules by regulators, price caps, emission controls, emissions costs, cost allocations to generators and out-of-market actions taken by others to build excess generation, all of which may negatively affect the price of power. In addition, our development projects rely on an orderly permitting process and any disruption to that process can have negative effects on project schedules and costs. We are an active participant in formal and informal regulatory proceedings and take legal action where required.

Compliance

Market rules, regulations and operating standards apply to our power business based on the jurisdictions in which they operate. Our trading and marketing activities may be subject to fair competition and market conduct requirements as well as specific rules that apply to physical and financial transactions in deregulated markets. Similarly, our generators may be subject to specific operating and technical standards relating to maintenance activities, generator availability and delivery of power and power-related products. While significant efforts are made to ensure we comply with all applicable statutory requirements, situations including unforeseen operational challenges, lack of rule clarity, and the ambiguous and unpredictable application of requirements by regulators and market monitors occasionally arise and create compliance risk. Deemed contravention of these requirements may result in mandatory mitigation activities, monetary penalties, imposition of operational limitations, or even prosecution.

Weather

Significant changes in temperature and weather, including the potential impacts of climate change, have many effects on our business, ranging from the impact on demand, availability and commodity prices, to efficiency and output capability. Extreme temperature and weather can affect market demand for power and natural gas and can lead to significant price volatility. Extreme weather can also restrict the availability of natural gas and power if demand is higher than supply. Seasonal changes in temperature can reduce the efficiency and production of our natural gas-fired power plants.

Competition

We face various competitive forces that impact our existing assets and prospects for growth. For instance, our existing power plants will compete over time with new power capacity. New supply could come in several forms including supply that employs more efficient power generation technologies or additional supply from regional power transmission interconnections. We also face competition from other power companies in Alberta and Ontario as well as in the development of greenfield power plants. Traditional and non-traditional players are entering the growing low-carbon economy in North America and, as a result, we face competition in building low-carbon platforms with energy and financial options to provide customer-driven solutions for energy transition.

Corporate

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, we continue to observe some slowdown on certain of our construction activities and capital expenditures. 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 described within the different business segment sections.

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 sections.

SIGNIFICANT EVENTS

Alberta Carbon Grid

On June 17, 2021, we announced a partnership with Pembina Pipeline Corporation to jointly develop a world-scale carbon transportation and sequestration system which, when fully constructed, will be capable of transporting more than 20 million tonnes of carbon dioxide annually, thereby providing opportunities to retrofit existing assets and reduce our carbon footprint. By leveraging existing pipelines and a newly developed sequestration hub, the 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. We are also pursuing opportunities to leverage our existing systems in support of hydrogen production and transportation.

Irving Oil Decarbonization

On August 12, 2021, we signed an MOU to explore the joint development of a series of proposed energy projects focused on reducing GHG emissions and creating new economic opportunities in New Brunswick and Atlantic Canada. Together with Irving Oil, we have identified a series of potential projects focused on decarbonizing existing assets and deploying emerging technologies to reduce overall emissions over the medium and long term. The partnership's initial focus will consider a suite of upgrade projects at Irving Oil's refinery in Saint John, New Brunswick, with the goal of significantly reducing emissions through the production and use of low-carbon power generation.

Hydrogen Hubs

We have entered into two JDAs, to support customer-driven hydrogen production for long-haul transportation, power generation, large industrials and heating customers across the United States and Canada. The first opportunity is a partnership with Nikola Corporation, a designer and manufacturer of zero-emission battery-electric and hydrogen-electric vehicles and related equipment, where Nikola will be a long-term anchor customer for hydrogen production infrastructure supporting hydrogen fueled zero-emission heavy-duty trucks. The JDA with Nikola supports co-development of large-scale green and blue hydrogen production hubs, utilizing our power and natural gas infrastructure.

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

Voluntary Retirement Program

In mid-2021, we offered a one-time VRP to eligible employees. Participants in the program retired by December 31, 2021 and received a transition payment in addition to existing retirement benefits. In 2021, we expensed a total of $81 million before income tax, mainly related to the VRP transition payments, which was included in Plant operating costs and other. Of the total program costs, $63 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.

Acquisition of Common Units 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 22, Common shares, of our 2021 Consolidated financial statements for additional information.

FINANCIAL RESULTS

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). Refer to page 11 for more information on non-GAAP measures we use.

year ended December 31 (millions of $)	**2021**	**2020**	**2019**
Comparable EBITDA and EBIT	**(24)**	(16)	(17)
Specific items:			
Voluntary Retirement Program	**(63)**	—	—
Foreign exchange gains/(losses) – inter-affiliate loans[1]	**41**	86	(53)
Segmented (losses)/earnings	**(46)**	70	(70)

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

Corporate segmented losses in 2021 increased by $116 million from segmented earnings of $70 million in 2020 to segmented losses of $46 million in 2021. Segmented earnings increased by $140 million in 2020 compared to segmented losses of $70 million in 2019.

Corporate segmented (losses)/earnings included 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 Corporate – Significant events section for additional information on the VRP and Other Information – Related party transactions section for additional information on our peso-denominated inter-affiliate loans.

Comparable EBITDA and EBIT for Corporate decreased by $8 million in 2021 compared to 2020. The decrease was primarily due to a U.S. capital tax adjustment recorded in 2020. Comparable EBITDA for Corporate in 2020 was consistent with 2019.

OTHER INCOME STATEMENT ITEMS

Interest expense

year ended December 31 (millions of $)	2021	2020	2019
Interest on long-term debt and junior subordinated notes			
Canadian dollar-denominated	**(712)**	(685)	(598)
U.S. dollar-denominated	**(1,259)**	(1,302)	(1,326)
Foreign exchange impact	**(320)**	(446)	(434)
	(2,291)	(2,433)	(2,358)
Other interest and amortization expense	**(85)**	(89)	(161)
Capitalized interest	**22**	294	186
Interest expense included in comparable earnings	**(2,354)**	(2,228)	(2,333)
Specific item:			
Keystone XL preservation and other	**(6)**	—	—
Interest expense	**(2,360)**	(2,228)	(2,333)

Interest expense in 2021 increased by $132 million compared to 2020 and included $6 million related to the Keystone XL project-level credit facility for the period following the revocation of the Presidential Permit for the Keystone XL pipeline project. This has been removed from our calculation of interest expense included in comparable earnings.

Interest expense included in comparable earnings in 2021 increased by $126 million compared to 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 on January 20, 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 2020 and the completion of the Napanee power plant in 2020
- the foreign exchange impact from a weaker U.S. dollar on translation of U.S. dollar-denominated interest
- lower interest rates on reduced levels of short-term borrowings
- long-term debt and junior subordinated note issuances, net of maturities. Refer to the Financial condition section for additional information on long-term debt and junior subordinated notes.

Interest expense included in comparable earnings in 2020 decreased by $105 million compared to 2019 mainly due to the net effect of:

- higher capitalized interest largely related to Keystone XL and Coastal GasLink prior to its change to equity accounting upon the sale of a 65 per cent interest in the project in May 2020, partially offset by lower capitalized interest due to the completion of Napanee construction in 2020. The increase of capitalized interest for Keystone XL was largely the result of additional capital expenditures along with the inclusion of previously impaired capital costs in the basis for calculating capitalized interest following the decision to proceed with construction of the pipeline. These legacy costs were not re-capitalized but were included for determining capitalized interest in accordance with GAAP
- lower interest rates on reduced levels of short-term borrowings
- long-term debt issuances, net of maturities
- foreign exchange impact from a stronger U.S. dollar on translation of U.S. dollar-denominated interest.

Allowance for funds used during construction

year ended December 31 (millions of $)	2021	2020	2019
Allowance for funds used during construction			
Canadian dollar-denominated	**140**	106	203
U.S. dollar-denominated	**101**	182	205
Foreign exchange impact	**26**	61	67
Allowance for funds used during construction	**267**	349	475

AFUDC decreased by $82 million in 2021 compared to 2020. The increase in Canadian dollar-denominated AFUDC is primarily related to a higher balance of NGTL System expansion projects under construction. The decrease in U.S. dollar-denominated AFUDC is mainly the result of the suspension of recording AFUDC on the Villa de Reyes project effective January 1, 2021 due to ongoing delays and the Columbia Gas BXP project which went into service on January 1, 2021, partially offset by the impact of increased capital expenditures on our U.S. natural gas pipeline projects.

AFUDC decreased by $126 million in 2020 compared to 2019. The lower Canadian dollar-denominated AFUDC in 2020 was mainly due to NGTL System expansion projects placed in service. The decrease in U.S. dollar-denominated AFUDC was primarily the result of the suspension of recording AFUDC on Tula, effective January 1, 2020, due to ongoing construction delays, partially offset by continuing construction of the Villa de Reyes project.

Interest income and other

year ended December 31 (millions of $)	2021	2020	2019
Interest income and other included in comparable earnings	**444**	173	162
Specific items:			
Foreign exchange (losses)/gains – inter-affiliate loan	**(41)**	(86)	53
Risk management activities	**(203)**	126	245
Interest income and other	**200**	213	460

Interest income and other decreased by $13 million in 2021 compared to 2020 and by $247 million in 2020 compared to 2019 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 gains and losses 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 gains and losses 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 Other Information – Related party transactions for additional information.

Interest income and other included in comparable earnings increased by $271 million in 2021 compared to 2020 primarily due to the net effect of:

- 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
- lower interest income in 2021 related to the peso-denominated inter-affiliate loan receivable from the Sur de Texas joint venture due to lower interest rates and the foreign exchange impact of a weaker peso on the translation of interest income during the year.

Interest income and other included in comparable earnings increased by $11 million in 2020 compared to 2019 due to the net effect of:

- lower realized losses in 2020 compared to 2019 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- lower interest income in 2020 related to the peso-denominated inter-affiliate loan receivable from the Sur de Texas joint venture due to lower interest rates and the foreign exchange impact of a weaker peso on the translation of interest income during the year.

Income tax expense

year ended December 31 (millions of $)	2021	2020	2019
Income tax expense included in comparable earnings	**(833)**	(654)	(898)
Specific items:			
Keystone XL asset impairment charge and other	**641**	—	—
Voluntary Retirement Program	**15**	—	—
Keystone XL preservation and other	**12**	—	—
Sale of Northern Courier	**6**	—	46
Sale of Ontario natural gas-fired power plants	**(10)**	131	85
Income tax valuation allowance releases	**—**	299	195
Partial sale of Coastal GasLink LP	**—**	38	—
Sale of Columbia Midstream assets	**—**	18	(173)
Alberta corporate income tax rate reduction	**—**	—	32
U.S. Northeast power marketing contracts	**—**	—	2
Sale of Coolidge generating station	**—**	—	(14)
Risk management activities	**49**	(26)	(29)
Income tax expense	**(120)**	(194)	(754)

Income tax expense in 2021 decreased by $74 million compared to 2020 and decreased by $560 million in 2020 compared to 2019 and included the specific items noted below which have been removed from our calculation of Income tax expense included in comparable earnings.

In addition, some of the income tax impacts noted in the table above relate to specific items referenced elsewhere in this MD&A. In 2021, all specific items are discussed in their respective business segment disclosure as they did not relate to income tax specific items.

Specific items in 2020:

- income tax valuation allowance releases of $299 million primarily related to the reassessment of deferred tax assets that were deemed more likely than not to be realized as a result of our March 31, 2020 decision to proceed with the Keystone XL pipeline project
- an $18 million income tax recovery related to state income taxes on the sale of certain Columbia Midstream assets.

Specific items in 2019:

- 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 tax assets that are more likely than not to be realized
- a $32 million income tax recovery on deferred tax balances attributable to our Canadian businesses not subject to RRA due to an Alberta corporate income tax rate reduction enacted in June 2019.

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 in 2021 increased by $179 million compared to 2020 primarily due to higher flow-through income taxes on Canadian rate-regulated pipelines, increased earnings subject to income tax and the impact of Mexico inflationary adjustments, partially offset by higher foreign tax rate differentials.

Income tax expense included in comparable earnings in 2020 decreased by $244 million compared to 2019 primarily due to lower flow-through income taxes on Canadian rate-regulated pipelines and higher foreign tax rate differentials.

Net income attributable to non-controlling interests

year ended December 31 (millions of $)	2021	2020	2019
Net income attributable to non-controlling interests	**(91)**	(297)	(293)

Net income attributable to non-controlling interests decreased by $206 million in 2021 compared to 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 Corporate – Significant events section and Note 21, Non-controlling interests, of our 2021 Consolidated financial statements for additional information.

In 2020, Net income attributable to non-controlling interests increased by $4 million compared to 2019 primarily due to higher earnings in TC PipeLines, LP, partially offset by the net loss attributable to redeemable non-controlling interest which includes a foreign currency translation loss and return accrual in 2020.

Preferred share dividends

year ended December 31 (millions of $)	2021	2020	2019
Preferred share dividends	**(140)**	(159)	(164)

Preferred share dividends decreased by $19 million in 2021 compared to 2020 primarily due to the redemption of all issued and outstanding Series 13 preferred shares on May 31, 2021. Preferred share dividends of $159 million in 2020 were generally consistent with 2019.

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. More information on how our credit ratings can impact our financing costs, liquidity and operations is available in our Annual Information Form available on SEDAR (www.sedar.com).

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.

Balance sheet analysis

At December 31, 2021, our current assets totaled $7.4 billion and current liabilities amounted to $13.0 billion, leaving us with a working capital deficit of $5.6 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 $5.0 billion of short-term borrowing capacity remains available, net of $5.0 billion backstopping outstanding commercial paper balances. We also have arrangements in place for a further $2.4 billion of demand credit facilities of which $1.2 billion remains available as of December 31, 2021
- our access to capital markets, including through securities issuances, incremental credit facilities, portfolio management activities, DRP and Corporate ATM programs, if deemed appropriate.

Our total assets at December 31, 2021 were $104.2 billion compared to $100.3 billion at December 31, 2020 with the increase primarily reflecting our 2021 capital spending program, working capital and equity investments, partially offset by depreciation, the Keystone XL asset impairment and the impact of a weaker U.S. dollar at December 31, 2021 compared to December 31, 2020 on translation of our U.S. dollar-denominated assets.

At December 31, 2021 our total liabilities were $70.8 billion, compared to $66.8 billion at December 31, 2020 due to the net effect of movements in debt, working capital and foreign exchange rates as discussed above.

Our equity at December 31, 2021 was $33.4 billion, consistent with $33.1 billion at December 31, 2020.

Consolidated capital structure

The following table summarizes the components of our capital structure.

at December 31 (millions of $, unless otherwise noted)	**2021**	**Per cent of total**	**2020**	**Per cent of total**
Notes payable	**5,166**	**6**	4,176	5
Redeemable non-controlling interest[1]	**—**	**—**	633	1
Long-term debt, including current portion	**38,661**	**45**	36,885	45
Cash and cash equivalents	**(673)**	**(1)**	(1,530)	(2)
	43,154	**50**	40,164	49
Junior subordinated notes	**8,939**	**11**	8,498	10
Redeemable non-controlling interest	**—**	**—**	393	1
Preferred shares	**3,487**	**4**	3,980	5
Common shareholders' equity	**29,784**	**35**	27,418	33
Non-controlling interests	**125**	**—**	1,682	2
	85,489	**100**	82,135	100

1 Classified in Current liabilities on the Consolidated balance sheet.

At February 9, 2022, we had unused capacity of $3.0 billion, $1.5 billion, US$4.0 billion and $1.5 billion under our TC Energy equity, TCPL Canadian and U.S. debt and TC Trust hybrid shelf prospectuses, respectively, to facilitate future access to capital markets.

Provisions of various trust indentures and credit arrangements with certain of our subsidiaries can restrict those subsidiaries' and, in certain cases, our ability to declare and pay dividends or make distributions under certain circumstances. In the opinion of management, these provisions do not currently restrict our ability to declare or pay dividends. These trust indentures and credit arrangements also require us to comply with various affirmative and negative covenants and maintain certain financial ratios. We were in compliance with all of our financial covenants at December 31, 2021.

Cash flows

The following tables summarize our consolidated cash flows.

year ended December 31 (millions of $)	**2021**	**2020**	**2019**
Net cash provided by operations	**6,890**	7,058	7,082
Net cash used in investing activities	**(7,712)**	(6,052)	(6,872)
Net cash (used in)/provided by financing activities	**(88)**	(800)	693
	(910)	206	903
Effect of foreign exchange rate changes on cash and cash equivalents	**53**	(19)	(6)
(Decrease)/increase in cash and cash equivalents	**(857)**	187	897

Cash provided by operating activities

year ended December 31 (millions of $)	**2021**	**2020**	**2019**
Net cash provided by operations	**6,890**	7,058	7,082
Increase/(decrease) in operating working capital	**287**	327	(293)
Funds generated from operations	**7,177**	7,385	6,789
Specific items:			
Current income tax expense on Keystone XL asset impairment charge, preservation and other	**131**	—	—
Keystone XL preservation and other	**49**	—	—
Voluntary Retirement Program	**63**	—	—
Current income tax recovery on Voluntary Retirement Program	**(14)**	—	—
Current income tax expense on sale of Columbia Midstream assets	**—**	—	320
U.S. Northeast power marketing contracts	**—**	—	8
Comparable funds generated from operations	**7,406**	7,385	7,117

Net cash provided by operations

Net cash provided by operations decreased by $168 million in 2021 compared to 2020 primarily due to lower funds generated from operations, partially offset by the amount and timing of working capital changes.

Net cash provided by operations decreased by $24 million in 2020 compared to 2019 primarily due to the amount and timing of working capital changes which was mostly offset by higher funds generated from operations.

Comparable funds generated from operations

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

Comparable funds generated from operations increased by $21 million in 2021 compared to 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 was partially offset by fees collected in 2020 associated with the construction of the Sur de Texas pipeline, as well as lower distributions from the operating activities of our equity investments in 2021.

Comparable funds generated from operations increased by $268 million in 2020 compared to 2019 primarily due to collection of fees related to the construction of Sur de Texas and Coastal GasLink, the recovery of higher depreciation on the NGTL System and higher comparable earnings, partially offset by lower distributions from the operating activities of our equity investments.

Cash used in investing activities

year ended December 31 (millions of $)	**2021**	**2020**	**2019**
Capital spending			
Capital expenditures	**(5,924)**	(8,013)	(7,475)
Capital projects in development	**—**	(122)	(707)
Contributions to equity investments	**(1,210)**	(765)	(602)
	(7,134)	(8,900)	(8,784)
Proceeds from sales of assets, net of transaction costs	**35**	3,407	2,398
Loan to affiliate	**(239)**	—	—
Acquisition	**—**	(88)	—
Other distributions from equity investments	**73**	—	186
Payment for unredeemed shares of Columbia Pipeline Group, Inc.	**—**	—	(373)
Deferred amounts and other	**(447)**	(471)	(299)
Net cash used in investing activities	**(7,712)**	(6,052)	(6,872)

Net cash used in investing activities increased from $6.1 billion in 2020 to $7.7 billion in 2021 largely as a result of proceeds received from the sale of assets in 2020, as discussed below, as well as higher contributions to equity investments and a loan issued to one of our affiliates in 2021, partially offset by lower capital spending in 2021.

Net cash used in investing activities decreased from $6.9 billion in 2019 to $6.1 billion in 2020 primarily as a result of proceeds received in 2020 on the sales of our Ontario natural gas-fired power plants and a 65 per cent equity interest in Coastal GasLink LP as well as the payment to dissenting Columbia Pipeline Group, Inc. (Columbia) shareholders in 2019. This was partially offset by the cost to acquire the remaining 50 per cent ownership interest in TC Turbines.

Capital spending[1]

The following table summarizes capital spending by segment.

year ended December 31 (millions of $)	2021	2020	2019
Canadian Natural Gas Pipelines	**2,737**	3,608	3,906
U.S. Natural Gas Pipelines	**2,820**	2,785	2,516
Mexico Natural Gas Pipelines	**129**	173	357
Liquids Pipelines	**571**	1,442	954
Power and Storage	**842**	834	1,019
Corporate	**35**	58	32
	7,134	8,900	8,784

1 Capital spending includes Capital expenditures, Capital projects in development and Contributions to equity investments. Refer to Note 4, Segmented information, of our 2021 Consolidated financial statements for the financial statement line items that comprise total capital spending.

Capital expenditures

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.

Capital projects in development

Costs incurred during 2020 and 2019 on Capital projects in development were predominantly attributable to spending on Keystone XL. The decrease in development spending in 2020 compared to 2019 is due to project costs being reflected in Capital expenditures subsequent to our March 31, 2020 decision to proceed with construction.

Contributions to equity investments

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

Contributions to equity investments increased in 2020 compared to 2019 mainly due to higher investment in Bruce Power and our investment in Coastal GasLink LP subsequent to its reclassification to an equity investment.

Contributions to equity investments in 2019 include our proportionate share of Sur de Texas debt financing.

Proceeds from sales of assets

In 2021, we completed the sale of our remaining 15 per cent equity interest in Northern Courier for gross proceeds of $35 million.

In 2020, we completed the following portfolio management transactions. All cash proceeds amounts are prior to income tax and post-closing adjustments:

- the sale of our Ontario natural gas-fired power plant assets for net proceeds of approximately $2.8 billion
- the sale of a 65 per cent equity interest in Coastal GasLink LP for net proceeds of $656 million.

In addition to the proceeds from the above transactions, in 2020, we received $1.5 billion from the initial draw by Coastal GasLink LP on the project-level financing which preceded the equity sale.

In 2019, we completed the following portfolio management transactions. All cash proceeds amounts are prior to income tax and post-closing adjustments:

- the sale of certain Columbia Midstream assets for proceeds of approximately US$1.3 billion
- the sale of the Coolidge generating station for proceeds of US$448 million
- the sale of an 85 per cent equity interest in Northern Courier for proceeds of $144 million.

In addition to the proceeds from the above transactions, in 2019, we received a $1.0 billion distribution from the Northern Courier debt issuance which preceded the equity sale.

Acquisition

On November 13, 2020, we acquired the remaining 50 per cent ownership interest in TC Turbines for cash consideration of US$67 million.

Other distributions from equity investments

Other distributions from equity investments relate to our proportionate share of the Sur de Texas debt repayments in 2021 along with 2019 distributions received from Bruce Power and Northern Border financings undertaken to fund their respective capital programs and to also make distributions to their partners. In 2021, we received distributions of $73 million from Sur de Texas in relation to the repayment on our 60 per cent proportionate share of long-term debt financing to the joint venture. In 2019, we received distributions of $120 million from Bruce Power in connection with their issuance of senior notes in the capital markets, as well as $66 million from Northern Border originating from a draw on its revolving credit facility to manage capitalization levels.

Cash (used in) / provided by financing activities

year ended December 31 (millions of $)	2021	2020	2019
Notes payable issued/(repaid), net	**1,003**	(220)	1,656
Long-term debt issued, net of issue costs	**10,730**	5,770	3,024
Long-term debt repaid	**(7,758)**	(3,977)	(3,502)
Junior subordinated notes issued, net of issue costs	**495**	—	1,436
Loss on settlement of financial instruments	**(10)**	(130)	—
Redeemable non-controlling interest repurchased	**(633)**	—	—
Contributions from redeemable non-controlling interest	**—**	1,033	—
Dividends and distributions paid	**(3,548)**	(3,367)	(2,174)
Common shares issued, net of issue costs	**148**	91	253
Preferred shares redeemed	**(500)**	—	—
Acquisition of TC PipeLines, LP transaction costs	**(15)**	—	—
Net cash (used in)/provided by financing activities	**(88)**	(800)	693

Net cash used in financing activities decreased by $0.7 billion in 2021 compared to 2020 primarily due to higher net issuances of long-term debt and notes payable along with the 2021 issuance of junior subordinated notes, partially offset by contributions received in 2020 in support of Keystone XL construction in the form of a redeemable non-controlling interest as well as the 2021 subsequent repurchase of the redeemable non-controlling interest in addition to the preferred shares redemption.

Net cash provided by financing activities decreased by $1.5 billion in 2020 compared to 2019 primarily due to the net repayment of notes payable in 2020, the issuance of junior subordinated notes in 2019 and higher cash dividends and distributions paid in 2020 as DRP participation was no longer satisfied through the issuance of common shares from treasury at a discount. This was partially offset by higher issuances of long-term debt and contributions in support of Keystone XL construction in the form of a redeemable non-controlling interest.

The principal transactions reflected in our financing activities are discussed in further detail below.

Long-term debt issued

The following table outlines significant long-term debt issuances in 2021:

(millions of Canadian $, unless otherwise noted) Company	Issue date	Type	Maturity date	Amount	Interest rate
TRANSCANADA PIPELINES LIMITED					
	October 2021	Senior Unsecured Notes	October 2024	US 1,250	1.00%
	October 2021	Senior Unsecured Notes	October 2031	US 1,000	2.50%
	June 2021	Medium Term Notes	June 2024	750	Floating
	June 2021	Medium Term Notes	June 2031	500	2.97%
	June 2021	Medium Term Notes	September 2047	250	4.33%
KEYSTONE XL SUBSIDIARIES[1]					
	Various	Project-Level Credit Facility	June 2021	US 849	Floating
COLUMBIA PIPELINE GROUP, INC.[2]					
	January 2021	Unsecured Term Loan	June 2022	US 4,040	Floating

1 On January 4, 2021, we established a US$4.1 billion project-level credit facility to support the construction of the Keystone XL pipeline, which was fully guaranteed by the Government of Alberta and non-recourse to TC Energy. The availability of this credit facility was subsequently reduced to US$1.6 billion and all amounts outstanding were fully repaid by the Government of Alberta in June 2021.

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

The net proceeds of the above TCPL debt issuances were used for general corporate purposes, to fund our capital program and to repay existing debt.

Long-term debt retired/repaid

The following table outlines significant long-term debt repaid in 2021:

(millions of Canadian $, unless otherwise noted) Company	Retirement/ repayment date	Type	Amount	Interest rate
TRANSCANADA PIPELINES LIMITED				
	November 2021	Medium Term Notes	500	3.65%
	January 2021	Debentures	US 400	9.875%
COLUMBIA PIPELINE GROUP, INC.				
	December 2021	Unsecured Term Loan	US 4,040	Floating
TC PIPELINES, LP				
	November 2021	Unsecured Term Loan	US 450	Floating
	March 2021	Senior Unsecured Notes	US 350	4.65%
ANR PIPELINE COMPANY				
	November 2021	Senior Unsecured Notes	US 300	9.625%
KEYSTONE XL SUBSIDIARIES[1]				
	June 2021	Project-Level Credit Facility	US 849	Floating

1 In June 2021, in accordance with the terms of the guarantee, the Government of Alberta repaid the US$849 million outstanding balance under the Keystone XL project-level credit facility bearing interest at a floating rate, and it was subsequently terminated, resulting in no cash impact to TC Energy.

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

Junior subordinated notes issued

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

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

For more information about long-term debt and junior subordinated notes issued and long-term debt repaid in 2021, 2020 and 2019, refer to the notes to our 2021 Consolidated financial statements.

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.

Dividend reinvestment plan

Under the DRP, eligible holders of common and preferred shares of TC Energy can reinvest their dividends and make optional cash payments to obtain additional TC Energy common shares. Commencing with the dividends declared October 31, 2019, common shares purchased under TC Energy's DRP are acquired on the open market at 100 per cent of the weighted average purchase price. From January 1, 2019 to October 31, 2019, common shares under the DRP were issued from treasury at a discount of two per cent to market prices over a specified period.

TC Energy Corporate ATM program

In December 2020, we established a new ATM program that allows us to issue common shares from treasury having an aggregate gross sales price of up to $1.0 billion, or the U.S. dollar equivalent, to the public from time to time, at our discretion, at the prevailing market price when sold through the TSX, the NYSE, or any other applicable existing trading market for TC Energy common shares in Canada or the U.S. While not a component of our base funding plan, the ATM program, which is effective for a 25-month period, provides additional financial flexibility in support of our consolidated credit metrics and capital program and may be activated if, and as, deemed appropriate. No common shares were issued under the program in 2021 or 2020.

Share information

as at February 9, 2022		
Common Shares	**issued and outstanding**	
	981 million	
Preferred Shares	**issued and outstanding**	**convertible to**
Series 1	14.6 million	Series 2 preferred shares
Series 2	7.4 million	Series 1 preferred shares
Series 3	10 million	Series 4 preferred shares
Series 4	4 million	Series 3 preferred shares
Series 5	12.1 million	Series 6 preferred shares
Series 6	1.9 million	Series 5 preferred shares
Series 7	24 million	Series 8 preferred shares
Series 9	18 million	Series 10 preferred shares
Series 11	10 million	Series 12 preferred shares
Series 15	40 million	Series 16 preferred shares
Options to buy common shares	**outstanding**	**exercisable**
	8 million	4 million

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, not beneficially owned by TC Energy, valued at approximately $2.1 billion, net of transaction costs. Refer to the Corporate – Significant events 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.

For more information on preferred shares refer to the notes to our 2021 Consolidated financial statements.

Dividends

year ended December 31	2021	2020	2019
Dividends declared			
per common share	$3.48	$3.24	$3.00
per Series 1 preferred share	$0.86975	$0.86975	$0.8165
per Series 2 preferred share	$0.50997	$0.7099	$0.89872
per Series 3 preferred share	$0.4235	$0.48075	$0.538
per Series 4 preferred share	$0.34997	$0.54989	$0.73872
per Series 5 preferred share	$0.48725	$0.56575	$0.56575
per Series 6 preferred share	$0.41622	$0.52537	$0.7976
per Series 7 preferred share	$0.97575	$0.97575	$0.98181
per Series 9 preferred share	$0.9405	$0.9405	$1.032
per Series 11 preferred share	$0.83775	$0.92194	$0.95
per Series 13 preferred share	$0.34375	$1.375	$1.375
per Series 15 preferred share	$1.225	$1.225	$1.225

On February 14, 2022, we increased the quarterly dividend on our outstanding common shares by 3.4 per cent to $0.90 per common share for the quarter ending March 31, 2022 which equates to an annual dividend of $3.60 per common share.

Credit facilities

We have several committed credit facilities that support our commercial paper programs and provide short-term liquidity for general corporate purposes. In addition, we have demand credit facilities that are also used for general corporate purposes, including issuing letters of credit and providing additional liquidity.

At February 9, 2022, we had a total of $12.4 billion of committed revolving and demand credit facilities, including:

(billions of Canadian $, unless otherwise noted) Borrower	Description	Matures	Total facilities	Unused capacity[1]
Committed, syndicated, revolving, extendible, senior unsecured credit facilities:				
TCPL	Supports TCPL's Canadian dollar commercial paper program and for general corporate purposes	December 2026	3.0	0.8
TCPL / TCPL USA / Columbia / TransCanada American Investments Ltd.	Supports TCPL's and TCPL USA's U.S. dollar commercial paper programs and for general corporate purposes of the borrowers, guaranteed by TCPL	December 2022	US 4.5	US 1.7
TCPL / TCPL USA / Columbia / TransCanada American Investments Ltd.	For general corporate purposes of the borrowers, guaranteed by TCPL	December 2024	US 1.0	US 1.0
Demand senior unsecured revolving credit facilities:				
TCPL / TCPL USA	Supports the issuance of letters of credit and provides additional liquidity; TCPL USA facility guaranteed by TCPL	Demand	2.1 [2]	1.0 [2]
Mexico subsidiary	For Mexico general corporate purposes, guaranteed by TCPL	Demand	MXN 5.0 [2]	MXN 2.6 [2]

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

2 Or the U.S. dollar equivalent.

Contractual obligations

Our contractual obligations include our long-term debt, operating leases, purchase obligations and other liabilities incurred in our business such as environmental liability funds and employee pension and post-retirement benefit plans.

Payments due (by period)

at December 31, 2021					
(millions of $)	Total	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Notes payable	5,166	5,166	—	—	—
Long-term debt and junior subordinated notes[1]	47,928	1,320	4,480	4,476	37,652
Operating leases[2]	554	73	136	129	216
Purchase obligations and other	4,625	2,211	773	432	1,209
	58,273	8,770	5,389	5,037	39,077

1 Excludes issuance costs.

2 Includes future payments for corporate offices, various premises, services, equipment, land and lease commitments from corporate restructuring. Some of our operating leases include the option to renew the agreement for one to 25 years.

Notes payable

Total notes payable outstanding were $5.2 billion at the end of 2021 compared to $4.2 billion at the end of 2020.

Long-term debt and junior subordinated notes

At December 31, 2021, we had $38.7 billion of long-term debt and $8.9 billion of junior subordinated notes outstanding compared to $36.9 billion of long-term debt and $8.5 billion of junior subordinated notes at December 31, 2020.

We attempt to ladder the maturity profile of our debt. The weighted-average maturity of our junior subordinated notes and long-term debt, excluding call features is approximately 20 years.

Interest payments

At December 31, 2021, scheduled interest payments related to our long-term debt and junior subordinated notes were as follows:

at December 31, 2021					
(millions of $)	Total	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Long-term debt	23,278	1,777	3,384	3,028	15,089
Junior subordinated notes	21,658	461	922	916	19,359
	44,936	2,238	4,306	3,944	34,448

Purchase obligations

We have purchase obligations that are transacted at market prices and in the normal course of business, including long-term natural gas transportation and purchase arrangements.

Capital expenditure commitments include obligations related to the construction of growth projects and are based on the projects proceeding as planned. Changes to these projects, including cancellation, would reduce or possibly eliminate these commitments as a result of cost mitigation efforts.

Payments due (by period)

at December 31, 2021 (millions of $)	**Total**	**< 1 year**	**1 - 3 years**	**4 - 5 years**	**> 5 years**
Canadian Natural Gas Pipelines					
Transportation by others[1]	1,829	160	327	308	1,034
Capital spending[2]	1,472	1,432	37	3	—
U.S. Natural Gas Pipelines					
Transportation by others[1]	619	128	219	97	175
Capital spending[2]	130	124	6	—	—
Mexico Natural Gas Pipelines					
Capital spending[2]	102	31	71	—	—
Liquids Pipelines					
Capital spending[2]	57	56	1	—	—
Other	9	3	6	—	—
Power and Storage					
Capital spending[2]	65	48	16	1	—
Other[3]	50	10	21	19	—
Corporate					
Other	278	205	69	4	—
Capital spending[2]	14	14	—	—	—
	4,625	2,211	773	432	1,209

1 Demand rates are subject to change. The contractual obligations in the table are based on demand volumes only and exclude variable charges incurred when volumes flow.

2 Amounts are primarily for capital expenditures and contributions to equity investments for capital projects. Amounts are estimates and are subject to variability based on timing of construction and project requirements.

3 Includes estimates of certain amounts which are subject to change depending on plant-fired hours, the consumer price index, actual plant maintenance costs, plant salaries as well as changes in regulated rates for fuel transportation.

Outlook

Our capital program is comprised of approximately $24 billion of secured projects, as well as our projects under development, which are subject to key corporate and regulatory approvals. The program is expected to be financed through our growing internally generated cash flows and a combination of other funding options including:

- senior debt
- hybrid securities
- preferred shares
- asset sales
- project financing
- potential involvement of strategic or financial partners.

In addition, we may access additional funding options below, as deemed appropriate:

- common shares issued from treasury under our DRP
- common shares issued under our ATM program
- discrete common equity issuance.

GUARANTEES

Sur de Texas

We and our partner on the Sur de Texas pipeline, IEnova, have jointly guaranteed the financial performance of the entity which owns the pipeline. Such agreements include a guarantee and a letter of credit which are primarily related to the delivery of natural gas. The guarantees have terms extending up to June 2022.

At December 31, 2021, our share of potential exposure under the Sur de Texas pipeline guarantees was estimated to be $93 million with a carrying amount of less than $1 million.

Bruce Power

We and our joint venture partner on Bruce Power, BPC Generation Infrastructure Trust, have each severally guaranteed certain contingent financial obligations of Bruce Power related to a lease agreement. The Bruce Power guarantee has a term to 2023.

At December 31, 2021, our share of the potential exposure under the Bruce Power guarantee was estimated to be $88 million with no carrying amount.

Other jointly-owned entities

We and our partners in certain other jointly-owned entities have also guaranteed (jointly, severally, jointly and severally, or exclusively) the financial performance of these entities. Such agreements include guarantees and letters of credit which are primarily related to delivery of natural gas, construction services including purchase agreements and the payment of liabilities. The guarantees have terms ranging to 2043.

Our share of the potential exposure under these assurances was estimated at December 31, 2021 to be approximately $80 million with a carrying amount of $4 million. In certain cases, if we make a payment that exceeds our ownership interest, the additional amount must be reimbursed by our partners.

OBLIGATIONS – PENSION AND OTHER POST-RETIREMENT BENEFIT PLANS

In 2021, we made funding contributions of $105 million to our defined benefit pension plans, $8 million for other post-retirement benefit plans and $58 million for the savings plan and defined contribution plans. We also provided an additional $20 million letter of credit to the Canadian defined benefit plan for funding of solvency requirements.

Considering current market conditions and the reduction to the number of active plan members due to the VRP, we expect 2022 required funding levels to be lower than 2021 levels, although actuarial valuations for determining 2022 funding of our pension and other post-retirement benefit plans as at January 1, 2022 will be carried out in mid-2022. We currently expect 2022 funding contributions of approximately $76 million for the defined benefit pension plans, approximately $7 million for other post-retirement benefit plans and approximately $55 million for the savings plans and defined contribution pension plans. In addition, we expect to provide an additional estimated $20 million letter of credit to the Canadian defined benefit plan for solvency funding requirements.

The net benefit cost for our defined benefit and other post-retirement plans decreased to $108 million in 2021 from $114 million in 2020 primarily due to the impact of a pension curtailment and settlement related to the VRP.

Future net benefit costs and the amount we will need to contribute to fund our plans will depend on a range of factors including:

- interest rates
- actual returns on plan assets
- changes to actuarial assumptions and plan design
- actual plan experience versus projections
- amendments to pension plan regulations and legislation.

We do not expect future increases in the level of funding needed to maintain our plans to have a material impact on our liquidity or financial condition.

Other information

ENTERPRISE RISK MANAGEMENT

Risk management is integral to the successful operation of our business. Our strategy is to ensure that our risks and related exposures are aligned with our business objectives and risk tolerance. We manage risk through a centralized enterprise risk management (ERM) program that identifies enterprise risks, including ESG-related risks, that could materially impact the achievement of our strategic objectives.

Our Board of Directors retains general oversight of all enterprise risks, as identified below, and specifically has direct oversight of reputation and relationships, regulatory uncertainty, capital allocation strategy and execution and capital costs. The Board reviews the enterprise risk register annually and is informed quarterly on emerging risks and how these risks are being managed and mitigated in accordance with TC Energy’s risk appetite and tolerances. The Board also participates in detailed presentations on each enterprise risks identified in the enterprise risk register as required or requested.

Our Board of Directors' Governance Committee oversees the ERM program, ensuring appropriate oversight of our risk management activities. Other Board committees oversee specific types of risk, including ESG risk, within their mandate. More specifically:

- the Human Resources Committee oversees executive resourcing, organizational capabilities and compensation risk to ensure human and labour policies and remuneration practices align with our overall business strategy
- the HSSE Committee oversees operational, health, safety, sustainability and environmental risk, including climate change related risks
- the Audit Committee oversees management's role in managing financial risk, including market risk, counterparty credit risk and cyber security.

Our executive leadership team is accountable for developing and implementing risk management plans and actions, and effective risk management is reflected in their compensation. Each identified enterprise risk has an executive leadership team member as the governance and execution owner who provides an in-depth review for the Board on an annual basis.

Key segment-specific financial, health, safety and environment risks are covered in their respective sections of this MD&A. The following is a summary of enterprise-wide risks with potential to affect all of our operations. These are being continuously monitored.

Risk and description	Impact	Monitoring and mitigation
Business interruption		
Operational risks, including equipment malfunctions and breakdowns, labour disputes, pandemic and other catastrophic events including those related to climate change, acts of terror, sabotage and third-party excavations on our right of way.	Decrease in revenues and increase in operating costs, legal proceedings or regulatory actions, or other expenses all of which could reduce our earnings. Losses not recoverable through tolls or contracts or covered by insurance could have an adverse effect on operations, cash flows and financial position. Certain events could lead to risk of injury or fatality, property and environmental damage.	Our management system, TOMS, includes our corporate health, safety, sustainability, environment and asset integrity programs to prevent incidents and protect employees, contractors, members of the public, the environment and our assets. TOMS includes process safety, incident, emergency and crisis management programs to ensure TC Energy can effectively respond to operational events, minimize loss or injury and enhance our ability to resume operations. This is supported by our business continuity program that identifies critical business processes and develops corresponding business resumption plans. We also have a comprehensive insurance program to mitigate a certain portion of our risks, but insurance does not cover all events in all circumstances.
Climate change		
As a leading energy infrastructure company in North America, our assets could be impacted by significant temperature or weather changes and our business may be impacted by market risks resulting from emerging decarbonization policies or shifts in energy consumption affecting long-term energy supply and demand trajectories.	Fluctuations in energy supply and demand, increasing commodity prices or volatility and output capability. Business interruption caused by physical changes to our environment which could result in a decrease in revenues and increase in operating costs, legal proceedings or regulatory actions, or other expenses, all of which could reduce our earnings.	In 2021, we established a dedicated energy transition team to assess relevant technologies and opportunities to support business resiliency irrespective of the pace or direction of energy transition. This team worked cross functionally to set our enterprise-wide goal of 30 per cent reduction of GHG emission intensity by 2030 which positions us to achieve net-zero emissions from our operations by 2050, using a 2019 baseline year. We evaluate the resilience of our asset portfolio over a range of potential energy supply and demand outcomes, also known as scenario analysis, as part of our strategic planning process. We monitor climate policy and related developments through our ERM program to ensure leadership has visibility to the broader perspective, and that treatments are applied in a holistic and consistent manner. Our engineering standards are also regularly reviewed to ensure assets continue to be designed and operated to withstand the potential impacts of climate change.
Cyber security		
We rely on our information technology to process, transmit and store electronic information, including information we use to safely operate our assets. We continue to face cyber security risks and could be subject to cyber security events directed against our information technology. The methods used to obtain unauthorized access, disable or degrade service or sabotage systems are constantly evolving and may be difficult to anticipate or to detect for long periods of time.	A breach in the security of our information technology could expose our business to a risk of loss, misuse or interruption of critical information and functions. This could affect our operations, damage our assets, result in safety incidents, damage to the environment and/or result in reputational harm, competitive disadvantage, regulatory enforcement actions and potential litigation, which could have a material adverse effect on our operations, financial position and results of operations.	We have a comprehensive cyber security strategy which aligns with industry and recognized standards for cyber security. This strategy is regularly reviewed and updated, and the status of our cyber security program is reported to the Audit Committee on a quarterly basis. The program includes cyber security risk assessments, continuous monitoring of networks and other information sources for threats to the organization, comprehensive incident response plans/processes and a robust cyber security awareness program for employees and contractors. We have insurance which may cover losses from physical damage to our facilities as a result of a cyber security event, but insurance does not cover all events in all circumstances.

Risk and description	Impact	Monitoring and mitigation
Reputation and relationships		
Our operations and growth prospects require us to have strong relationships with key stakeholders including customers, Indigenous communities, landowners, suppliers, investors, governments and government agencies and environmental non-governmental organizations.	Inadequately managing stakeholder expectations and concerns, including those related to ESG, can have a significant impact on our operations and projects, infrastructure development and overall reputation. It could also affect our ability to operate and grow.	Our core values – safety, responsibility, collaboration, integrity and innovation – guide us in building and maintaining our key relationships as well as our interactions with stakeholders. We are proud of the strong relationships we have built with stakeholders across our geographies, and we are continuously seeking ways to strengthen these relationships. Beyond our core values, we have specific stakeholder programs and policies that shape our interactions, clarify expectations, assess risks and facilitate mutually beneficial outcomes. Our most recent Report on Sustainability includes details on our specific commitments related to safety, partnerships with Indigenous communities, focus on landowner relationships and our workplace inclusion and diversity.
Regulatory uncertainty		
Our ability to construct and operate energy infrastructure requires regulatory approvals and is dependent on evolving policies and regulations by government authorities. This includes changes in regulation that may affect our projects and operations.	Adverse impacts on competitive geographic and business positions could result in the inability to meet our growth targets through missed or lost organic, greenfield and brownfield opportunities. Financial impacts of denied or delayed projects could include lost development costs, loss of investor confidence and potential legal costs from litigation.	We monitor regulatory and government developments and decisions to analyze their possible impact on our businesses. We build scenario analysis into our strategic outlook and work closely with our rightsholders and stakeholders in the development and operation of our assets. We identify emerging risks and signposts including customer, regulatory and government decisions as well as innovative technology development, and report on our management of these risks quarterly through the ERM program to the Board. We also use this information to inform our capital allocation strategy and adapt to changing market conditions.
Access to capital at a competitive cost		
We require substantial amounts of capital in the form of debt and equity to finance our portfolio of growth projects and maturing debt obligations at costs that are sufficiently lower than the returns on our investments.	Significant deterioration in market conditions for an extended period of time and changes in investor and lender sentiment could affect our ability to access capital at a competitive cost, which could negatively impact our ability to deliver an attractive return on our investments or inhibit our growth.	We operate within our financial means and risk tolerances, maintain a diverse array of funding levers and also utilize portfolio management as an important component of our financing program. In addition, we have candid and proactive engagement with the investment community, including credit rating agencies, with the objective of hearing their feedback and keeping them apprised of developments in our business and factually communicating our prospects, risks and challenges as well as ESG-related updates. We also conduct research around the evolving ESG preferences of our investors and financial partners which we consider in our decision making.
Capital allocation strategy		
To be competitive, we must offer integral energy infrastructure services in supply and demand areas, and in forms of energy that are attractive to customers.	Should alternative lower-carbon forms of energy result in decreased demand for our services on an accelerated timeline versus our pace of depreciation, the value of our long-lived energy infrastructure assets could be negatively impacted.	We have a diverse portfolio of assets and use portfolio management to divest of non-strategic assets, effectively rotating capital while adhering to our risk preferences and focus on per share metrics. We conduct analyses to identify resilient supply sources as part of our energy fundamentals and strategic development reviews. We recover depreciation through our regulated pipeline rates which is an important lever to accelerate or decelerate the return of capital from a substantial portion of our assets. We also monitor signposts including customer, regulatory and government decisions as well as innovative technology development to inform our capital allocation strategy and adapt to changing market conditions.

Risk and description	Impact	Monitoring and mitigation
Execution and capital costs		
Investing in large infrastructure projects involves substantial capital commitments and associated execution risks based on the assumption that these assets will deliver an attractive return on investment in the future.	While we carefully determine the expected cost of our capital projects, under some commercial arrangements, we bear capital cost overrun and schedule risk which may decrease our return on these projects.	Our Project Governance program supports project execution and operational excellence. The program aligns with TOMS which provides the framework and standards to optimize project execution, supporting timely and on budget completion. We prefer to contractually structure our projects to recover development costs if a project does not proceed along with mechanisms to minimize the impact should cost overruns occur. However, under some commercial arrangements, we share or bear the cost of execution risk. Additionally, we can utilize project financing and/or involve partners in our projects to manage capital at risk.

Health, safety, sustainability and environment

The Board's HSSE Committee oversees operational risk, occupational and process safety, sustainability, security of personnel, environmental and climate change related risks and monitors development and implementation of systems, programs and policies relating to HSSE matters through regular reporting from management. We use an integrated management system that establishes a framework for managing these risks and is used to capture, organize, document, monitor and improve our related policies, programs and procedures.

Our management system, TOMS, is modeled after international standards, including the International Organization for Standardization (ISO) standard for environmental management systems, ISO 14001, and the Occupational Health and Safety Assessment Series for occupational health and safety. TOMS also conforms to applicable industry standards and complies with applicable regulatory requirements. It covers the lifecycle of our assets and follows a continuous improvement cycle organized into four key areas:

- Plan – risk and regulatory assessment as well as objective and target setting, which includes establishing total recordable case rate targets while striving for zero incidents plus defining roles and responsibilities
- Do – development and implementation of programs, procedures and standards to manage operational risk
- Check – incident reporting, investigation, assurance activities, including internal and external audits and performance monitoring
- Act – non-conformance, non-compliance and opportunities for improvement are managed and assessed by management.

The HSSE Committee reviews performance and operational risk management. It receives updates and reports on:

- overall HSSE corporate governance
- operational performance and preventive maintenance metrics
- asset integrity programs
- environment programs
- significant occupational safety, process safety and asset integrity incidents
- emergency preparedness, incident response and evaluation
- occupational and process safety performance metrics
- biodiversity and land reclamation
- developments in and compliance with applicable legislation and regulations, including those related to the environment
- prevention, mitigation and management of risks related to HSSE matters, including climate change or business interruption risks, such as pandemics, that may adversely impact TC Energy
- sustainability matters, including social, environmental and climate change related risks and opportunities as well as related voluntary public disclosure such as our Report on Sustainability, Reconciliation Action Plan, ESG Data Sheet and GHG Emissions Reduction Plan
- our Occupational Health and Hygiene Program, which includes physical and mental health and psychological safety.

Health, safety and asset integrity
The safety of our employees, contractors and the public as well as the integrity of our pipelines, power and storage infrastructure, are a top priority. All assets are designed, constructed and commissioned with full consideration given to safety and integrity, and are placed into service only after all necessary requirements, both regulatory and internal, have been satisfied.

In 2021, we spent $1.4 billion for pipeline integrity on the natural gas and liquids pipelines we operate, similar to 2020. Pipeline integrity spending will fluctuate based on the results of annual risk assessments conducted on our pipeline systems and evaluations of information obtained from recent inspections, incidents and maintenance activities.

Under the approved regulatory models in Canada, non-capital pipeline integrity expenditures on CER-regulated natural gas pipelines are generally treated on a flow-through basis and, as a result, fluctuations in these expenditures generally have no impact on our earnings. Similarly, under our Keystone Pipeline System contracts, pipeline integrity expenditures are recovered through the tolling mechanism and, as a result, generally have no impact on our earnings. Non-capital pipeline integrity expenditures on our U.S. natural gas pipelines are primarily treated as operations and maintenance expenditures and are typically recoverable through tolls approved by FERC.

Spending associated with process safety and various integrity programs for the power and storage assets we operate is used to minimize risk to employees, contractors, the public, equipment and the surrounding environment, and also prevent disruptions to serving the energy needs of our customers.

As described in the Business interruption and Climate change risk discussions above, we have a set of procedures in place to manage our response to natural disasters, which include catastrophic events such as forest fires, tornadoes, earthquakes, floods, volcanic eruptions and hurricanes. The procedures, which are included in our Emergency Management Program, are designed to help protect the health and safety of our employees and contractors, minimize risk to the public and limit the potential for adverse effects on the environment.

We are committed to protecting the health and safety of all individuals involved in our activities. Our Occupational Health and Hygiene Program provides comprehensive strategies for health promotion and protection. We are committed to delivering effective programs that:
- reduce the human and financial impact of illness and injury
- ensure fitness for work
- strengthen worker resiliency
- build organizational capacity by focusing on individual well-being, health education and improved working conditions to sustain a productive workforce
- increase mental well-being awareness, provide various mental health supports and training to employees and leaders, measure the success of programs and improve psychological health and safety.

In response to the COVID-19 pandemic, with guidance from government and public health authorities, we have implemented enhanced COVID-19 health and safety protocols and procedures to protect our employees, contractors and other stakeholders.

Environmental risk, compliance and liabilities
TOMS provides requirements for our day-to-day work to protect employees, contractors, our workplace and assets, the communities in which we work and the environment. It conforms to external industry consensus standards and voluntary programs plus complies with applicable legislative requirements. Under TOMS, mandated programs set requirements to manage specific risk areas for TC Energy, including the Environment Program, which is a documented set of processes and procedures that identifies our requirements to proactively and systematically manage environmental hazards and risks throughout the lifecycle of our assets. As part of our Environment Program, we complete environmental assessments for our projects which include field studies that examine existing natural resources, biodiversity and land use along our proposed project footprint such as vegetation, soils, wildlife, water resources, wetland and protected areas. To conserve and protect the environment during construction, information gathered for an environmental impact assessment is used to develop project-specific environmental protection plans. Additionally, the Environment Program, which applies to all of our operations, includes practices and procedures to manage potential adverse environmental effects to these resources during the full lifecycle of our facilities.

Our primary sources of risk related to the environment include:
- changing regulations and requirements coupled with increased costs related to impacts on the environment
- product releases, including crude oil, diluent and natural gas, that may cause harm to the environment (land, water and air)
- use, storage and disposal of chemicals and hazardous materials
- natural disasters and other catastrophic events, including those related to climate change, that may impact our operations.

Our assets are subject to federal, state, provincial and local environmental statutes and regulations governing environmental protection, including air and GHG emissions, water quality, species at risk, wastewater discharges and waste management. Operating our assets requires obtaining and complying with a wide variety of environmental registrations, licenses, permits and other approvals and requirements. Failure to comply could result in administrative, civil or criminal penalties, remedial requirements, or orders affecting future operations.

Through the implementation of our Environment Program, we continually monitor our facilities for compliance with all material legal and regulatory environmental requirements across all jurisdictions where we operate. We also comply with all material legal and regulatory permitting requirements in our project routing and development. We routinely monitor proposed changes to environmental policy, legislation and regulation. Where the risks are uncertain or have the potential to affect our ability to effectively operate our business, we comment on proposals independently or through industry associations.

We are not aware of any material outstanding orders, claims or lawsuits against us related to releasing or discharging any material into the environment or in connection with environmental protection.

Compliance obligations can result in significant costs associated with installing and maintaining pollution controls, fines and penalties resulting from any failure to comply and potential limitations on operations. Remediation obligations can result in significant costs associated with the investigation and remediation of contaminated properties, and with damage claims arising from the contamination of properties.

The timing and complete extent of future expenditures related to environmental matters is difficult to estimate accurately because:
- environmental laws and regulations and their interpretations and enforcement change
- new claims can be brought against our existing or discontinued assets
- our pollution control and clean-up cost estimates may change, especially when our current estimates are based on preliminary site investigations or agreements
- new contaminated sites may be found, or what we know about existing sites could change
- where there is potentially more than one responsible party involved in litigation, we cannot estimate our joint and several liability with certainty.

At December 31, 2021, accruals related to these obligations totaled $30 million (2020 – $24 million), representing the estimated amount we will need to manage our currently known environmental liabilities. We believe we have considered all necessary contingencies and established appropriate reserves for environmental liabilities, however, a risk exists that unforeseen matters may arise requiring us to set aside additional amounts. We adjust reserves regularly to account for changes in liabilities.

Climate change and related regulation

We own assets and have business interests in a number of regions subject to GHG emissions regulations, including GHG emissions management and carbon pricing policies. In 2021, we incurred $59 million (2020 – $64 million) of expenses under existing carbon pricing programs. Across North America, there are a variety of new and evolving initiatives and policies in development at the federal, regional, state and provincial level aimed at reducing GHG emissions. We actively monitor and submit comments to regulators as these new and evolving initiatives are undertaken and policies implemented. We support transparent climate change policies that promote sustainable and economically responsible natural resource development and, in October 2021, we published a GHG Emissions Reduction Plan that includes GHG reduction targets in support of global climate goals. Our assets in specific geographies are currently subject to GHG regulations and we expect that the number of our assets subject to GHG regulations will continue to increase over time across our footprint. Changes in regulations may result in higher operating costs, other expenses or capital expenditures to comply with possible new regulations.

Existing policies

Canadian jurisdictions

- ECCC's methane reduction regulations that detail requirements to reduce methane emissions through operational and capital modifications came into effect in January 2020. ECCC’s methane reduction regulation aims to reduce the oil and gas sector emissions by 40 to 45 per cent below 2012 levels by 2025. Alberta, British Columbia and Saskatchewan have drafted their own methane regulations that take the place of the federal regulation for provincially-regulated assets. For federally-regulated facilities in these jurisdictions, the federal methane regulation is applicable. Compliance with the regulations requires an increased level of leak detection and repair (LDAR) surveys and measurements to quantify emission reductions. Power facilities are not affected by this regulation at the current time
- the Federal OBPS regulation imposes carbon pricing for larger industrial facilities and sets federal benchmarks for GHG emissions for various industry sectors. This federal regulation is currently in effect in the provinces of Ontario, Manitoba, Saskatchewan and New Brunswick as those jurisdictions did not have a provincial plan in place for carbon pricing which met the criteria of the Government of Canada when the policy was developed. As a result, our assets across Canada are all subject to some type of carbon pricing
- new requirements for federally regulated project applications under the Impact Assessment Agency were introduced through the Strategic Assessment of Climate Change, requiring a project proponent to provide a credible plan for a proposed project to achieve net-zero emissions by 2050. The CER published a revision to its Filing Manual to integrate the Strategic Assessment of Climate Change, which includes a requirement that projects regulated by the CER with a lifetime beyond 2050 must also include a credible plan to achieve net-zero emissions by 2050. Responses to this requirement are being developed and provided as part of the project applications on a case by case basis
- British Columbia implemented a tax on GHG emissions from fossil fuel combustion. While we are subject to this tax, the compliance costs are recovered through tolls. Additionally, British Columbia established the CleanBC program which provides incentive payments or tax rebates for industrial operations that meet an established emission intensity benchmark, and the CleanBC Industry Fund which directs a portion of the carbon tax paid by industry to fund incentives for cleaner operations by means of performance benchmarking or funding emissions reduction projects
- in Alberta, the Technology Innovation and Emissions Reduction (TIER) regulation has been in effect since January 2020. The TIER regulation requires established industrial facilities with GHG emissions above a certain threshold to reduce their emissions below an intensity baseline. The TIER system covers all of our natural gas pipelines and power and storage assets in Alberta. Compliance costs with respect to our regulated Canadian natural gas pipelines are recovered through tolls. A portion of the compliance costs for the power and storage assets are recovered through market pricing and hedging activities
- Québec has a GHG cap-and-trade program under the Western Climate Initiative (WCI) GHG emissions market. In Québec, our Bécancour cogeneration plant is subject to this program. The government allocates free emission units for the majority of Bécancour's compliance requirements. The remaining requirements were met with GHG instruments purchased at auctions or secondary markets. The costs of these emissions units are recovered through commercial contracts. The Canadian Mainline and TQM natural gas pipeline facilities in Québec are also subject to this program and compliance instruments have been or will be purchased in order to comply with the requirements of this initiative
- On March 29, 2021, the Ontario and Federal governments reached an agreement whereby the Federal OBPS in Ontario will be replaced on January 1, 2022 by the Ontario Emissions Performance Standards program. Covered facilities are required to meet the Federal OBPS regulations for the 2020 and 2021 compliance periods. Federal OBPS and the Ontario Emissions Performance Standards that apply to our Canadian Mainline operations in the province and costs under this program will be recovered in tolls. At this time, we do not anticipate a material impact to the financial performance of our Ontario natural gas facilities as a result of the Ontario Emissions Performance Standards program.

U.S. jurisdictions

- *Federal:* On June 30, 2021, a joint Congressional resolution (CRA resolution) disapproving the 2020 policy amendment was signed into law. The CRA resolution reinstated the 2016 New Source Performance Standards on the transmission and storage segments. The impact to us from the reinstatement was minimal as we previously made the decision to continue to comply even though the 2020 policy amendments removed the transmission and storage segment as an applicable source category
- *California:* Tuscarora facilities are subject to the California Air Resources Board's LDAR program requiring owners/operators of oil and gas facilities to monitor and repair methane leaks. Beginning in January 2020, thresholds for leak repair under this program were reduced. California also has a GHG cap-and-trade program linked with Québec's program through the WCI. All Tuscarora facilities fall below the threshold requiring participation in the GHG cap-and-trade program
- *Pennsylvania:* The Pennsylvania Department of Environmental Protection has an LDAR program for new source installations which require leak repair within 15 days of discovery
- *Maryland:* Effective November 2020, the Maryland Department of the Environment (MDE) finalized a methane regulation program for new and existing natural gas facilities that includes an LDAR program, emission control and reporting requirements, plus a requirement to notify not only the MDE, but also the public of any events above a specific threshold. We have one electric-powered compressor station and associated pipeline segments impacted by this regulation.

Mexico jurisdictions

- the General Climate Change Law (LGCC) establishes various public policy instruments, including the National Emissions Registry and its regulations, which allow for the compilation of information on the emission of compounds and GHGs of the different productive sectors of the country. The LGCC defines the National Inventory of GHGs and compounds as the document that contains the estimate of anthropogenic emissions by sources and absorption by sinks in Mexico. This law requires an annual submission of our emissions
- in 2018, the Government of Mexico published a regulation that established guidelines for the prevention and control of methane emissions from the hydrocarbon sector. Companies are required to prepare a Program for the Comprehensive Prevention and Control of Methane Emissions (PPCIEM) which includes identification of sources of methane, quantification of baseline emissions and an estimate of the expected emission reductions from prevention and control activities. This regulation requires the PPCIEM, through which operational and technological practices are adopted, to determine a reduction goal that must be met within a period not exceeding six calendar years from the delivery of the PPCIEM. TC Energy developed and applied the PPCIEM to all of its facilities in Mexico in 2020
- in 2019, the Secretariat of Environment and Natural Resources published an agreement to progressively and gradually establish an emissions commerce system in Mexico and comply with the LGCC. It will function as a three-year pilot from 2020 to 2022 that allows the Secretariat to test the design and rules of the system as well as evaluate its performance and then propose adjustments for a subsequent operational phase after 2022.

Anticipated policies

Canadian jurisdictions

- the Government of Canada is developing the Clean Fuel Standard (CFS) to achieve reductions in GHG emissions. In December 2020, the Canadian Federal Government unveiled its plan aimed to exceed their previous 2030 GHG emissions reduction target of 30 per cent below 2005 levels to a new target of 32 to 40 per cent below 2005 levels with the ultimate goal of achieving net-zero emissions by 2050. As part of this plan, the Federal Government narrowed the CFS scope to include only liquid fuels, which will not directly impact TC Energy. This plan also increased carbon pricing levels and released a complementary hydrogen strategy. Carbon prices are scheduled to increase by $15/tonne every year after 2022 to $170/tonne in 2030. While the scope of the CFS is limited to liquid fuels, there will be opportunities to generate credits for the gaseous fuel stream to incentivize emission reduction opportunities. We will continue to engage with Canadian policy makers and monitor and assess the extent of the impacts as more information is made available
- On October 11, 2021, ECCC committed to developing a plan to reduce oil and gas sector methane emissions by at least 75 per cent below 2012 levels by 2030. We will assess the potential implications of any policy and regulatory updates associated with this announcement through 2022 as more information is made available.

U.S. jurisdictions

- *Federal:* In August 2020, the U.S. Senate passed the PHMSA reauthorization bill, the PIPES Act, which included methane regulations requiring, for example, pipeline owners/operators to implement methane LDAR programs, deploy advanced leak detection technology and incorporate LDAR surveys in inspection and maintenance plans. If the U.S. House of Representatives also supports the inclusion of these methane provisions, PHMSA will join the United States Environmental Protection Agency (USEPA) as another federal regulator of GHG emissions, indicating the nation's increasing desire to combat climate change. The expected impact to our assets is still being evaluated
- *Federal:* On November 2, 2021, the USEPA released proposed rulemaking to reduce methane and other harmful air pollutants from both new and existing sources in the oil and natural gas industry. The methane rule was posted to the federal register on November 15, 2021 with a public hearing scheduled on November 30, 2021 and the public comment period closing on January 14, 2022. An additional supplemental proposal was released on November 15,2021 which included supporting regulator text. The proposed rule for new or modified sources is expected to impact any new projects that begin in 2022 and beyond. The guidelines for existing emission sources have the potential to impact all of our existing facilities when fully implemented in the future
- *Washington:* The state has announced the beginning of the rulemaking process for its cap-and-trade program, which passed through legislature in 2021. Rulemaking will proceed through 2022 with the program launching in January of 2023. The state is continuing rulemaking on its Greenhouse Gas Assessment for Projects rule, which would require projects to provide an estimate of their potential GHG emissions using the environmental assessment methods described in the rule. Rule language will be proposed in early 2022 and the state will hold public comments and hearings before finalizing later in the year. This program and associated rules would apply to our assets and projects in the state. They have also begun the process to update the Washington Commercial Building Code, including language that would limit the use of natural gas in new construction. This process will continue into 2022
- *California:* Our assets may be affected by the Governor of California's executive order, issued in September 2020, requiring all new cars and light trucks sold in California to be emission-free by 2035 and heavy and medium trucks to be emission-free by 2045. The significance of the impact on our assets is still being evaluated
- *Oregon:* In March 2020, the Governor of Oregon issued an executive order to reduce and regulate GHGs by establishing annual reduction goals, developing a new carbon cap and reduce program and enhancing clean fuel standards by January 1, 2022. The state Department of Environmental Quality recommended a final draft of the rule to the state Environmental Quality Commission (EQC) for a vote at the EQC's December 2021 meeting. The EQC approved the program which still exempts our facilities and their emissions
- *Michigan:* The Michigan Department of Environment, Great Lakes and Energy is currently evaluating potential ozone control strategies for the southeast Michigan ozone non-attainment area and the interaction of methane and ozone, which may lead to the development of laws and regulations that affect TC Energy through impacted ANR and Great Lakes facilities in the state
- *New York:* In August 2020, New York's Department of Environmental Conservation (NY DEC) released its proposed GHG reduction regulations, implementing the Climate Leadership and Community Protection Act, which directed the NY DEC to adopt GHG limits for all state emission sources. The proposed regulations require a reduction in GHGs equal to 60 per cent of the 1990 GHG emission levels by 2030 and to 15 per cent of the 1990 GHG emission levels by 2050. The proposed regulation does not include any compliance requirements and, as such, the impact to our assets cannot yet be measured.

Changes to environmental remediation regulations – U.S. Jurisdictions

- *Federal:* On October 22, 2021, the USEPA proposed a rule entitled, Alternate Polychlorinated Biphenyl (PCB) Extraction Methods and Amendments to PCB Cleanup and Disposal Regulations. The rule addresses a myriad of issues related to laboratory methodologies, performance-based disposal options for PCB remediation waste and during emergency situations, among other proposed changes. We are currently reviewing the proposed rule to determine its impact, if any, to our PCB Management activities but at this time do not believe that it will have a material impact on our business, financial condition or results of operations.

Financial risks

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. Market risk and counterparty credit risk are managed within limits that are established by our Board of Directors, implemented by senior management and monitored by our risk management, internal audit and business segment groups. Our Board of Directors' Audit Committee oversees how management monitors compliance with market risk and counterparty credit risk management policies and procedures and oversees management's review of the adequacy of the risk management framework.

Market risk

We construct and invest in energy infrastructure projects, purchase and sell commodities, issue short- and long-term debt, including amounts in foreign currencies, and invest in foreign operations. Certain of these activities expose us to market risk from changes in commodity prices, foreign exchange rates and interest rates, which may affect our earnings, cash flows and the value of our financial assets and liabilities. We assess contracts used to manage market risk to determine whether all, or a portion, meet the definition of a derivative.

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

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

Commodity price risk

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

- in our natural gas marketing business, we enter into natural gas transportation and storage contracts as well as natural gas purchase and sale agreements. We manage our exposure on these contracts using financial instruments and hedging activities to offset market price volatility
- in our liquids marketing business, we enter into pipeline and storage terminal capacity contracts as well as crude oil purchase and sale agreements. We fix a portion of our exposure on these contracts by entering into financial instruments to manage variable price fluctuations that arise from physical liquids transactions
- in our power businesses, we enter into contracts and engage in hedging activities as well as selling and purchasing electricity and natural gas in forward markets
- in our non-regulated natural gas storage business, our exposure to seasonal natural gas price spreads is managed with a portfolio of third-party storage capacity contracts and through offsetting purchases and sales of natural gas in forward markets to lock in future positive margins.

Lower natural gas, crude oil and electricity prices could lead to reduced investment in the development, expansion and production of these commodities. A reduction in the supply of these commodities could negatively impact opportunities to expand our asset base and re-contract with our shippers and customers as their contractual agreements expire.

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

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 have ceased to be published at the end of 2021 with full cessation by mid-2023. We have completed necessary system changes to facilitate the adoption of the proposed standard market reference rates. We have also completed the analysis of contracts impacted by reference rate reform and contract modifications, if required, will take place prior to the full cessation date in mid-2023. These changes are not expected to have a material impact on our consolidated financial statements; however, we will continue to monitor any new developments up to the full cessation date.

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 2021 Financial highlights – 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.

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.

The sustained impact of the COVID-19 pandemic and related global energy demand and supply disruption continues to contribute to market uncertainty impacting a number of our customers. While the majority of our credit exposure is to large creditworthy entities, we have increased our monitoring and communication with those counterparties experiencing greater financial pressures.

At times, our counterparties may endure financial challenges resulting from commodity price and market volatility, economic instability and political or regulatory changes. In addition to actively monitoring these situations, there are a number of factors that reduce our counterparty credit risk exposure in the event of default, including:

- contractual rights and remedies together with the utilization of contractually-based financial assurances
- current regulatory frameworks governing certain of our operations
- the competitive position of our assets and the demand for our services
- potential recovery of unpaid amounts through bankruptcy and similar proceedings.

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 December 31, 2021 and 2020, we had no significant credit losses, no significant credit risk concentrations 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. Refer to the Financial condition section for more information about our liquidity.

Legal proceedings

Legal proceedings, arbitrations and actions are part of doing business. While we cannot predict the final outcomes of proceedings and actions with certainty, management does not expect any current or potential legal proceeding or action to have a material impact on our consolidated financial position or results of operations.

CONTROLS AND PROCEDURES

We meet Canadian and U.S. regulatory requirements for disclosure controls and procedures, internal control over financial reporting and related CEO and CFO certifications.

Disclosure controls and procedures

Under the supervision and with the participation of management, including our President and CEO and our CFO, we carried out quarterly evaluations of the effectiveness of our disclosure controls and procedures, including for the year ended December 31, 2021, as required by the Canadian securities regulatory authorities and by the SEC. Based on this evaluation, our President and CEO and our CFO have concluded that the disclosure controls and procedures are effective in that they are designed to ensure that the information we are required to disclose in reports we file with or send to securities regulatory authorities is recorded, processed, summarized and reported accurately within the time periods specified under Canadian and U.S. securities laws.

Management's annual report on internal control over financial reporting

We are responsible for establishing and maintaining adequate internal control over financial reporting, which is a process designed by, or under the supervision of, our President and CEO and our CFO, and effected by our Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP.

Under the supervision and with the participation of management, including our President and CEO and our CFO, an evaluation of the effectiveness of the internal control over financial reporting was conducted as of December 31, 2021, based on the criteria described in "Internal Control – Integrated Framework" issued in 2013 by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management determined that, as of December 31, 2021, the internal control over financial reporting was effective.

Our internal control over financial reporting as of December 31, 2021 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their attestation report which is included in our 2021 Consolidated financial statements.

CEO and CFO certifications

Our President and CEO and our CFO have attested to the quality of the public disclosure in our fiscal 2021 reports filed with Canadian securities regulators and the SEC and have filed certifications with them.

Changes in internal control over financial reporting

There were no changes during the year covered by this annual report that had or are reasonably likely to have a material impact on our internal control over financial reporting.

CRITICAL ACCOUNTING ESTIMATES

When we prepare financial statements that conform with 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.

The following accounting estimates require us to make significant assumptions based on factors that are either subjective or highly uncertain when preparing our financial statements and changes in these assumptions could have a material impact on the financial statements. Our accounting policies disclose the critical accounting estimates we make when preparing our financial statements.

Impairment of long-lived assets and goodwill

We review long-lived assets, such as plant, property and equipment, equity investments, goodwill and capital projects in development, for impairment whenever events or changes in circumstances lead us to believe we might not be able to recover an asset's carrying value. Factors we consider in our assessment of the recoverability of long-lived assets include, but are not limited to, macroeconomic conditions, changes in the industries and markets in which we operate, our ability to renew contracts, and the financial performance and prospects of our assets. If the total of the undiscounted future cash flows that we estimate for an asset within Property, plant and equipment, or the estimated selling price of any long-lived asset is less than its carrying value, we consider its fair value to be less than its carrying value and record an impairment loss to recognize this. For goodwill, if the fair value of the reporting unit determined using discounted cash flows is less than its carrying value, including goodwill, we consider it to be impaired.

In 2021 we recorded a $2.8 billion pre-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 ($2.1 billion after tax).

In 2020 and 2019, no impairments were recorded.

Goodwill

We test goodwill for impairment annually or more frequently if events or changes in circumstances lead us to believe it might be impaired. We can initially assess qualitative factors which include, but are not limited to, macroeconomic conditions, industry and market considerations, current valuation multiples and discount rates, cost factors, historical and forecasted financial results, or events specific to that reporting unit. If we conclude that it is not more likely than not that the fair value of the reporting unit is greater than its carrying value, we will then perform a quantitative goodwill impairment test. We can elect to proceed directly to the quantitative goodwill impairment test for any reporting unit. If the quantitative goodwill impairment test is performed, we compare the fair value of the reporting unit to its carrying value, including its goodwill. If the carrying value of a reporting unit exceeds its fair value, goodwill impairment is measured at the amount by which the reporting unit's carrying value exceeds its fair value.

When a portion of a reporting unit that constitutes a business is disposed, goodwill associated with that business is included in the carrying amount of the business in determining the gain or loss on disposal. The amount of goodwill disposed is determined based on the relative fair values of the business to be disposed and the portion of the reporting unit that will be retained. In August 2019, we completed the sale of certain Columbia Midstream assets to a third party. As these assets constituted a business within the Columbia reporting unit, $595 million of Columbia's goodwill allocated to these assets was released and netted in the gain on sale.

We determine the fair value of a reporting unit based on our projections of future cash flows, which involves making estimates and assumptions about transportation rates, market supply and demand, growth opportunities, output levels, competition from other companies, operating costs, regulatory changes, discount rates and earnings and other multiples.

As part of the annual goodwill impairment assessment, we evaluated qualitative factors impacting the fair value of the reporting units, other than the Columbia reporting unit for which we elected to proceed directly to a quantitative impairment test. It was determined that it was more likely than not that the fair value of all reporting units exceeded their carrying amounts, including goodwill, and therefore, goodwill was not impaired.

Following the uncontested rate case settlement with shippers in 2021, we performed a quantitative annual goodwill impairment test for Columbia as at December 31, 2021. It was determined that the fair value of Columbia exceeded its carrying value, including goodwill, at December 31, 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:

at December 31 (millions of $)	**2021**	**2020**
Other current assets	**169**	235
Other long-term assets	**48**	41
Accounts payable and other	**(221)**	(72)
Other long-term liabilities	**(47)**	(59)
	(51)	145

Anticipated timing of settlement of derivative instruments

The anticipated timing of settlement of derivative instruments assumes constant commodity prices, interest rates and foreign exchange rates. Settlements will vary based on the actual value of these factors at the date of settlement.

at December 31, 2021 (millions of $)	**Total fair value**	**< 1 year**	**1 - 3 years**	**4 - 5 years**	**> 5 years**
Derivative instruments held for trading					
Assets	173	159	8	6	—
Liabilities	(200)	(184)	(12)	(3)	(1)
Derivative instruments in hedging relationships					
Assets	44	10	29	5	—
Liabilities	(68)	(37)	(30)	(1)	—
	(51)	(52)	(5)	7	(1)

Unrealized and realized gains/(losses) on derivative instruments

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

year ended December 31 (millions of $)	2021	2020	2019
Derivative instruments held for trading[1]			
Amount of unrealized gains/(losses) in the year			
Commodities	**9**	(23)	(111)
Foreign exchange	**(203)**	126	245
Amount of realized gains/(losses) in the year			
Commodities	**287**	183	378
Foreign exchange	**240**	(33)	(70)
Derivative instruments in hedging relationships[2]			
Amount of realized (losses)/gains in the year			
Commodities	**(44)**	6	(6)
Interest rate	**(32)**	(16)	2

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

2 There were no gains and 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 26, Risk management and financial instruments, of our 2021 Consolidated financial statements.

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 December 31, 2021, the Loans receivable from affiliates on our Consolidated balance sheet of MXN$19.7 billion or $1.2 billion, represented our 60 per cent proportionate share of debt financing to the Sur de Texas joint venture. At December 31, 2020, this loan was recorded as Long-term loans receivable from affiliates on our Consolidated balance sheet and amounted to MXN$20.9 billion or $1.3 billion.

Our 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:

year ended December 31 (millions of $)	2021	2020	2019	Affected line item in the Consolidated statement of income
Interest income[1]	**87**	110	147	Interest income and other
Interest expense[2]	**(87)**	(110)	(147)	Income from equity investments
Foreign exchange (losses)/gains[1]	**(41)**	(86)	53	Interest income and other
Foreign exchange gains/(losses)[1]	**41**	86	(53)	Income from equity investments

1 Included in our Corporate segment.

2 Included in our Mexico Natural Gas Pipelines segment.

Coastal GasLink LP

We hold a 35 per cent equity interest in Coastal GasLink LP and have been contracted to develop and operate the Coastal GasLink pipeline. We have a subordinated demand revolving credit facility with Coastal GasLink LP to provide additional short-term liquidity and funding flexibility to the project. The facility bears interest at a floating market-based rate and had a capacity of $500 million at December 31, 2021 with an outstanding balance of $1 million (December 31, 2020 – nil) reflected in Loans receivable from affiliates on our Consolidated balance sheet.

On December 6, 2021, we entered into a subordinated loan agreement with Coastal GasLink LP to provide interim temporary financing, if necessary, of up to $3.3 billion to fund incremental project costs as a bridge to a required increase in the project-level financing. Financing available to Coastal GasLink LP under this agreement is provided through a combination of interest-bearing facilities subject to floating market-based rates and non-interest-bearing facilities that are subject to a return to us under certain conditions at the time the final cost of the project is determined. At December 31, 2021, Long-term loans receivable from affiliates on our Consolidated balance sheet reflected $238 million in amounts outstanding under the subordinated loan agreement.

ACCOUNTING CHANGES

For a description of our significant accounting policies and a summary of changes in accounting policies and standards impacting our business, refer to Note 2, Accounting policies, and Note 3, Accounting changes, of our 2021 Consolidated financial statements.

QUARTERLY RESULTS

Selected quarterly consolidated financial data

2021 (millions of $, except per share amounts)	Fourth	Third	Second	First
Revenues	**3,584**	**3,240**	**3,182**	**3,381**
Net income/(loss) attributable to common shares	**1,118**	**779**	**975**	**(1,057)**
Comparable earnings	**1,035**	**972**	**1,038**	**1,108**
Share statistics:				
Net income/(loss) per common share – basic	**$1.14**	**$0.80**	**$1.00**	**($1.11)**
Comparable earnings per common share	**$1.06**	**$0.99**	**$1.06**	**$1.16**
Dividends declared per common share	**$0.87**	**$0.87**	**$0.87**	**$0.87**

2020 (millions of $, except per share amounts)	Fourth	Third	Second	First
Revenues	3,297	3,195	3,089	3,418
Net income attributable to common shares	1,124	904	1,281	1,148
Comparable earnings	1,080	893	863	1,109
Share statistics:				
Net income per common share – basic	$1.20	$0.96	$1.36	$1.22
Comparable earnings per common share	$1.15	$0.95	$0.92	$1.18
Dividends declared per common share	$0.81	$0.81	$0.81	$0.81

Factors affecting quarterly financial information by business segment

Quarter-over-quarter revenues and net income fluctuate for reasons that vary across our business segments.

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

- regulatory decisions
- negotiated settlements with 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 fourth quarter 2021, comparable earnings also excluded:

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

In third quarter 2021, comparable earnings also excluded:

- a $55 million after-tax expense with respect to transition payments incurred as part of the VRP
- preservation and storage costs for Keystone XL pipeline project assets of $11 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge.

In second quarter 2021, comparable earnings also excluded:

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

In first quarter 2021, comparable earnings also excluded:

- an after-tax asset impairment charge, net of expected contractual recoveries and other contractual and legal obligations, of $2.2 billion related to the formal suspension of the Keystone XL pipeline project following the January 20, 2021 revocation of the Presidential Permit.

In fourth quarter 2020, comparable earnings also excluded:

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

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 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.

FOURTH QUARTER 2021 HIGHLIGHTS

Consolidated results

three months ended December 31 (millions of $, except per share amounts)	**2021**	**2020**
Canadian Natural Gas Pipelines	**389**	350
U.S. Natural Gas Pipelines	**818**	730
Mexico Natural Gas Pipelines	**123**	137
Liquids Pipelines	**373**	300
Power and Storage	**191**	43
Corporate	**(6)**	(150)
Total segmented earnings	**1,888**	1,410
Interest expense	**(611)**	(530)
Allowance for funds used during construction	**72**	95
Interest income and other	**87**	373
Income before income taxes	**1,436**	1,348
Income tax expense	**(278)**	(116)
Net income	**1,158**	1,232
Net income attributable to non-controlling interests	**(8)**	(69)
Net income attributable to controlling interests	**1,150**	1,163
Preferred share dividends	**(32)**	(39)
Net income attributable to common shares	**1,118**	1,124
Net income per common share – basic	**$1.14**	$1.20

Net income attributable to common shares decreased by $6 million or $0.06 per common share for the three months ended December 31, 2021 compared to the same period in 2020. Net income per common share in fourth quarter 2021 reflects 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:

Fourth quarter 2021 results included:

- an incremental $60 million after-tax reduction to the Keystone XL asset impairment charge, net of expected contractual recoveries and other contractual and legal obligations, related to the termination of the Keystone XL pipeline project following the January 20, 2021 revocation of the Presidential Permit
- an after-tax gain of $19 million related to the sale of the remaining interest in Northern Courier
- preservation and storage costs for Keystone XL pipeline project assets of $10 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge
- a $7 million after-tax gain primarily related to pension adjustments incurred as part of the VRP
- an incremental $6 million income tax expense related to the sale of our 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 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 Consolidated statement of equity in second quarter 2021 and served to reduce our net financial impact from the Keystone XL pipeline project termination.

Fourth quarter 2020 results included:

- an incremental after-tax loss of $81 million related to the Ontario natural-gas fired power plants sold in April 2020
- an income tax valuation allowance release of $18 million following our reassessment of deferred tax assets that were deemed more likely than not to be realized in 2020
- an additional $18 million income tax recovery related to state income taxes on the sale of certain Columbia Midstream assets.

Net income in all 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 December 31 (millions of $, except per share amounts)	2021	2020
Net income attributable to common shares	**1,118**	1,124
Specific items (net of tax):		
Keystone XL asset impairment charge and other	**(60)**	—
Gain on partial sale of Northern Courier	**(19)**	—
Voluntary Retirement Program	**(7)**	—
Keystone XL preservation and other	**10**	—
Loss on sale of Ontario natural gas-fired power plants	**6**	81
Income tax valuation allowance releases	**—**	(18)
Gain on sale of Columbia Midstream assets	**—**	(18)
Risk management activities[1]	**(13)**	(89)
Comparable earnings	**1,035**	1,080
Net income per common share	**$1.14**	$1.20
Specific items (net of tax):		
Keystone XL asset impairment charge and other	**(0.06)**	—
Gain on partial sale of Northern Courier	**(0.02)**	—
Voluntary Retirement Program	**(0.01)**	—
Keystone XL preservation and other	**0.01**	—
Loss on sale of Ontario natural gas-fired power plants	**0.01**	0.08
Income tax valuation allowance releases	**—**	(0.02)
Gain on sale of Columbia Midstream assets	**—**	(0.02)
Risk management activities	**(0.01)**	(0.09)
Comparable earnings per common share	**$1.06**	$1.15

1

three months ended December 31 (millions of $)	2021	2020
U.S. Natural Gas Pipelines	**7**	—
Liquids Pipelines	**(5)**	(25)
Canadian Power	**4**	(1)
Natural Gas Storage	**30**	(5)
Foreign exchange	**(20)**	150
Income taxes attributable to risk management activities	**(3)**	(30)
Total unrealized gains from risk management activities	**13**	89

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.

three months ended December 31 (millions of $, except per share amounts)	2021	2020
Comparable EBITDA		
Canadian Natural Gas Pipelines	**674**	682
U.S. Natural Gas Pipelines	**1,032**	919
Mexico Natural Gas Pipelines	**151**	166
Liquids Pipelines	**380**	408
Power and Storage	**177**	161
Corporate	**(10)**	(13)
Comparable EBITDA	**2,404**	2,323
Depreciation and amortization	**(634)**	(652)
Interest expense	**(611)**	(530)
Allowance for funds used during construction	**72**	95
Interest income and other included in comparable earnings	**103**	86
Income tax expense included in comparable earnings	**(259)**	(134)
Net income attributable to non-controlling interests	**(8)**	(69)
Preferred share dividends	**(32)**	(39)
Comparable earnings	**1,035**	1,080
Comparable earnings per common share	**$1.06**	$1.15

Comparable EBITDA – 2021 versus 2020

Comparable EBITDA increased by $81 million for the three months ended December 31, 2021 compared to the same period in 2020 primarily due to the net effect of the following:

- increased earnings in U.S. Natural Gas Pipelines primarily from higher Columbia Gas transportation rates effective February 1, 2021 as a result of the subsequently uncontested rate case settlement, lower operating costs across a number of pipelines and improved earnings from our mineral rights business
- higher Power and Storage comparable EBITDA resulting from increased Canadian Power earnings mainly due to contributions from trading activities and higher realized margins, as well as increased earnings from Bruce Power due to higher volumes resulting from fewer outage days
- 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 comparable EBITDA from Canadian Natural Gas Pipelines due to the net effect of lower flow-through depreciation and financial charges, partially offset by higher incentive earnings and the elimination of the TC Energy contribution on the Canadian Mainline, offset in part by higher flow-through income taxes as well as increased rate-base earnings on the NGTL System
- 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$92 million to US$1.2 billion compared to US$1.1 billion in 2020; however, this was translated at a rate of 1.26 in 2021 versus 1.30 in 2020. Refer to the Foreign exchange discussion below for additional information.

While the weakening of the U.S. dollar in fourth quarter 2021 compared to the same period in 2020 had a considerable negative impact on 2021 comparable EBITDA for the three months ended December 31, 2021, 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 decreased by $45 million or $0.09 per common share for the three months ended December 31, 2021 compared to the same period in 2020 and was primarily the net effect of:

- changes in comparable EBITDA described above
- higher Income tax expense mainly due to the impact of lower foreign tax rate differentials, Mexico inflationary adjustments, as well as increased flow-through income taxes on Canadian rate-regulated pipelines
- 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 on January 20, 2021, partially offset by the foreign exchange impact from a weaker U.S. dollar on translation of U.S. dollar-denominated interest
- lower AFUDC, predominantly due to suspension of recording AFUDC on the Villa de Reyes project effective January 1, 2021 resulting from ongoing delays, partially offset by NGTL System expansion projects under construction
- lower Non-controlling interests following the March 3, 2021 acquisition of all outstanding common units of TC PipeLines, LP not beneficially owned by TC Energy
- decreased Depreciation and amortization in our Canadian Natural Gas Pipelines due to one section of the Canadian Mainline being fully depreciated in 2021, partially offset by new projects in U.S. Gas Natural Gas Pipelines placed in service and certain fourth quarter 2021 adjustments related to the Columbia Gas uncontested rate case settlement
- higher Interest income and other mainly attributable to higher realized gains in 2021 compared to 2020 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income.

Foreign exchange

Despite the decrease in the average exchange rate for the three months ended December 31, 2021 compared to 2020, the net impact of U.S. dollar movements on comparable earnings over this period, after considering natural offsets and economic hedges, was not significant. The components of our financial results denominated in U.S. dollars are set out in the table below, including our U.S. and Mexico Natural Gas Pipelines operations along with the majority of our Liquids Pipelines business. Comparable EBITDA is a non-GAAP measure.

Pre-tax U.S. dollar-denominated income and expense items

three months ended December 31 (millions of US$)	2021	2020
Comparable EBITDA		
U.S. Natural Gas Pipelines	**819**	706
Mexico Natural Gas Pipelines[1]	**140**	146
U.S. Liquids Pipelines	**216**	231
	1,175	1,083
Depreciation and amortization	**(245)**	(216)
Interest on long-term debt and junior subordinated notes	**(314)**	(315)
Capitalized interest	**—**	42
Allowance for funds used during construction	**28**	56
Non-controlling interests and other	**(9)**	(70)
	635	580
Average exchange rate - U.S. to Canadian dollars	**1.26**	1.30

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

Highlights by business segment

Canadian Natural Gas Pipelines

Canadian Natural Gas Pipelines segmented earnings increased by $39 million for the three months ended December 31, 2021 compared to the same period in 2020.

Net income for the NGTL System increased by $18 million for the three months ended December 31, 2021 compared to the same period in 2020 mainly due to a higher average investment base resulting from continued system expansions. Effective January 1, 2020, the NGTL System is operating under the 2020-2024 Revenue Requirement Settlement which includes an ROE of 10.1 per cent on 40 per cent deemed common equity. This settlement provides the NGTL System the opportunity to increase depreciation rates if tolls fall below specified levels and an incentive mechanism for certain operating costs where variances from projected amounts are shared with our customers.

Net income for the Canadian Mainline increased by $15 million for the three months ended December 31, 2021 compared to the same period in 2020 mainly as a result of higher incentive earnings and the elimination of a $20 million after-tax annual TC Energy contribution included in the previous settlement. Effective 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. In 2020, the Canadian Mainline operated under the terms of the 2015-2030 Tolls Application approved in 2014. The terms of the previous settlement included an ROE of 10.1 per cent on deemed common equity of 40 per cent, an incentive mechanism with both upside and downside risk and a $20 million after-tax annual TC Energy contribution to reduce the revenue requirement.

Comparable EBITDA for Canadian Natural Gas Pipelines decreased by $8 million for the three months ended December 31, 2021 compared to the same period in 2020 primarily due to the net effect of:

- lower flow-through depreciation and financial charges, partially offset by higher incentive earnings, the elimination of the TC Energy contribution and higher flow-through income taxes on the Canadian Mainline
- higher flow-through depreciation and income taxes as well as increased rate-base earnings on the NGTL System.

Depreciation and amortization decreased by $47 million for the three months ended December 31, 2021 compared to the same period in 2020 mainly due to one section of the Canadian Mainline being fully depreciated in 2021, partially offset by higher depreciation on the NGTL System from facilities that were placed in service.

U.S. Natural Gas Pipelines

U.S. Natural Gas Pipelines segmented earnings increased by $88 million for the three months ended December 31, 2021 compared to the same period in 2020 and included unrealized gains 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.

Comparable EBITDA for U.S. Natural Gas Pipelines increased by US$113 million for the three months ended December 31, 2021 compared to the same period in 2020 and was primarily due to the net effect of:

- a net increase in comparable EBITDA from Columbia Gas as a result of the higher transportation rates effective February 1, 2021, pursuant to the Columbia Gas uncontested rate case settlement. Refer to U.S. Natural Gas Pipelines – Significant events for additional information
- increased earnings from lower operating costs across a number of pipelines and the contribution from growth projects placed in service primarily on Columbia Gas and ANR
- increased earnings from our mineral rights business due to higher commodity prices.

Depreciation and amortization increased by US$30 million for the three months ended December 31, 2021 compared to the same period in 2020 mainly due to new projects placed in service and certain fourth quarter 2021 adjustments related to the Columbia Gas uncontested rate case settlement.

Mexico Natural Gas Pipelines

Mexico Natural Gas Pipelines comparable EBIT and segmented earnings decreased by $14 million for the three months ended December 31, 2021, compared to the same period in 2020. A weaker U.S. dollar in fourth quarter 2021 had a negative impact on the Canadian dollar equivalent segmented earnings compared to the same period in 2020.

Comparable EBITDA for Mexico Natural Gas Pipelines decreased by US$6 million for the three months ended December 31, 2021 compared to the same period in 2020 as a result of lower equity income from Sur de Texas.

Depreciation and amortization for the three months ended December 31, 2021 was consistent with the same period in 2020.

Liquids Pipelines

Liquids Pipelines segmented earnings increased by $73 million for the three months ended December 31, 2021 compared to the same period in 2020 and included the following specific items which have been excluded from our calculation of comparable EBIT:

- pre-tax asset impairment charge reduction of $79 million for the three months ended December 31, 2021, associated with the termination of the Keystone XL pipeline and related projects following the January 20, 2021 revocation of the Presidential Permit
- pre-tax preservation and storage costs for Keystone XL pipeline project assets of $14 million for the three months ended December 31, 2021, which could not be accrued as part of the Keystone XL asset impairment charge
- pre-tax gain of $13 million related to the sale of the remaining 15 per cent interest in Northern Courier in fourth quarter 2021
- unrealized gains and losses 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 period in 2020.

Comparable EBITDA for Liquids Pipelines decreased by $28 million for the three months ended December 31, 2021 compared to the same period 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
- increased contributions from liquids marketing activities due to higher margins and volumes.

Depreciation and amortization decreased by $3 million for the three months ended December 31, 2021 compared to the same period in 2020 primarily as a result of a weaker U.S. dollar.

Power and Storage

Power and Storage segmented earnings increased by $148 million for the three months ended December 31, 2021 compared to the same period in 2020 and included the following specific items which have been excluded from comparable EBIT:

- a pre-tax loss of $93 million for the three months ended December 31, 2020 related to the sale of our Ontario natural gas-fired power plants
- unrealized gains and losses from changes in the fair value of derivatives used to manage our exposure to commodity price risk.

Comparable EBITDA for Power and Storage increased by $16 million for the three months ended December 31, 2021 compared to the same period in 2020 primarily due to the net effect of:

- increased Canadian Power earnings primarily due to contributions from trading activities and higher realized margins
- increased contributions from Bruce Power mainly due to higher volumes resulting from lower outage days, partially offset by increased operating costs
- decreased Natural Gas Storage and other earnings as a result of increased business development activities across the segment and lower realized Alberta natural gas storage spreads.

Depreciation and amortization for the three months ended December 31, 2021 was consistent with the same period in 2020.

Corporate

Corporate segmented losses decreased by $144 million for the three months ended December 31, 2021 compared to the same period in 2020. Corporate segmented losses included an $8 million gain primarily due to a pension settlement and curtailment following the VRP offered in mid-2021. In addition, segmented losses included foreign exchange losses and gains on our proportionate share of peso-denominated inter-affiliate loans to the Sur de Texas joint venture from its partners. These foreign exchange losses and gains 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 gains and losses on the inter-affiliate loan receivable included in Interest income and other.

Comparable EBITDA and EBIT for Corporate for the three months ended December 31, 2021 was largely consistent with the same period in 2020.

Glossary

Units of measure

Bbl/d	Barrel(s) per day
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
GWh	Gigawatt hours
km	Kilometres
MMcf/d	Million cubic feet per day
MW	Megawatt(s)
MWh	Megawatt hours
PJ/d	Petajoule per day
TJ/d	Terajoule per day

General terms and terms related to our operations

ATM	An at-the-market program allowing us to issue common shares from treasury at the prevailing market price
bitumen	A thick, heavy oil that must be diluted to flow (also see: diluent). One of the components of the oil sands, along with sand, water and clay
CEO	Chief Executive Officer
CFO	Chief Financial Officer
cogeneration facilities	Facilities that produce both electricity and useful heat at the same time
diluent	A thinning agent made up of organic compounds. Used to dilute bitumen so it can be transported through pipelines
DRP	Dividend Reinvestment and Share Purchase Plan
ESG	Environmental, social and governance
Empress	A major delivery/receipt point for natural gas near the Alberta/Saskatchewan border
force majeure	Unforeseeable circumstances that prevent a party to a contract from fulfilling it
GHG	Greenhouse gas
HSSE	Health, safety, sustainability and environment
investment base	Includes rate base as well as assets under construction
LDC	Local distribution company
LNG	Liquefied natural gas
MOU	Memorandum of understanding
OM&A	Operating, maintenance and administration
PPA	Power purchase arrangement
rate base	Average assets in service, working capital and deferred amounts used in setting of regulated rates
TSA	Transportation Service Agreement
TOMS	TC Energy's Operational Management System
WCSB	Western Canadian Sedimentary basin

Accounting terms

AFUDC	Allowance for funds used during construction
GAAP	U.S. generally accepted accounting principles
LIBOR	London Interbank Offered Rate
RRA	Rate-regulated accounting
ROE	Return on common equity

Government and regulatory bodies terms

CER	Canada Energy Regulator (formerly the National Energy Board (Canada))
CFE	Comisión Federal de Electricidad (Mexico)
CRE	Comisión Reguladora de Energia, or Energy Regulatory Commission (Mexico)
ECCC	Environment and Climate Change Canada
FERC	Federal Energy Regulatory Commission (U.S.)
IESO	Independent Electricity System Operator (Ontario)
NYSE	New York Stock Exchange
OBPS	Output Based Pricing System
OPEC+	Organization of the Petroleum Exporting Countries plus certain other oil-exporting nations
OPG	Ontario Power Generation
PHMSA	Pipeline and Hazardous Materials Safety Administration
SEC	U.S. Securities and Exchange Commission
TSX	Toronto Stock Exchange