# Management's discussion and analysis

February 17, 2021

This management's discussion and analysis (MD&A) contains information to help the reader make investment decisions about TC Energy Corporation (TC Energy). It discusses our business, operations, financial position, risks and other factors for the year ended December 31, 2020.

This MD&A should be read with our accompanying December 31, 2020 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 110. All information is as of February 17, 2021 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
- expected cash flows and future financing options available, including portfolio management
- expected dividend growth
- expected access to and cost of capital
- expected costs and schedules for planned projects, including projects under construction and in development
- expected capital expenditures, contractual obligations, commitments and contingent liabilities
- expected regulatory processes and outcomes
- expected outcomes with respect to legal proceedings, including arbitration and insurance claims
- the expected impairment charge for Keystone XL in first quarter 2021
- 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

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

### Risks and uncertainties

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

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

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

## FOR MORE INFORMATION

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

## NON-GAAP MEASURES

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

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

These measures do not have any standardized meaning as prescribed by GAAP and therefore may not be comparable to similar measures presented by other entities.

## Comparable measures

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

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

- gains or losses on sales of assets or assets held for sale
- income tax refunds, adjustments to enacted tax rates and valuation allowances
- certain fair value adjustments relating to risk management activities
- legal, contractual and bankruptcy settlements
- impairment of goodwill, investments and other assets
- acquisition and integration costs
- restructuring costs.

We exclude the unrealized gains and losses from changes in the fair value of derivatives used to reduce our exposure to certain financial and commodity price risks. These derivatives generally provide effective economic hedges, but do not meet the criteria for hedge accounting. As a result, the changes in fair value are recorded in net income. As these amounts do not accurately reflect the gains and losses that will be realized at settlement, we do not consider them reflective of our underlying operations. We also exclude the unrealized foreign exchange gains and losses on the Loan receivable from affiliate as well as the corresponding proportionate share of Sur de Texas foreign exchange gains and losses, as these amounts do not accurately reflect the gains and losses that will be realized at settlement. These amounts offset within each reporting period, resulting in no impact on net income.

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

| Comparable measure | GAAP measure |
|---|---|
| comparable EBITDA | segmented earnings |
| comparable EBIT | segmented earnings |
| comparable earnings | net income attributable to common shares |
| comparable earnings per common share | net income per common share |
| comparable funds generated from operations | net cash provided by operations |

### Comparable EBITDA and comparable EBIT

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

### Comparable earnings and comparable earnings per common share

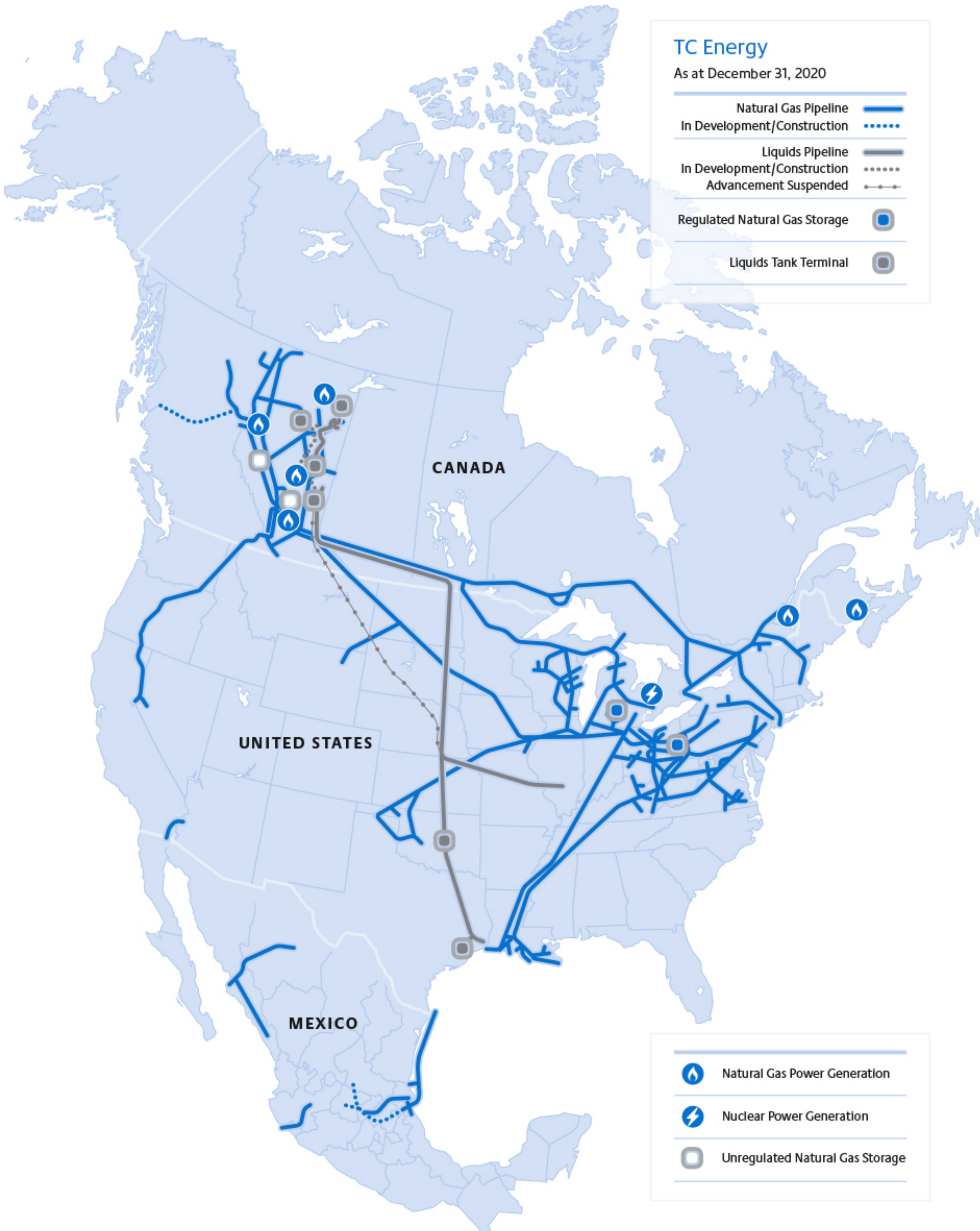
Comparable earnings represents earnings or losses attributable to common shareholders on a consolidated basis, adjusted for specific items. Comparable earnings is comprised of segmented earnings, Interest expense, AFUDC, Interest income and other, Income tax expense, Non-controlling interests and Preferred 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. We believe it is a useful measure of our consolidated operating cash flows because it excludes fluctuations from working capital balances, which do not necessarily reflect underlying operations in the same period, and is used to provide a consistent measure of the cash generating performance of our assets. Comparable funds generated from operations is adjusted for the cash impact of specific items noted above. Refer to the Financial condition section for a reconciliation to Net cash provided by operations.

# 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<br>(millions of $) | 2020 | 2019 |
|---|---|---|
| **Total assets by segment** | | |
| Canadian Natural Gas Pipelines[1] | **22,852** | 21,983 |
| U.S. Natural Gas Pipelines | **43,217** | 41,627 |
| Mexico Natural Gas Pipelines | **7,215** | 7,207 |
| Liquids Pipelines | **16,744** | 15,931 |
| Power and Storage[2] | **5,062** | 7,788 |
| Corporate | **5,210** | 4,743 |
| | **100,300** | 99,279 |

1 Reflects the sale of a 65 per cent equity interest in Coastal GasLink Pipeline Limited Partnership on May 22, 2020.
2 Includes our Ontario natural gas-fired power plants until sold on April 29, 2020.

| year ended December 31<br>(millions of $) | 2020 | 2019 |
|---|---|---|
| **Total revenues by segment** | | |
| Canadian Natural Gas Pipelines[1] | **4,469** | 4,010 |
| U.S. Natural Gas Pipelines[2] | **5,031** | 4,978 |
| Mexico Natural Gas Pipelines | **716** | 603 |
| Liquids Pipelines[3] | **2,371** | 2,879 |
| Power and Storage[4] | **412** | 785 |
| | **12,999** | 13,255 |

1 Reflects the sale of a 65 per cent equity interest in Coastal GasLink Pipeline Limited Partnership on May 22, 2020.
2 Includes certain Columbia Midstream assets until sold in August 2019.
3 Reflects the sale of an 85 per cent equity interest in Northern Courier in July 2019.
4 Includes our Ontario natural gas-fired power plants until sold on April 29, 2020 and Coolidge generating station until sold in May 2019.

| year ended December 31<br>(millions of $) | 2020 | 2019 |
|---|---|---|
| **Comparable EBITDA by segment** | | |
| Canadian Natural Gas Pipelines[1] | **2,566** | 2,274 |
| U.S. Natural Gas Pipelines[2] | **3,638** | 3,480 |
| Mexico Natural Gas Pipelines | **786** | 605 |
| Liquids Pipelines[3] | **1,700** | 2,192 |
| Power and Storage[4] | **677** | 832 |
| Corporate | **(16)** | (17) |
| | **9,351** | 9,366 |

1 Reflects the sale of a 65 per cent equity interest in Coastal GasLink Pipeline Limited Partnership on May 22, 2020.
2 Includes certain Columbia Midstream assets until sold in August 2019.
3 Reflects the sale of an 85 per cent equity interest in Northern Courier in July 2019.
4 Includes our Ontario natural gas-fired power plants until sold on April 29, 2020 and Coolidge generating station until sold in May 2019.

## OUR STRATEGY

Our vision is to be the leading energy infrastructure company in North America, focused on pipeline and power generation opportunities where we have, or can develop, a significant competitive advantage.

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. 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 $20 billion in secured projects and $8 billion in largely commercially-supported projects under development. These investments will contribute incremental earnings and cash flows as they are placed in service
- Our existing extensive footprint offers significant, highly executable in-corridor growth opportunities
- We continue to develop projects and manage construction risk in a disciplined manner that maximizes capital productivity 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 early stages of projects
- We will advance selected opportunities 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 contributes to 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.

- 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
- 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 and recently published 10 sustainability commitments as part of our 2020 Report on Sustainability, which support the United Nations Sustainable Development Goals
- 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:

| **Live within our means** |
| --- |
| • Rely on internally-generated cash flows, existing debt capacity, partnerships and portfolio management to finance new initiatives. Reserve issuing common equity for transformational opportunities. |
| **Project risks known and acceptable** |
| • 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 the midstream 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. |

## COVID-19

On March 11, 2020, the World Health Organization declared the novel coronavirus, or COVID-19, a global pandemic. Company business continuity plans remain in place across our organization and we continue to effectively operate our assets, conduct commercial activities and execute on projects with a focus on health, safety and reliability. Our businesses are broadly considered essential in Canada, the United States and Mexico given the important role our infrastructure plays in providing energy to North American markets. We are confident that our robust continuity and business resumption plans for critical teams, including natural gas, liquids and power plant control as well as commercial and field operations, will continue to ensure the safe and reliable delivery of energy for our customers.

With approximately 95 per cent of our comparable EBITDA generated from rate-regulated assets and/or long-term contracts, we are largely insulated from the short-term volatility associated with fluctuations in volume throughput and commodity prices. Aside from the impact of maintenance activities and normal seasonal factors, to date we have not seen any pronounced changes in the utilization of our assets, with the exception of the Keystone Pipeline System which has experienced a reduction in uncontracted volumes that we expect to remain until market conditions rebalance and normalize. As well, we have not encountered any significant impacts on our supply chain.

In March 2020, as a result of COVID-19 impacts, Bruce Power declared force majeure with respect to its Unit 6 Major Component Replacement (MCR) and certain Asset Management work. While the MCR and Asset Management activities continue to progress, the ultimate impact of the Unit 6 force majeure at Bruce Power will depend on the extent and duration of the pandemic and their ability to implement mitigation measures throughout the project. In December 2020, the Government of British Columbia issued an order limiting the presence of construction personnel in Northern British Columbia. This order will have an impact on 2021 planned construction for the Coastal GasLink pipeline project (Coastal GasLink). The extent of the ultimate impact will depend on the duration of the restrictions. While it is too early to ascertain any long-term impact that COVID-19 may have on our capital program, in addition to the impacts on Bruce Power Unit 6 MCR and Coastal GasLink construction, directionally we have observed some slowdown of our construction activities and capital expenditures in 2020. This is largely due to permitting delays as regulators have been unable to process permits and conduct consultations within timeframes that were originally anticipated.

Capital market conditions in 2020 saw periods of extreme volatility and reduced liquidity. Despite this challenging backdrop, we were able to enhance our liquidity by continuing to access debt capital markets, completing sizable portfolio management transactions and arranging incremental committed credit facilities, which were extinguished in fourth quarter 2020 as they were no longer required. With the combination of our predictable and growing cash flows from operations, cash on hand, substantial committed credit facilities and various other financing levers available to us, we believe we are well positioned to continue to fund our obligations, including in the event similarly challenging market conditions re-emerge.

The combination of the COVID-19 pandemic and the unparalleled energy demand and supply disruption has had a significant impact on certain of our customers. While counterparty risk has heightened and the long-term impacts of COVID-19 and related disruptions on our customers are difficult to predict, we are not expecting a material negative impact to our 2021 earnings or cash flows as a result of this increased risk.

Since the pandemic began, we have endeavored to understand and respond to the requirements of the communities in which we operate. Based on the paramount needs of people in our communities, our support has focused on food security and first responder organizations. As our multi-billion dollar capital projects continue to progress, where possible, we continue to focus on buying and hiring locally, benefiting small businesses and creating jobs in many communities that have been significantly impacted by the COVID-19 crisis.

The full extent and lasting impact of the COVID-19 pandemic on the global economy is as yet undetermined but to date has included extreme volatility in financial markets and commodity prices, a significant reduction in overall economic activity, widespread extended shutdowns of businesses and supply chain disruptions. 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 highly 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, Significant events within each business segment, Financial condition and Financial risks sections.

## CAPITAL PROGRAM

We are developing quality projects under our capital program. These long-life infrastructure assets are supported by long-term commercial arrangements with creditworthy counterparties and/or regulated business models and are expected to generate significant growth in earnings and cash flows.

Our capital program consists of $20 billion of secured projects which include commercially supported, committed projects that are either under construction or are in or preparing to commence the permitting stage. An additional $8 billion of projects under development are commercially supported (except where noted) but have greater uncertainty with respect to timing and estimated project costs and are subject to certain key approvals.

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

In the year ended December 31, 2020, we placed approximately $5.9 billion of capacity capital projects in service, mainly comprised of NGTL System expansions. In addition, approximately $1.8 billion of maintenance capital expenditures were incurred.

All projects are subject to cost and timing adjustments due to weather, market conditions, route refinement, permitting conditions, scheduling and timing of regulatory permits, among other factors as well as the additional restrictions and uncertainty presented by the ongoing impact of COVID-19. Amounts included in the following tables exclude capitalized interest and AFUDC.

## Secured projects

| (billions of $) | Expected in-service date | Estimated project cost[1] | Carrying value at December 31, 2020 |
|---|---|---|---|
| **Canadian Natural Gas Pipelines** | | | |
| Canadian Mainline | 2021-2024 | 0.2 | 0.1 |
| NGTL System[2] | 2021 | 1.4 | 0.9 |
| | 2022 | 3.1 | 0.1 |
| | 2023 | 1.7 | 0.1 |
| | 2024+ | 0.5 | — |
| Coastal GasLink[3] | 2023 | 0.2 | 0.2 |
| Regulated maintenance capital expenditures | 2021-2023 | 2.0 | — |
| **U.S. Natural Gas Pipelines** | | | |
| Other capacity capital | 2021-2023 | US 2.3 | US 0.7 |
| Regulated maintenance capital expenditures | 2021-2023 | US 2.0 | — |
| **Mexico Natural Gas Pipelines** | | | |
| Villa de Reyes | 2021 | US 0.9 | US 0.8 |
| Tula[4] | — | US 0.8 | US 0.6 |
| **Liquids Pipelines** | | | |
| Keystone XL[5] | — | — | US 2.0 |
| Other capacity capital | 2022 | US 0.1 | — |
| Recoverable maintenance capital expenditures | 2021-2023 | 0.1 | — |
| **Power and Storage** | | | |
| Bruce Power – life extension[6] | 2021-2024 | 2.6 | 1.2 |
| **Other** | | | |
| Non-recoverable maintenance capital expenditures[7] | 2021-2023 | 0.6 | — |
| | | **18.5** | **6.7** |
| Foreign exchange impact on secured projects[8] | | **1.7** | **1.1** |
| **Total secured projects** (Cdn$) | | **20.2** | **7.8** |

1 Amounts reflect 100 per cent of costs related to wholly-owned assets and assets held through TC PipeLines, LP as well as cash contributions to our joint venture investments.

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

3 On May 22, 2020, we sold a 65 per cent equity interest in Coastal GasLink Pipeline Limited Partnership and began to account for our remaining 35 per cent investment using equity accounting. As a result, the estimated project cost and carrying value represent our share of 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 regarding the ongoing review of project cost and schedule.

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

5 Advancement of the Keystone XL project has been suspended pending assessment of the implications and options available to us following the January 20, 2021 revocation of the Presidential Permit and an asset impairment is expected to be recorded in first quarter 2021. The Keystone XL project carrying value reflects the amount remaining after the 2015 impairment charge, along with additional amounts expended and capitalized since January 2018. A portion of the carrying value has been funded by Government of Alberta contributions or is subject to recovery from shippers under contract. Refer to the Liquids Pipelines - Significant events section for further information.

6 Reflects our expected share of cash contributions for the Unit 6 MCR program costs, expected to be in service in 2023, and amounts to be invested under the Asset Management program through 2024.

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 1.28 at December 31, 2020.

## Projects under development

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

| (billions of $) | Estimated project cost[1] | Carrying value at December 31, 2020 |
|---|---|---|
| **U.S. Natural Gas Pipelines** | | |
| Other capacity capital[2] | US 0.3 | — |
| **Liquids Pipelines** | | |
| Heartland Pipeline and TC Terminals[3,4] | 0.9 | 0.1 |
| Grand Rapids Phase 2[3] | 0.7 | — |
| Keystone Hardisty Terminal[3,4] | 0.3 | 0.1 |
| **Power and Storage** | | |
| Bruce Power – life extension[5] | 5.9 | 0.2 |
| | **8.1** | **0.4** |
| Foreign exchange impact on projects under development[6] | **0.1** | **—** |
| **Total projects under development** (Cdn$) | **8.2** | **0.4** |

1 Amounts reflect our proportionate share of joint venture costs where applicable and 100 per cent of costs related to wholly-owned assets and assets held through TC PipeLines, LP.
2 Includes projects subject to a positive customer FID.
3 Regulatory approvals have been obtained and additional commercial support is being pursued.
4 Management is currently reviewing the viability of these projects following the January 20, 2021 revocation of the Presidential Permit for the Keystone XL pipeline.
5 Reflects our proportionate share of MCR program costs for Units 3, 4, 5, 7 and 8, and the remaining Asset Management program costs beyond 2024.
6 Reflects U.S./Canada foreign exchange rate of 1.28 at December 31, 2020.

## 2020 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 24 and 77 as well as the business segment Financial results sections for reconciliations to the most directly comparable GAAP measures.

| **year ended December 31**<br>(millions of $, except per share amounts) | **2020** | **2019** | **2018** |
|---|---|---|---|
| **Income** | | | |
| Revenues | **12,999** | 13,255 | 13,679 |
| Net income attributable to common shares | **4,457** | 3,976 | 3,539 |
| per common share – basic | **$4.74** | $4.28 | $3.92 |
| Comparable EBITDA | **9,351** | 9,366 | 8,563 |
| Comparable earnings | **3,945** | 3,851 | 3,480 |
| per common share | **$4.20** | $4.14 | $3.86 |
| **Cash flows** | | | |
| Net cash provided by operations | **7,058** | 7,082 | 6,555 |
| Comparable funds generated from operations | **7,385** | 7,117 | 6,522 |
| Capital spending[1] | **8,900** | 8,784 | 10,929 |
| Proceeds from sales of assets, net of transaction costs | **3,407** | 2,398 | 614 |
| Reimbursement of costs related to capital projects in development | **—** | — | 470 |
| **Balance sheet** | | | |
| Total assets | **100,300** | 99,279 | 98,920 |
| Long-term debt, including current portion | **36,885** | 36,985 | 39,971 |
| Junior subordinated notes | **8,498** | 8,614 | 7,508 |
| Redeemable non-controlling interest[2] | **393** | — | — |
| Preferred shares | **3,980** | 3,980 | 3,980 |
| Non-controlling interests | **1,682** | 1,634 | 1,655 |
| Common shareholders' equity | **27,418** | 26,783 | 25,358 |
| **Dividends declared** | | | |
| per common share | **$3.24** | $3.00 | $2.76 |
| **Basic common shares (millions)** | | | |
| – weighted average for the year | **940** | 929 | 902 |
| – issued and outstanding at end of year | **940** | 938 | 918 |

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

2 Redeemable non-controlling interest classified in mezzanine equity.

## Consolidated results

| year ended December 31<br>(millions of $, except per share amounts) | 2020 | 2019 | 2018 |
|---|---|---|---|
| Canadian Natural Gas Pipelines | **1,657** | 1,115 | 1,250 |
| U.S. Natural Gas Pipelines | **2,837** | 2,747 | 1,700 |
| Mexico Natural Gas Pipelines | **669** | 490 | 510 |
| Liquids Pipelines | **1,359** | 1,848 | 1,579 |
| Power and Storage | **181** | 455 | 779 |
| Corporate | **70** | (70) | (54) |
| **Total segmented earnings** | **6,773** | 6,585 | 5,764 |
| Interest expense | **(2,228)** | (2,333) | (2,265) |
| Allowance for funds used during construction | **349** | 475 | 526 |
| Interest income and other | **213** | 460 | (76) |
| **Income before income taxes** | **5,107** | 5,187 | 3,949 |
| Income tax expense | **(194)** | (754) | (432) |
| **Net income** | **4,913** | 4,433 | 3,517 |
| Net (income) / loss attributable to non-controlling interests | **(297)** | (293) | 185 |
| **Net income attributable to controlling interests** | **4,616** | 4,140 | 3,702 |
| Preferred share dividends | **(159)** | (164) | (163) |
| **Net income attributable to common shares** | **4,457** | 3,976 | 3,539 |
| **Net income per common share** | | | |
| – basic | **$4.74** | $4.28 | $3.92 |

Net income attributable to common shares in 2020 was $4.5 billion or $4.74 per share (2019 – $4.0 billion or $4.28 per share; 2018 – $3.5 billion or $3.92 per share). Net income per common share increased by $0.46 per share in 2020 compared to 2019 and $0.36 in 2019 compared to 2018 due to the increases in net income and reflects the dilutive impact of common shares issued under our DRP in 2019 and 2018 and Corporate ATM program in 2018.

The following specific items were recognized in net income attributable to common shares and were excluded from comparable earnings in the relevant periods:

**2020**

- 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)
- 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 project. Refer to the Liquids Pipelines - Significant events section for additional information
- an additional $18 million income tax recovery related to state income taxes on the sale of certain Columbia Midstream assets
- an after-tax loss of $283 million related to the Ontario natural gas-fired power plant assets sold on April 29, 2020. The total after-tax loss on this transaction was $477 million including losses accrued in 2019 upon classification of the assets as held for sale.

**2019**

- an income tax valuation allowance release of $195 million related to certain prior years' U.S. 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 loss of $194 million related to the Ontario natural gas-fired power plant assets held for sale
- an after-tax gain of $115 million related to the partial sale of Northern Courier
- 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 rate-regulated accounting (RRA)
- an after-tax loss of $6 million related to the sale of the remainder of our U.S. Northeast power marketing contracts.

**2018**

- an after-tax net loss of $4 million related to our U.S. Northeast power marketing contracts
- a $143 million after-tax gain related to the sale of our interests in the Cartier Wind power facilities
- a $115 million deferred income tax recovery from an MLP regulatory liability write-off as a result of changes in U.S. income tax regulations
- a $52 million recovery of deferred income taxes as a result of finalizing the impact of U.S. Tax Reform
- a $27 million income tax recovery related to the sales of our U.S. Northeast power generation assets
- $25 million of after-tax income recognized on Bison contract terminations
- a $140 million after-tax impairment charge on Bison
- a $15 million after-tax goodwill impairment charge on Tuscarora.

Refer to the Results section 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<br>(millions of $, except per share amounts) | 2020 | 2019 | 2018 |
|---|---|---|---|
| **Net income attributable to common shares** | **4,457** | 3,976 | 3,539 |
| **Specific items (net of tax):** | | | |
| Gain on partial sale of Coastal GasLink LP | **(402)** | — | — |
| Income tax valuation allowance releases | **(299)** | (195) | — |
| Loss on sale of Columbia Midstream assets | **(18)** | 152 | — |
| Loss on sale of Ontario natural gas-fired power plants | **283** | 194 | — |
| Gain on partial sale of Northern Courier | **—** | (115) | — |
| Gain on sale of Coolidge generating station | **—** | (54) | — |
| Alberta corporate income tax rate reduction | **—** | (32) | — |
| U.S. Northeast power marketing contracts | **—** | 6 | 4 |
| Gain on sale of Cartier Wind power facilities | **—** | — | (143) |
| MLP regulatory liability write-off | **—** | — | (115) |
| U.S. Tax Reform | **—** | — | (52) |
| Net gain on sales of U.S. Northeast power generation assets | **—** | — | (27) |
| Bison contract terminations | **—** | — | (25) |
| Bison asset impairment | **—** | — | 140 |
| Tuscarora goodwill impairment | **—** | — | 15 |
| Risk management activities[1] | **(76)** | (81) | 144 |
| **Comparable earnings** | **3,945** | 3,851 | 3,480 |
| **Net income per common share** | **$4.74** | $4.28 | $3.92 |
| Gain on partial sale of Coastal GasLink LP | **(0.43)** | — | — |
| Income tax valuation allowance releases | **(0.32)** | (0.21) | — |
| Loss on sale of Columbia Midstream assets | **(0.02)** | 0.16 | — |
| Loss on sale of Ontario natural gas-fired power plants | **0.30** | 0.21 | — |
| Gain on partial sale of Northern Courier | **—** | (0.12) | — |
| 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 | 0.01 |
| Gain on sale of Cartier Wind power facilities | **—** | — | (0.16) |
| MLP regulatory liability write-off | **—** | — | (0.13) |
| U.S. Tax Reform | **—** | — | (0.06) |
| Net gain on sales of U.S. Northeast power generation assets | **—** | — | (0.03) |
| Bison contract terminations | **—** | — | (0.03) |
| Bison asset impairment | **—** | — | 0.16 |
| Tuscarora goodwill impairment | **—** | — | 0.02 |
| Risk management activities | **(0.07)** | (0.10) | 0.16 |
| **Comparable earnings per common share** | **$4.20** | $4.14 | $3.86 |

1

| year ended December 31<br>(millions of $) | 2020 | 2019 | 2018 |
|---|---|---|---|
| Liquids marketing | **(9)** | (72) | 71 |
| Canadian power | **(2)** | — | 3 |
| U.S. power | **—** | (52) | (11) |
| Natural gas storage | **(13)** | (11) | (11) |
| Foreign exchange | **126** | 245 | (248) |
| Income taxes attributable to risk management activities | **(26)** | (29) | 52 |
| **Total unrealized gains / (losses) from risk management activities** | **76** | 81 | (144) |

## Comparable EBITDA to Comparable Earnings

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

| year ended December 31<br>(millions of $, except per share amounts) | 2020 | 2019 | 2018 |
|---|---|---|---|
| **Comparable EBITDA** | | | |
| Canadian Natural Gas Pipelines | **2,566** | 2,274 | 2,379 |
| U.S. Natural Gas Pipelines | **3,638** | 3,480 | 3,035 |
| Mexico Natural Gas Pipelines | **786** | 605 | 607 |
| Liquids Pipelines | **1,700** | 2,192 | 1,849 |
| Power and Storage | **677** | 832 | 752 |
| Corporate | **(16)** | (17) | (59) |
| **Comparable EBITDA** | **9,351** | 9,366 | 8,563 |
| Depreciation and amortization | **(2,590)** | (2,464) | (2,350) |
| Interest expense | **(2,228)** | (2,333) | (2,265) |
| Allowance for funds used during construction | **349** | 475 | 526 |
| Interest income and other included in comparable earnings | **173** | 162 | 177 |
| Income tax expense included in comparable earnings | **(654)** | (898) | (693) |
| Net income attributable to non-controlling interests included in comparable earnings | **(297)** | (293) | (315) |
| Preferred share dividends | **(159)** | (164) | (163) |
| **Comparable earnings** | **3,945** | 3,851 | 3,480 |
| **Comparable earnings per common share** | **$4.20** | $4.14 | $3.86 |

### 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 on January 17, 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 on April 29, 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 first quarter 2020 related to fees associated with our successful construction of Sur de Texas
- 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 earnings from our U.S. dollar-denominated operations.

**Comparable EBITDA – 2019 versus 2018**

Comparable EBITDA in 2019 increased by $803 million compared to 2018 primarily due to the net result of the following:

- increased contribution from U.S. Natural Gas Pipelines mainly attributable to incremental earnings from Columbia Gas and Columbia Gulf growth projects placed in service, partially offset by decreased earnings from Bison (wholly owned by TC PipeLines, LP) contract terminations and from the sale of certain Columbia Midstream assets in August 2019
- increased contribution from Liquids Pipelines primarily resulting from higher volumes on the Keystone Pipeline System and earnings from liquids marketing activities, partially offset by decreased earnings as a result of the sale of an 85 per cent equity interest in Northern Courier in July 2019
- higher contribution from Power and Storage primarily attributable to increased Bruce Power results from a higher realized power price, partially offset by the sale of our interests in the Cartier Wind power facilities in late 2018 and the sale of the Coolidge generating facility in May 2019
- lower contribution from Canadian Natural Gas Pipelines mainly due to lower flow-through income taxes on the Canadian Mainline reflecting the impact of the Canadian Mainline 2018-2020 Tolls Review (NEB 2018 Decision) and on the NGTL System as a result of accelerated tax depreciation enacted by the Canadian Federal Government, partially offset by higher rate-base earnings and depreciation on the NGTL System as additional facilities were placed in service
- foreign exchange impact of a stronger U.S. dollar on the Canadian dollar equivalent earnings from our U.S. dollar-denominated operations.

Due to the flow-through treatment of certain expenses, including income taxes and depreciation on our Canadian rate-regulated pipelines, the accelerated tax depreciation changes in 2019 and increased depreciation expense impacts our comparable EBITDA despite having no significant effect on net income.

**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 first quarter 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 expansions 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 largely in Canadian Natural Gas Pipelines and U.S. Natural Gas Pipelines reflecting new assets placed in service. In Canadian Natural Gas Pipelines, however, it is fully recovered in tolls on a flow-through basis as discussed in comparable EBITDA above, and therefore has no significant impact on comparable earnings.

**Comparable earnings – 2019 versus 2018**

Comparable earnings in 2019 were $371 million or $0.28 per common share higher than in 2018, and were primarily the net result of:

- changes in comparable EBITDA described above
- higher income tax expense due to increased comparable earnings before income taxes and lower foreign tax rate differentials, partially offset by lower flow-through income taxes on the Canadian Mainline reflecting the impact of the NEB 2018 Decision and on the NGTL System from the effect of accelerated tax depreciation
- higher depreciation largely in Canadian Natural Gas Pipelines, which is subject to flow-through treatment, and U.S. Natural Gas Pipelines, both reflecting new projects placed in service
- increased interest expense primarily as a result of long-term debt issuances, net of maturities, the foreign exchange impact on translation of U.S. dollar-denominated interest and higher levels of short-term borrowings, partially offset by higher capitalized interest
- lower AFUDC primarily due to Columbia Gas and Columbia Gulf growth projects placed in service, partially offset by capital expenditures on our NGTL System and continued investment in our Mexico projects.

Comparable earnings per share reflected the dilutive impact of common shares issued under our DRP in 2019 and 2018, and Corporate ATM program in 2018. Refer to the Financial condition section of this MD&A for further information on common share issuances.

## Cash flows

Net cash provided by operations of $7.1 billion in 2020 remained consistent with 2019, and comparable funds generated from operations of $7.4 billion were four per cent higher in 2020 compared to 2019, primarily due to the 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.

**Funds used in investing activities**

***Capital spending***[1]

| **year ended December 31**<br>(millions of $) | **2020** | **2019** | **2018** |
|---|---|---|---|
| Canadian Natural Gas Pipelines | **3,608** | 3,906 | 2,478 |
| U.S. Natural Gas Pipelines | **2,785** | 2,516 | 5,771 |
| Mexico Natural Gas Pipelines | **173** | 357 | 797 |
| Liquids Pipelines | **1,442** | 954 | 581 |
| Power and Storage | **834** | 1,019 | 1,257 |
| Corporate | **58** | 32 | 45 |
| | **8,900** | 8,784 | 10,929 |

1 Capital spending includes capacity capital expenditures, maintenance capital expenditures, capital projects in development and contributions to equity investments.

In 2020 and 2019, we invested $8.9 billion and $8.8 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 2020 and 2019 included contributions of $0.8 billion and $0.6 billion, respectively, to our equity investments, predominantly related to Bruce Power.

***Proceeds from sales of assets***

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 a $1.5 billion distribution from a Coastal GasLink LP project-level credit facility draw 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 a Northern Courier debt issuance which preceded the equity sale.

## Balance sheet

We continue to maintain a solid financial position while growing our total assets by $1.0 billion in 2020. At December 31, 2020, common shareholders' equity, including non-controlling interests, represented 35 per cent (2019 – 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 16 per cent (2019 – 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 7.4 per cent to $0.87 per common share for the quarter ending March 31, 2021 which equates to an annual dividend of $3.48 per common share. This was the 21st 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 five to seven 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. From July 1, 2016 to October 31, 2019, participation was satisfied through common shares issued from treasury at a discount of two per cent to market prices over a specified period.

Commencing with the dividends declared October 31, 2019, common shares purchased with reinvested cash dividends under TC Energy’s DRP are instead acquired on the open market at 100 per cent of the weighted average purchase price. The DRP is available for dividends payable on TC Energy's common and preferred shares.

### Cash dividends paid

| **year ended December 31**<br>(millions of $) | **2020** | **2019** | **2018** |
|---|---|---|---|
| Common shares | **2,987** | 1,798 | 1,571 |
| Preferred shares | **159** | 160 | 158 |

## OUTLOOK

### Comparable earnings

Our 2021 comparable earnings per common share are expected to be generally consistent with 2020 considering the net impact of the following:

- growth in the NGTL System and increased incentive earnings from the Canadian Mainline
- increased Coastal GasLink development fee revenue due to an expected increase in project activity
- an increase in transportation rates on Columbia Gas that is dependent on the outcome of the Section 4 Rate Case filed with FERC
- a full-year impact from assets placed in service in 2020 and new projects to be placed in service in 2021

Offset by:

- reduced capitalized interest due to the revocation of the Keystone XL Presidential Permit and resulting suspension of the advancement of the project
- continuing lower uncontracted volumes on the Keystone Pipeline System and reduced margins in the liquids marketing business
- lower contribution from Bruce Power as a result of greater planned outage days and higher operating costs
- the sale of our Ontario natural gas-fired power plants in 2020
- fees recognized in 2020 associated with the construction of the Sur de Texas pipeline
- suspension of AFUDC on Villa de Reyes.

We will continue to monitor the impact that COVID-19 may have on energy markets, our construction projects and regulatory proceedings and the potential effect on our 2021 comparable earnings per share.

In addition to the items noted above, a non-cash impairment on the Keystone XL project is expected to be recorded in first quarter 2021, which will be excluded from comparable earnings.

### Consolidated capital spending and equity investments

We expect to spend approximately $7 billion in 2021 on growth projects, maintenance capital expenditures and contributions to equity investments. The majority of the 2021 capital program is attributable to spending on NGTL System expansions, U.S. Natural Gas Pipelines projects, the Bruce Power life extension program and normal course maintenance capital expenditures. We do not believe disruptions related to COVID-19 will be material to our overall 2021 capital program but recognize that uncertainty exists in both the short and longer term.

Refer to the relevant business segment and Financial condition outlook sections for additional details on expected earnings and capital spending for 2021.

# 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 – 81,500 km (50,640 miles)
- partially-owned natural gas pipelines – 11,921 km (7,407 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

Optimizing the value of our existing natural gas pipeline systems, while responding to the changing flow patterns of natural gas in North America, is a top priority. 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 large 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, along the U.S. Gulf Coast; the west coast of the U.S., Mexico and Canada; and the east coast of Canada
- connections to growing Canadian and U.S. shale gas and other supplies.

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

## Recent highlights

**Canadian Natural Gas Pipelines**

- approximately $3.5 billion of projects placed in service in 2020 including the $1.1 billion Aitken Creek section of the $1.6 billion North Montney project in service on January 31, 2020. The final section of pipeline went into service May 1, 2020
- completed the sale of a 65 per cent equity interest in Coastal GasLink LP for net proceeds of $656 million and entered into a project-level credit facility with a current total capacity of $6.8 billion
- CER approved a five-year negotiated settlement on the NGTL System (NGTL System 2020-2024 Settlement)
- all elements of the NGTL System Rate Design and Services Application were approved by the CER as filed
- CER recommended and Governor in Council (GIC) approved the 2021 NGTL System Expansion Program
- CER approved a six-year negotiated settlement on the Canadian Mainline (Mainline 2021-2026 Settlement).

**U.S. Natural Gas Pipelines**

- placed in service approximately US$1.9 billion of projects including completion of the capital spend on the Columbia Gas Modernization II program
- originated an additional US$0.8 billion of growth projects
- Columbia Gas filed a Section 4 Rate Case with FERC on July 31, 2020 requesting an increase to maximum transportation rates effective February 1, 2021, subject to refund. The rate case is progressing as expected as we continue to pursue a collaborative process through settlement negotiations.

**Mexico Natural Gas Pipelines**

- completed the Guadalajara pipeline flow reversal project and renegotiated the TSA with the CFE enabling bidirectional flows connecting LNG imports and continental natural gas to regional markets
- continued construction of the Villa de Reyes pipeline project with in-service expected in 2021
- 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 34 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 believe we are well positioned to connect growing supply in northeast B.C. and northwest Alberta. Our large 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/B.C. 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.

***TC PipeLines, LP:*** We own a 25.5 per cent interest in TC PipeLines, LP, which has ownership interests in eight wholly-owned or partially-owned natural gas pipelines serving major markets in the U.S. Refer to the Corporate - Significant events section for additional information regarding the proposed acquisition of all outstanding common units not beneficially owned by TC Energy or our affiliates in exchange for TC Energy common shares.

**Mexico Natural Gas Pipelines**

***Sur de Texas:*** This offshore pipeline transports 20 per cent of Mexico's natural gas requirements from Texas to power and industrial markets in the eastern and central regions of the country. 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 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, increasingly, 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 access to international markets via LNG exports. We expect North American natural gas demand, including LNG exports, of approximately 128 Bcf/d by 2025, reflecting an increase of approximately 17 Bcf/d from 2020 levels.

This expected increased demand for natural gas, coupled with the replacement of existing supply sources that have an approximate 25 per cent annual decline rate, implies that over 45 Bcf/d of new natural gas supply connections will be needed in the next two years, providing investment opportunities for pipeline infrastructure companies to build new facilities or increase utilization of the existing footprint.

### Changing demand

The growing supply of natural gas has resulted in relatively low natural gas prices in North America which has supported increased demand, particularly in the following areas:

- natural gas-fired electric-power generation
- petrochemical and industrial facilities
- Alberta oil sands
- increased demand in Mexico to fuel power generation and other industrial facilities.

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 demand created by the addition of these new markets provides opportunities for us to build new pipeline infrastructure and to increase throughput on our existing pipelines.

**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 fixed transportation costs 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. For example, lower natural gas prices have allowed North American natural gas to gain market share over coal in serving power generation markets and to compete globally through LNG exports.

**More competition**

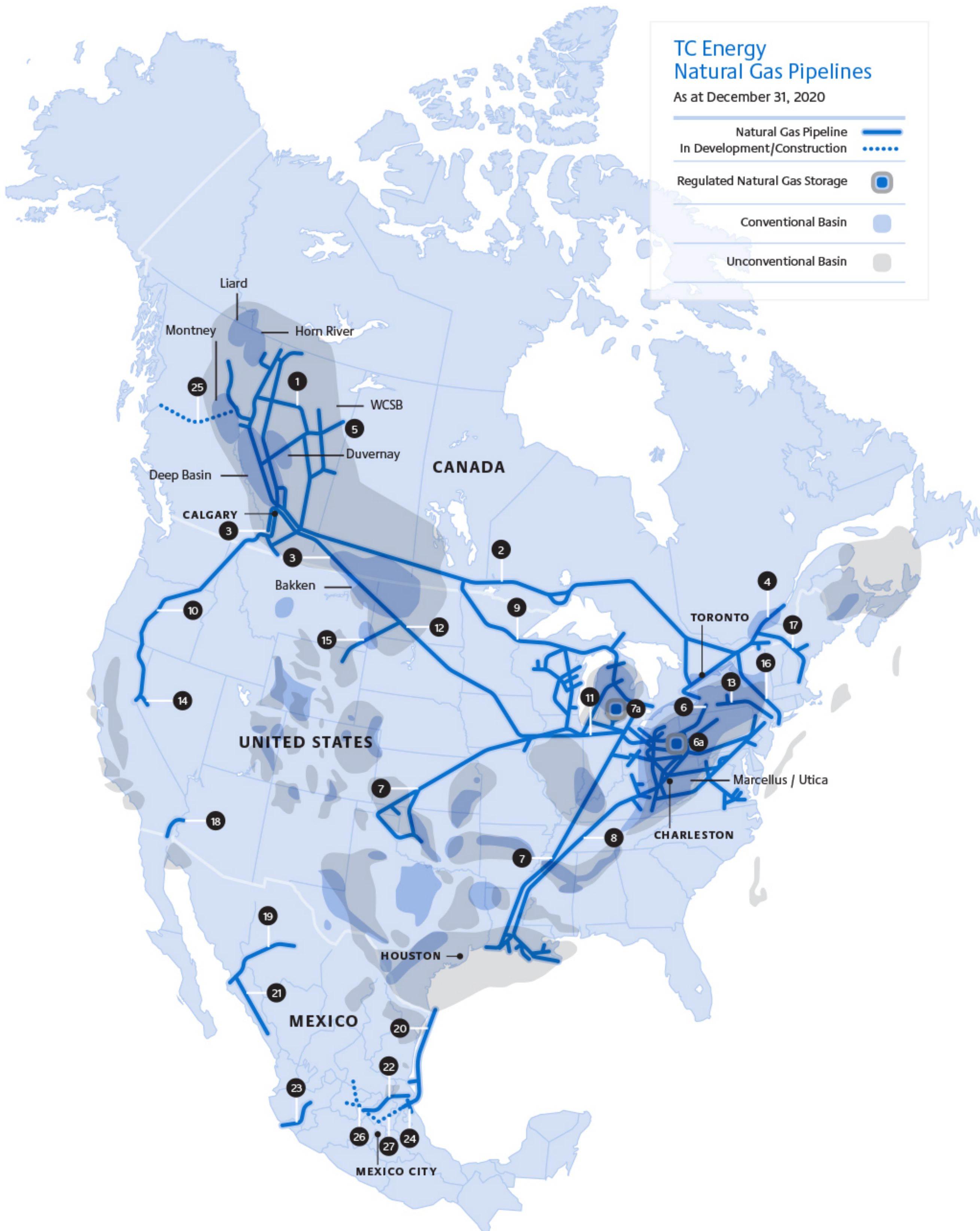
Changes in supply and demand levels and locations have resulted in increased competition to provide transportation services throughout North America. Our well-distributed footprint of natural gas pipelines, particularly in the liquids-rich and low-cost WCSB and the Appalachian basin, both of which are 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 the changing natural gas flow dynamics.

In 2021, 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 in service on time and on budget while ensuring the safety of the environment and general public impacted by the construction and operation of these facilities.

Our U.S. and Mexico natural gas marketing entities will complement 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, 2020
Natural Gas Pipeline
In Development/Construction
Regulated Natural Gas Storage
Conventional Basin
Unconventional Basin
Liard
Montney
Horn River
WCSB
Duvernay
Deep Basin
CALGARY
CANADA
Bakken
UNITED STATES
TORONTO
Marcellus / Utica
CHARLESTON
HOUSTON
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MEXICO CITY
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We are the operator of all of the following natural gas pipelines and regulated natural gas storage assets except for Iroquois.

| | | Length | Description | Effective ownership |
|---|---|---|---|---|
| | **Canadian pipelines** | | | |
| 1 | NGTL System | 24,622 km (15,299 miles) | Receives, transports and delivers natural gas within Alberta and B.C., and connects with the Canadian Mainline, Foothills system 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 | 1,236 km (768 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 the Portland pipeline system. | 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[2] | 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. We effectively own 65.4 per cent of the system through the combination of our 53.6 per cent direct ownership interest and our 25.5 per cent interest in TC PipeLines, LP. | 65.4% |
| 10 | Gas Transmission Northwest (GTN)[2] | 2,216 km (1,377 miles) | Transports WCSB and Rockies natural gas to Washington, Oregon and California. Connects with Tuscarora and Foothills. We effectively own 25.5 per cent of the system through our interest in TC PipeLines, LP. | 25.5% |
| 11 | Crossroads | 325 km (202 miles) | Interstate natural gas pipeline operating in Indiana and Ohio with multiple interconnects to other pipelines. | 100% |
| 12 | Northern Border[2] | 2,272 km (1,412 miles) | Transports WCSB, Bakken and Rockies natural gas from connections with Foothills and Bison to U.S. Midwest markets. We effectively own 12.7 per cent of the system through our 25.5 per cent interest in TC PipeLines, LP. | 12.7% |
| 13 | 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% |

| | | Length | Description | Effective ownership |
|---|---|---|---|---|
| 14 | Tuscarora[2] | 491 km (305 miles) | Transports natural gas from GTN at Malin, Oregon to markets in northeastern California and northwestern Nevada. We effectively own 25.5 per cent of the system through our interest in TC PipeLines, LP. | 25.5% |
| 15 | Bison[2] | 488 km (303 miles) | Transports natural gas from the Powder River basin in Wyoming to Northern Border in North Dakota. We effectively own 25.5 per cent of the system through our interest in TC PipeLines, LP. | 25.5% |
| 16 | Iroquois[2] | 669 km (416 miles) | Connects with the Canadian Mainline and serves markets in New York. We effectively own 13.2 per cent of the system through a 0.7 per cent direct ownership and our 25.5 per cent interest in TC PipeLines, LP. | 13.2% |
| 17 | Portland[2] | 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. We effectively own 15.7 per cent of the system through our 25.5 per cent interest in TC PipeLines, LP. | 15.7% |
| 18 | North Baja[2] | 138 km (86 miles) | Transports natural gas between Arizona and California and connects with a third-party pipeline on the California/Mexico border. We effectively own 25.5 per cent of the system through our interest in TC PipeLines, LP. | 25.5% |
| | **Mexico pipelines** | | | |
| 19 | 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% |
| 20 | 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% |
| 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[3]** | | | |
| | **Canadian pipelines** | | | |
| | NGTL System 2021 Facilities[1] | 365 km (227 miles) | An expansion program on the NGTL System including multiple pipeline projects and compression additions with in-service dates expected by April 2022 along with other facilities. | 100% |
| 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, B.C. | 35% |

| | Under construction[3] (continued) | Length | Description | Effective ownership |
|---|---|---|---|---|
| | **U.S. pipelines** | | | |
| | Louisiana XPress[4] | n/a | An expansion project on Columbia Gulf through compressor station modifications and additions with interim in-service currently in place and full in-service expected in 2022. | 100% |
| | Grand Chenier XPress[4] | n/a | An expansion project on the ANR pipeline through compressor station modifications and additions with expected in-service commencing in 2021 and 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[1,3]** | | | |
| | **Canadian pipelines** | | | |
| | NGTL System 2022 Facilities | 221 km (137 miles) | The 2022 NGTL System Expansion Program, including multiple pipeline projects and compression additions, along with other facilities. Expected completion is by April 2022 and April 2023. | 100% |
| | NGTL System 2023 Facilities | 228 km (142 miles) | The 2023 Expansion Program for the NGTL System and Foothills including multiple pipeline projects and compression additions with expected in-service dates in 2022, 2023 and 2024. | 100% |
| | **U.S. pipelines** | | | |
| | Elwood Power/ANR Horsepower Replacement[4] | n/a | A reliability project on the ANR pipeline that will replace, upgrade and modernize certain facilities with expected in-service in 2022. | 100% |
| | Wisconsin Access[4] | n/a | A reliability project on the ANR pipeline that will replace, upgrade and modernize certain facilities with expected in-service in 2022. | 100% |
| | GTN XPress[4] | n/a | An expansion project of GTN through compressor station modifications and additions with expected in-service commencing in 2022 and 2023. | 25.5% |
| | Alberta XPress[4] | n/a | An expansion project of the ANR pipeline through compressor station modifications and additions with expected in-service commencing in 2022. | 100% |
| | **In development** | | | |
| | **U.S. pipelines** | | | |
| | East Lateral XPress[1,4] | n/a | An expansion project on Columbia Gulf through compressor station modifications and additions with an expected in-service date of 2023. | 100% |

1 Facilities and some pipelines are not shown on the map.

2 The ownership of these assets would increase dependent on the outcome of the proposed merger between TC Energy and TC PipeLines, LP. Refer to the Corporate - Significant events section for additional information.

3 Final pipe lengths are subject to change during construction and/or final design considerations.

4 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 that includes an incentive mechanism for certain operating costs. The Canadian Mainline was in the final year of a six-year fixed toll settlement that included an incentive arrangement, which ended on December 31, 2020. As of January 1, 2021, the Canadian Mainline will operate under a new six-year settlement which also includes an incentive to decrease costs and/or increase revenues.

## SIGNIFICANT EVENTS

### Coastal GasLink Pipeline Project

On May 22, 2020, we completed the sale of a 65 per cent equity interest in Coastal GasLink LP for net proceeds of $656 million before post-closing adjustments and recorded a pre-tax gain of $364 million ($402 million after tax). The after-tax gain includes the gain on sale, utilization of previously unrecognized tax loss benefits and the required remeasurement of our 35 per cent retained ownership to fair value including a derivative instrument used to hedge the interest rate risk on the project-level credit facilities. Under the terms of the equity purchase agreement, the net proceeds included reimbursement of a 65 per cent equity share of project costs incurred to May 22, 2020. As part of the transaction, we were contracted by Coastal GasLink LP to construct and operate the pipeline. Effective with closing, we commenced recognition of development fee revenue earned during the construction of the pipeline for management and financial services provided and began accounting for our remaining 35 per cent investment using equity accounting.

In conjunction with the equity sale, Coastal GasLink LP entered into project-level credit facilities with a current total capacity of $6.8 billion which will fund the majority of the construction costs of Coastal GasLink. Immediately preceding the equity sale, Coastal GasLink LP drew down $1.6 billion on the facilities, of which approximately $1.5 billion was paid to TC Energy. Coastal GasLink LP has also entered into a subordinated demand revolving credit facility with TC Energy on commercial terms to provide additional short-term liquidity and funding flexibility to the project.

We continue to work with the 20 First Nations that have executed agreements with Coastal GasLink LP to provide them with an opportunity to invest in the project through an option to acquire a 10 per cent equity interest.

The introduction of partners, utilization of dedicated project-level credit facilities, recovery of cash payments through construction for carrying charges on costs incurred and remuneration for costs paid to close of the sale are expected to substantially satisfy our funding requirements through project completion.

Due to COVID-19, on December 29, 2020, the British Columbia Provincial Health Officer issued an order restricting the number of workers on site for industrial projects in the Northern Health Authority region of British Columbia. Industrial projects must submit restart plans to the Provincial Health Officer detailing steps to resume site work. Coastal GasLink LP is working with the provincial health authorities to safely resume construction activities in accordance with the objectives and timelines defined in the order.

The project is working with LNG Canada on establishing a revised project plan for Coastal GasLink. We expect that project costs will increase significantly and the schedule will be delayed compared to the previously disclosed estimate due to scope increases, permit delays and the impacts from COVID-19, including the provincial health order, although Coastal GasLink will continue to mitigate these impacts to the extent possible. These incremental costs will be included in the final pipeline tolls, subject to certain conditions. We do not anticipate our future equity contributions will increase significantly following the conclusion of this process.

**NGTL System**

In the year ended December 31, 2020, the NGTL System placed approximately $3.4 billion of capacity projects in service.

***NGTL System Expansion Programs***

On February 19, 2020, the CER issued a report recommending that the GIC approve the 2021 NGTL System Expansion Program, which the GIC approved on October 19, 2020. The NGTL System subsequently progressed construction activities in accordance with the regulatory requirements resulting in compressor station field work beginning in December 2020 and pipeline construction activities in January 2021.

Once facilities are placed in service, the 2021 NGTL System Expansion Program is expected to provide 1.59 PJ/d (1.45 Bcf/d) of incremental system capacity underpinned by long-term receipt and delivery contracts, connecting incremental supply to growing intra-basin and export markets. In-service is expected to commence in late 2021 with remaining program components completed by April 2022.

In second quarter 2020, the NGTL System held a Capacity Optimization Open Season soliciting requests for the deferral or advancement of pending contracts to assist customers in optimizing their transportation service needs and align system expansions with customer growth requirements. Following analysis of the results of the open season, we concluded that all proposed system expansion projects continue to be required to meet aggregate system demand, although the in-service dates for some facilities have been delayed. This resulted in the deferral of a portion of planned capital program spending from 2020 and 2021 to 2022 through 2024. The net impact of these deferrals, together with some expected increase in project costs on the 2021 NGTL System Expansion Program, have been incorporated into the Secured projects table in this MD&A.

***North Montney***

The North Montney project consists of approximately 206 km (128 miles) of new pipeline along with three compressor units and 13 meter stations. On January 31, 2020, the $1.1 billion Aitken Creek section of the North Montney project was placed into service with the final section of the project, Kahta South, in service on May 1, 2020. All compressor stations, pipeline sections and 11 of the 13 meter stations are complete and operational, with the remaining two meter stations expected to be in service in 2021.

***NGTL System Rate Design***

In March 2019, the NGTL System Rate Design and Services Application was filed with the NEB which addressed rate design, terms and conditions of service for the NGTL System and a tolling methodology for the North Montney Mainline. The CER issued a decision on March 25, 2020 approving all elements of the application as filed.

***NGTL System Revenue Requirement Settlement***

On August 17, 2020, the CER approved the NGTL System's 2020-2024 Revenue Requirement Settlement negotiated with its customers and other interested parties. The settlement, effective January 1, 2020, maintains the equity return at 10.1 per cent on 40 per cent deemed common equity, provides the NGTL System with the opportunity to increase depreciation rates if tolls fall below projected levels and includes an incentive mechanism for certain operating costs where variances from projected amounts are shared between the NGTL System and its customers. It also includes a mechanism to review the settlement should tolls exceed a pre-determined level, without affecting the equity return.

**Canadian Mainline**

During 2020, the Canadian Mainline placed approximately $0.2 billion of capacity projects in service.

On April 17, 2020, the CER approved a six-year unanimously supported negotiated settlement between the Canadian Mainline, its customers and other stakeholders. The settlement, effective January 1, 2021, sets a base equity return of 10.1 per cent on 40 per cent deemed common equity and includes an incentive to either decrease costs and/or increase revenues on the pipeline with a beneficial sharing mechanism to both the shippers and us.

## 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**<br>(millions of $) | **2020** | **2019** | **2018** |
|---|---|---|---|
| NGTL System | **1,509** | 1,210 | 1,197 |
| Canadian Mainline | **911** | 952 | 1,073 |
| Other Canadian pipelines[1] | **146** | 112 | 109 |
| **Comparable EBITDA** | **2,566** | 2,274 | 2,379 |
| Depreciation and amortization | **(1,273)** | (1,159) | (1,129) |
| **Comparable EBIT** | **1,293** | 1,115 | 1,250 |
| Specific item: | | | |
| Gain on partial sale of Coastal GasLink LP | **364** | — | — |
| **Segmented earnings** | **1,657** | 1,115 | 1,250 |

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 increased by $542 million in 2020 compared to 2019 which included a pre-tax gain in 2020 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 EBIT and comparable earnings. Canadian Natural Gas Pipelines comparable EBIT and segmented earnings decreased by $135 million in 2019 compared to 2018.

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**<br>(millions of $) | **2020** | **2019** | **2018** |
|---|---|---|---|
| **Net income** | | | |
| NGTL System | **565** | 484 | 398 |
| Canadian Mainline | **160** | 173 | 182 |
| **Average investment base** | | | |
| NGTL System | **14,070** | 11,959 | 9,669 |
| Canadian Mainline | **3,673** | 3,690 | 3,828 |

Net income for the NGTL System increased by $81 million in 2020 compared to 2019 and $86 million in 2019 compared to 2018 mainly due to a higher average investment base resulting from continued system expansions. On August 17, 2020, the CER approved the NGTL System's 2020-2024 Revenue Requirement Settlement Application. This settlement, which is effective from January 1, 2020 to December 31, 2024, includes an ROE of 10.1 per cent on 40 per cent deemed equity, provides the NGTL System the opportunity to increase depreciation rates if tolls fall below pre-determined levels and includes an incentive mechanism for certain operating costs where variances from projected amounts are shared between the NGTL System and its customers. It also includes a mechanism to review the settlement should tolls exceed a pre-determined level, without affecting the equity return. The NGTL System's 2019 and 2018 results reflected the 2018-2019 Revenue Requirement Settlement that expired on December 31, 2019 which 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.

The Canadian Mainline's net income in 2020 decreased by $13 million compared to 2019 mainly as a result of lower incentive earnings. Net income in 2019 decreased by $9 million compared to 2018 mainly as a result of lower incentive earnings and a lower average investment base, partially offset by lower carrying charges to shippers on the 2019 net revenue surplus.

In 2020, the Canadian Mainline was in the final year of a six-year fixed-toll settlement under the terms of the 2015-2030 Tolls Application approved in 2014 (the NEB 2014 Decision). The terms of the 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. Toll stabilization was achieved through the use of deferral accounts, namely the bridging amortization account and the long-term adjustment account (LTAA), to capture the surplus or shortfall between system revenues and cost of service for each year over the 2015-2020 six-year fixed-toll term of the NEB 2014 Decision.

The NEB 2014 Decision also directed TC Energy to file an application to review tolls for the 2018-2020 period. In December 2018, the NEB 2018 Decision was received which included an accelerated amortization of the December 31, 2017 LTAA balance and an increase to the composite depreciation rate from 3.2 per cent to 3.9 per cent which was reflected in 2019 and 2020 tolls.

### Comparable EBITDA

Comparable EBITDA for Canadian Natural Gas Pipelines was $292 million higher in 2020 compared to 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 recognized in 2020. Refer to the Canadian Natural Gas Pipelines - Significant events section for additional information.

Comparable EBITDA for Canadian Natural Gas Pipelines in 2019 was $105 million lower than 2018 largely resulting from the net effect of:

- lower flow-through income taxes on the NGTL System and on the Canadian Mainline from the impact of the NEB 2018 Decision to accelerate amortization of the LTAA as well as accelerated tax depreciation enacted by the Canadian Federal Government in June 2019 to allow businesses in Canada to deduct the cost of their investments more quickly for income tax purposes. Due to the flow-through treatment of income taxes on our Canadian rate-regulated pipelines, such reductions to income tax reduced our comparable EBITDA despite having no significant impact on net income
- increased rate-base earnings and depreciation on the NGTL System due to additional facilities that were placed in service, which were partially offset by the impact of a lower rate base in the Canadian Mainline.

### Depreciation and amortization

Depreciation and amortization was $114 million higher in 2020 compared to 2019 and $30 million higher in 2019 compared to 2018 mainly due to additional NGTL System facilities placed in service in 2020 and 2019.

## OUTLOOK

### 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 earnings in 2021 are expected to be higher than 2020 mainly due to continued growth in the NGTL System as we extend and expand the supply facilities in the North Montney region, enhance delivery facilities in northeastern Alberta and provide incremental service at our major border delivery locations in response to requests for firm service on the system. In addition, we expect a higher contribution from the Canadian Mainline in 2021 due to increased incentive earnings.

Other Canadian pipelines earnings are expected to be higher in 2021 due to increased Coastal GasLink development fee revenue reflecting the planned increase in project activity in 2021, subject to the extent of the impact of COVID-19 delays and restrictions.

### Capital spending

We spent a total of $3.6 billion in 2020 in our Canadian natural gas pipelines business, of which $0.9 billion related to our investment in Coastal GasLink prior to the sale of an equity interest in Coastal GasLink LP as well as subsequent equity contributions to the project. We expect to spend approximately $3.4 billion in 2021, primarily on NGTL System expansion projects, Canadian Mainline capacity 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 the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (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 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. We continue to assess the operational and financial impact related to this final rule over its 15-year implementation window that began July 1, 2020 and seek to optimize recovery of those costs. The remaining rulemakings comprising the Gas Mega Rule are expected to be issued in 2021.

In addition to the rulemakings noted above, new pipeline safety legislation (Pipes Act of 2020) was signed into law on December 27, 2020 that reauthorized PHMSA pipeline safety programs which expired under the 2016 Pipeline Safety Act at the end of September 2019. We are in the process of assessing impacts associated with this new legislation.

### TC PipeLines, LP

We currently own a 25.5 per cent interest in, and are the general partner of, TC PipeLines, LP, a master limited partnership (MLP) which trades on the NYSE under the symbol TCP. TC PipeLines, LP has ownership interests in the GTN, Northern Border, Bison, Great Lakes, North Baja, Tuscarora, Iroquois, and Portland pipeline systems. Our overall effective ownership for each of these assets considering the ownership through the MLP is provided in the asset listing of our major pipelines starting on page 35. Refer to the Corporate - Significant events section for additional information regarding the proposed acquisition of all outstanding common units of TC PipeLines, LP not beneficially owned by TC Energy or our affiliates.

## SIGNIFICANT EVENTS

### Wisconsin Access

On October 28, 2020, we approved the Wisconsin Access Project that will replace, upgrade and modernize certain facilities while reducing emissions along portions of the ANR pipeline system. The enhanced facilities will improve reliability of the ANR pipeline system and also allow for additional contracted transportation services of approximately 77 TJ/d (72 MMcf/d) to be provided to utilities serving the Midwestern U.S. under long-term contracts. The anticipated in-service date of the combined project is in the second half of 2022 with an estimated cost of US$0.2 billion.

### Elwood Power Project/ANR Horsepower Replacement

On July 29, 2020, we approved the Elwood Power Project/ANR Horsepower Replacement that will replace, upgrade and modernize certain facilities while reducing emissions along a highly utilized section of the ANR pipeline system. The enhanced facilities will improve reliability of the ANR pipeline system and also allow for additional contracted transportation services of approximately 132 TJ/d (123 MMcf/d) to be provided to an existing power plant near Joliet, Illinois. The anticipated in-service date of the combined project is in the second half of 2022 with an estimated cost of US$0.4 billion.

### Alberta XPress

On February 12, 2020, we approved the Alberta XPress project, an expansion project on the ANR pipeline system that utilizes existing capacity on the Great Lakes and Canadian Mainline systems to connect growing supply from the WCSB to U.S. Gulf Coast LNG export markets. The project has been modified to reflect revised shipper commitments. The anticipated in-service date is in the second half of 2022 with an estimated project cost of US$0.2 billion.

### BXP

BXP, a Columbia Gas project representing an upsizing of existing pipeline replacement, in conjunction with our modernization program, was partially placed into service in October 2020 with full in-service commencing on January 1, 2021.

### Columbia Gas Section 4 Rate Case

Columbia Gas filed a Section 4 Rate Case with FERC on July 31, 2020 requesting an increase to Columbia Gas' maximum transportation rates effective February 1, 2021, subject to refund. The rate case is progressing as expected as we continue to pursue a collaborative process to find a mutually beneficial outcome with our customers through settlement negotiations.

### Acquisition of common units of TC PipeLines, LP

On December 15, 2020, we announced that we have entered into a definitive agreement and plan of merger to acquire all the outstanding common units of TC PipeLines, LP not beneficially owned by TC Energy or our affiliates in exchange for TC Energy common shares. Refer to the Corporate - Significant events section for additional information.

## 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<br>(millions of US$, unless otherwise noted) | 2020 | 2019 | 2018 |
|---|---|---|---|
| Columbia Gas | **1,305** | 1,222 | 873 |
| ANR | **512** | 492 | 508 |
| TC PipeLines, LP[1,2] | **119** | 119 | 138 |
| Columbia Gulf | **195** | 164 | 120 |
| Great Lakes[3] | **91** | 86 | 97 |
| Other U.S. pipelines[1,4] | **117** | 172 | 190 |
| Non-controlling interests[5] | **375** | 368 | 415 |
| **Comparable EBITDA** | **2,714** | 2,623 | 2,341 |
| Depreciation and amortization | **(597)** | (568) | (511) |
| **Comparable EBIT** | **2,117** | 2,055 | 1,830 |
| Foreign exchange impact | **720** | 671 | 541 |
| **Comparable EBIT** (Cdn$) | **2,837** | 2,726 | 2,371 |
| Specific items: | | | |
| Pre-tax gain on sale of Columbia Midstream assets | **—** | 21 | — |
| Bison asset impairment[6] | **—** | — | (722) |
| Tuscarora goodwill impairment[6] | **—** | — | (79) |
| Bison contract terminations[6] | **—** | — | 130 |
| **Segmented earnings** (Cdn$) | **2,837** | 2,747 | 1,700 |

1 Results reflect our earnings from TC PipeLines, LP's ownership interests in eight natural gas pipelines as well as general and administrative costs related to TC PipeLines, LP.
2 In prior years, TC PipeLines, LP periodically conducted ATM issuances which decreased our ownership in TC PipeLines, LP. Effective March 2018, this program ceased to be utilized. Our ownership interest in TC PipeLines, LP was 25.5 per cent as at December 31, 2020, 2019 and 2018.
3 Reflects our 53.55 per cent direct interest in Great Lakes. The remaining 46.45 per cent is held by TC PipeLines, LP.
4 Reflects earnings from our effective ownership in Crossroads, Millennium and Hardy Storage and certain Columbia Midstream assets until sold in August 2019, as well as general and administrative and business development costs related to U.S. natural gas pipelines.
5 Reflects earnings attributable to portions of TC PipeLines, LP, that we do not own.
6 These amounts were recorded in TC PipeLines, LP. The pre-tax impact to us is 25.5 per cent of these amounts net of non-controlling interests.

U.S. Natural Gas Pipelines segmented earnings in 2020 increased by $90 million compared to 2019 and increased by $1.0 billion in 2019 compared to 2018 and included the following specific items which have been excluded from our calculation of comparable EBIT and comparable earnings:

- a pre-tax gain of $21 million related to the sale of certain Columbia Midstream assets in August 2019
- a $722 million pre-tax non-cash asset impairment charge in 2018 related to Bison
- a $79 million pre-tax non-cash goodwill impairment charge in 2018 related to Tuscarora
- $130 million of pre-tax customer termination payments in 2018 that were recorded in Revenues with respect to two of Bison's transportation contracts.

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 with a similar impact on 2019 compared to 2018.

Each of the specific items in 2018 noted above are prior to recognition of the 74.5 per cent non-controlling interests in TC PipeLines, LP.

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 storage capacity and incidental commodity sales. 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$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.

Comparable EBITDA for U.S. Natural Gas Pipelines was US$282 million higher in 2019 than 2018 primarily due to the net effect of:

- incremental earnings from Columbia Gas and Columbia Gulf growth projects placed in service
- decreased earnings from Bison (wholly owned by TC PipeLines, LP) following 2018 customer agreements to settle their future contracted revenues and terminate their contracts
- decreased earnings as a result of the sale of certain Columbia Midstream assets in August 2019.

### Depreciation and amortization

Depreciation and amortization was US$29 million higher in 2020 compared to 2019 and was US$57 million higher in 2019 compared to 2018 mainly due to new projects placed in service. The 2019 amount also reflects lower depreciation as a result of the Bison asset impairment in 2018.

## OUTLOOK

### Comparable earnings

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. Earnings are also affected by the level of 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 earnings are expected to be slightly higher in 2021 than in 2020 due to an increase in transportation rates on Columbia Gas that is dependent on the outcome of the Section 4 Rate Case filed with FERC. In addition, revenues are expected to increase following the completion of expansion projects on the Columbia Gas and ANR systems in 2021 which will provide our customers with greater access to new sources of supply while extending their market reach. Our pipeline systems continue to see historically strong demand for service and we anticipate our assets will maintain high utilization levels as were experienced in 2020. These expected positive results will be partially offset by an anticipated increase in property taxes from capital projects placed in service.

While certain of our counterparties may have varying risks to their operations from the outcomes related to COVID-19, we do not expect a significant impact to our business.

### Capital spending

We spent a total of US$2.0 billion in 2020 on our U.S. natural gas pipelines and expect to spend approximately US$2.2 billion in 2021 primarily on ANR, Columbia Gulf and GTN expansion projects as well as Columbia Gas and ANR maintenance capital, 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. Large natural gas pipelines in Mexico have been developed primarily through a competitive bid process. 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 at risk for operating and construction costs and in-service delay penalties, excluding force majeure events. 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 suspended while management advances settlement discussions with the CFE.

Villa de Reyes project construction is ongoing. Phased in-service has been delayed due to COVID-19 contingency measures which have impeded our ability to obtain work authorizations as a result of administrative closures. Subject to the timely re-opening of government agencies, we expect to complete construction of Villa de Reyes in 2021.

### Guadalajara

A project to allow bidirectional flows was completed in December 2020 and the TSA with the CFE was renegotiated. The bidirectional flow allows access to either LNG imports from the Manzanillo terminus or access to continental natural gas at the Guadalajara terminus for delivery to regional markets.

## 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**<br>(millions of US$, unless otherwise noted) | **2020** | **2019** | **2018** |
|---|---|---|---|
| Topolobampo | **159** | 159 | 172 |
| Tamazunchale | **120** | 120 | 127 |
| Mazatlán | **70** | 70 | 78 |
| Guadalajara | **64** | 65 | 71 |
| Sur de Texas[1] | **171** | 43 | 16 |
| Other | **—** | — | 4 |
| **Comparable EBITDA** | **584** | 457 | 468 |
| Depreciation and amortization | **(87)** | (87) | (75) |
| **Comparable EBIT** | **497** | 370 | 393 |
| Foreign exchange impact | **172** | 120 | 117 |
| **Comparable EBIT and segmented earnings** (Cdn$) | **669** | 490 | 510 |

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 2020 increased by $179 million compared to 2019 and decreased by $20 million in 2019 compared to 2018. 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, with a similar impact on 2019 compared to 2018.

Comparable EBITDA for Mexico Natural Gas Pipelines increased by US$127 million in 2020 compared to 2019 mainly due to higher earnings from our investment in the Sur de Texas pipeline resulting from:

- 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 successful completion 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.

Comparable EBITDA for Mexico Natural Gas Pipelines decreased by US$11 million in 2019 compared to 2018 primarily from the net effect of:

- lower revenues from wholly-owned operations primarily as a result of changes in timing of revenue recognition in 2018
- higher equity earnings from our investment in the Sur de Texas pipeline following its September 2019 in-service. Prior to this, Sur de Texas equity income reflected AFUDC, net of our proportionate share of interest expense on aforementioned inter-affiliate loans which is fully offset in Interest income and other.

### Depreciation and amortization

Depreciation and amortization in 2020 was consistent with the same period in 2019. Depreciation and amortization in 2019 increased by US$12 million compared with the same period in 2018 reflecting new assets being placed in service and other adjustments.

## OUTLOOK

### Comparable earnings

Mexico Natural Gas Pipelines earnings reflect long-term, stable, principally U.S. dollar-denominated transportation contracts that are affected by the cost of providing service and include 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, earnings are generally consistent year-over-year except when new assets are placed into service. Earnings for 2021 are expected to be lower than 2020 due to the fees recognized in 2020 associated with the completion of Sur de Texas, partially offset by the expected in-service of Villa de Reyes in 2021.

### Capital spending

We spent approximately US$0.1 billion in 2020 primarily related to the construction of the Villa de Reyes pipeline. Capital spending in 2021 to complete construction of Villa de Reyes 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 88 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. Our Columbia Gas system 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 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 being developed closer to markets we have historically served 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 expansion

We face competition from other pipeline companies seeking to invest in greenfield natural gas pipeline development opportunities. This competition could result in fewer projects being available that meet our investment hurdles or projects that proceed with lower overall financial returns.

### Demand for pipeline capacity

Demand for pipeline capacity is ultimately the key driver that enables pipeline transportation services to be sold and is impacted by supply and market competition, variations in economic activity, weather variability, natural gas pipeline and storage competition, energy conservation and 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 for the demand of transportation services and/or new natural gas pipeline infrastructure. As well, sustained low natural gas prices 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 have an impact on 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 therefore could 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 influence from the evolving role of activists and other stakeholders and their impact on public opinion and government policy related to natural gas pipeline infrastructure development. In addition, a number of these matters may also involve legal disputes that are prosecuted in a court of law, thereby further impacting project costs and creating delays.

Increased scrutiny of construction and operations processes by the regulator, courts 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 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 by existing bodies or following changes in government can impact our ability to grow our business. Restrictions on carbon fuel use, cross-border economic activity, and development of new infrastructure 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 500 km (300 miles).

### Strategy
Optimizing the value of our existing Liquids Pipelines assets by expanding and leveraging our existing infrastructure is a top priority. We are also pursuing emerging growth opportunities to add incremental value to our business.

Our key areas of focus include:
- accessing and delivering growing North American liquids supply to key markets by expanding our crude oil pipelines infrastructure to deliver directly from supply regions seamlessly along a contiguous path to market
- maximizing the value from our current operating assets and securing organic growth around these assets
- positioning our business development activities to identify and capture attractive organic growth and acquisition opportunities consistent with our risk preferences
- expand transportation service offerings to other areas of the liquids value chain including ancillary services such as short-term and long-term storage of liquids, which complement our pipeline transportation infrastructure.

### Recent highlights
- U.S. President Biden revoked the existing Presidential Permit for the Keystone XL pipeline on January 20, 2021. As a result, we have suspended the advancement of the project and are assessing the implications and options available to us
- During 2020 and 2021, we achieved the following milestones towards advancing the Keystone XL pipeline:
  - announced that we would proceed with construction of Keystone XL which commenced in April 2020 in both the U.S. and Canada
  - completed the U.S./Canada border crossing on the Keystone XL pipeline in June 2020
  - executed a Project Labor Agreement with four pipeline trade unions (Operating Engineers, Laborers, Teamsters and United Association) to utilize 100 per cent unionized labor in the construction of the Keystone XL pipeline
  - announced that the Keystone XL pipeline would be operated with net-zero emissions once placed into service and would utilize 100 per cent green energy by 2030 to power the operating pump stations
  - entered into an agreement whereby the Government of Alberta invested approximately US$0.8 billion in equity in Keystone XL as at December 31, 2020
  - executed a US$4.1 billion credit facility, guaranteed by the Government of Alberta and non-recourse to us, to partially finance the construction of Keystone XL
  - executed definitive agreements with Natural Law Energy, a consortium of five Canadian First Nations, for a potential investment of up to $1.0 billion equity investment in Keystone XL and future liquids projects.


TC Energy
Liquids Pipelines
As at December 31, 2020
Liquids Pipeline
In Development/Construction
Advancement Suspended
Liquids Tank Terminal
Production Basin
Western Canadian Sedimentary Basin
Oil Sands
CANADA
CALGARY
Williston
Powder River
Denver-Julesburg
UNITED STATES
Anadarko
Permian
HOUSTON
Eagle Ford
MEXICO
MEXICO CITY
TORONTO
CHARLESTON
1
2
3
4
5
6
7
8
9
10

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% |
| 5 | Northern Courier | 90 km (56 miles) | Transports bitumen and diluent between the Fort Hills mine site and Suncor Energy's terminal located north of Fort McMurray, Alberta. | 15% |
| | **In development** | | | |
| 6 | Keystone Hardisty Terminal[1] | | Crude oil terminal located at Hardisty, Alberta. | 100% |
| 7<br>8 | Heartland Pipeline and<br>TC Terminals[1] | 200 km (125 miles) | Terminal and pipeline facilities to transport crude oil from the Edmonton/Heartland, Alberta region to Hardisty, Alberta. | 100% |
| 9 | 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% |
| | **Advancement suspended** | | | |
| 10 | Keystone XL[2] | 1,947 km (1,210 miles) | To transport crude oil from Hardisty, Alberta to Steele City, Nebraska to expand capacity of the Keystone Pipeline System. | 100% |

1 Management is currently reviewing the viability of these projects following the January 20, 2021 revocation of the Presidential Permit for the Keystone XL pipeline.

2 The advancement of the Keystone XL project has been suspended as we assess the implications and options available to us following the January 20, 2021 revocation of the Presidential Permit and an asset impairment is expected to be recorded in first quarter 2021. Refer to the Liquids Pipelines - Significant events section for further information.

## 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, transport diluent and diesel products within Alberta, and offer ancillary services such as short- and long-term storage of liquids at key terminal locations to optimize the value of our pipeline assets.

We provide pipeline transportation capacity to shippers 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 shippers which provide for the recovery of costs we incur to construct, operate and maintain the system. 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 western Canadian crude oil exports to key refining markets in the U.S. Midwest and the U.S. Gulf Coast. It also provides significant capacity between Cushing, Oklahoma and the U.S. Gulf Coast market, primarily transporting U.S. crude oil. Three intra-Alberta liquids pipelines – Grand Rapids, Northern Courier and White Spruce – provide crude oil, diluent and diesel 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 was significantly impacted by the COVID-19 pandemic as containment measures imposed by most countries around the world temporarily reduced transportation, commercial and non-essential activities. Demand is expected to gradually recover to pre-COVID-19 levels by 2022.

Global crude oil and liquids demand is projected to increase after this near-term recovery from 92 million Bbl/d in 2020 to 113 million Bbl/d in 2035, driven generally by the transportation and industrial sectors which account for 79 per cent of total crude oil and liquids demand. In addition to meeting this anticipated demand growth of approximately 21 million Bbl/d, a significant amount of crude oil production capacity is required to offset global conventional decline rates expected to reach approximately 16 million Bbl/d annually by 2035. To meet this demand requirement, a strong crude oil price environment is needed to support continuing investment in the energy sector. 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 and the Middle East.

Crude oil prices were severely impacted in 2020 by the COVID-19 pandemic and competition for market share by OPEC+ producers. However, a recovery will be supported by crude oil supply management efforts, primarily by OPEC+, and global demand growth that provides sufficient support for ongoing investments in new supply sources.

### Supply outlook

#### Canada

Canada has the world's third largest crude oil reserves with approximately 162 billion barrels of economically and technically recoverable conventional and oil sands reserves, primarily in Alberta. Total 2020 WCSB crude oil production was approximately 4 million Bbl/d and is expected to increase to approximately 5 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 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 2020. The majority of continental U.S. crude oil production is in the form of light tight oil from the Williston, Eagle Ford, Niobrara and Permian 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 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. Despite the global demand impact from the COVID-19 pandemic, U.S. crude oil exports increased to a record 3.1 million Bbl/d in 2020 compared to 3.0 million Bbl/d in 2019. By 2035, the U.S. is expected to export approximately 5 million Bbl/d of predominantly light crude oil and import approximately 5 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 over 19 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 2020, and a five-year average of approximately 5 million Bbl/d. The U.S. Midwest refiners have total refining capacity of approximately 4 million Bbl/d, which requires approximately 2 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 of 10 million Bbl/d, representing more than half of the total U.S. refining capacity. The U.S. Gulf Coast imported approximately 2 million Bbl/d of primarily heavy crude oil in 2020 to meet demand.

Canada is currently the largest exporter of crude oil to the U.S. at approximately 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 fall by almost 70 per cent between 2021 and 2023 due to the continued declines in its production and new domestic demand. Approximately 40 per cent of the U.S. Gulf Coast heavy crude oil demand is currently met by Mexican imports which presents a significant opportunity for Canada to become a more prominent supplier of crude oil to the U.S.

## Strategic priorities

Our strategic focus is to provide transportation solutions which link growing North American supply basins to key market hubs and demand regions. Our intra-Alberta liquids pipelines and Keystone Pipeline System will form a contiguous path from Alberta through the U.S. Midwest to the U.S. Gulf Coast, which strategically positions TC Energy to provide competitive transportation solutions for growing supplies of Alberta heavy crude oil and U.S. light tight oil.

COVID-19 has had a material impact on energy markets which will disrupt and likely delay certain growth plans. 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.

Within our established risk preferences we remain committed to:

- protecting and optimizing the value 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.

We continuously work with existing and new customers to provide pipeline transportation and terminal services. The combination of the scale and location of our assets assists us in attracting new volumes and in growing our business.

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. Resolution of WCSB egress issues is expected to drive substantial production growth requiring additional transportation solutions. With additional commercial support, the Heartland Pipeline, TC Terminals and Hardisty terminal projects, all of which have received regulatory approval, would allow shippers to seamlessly connect from the Fort McMurray production region directly to market. This would provide shippers with a contiguous path between the WCSB and destination markets, including the U.S. Gulf Coast. After suspending advancement of Keystone XL, we continue to assess the implications and options available to us with respect to these three projects.

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. The cyclical nature of commodity prices may influence the pace at which our shippers 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.

We closely monitor the market place for strategic asset acquisitions 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.

## SIGNIFICANT EVENTS

### Keystone XL

***Permit revocation and impairment***

On January 20, 2021, U.S. President Biden revoked the existing Presidential Permit for the Keystone XL pipeline. As a result, we suspended the advancement of the Keystone XL pipeline project and ceased capitalizing costs, including interest during construction, and also ceased accruing a return on the Government of Alberta interests as of that date, while we assess our options along with our partner, the Government of Alberta, and other stakeholders. We expect to record a substantive, predominantly non-cash, after-tax charge to our earnings in first quarter 2021, which will be excluded from comparable earnings.

Accounting implications in first quarter 2021 and beyond will depend on the assessment and consideration of options as noted above, including the impacts that this had on contractual arrangements. As a result, the magnitude of the impairment charge and related recoveries cannot be quantified at this time. The determination of the amount of the pre-tax impairment of the Keystone XL assets will consider the then-carrying value of the project and any associated projects, outstanding contractual commitments, the estimated net recoverable value of tangible plant and equipment and specified contractual recoveries, which cannot be reasonably estimated until the options have been assessed and next steps have been determined. The carrying value of the plant, property and equipment for Keystone XL, including capitalized interest, was $2.8 billion at December 31, 2020. The viability of certain projects currently associated with the Keystone XL pipeline is also being reviewed for which the carrying value was $0.2 billion at December 31, 2020. Refer to the notes to our 2020 Consolidated financial statements for additional information.

***Construction commencement***

Prior to U.S. President Biden revoking the Presidential Permit, on March 31, 2020, we announced that we would proceed with construction of the Keystone XL pipeline project which commenced in April. We advanced construction of 180 km (112 miles) of pipeline and five pump stations in Canada, 12 pump stations in the United States, and completed the U.S./Canada border crossing in June 2020.

On August 5, 2020, we announced that Keystone XL had committed to construct the project using all union labor in the U.S. along with committing in excess of $10 million to create a Green Jobs Training Fund to help train union workers on renewable energy projects.

On January 17, 2021, we announced that the Keystone XL project would achieve net-zero emissions by the time it was placed into service in 2023. Additionally, we committed to ensure enough new renewable electricity was constructed along the pipeline route by 2030 to fully power the pipeline's operational needs.

***Financial matters***

As part of the Keystone XL funding plan, the Government of Alberta has invested approximately US$0.8 billion in equity as of December 31, 2020, which substantially funded construction costs through the end of 2020. On January 4, 2021, we executed a US$4.1 billion project-level credit facility that is fully guaranteed by the Government of Alberta and non-recourse to us, and made initial cash draws on January 8, 2021, in part to repurchase a majority of the Government of Alberta's equity interest under the terms of the contract. The suspension of the advancement of the project does not require immediate repayment of the debt as repayment is dependent upon certain other events or decisions specified in the credit facility agreement.

On November 6, 2020, we signed an agreement with Natural Law Energy, which included a potential investment by five First Nations in Alberta and Saskatchewan, of up to $1.0 billion in Keystone XL and future liquids projects.

***Legal and permitting matters***

Keystone XL continues to face legal and permitting challenges. After suspending advancement of the project on January 20, 2021, we are assessing our next steps with respect to these matters.

## 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**<br>(millions of $) | **2020** | **2019** | **2018** |
|---|---|---|---|
| Keystone Pipeline System | **1,474** | 1,654 | 1,443 |
| Intra-Alberta pipelines[1] | **92** | 137 | 160 |
| Liquids marketing and other | **134** | 401 | 246 |
| **Comparable EBITDA** | **1,700** | 2,192 | 1,849 |
| Depreciation and amortization | **(332)** | (341) | (341) |
| **Comparable EBIT** | **1,368** | 1,851 | 1,508 |
| Specific items: | | | |
| Gain on partial sale of Northern Courier | **—** | 69 | — |
| Risk management activities | **(9)** | (72) | 71 |
| **Segmented earnings** | **1,359** | 1,848 | 1,579 |
| **Comparable EBIT denominated as follows:** | | | |
| Canadian dollars | **345** | 356 | 370 |
| U.S. dollars | **762** | 1,127 | 876 |
| Foreign exchange impact | **261** | 368 | 262 |
| **Comparable EBIT** | **1,368** | 1,851 | 1,508 |

1 Intra-Alberta pipelines include Grand Rapids, White Spruce and Northern Courier. In July 2019, we sold an 85 per cent interest in Northern Courier and began to apply equity accounting to our remaining 15 per cent investment.

Liquids Pipelines segmented earnings decreased by $489 million in 2020 compared to 2019 and increased by $269 million in 2019 compared to 2018 and included the following specified items which have been excluded from our calculation of comparable EBIT and comparable earnings:

- a pre-tax gain in 2019 of $69 million related to the sale of an 85 per cent interest in Northern Courier
- unrealized gains and losses from changes in the fair value of derivatives related to our liquids marketing business.

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, with a similar impact on 2019 compared to 2018.

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.

Comparable EBITDA for Liquids Pipelines was $343 million higher in 2019 compared to 2018 primarily due to the net effect of:

- increased volumes on the Keystone Pipeline System
- greater contribution from liquids marketing activities due to improved margins and volumes
- incremental contribution from the White Spruce pipeline, which was placed in service in May 2019
- 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 $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. Depreciation and amortization was $341 million for both 2019 and 2018 reflecting the net result of new facilities being placed in service and a stronger U.S. dollar, partially offset by the sale of an 85 per cent equity interest in Northern Courier.

## OUTLOOK

### Comparable earnings

Our 2021 earnings are expected to be lower than 2020 in both the Keystone Pipeline System and liquids marketing business as a result of continuing lower uncontracted volumes and decreased margins, respectively. As discussed in the Understanding our Liquids Pipelines business section, global crude oil demand and prices have been significantly impacted by the COVID-19 pandemic but are expected to gradually recover to pre-COVID-19 levels by 2022.

### Capital spending

We spent a total of $1.4 billion in 2020 primarily on the advancement of Keystone XL and expect to spend approximately $0.1 billion in 2021 on our liquids pipelines which excludes any impacts from the assessment of our options with respect to the Keystone XL project.

## BUSINESS RISKS

The following are risks specific to our liquids pipelines business. Refer to page 88 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.

### Construction and operations

Constructing and 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.

While the majority of the costs to operate the liquids pipelines are passed through to our shippers, a portion of our volume is transported under an all-in fixed toll structure where we are exposed to changing costs which may adversely impact our earnings.

### 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 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. 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 would negatively impact opportunities to expand our liquids pipelines infrastructure and, in the longer term, to re-contract with shippers 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 and diluent 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.

# Power and Storage

Our power business includes approximately 4,200 MW of generation capacity located in Alberta, Ontario, Québec and New Brunswick and uses natural gas and nuclear fuel sources. These assets are supported by long-term contracts.

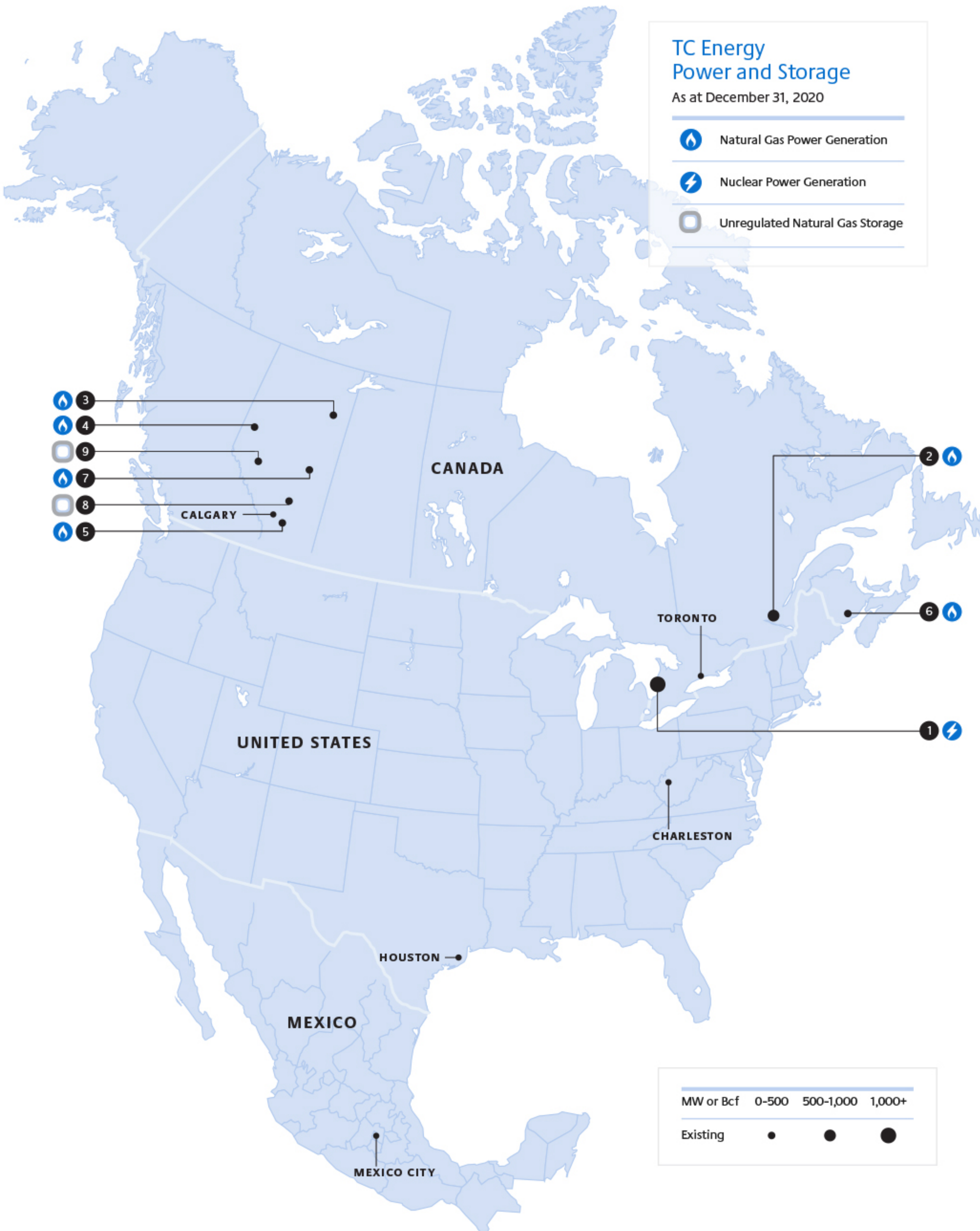
We own and operate approximately 118 Bcf of non-regulated natural gas storage capacity in Alberta.

## Strategy

- maximize the value of our portfolio of Power and Storage assets by managing them safely and reliably with a focus on optimization
- pursue North American growth in low-risk, highly contracted power infrastructure
- explore opportunities to provide renewable energy to serve our existing energy loads.

## Recent highlights

- advanced the life extension program at Bruce Power with the commencement of the Unit 6 MCR outage on January 17, 2020. On October 1, 2020, the Unit 6 MCR project achieved a major milestone with the completion of the preparation phase and the commencement of the Fuel Channel and Feeder Replacement Program
- concluded construction and commissioning activities and placed the Napanee natural gas-fired power plant in service on March 13, 2020
- completed the sale of our Ontario natural gas-fired power plants: Halton Hills, Napanee as well as our 50 per cent interest in Portlands Energy Centre on April 29, 2020
- completed the purchase of the remaining 50 per cent interest in TransCanada Turbines Ltd. (TC Turbines) for US$67 million on November 13, 2020.


TC Energy
Power and Storage
As at December 31, 2020
Natural Gas Power Generation
Nuclear Power Generation
Unregulated Natural Gas Storage
3
4
9
7
8
5
CALGARY
CANADA
2
6
1
TORONTO
UNITED STATES
CHARLESTON
HOUSTON
MEXICO
MEXICO CITY
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 4,197 MW and we operate each facility except for Bruce Power.

| | | Generating Capacity (MW) | Type of fuel | Description | Ownership |
|---|---|---|---|---|---|
| 1 | Bruce Power[1] | 3,109 | 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** 118 Bcf of natural gas storage capacity | | | | |
| 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 48.4 per cent 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 approximately 1,100 MW of power supply in Canada, excluding our investment in Bruce Power. On April 29, 2020, we completed the sale of our Ontario natural gas-fired power plants. Results from these facilities were included in comparable EBITDA until their sale.

We own four natural gas-fired cogeneration facilities in Alberta and exercise a disciplined operating strategy to maximize revenues at these facilities. 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 6,430 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 outage commenced on January 17, 2020 and has an expected completion in late 2023. Investments in the remaining five-unit MCR program 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.

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 will be paid to the IESO in 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.

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 and is harvested during certain planned maintenance outages and provided for medical use. In 2020, Bruce Power supplied enough Cobalt-60 to sterilize between 20-25 billion pieces of medical equipment and supplies including gloves, COVID-19 swabs, single use medical equipment and materials used in vaccine production. Cobalt-60 is also used 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.

### 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.

## SIGNIFICANT EVENTS

**Ontario natural gas-fired power plants**

On March 13, 2020, we placed the Napanee power plant into service after we completed construction and commissioning activities.

On April 29, 2020, we completed the sale of our Halton Hills and Napanee power plants as well as our 50 per cent interest in Portlands Energy Centre to a subsidiary of Ontario Power Generation Inc. for net proceeds of approximately $2.8 billion before post-closing adjustments. Pre-tax losses of $414 million ($283 million after tax) were recognized in 2020 and reflect the finalization of post-closing obligations. The total pre-tax loss of $693 million ($477 million after tax) on this transaction includes losses accrued during 2019 while classified as an asset held for sale as well as utilization of previously unrecognized tax loss benefits. This loss may be amended in the future upon the settlement of existing insurance claims.

**Bruce Power – Life Extension**

The Unit 6 MCR outage commenced on January 17, 2020 and is expected to be completed in late 2023. In late March 2020, as a result of COVID-19 impacts, Bruce Power declared force majeure under its contract with the IESO. This force majeure notice covers the Unit 6 MCR and certain Asset Management work. On May 11, 2020, work on the Unit 6 MCR and Asset Management programs was restarted with additional prevention measures in place for worker safety related to COVID-19 and progress is continuing on critical path activities. The impact of the force majeure will ultimately depend on the extent and duration of disruptions resulting from the pandemic and Bruce Power's ability to implement mitigation measures.

On October 1, 2020, the Unit 6 MCR project achieved a major milestone with the completion of the preparation phase and commencement of the Fuel Channel and Feeder Replacement Program and as of December 31, 2020 the Unit 6 MCR project remains on schedule and on budget. Operations on the remaining units continue as normal with scheduled outages successfully completed on Units 3, 4 and 5 in second quarter 2020 and on Unit 8 in fourth quarter 2020.

**TC Turbines**

On November 13, 2020, we acquired the remaining 50 per cent ownership interest in TC Turbines for cash consideration of US$67 million. TC Turbines provides industrial gas turbine maintenance, parts, repair and overhaul services. Following the acquisition, we began to fully consolidate TC Turbines within our financial results.

## 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**<br>(millions of $) | **2020** | **2019** | **2018** |
|---|---|---|---|
| Bruce Power[1] | **439** | 527 | 311 |
| Canadian Power[2] | **213** | 285 | 428 |
| Natural Gas Storage and other | **25** | 20 | 13 |
| **Comparable EBITDA** | **677** | 832 | 752 |
| Depreciation and amortization | **(67)** | (95) | (119) |
| **Comparable EBIT** | **610** | 737 | 633 |
| Specific items: | | | |
| Loss on sale of Ontario natural gas-fired power plants | **(414)** | (279) | — |
| Gain on sale of Coolidge generating station | **—** | 68 | — |
| U.S. Northeast power marketing contracts | **—** | (8) | (5) |
| Gain on sale of Cartier Wind power facilities | **—** | — | 170 |
| Risk management activities | **(15)** | (63) | (19) |
| **Segmented earnings** | **181** | 455 | 779 |

1 Includes our share of equity income from Bruce Power.

2 Includes our Ontario natural gas-fired power plants until sold on April 29, 2020, Coolidge generating station until sold in May 2019 and Cartier Wind power facilities until sold in October 2018.

Power and Storage segmented earnings decreased by $274 million in 2020 compared to 2019 and decreased by $324 million in 2019 compared to 2018 and included the following specific items which have been excluded from our calculation of comparable EBIT and comparable earnings:

- a pre-tax loss in 2020 of $414 million (2019 – $279 million) related to the sale of our Ontario natural gas-fired power plants. Refer to the Power and Storage - Significant events section for additional information
- 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 (2018 – $5 million, including a gain in first quarter 2018 on the sale of our retail contracts)
- a pre-tax gain in 2018 of $170 million related to the sale of our interests in the Cartier Wind power facilities
- unrealized 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 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 on January 17, 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 on April 29, 2020, although the Napanee plant added incremental earnings to that date following its March 13, 2020 in-service. In addition, we sold our Coolidge generating station in May 2019.

Comparable EBITDA for Power and Storage increased by $80 million in 2019 compared to 2018 primarily due to the net effect of:

- increased Bruce Power results mainly due to a higher realized power price in 2019 and lower income on funds invested for future retirement benefits in 2018, partially offset by lower volumes from greater outage days. Additional financial and operating information on Bruce Power is provided below
- lower Canadian Power contribution largely as a result of the sale of our interests in the Cartier Wind power facilities in October 2018 and the sale of our Coolidge generating station in May 2019. We also experienced lower results from our Alberta cogeneration plants due to greater outage days and a prior period billing adjustment at one of the plants.

### Depreciation and amortization

Depreciation and amortization decreased by $28 million in 2020 compared to 2019 primarily due to the cessation of depreciation on our Halton Hills power plant in July 2019. Depreciation was $24 million lower in 2019 compared to 2018 primarily due to the cessation of depreciation on the Cartier Wind power facilities in June 2018, the Coolidge generating station in December 2018 and the Halton Hills power plant in July 2019 upon their classifications as held for sale. These decreases were partially offset by increased depreciation at our Alberta cogeneration plants due to a reassessment of the useful life of certain components.

### 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**<br>(millions of $, unless otherwise noted) | **2020** | **2019** | **2018** |
|---|---|---|---|
| Equity income included in comparable EBITDA and EBIT comprised of: | | | |
| Revenues[1] | **1,681** | 1,746 | 1,526 |
| Operating expenses | **(884)** | (883) | (852) |
| Depreciation and other | **(358)** | (336) | (363) |
| **Comparable EBITDA and EBIT[2]** | **439** | 527 | 311 |
| **Bruce Power – other information** | | | |
| Plant availability[3,4] | **88%** | 84% | 87% |
| Planned outage days[4] | **276** | 393 | 280 |
| Unplanned outage days | **36** | 58 | 92 |
| Sales volumes (GWh)[2] | **20,956** | 22,669 | 23,486 |
| Realized power price per MWh[5] | **$80** | $76 | $67 |

1 Net of amounts recorded to reflect operating cost efficiencies shared with the IESO.
2 Represents our 48.4 per cent (2019 – 48.4 per cent; 2018 – 48.3 per cent) ownership interest in Bruce Power. Sales volumes include deemed generation and Unit 6 output until January 17, 2020 when its MCR program commenced.
3 The percentage of time the plant was available to generate power, regardless of whether it was running.
4 Excludes Unit 6 MCR outage days.
5 Calculation based on actual and deemed generation. Realized power price per MWh includes realized gains and losses from contracting activities and cost flow-through items. Excludes unrealized gains and losses on contracting activities and non-electricity revenues.

The Unit 6 MCR outage commenced on January 17, 2020. Excluding the Unit 6 MCR, plant availability in 2020 was 88 per cent as planned maintenance was completed on Bruce Units 3, 4, 5 and 8. Plant availability in 2019 was 84 per cent as planned maintenance was completed on Bruce Units 2, 3, 5 and 7. Plant availability in 2018 was 87 per cent as planned maintenance was completed on Bruce Units 1, 4 and 8.

## OUTLOOK

### Comparable earnings

Our 2021 comparable earnings for the Power and Storage segment are expected to be lower than 2020 primarily as a result of a lower contribution from Bruce Power as described below and the sale of our Ontario natural gas-fired power plants on April 29, 2020.

Bruce Power equity income in 2021 is expected to be lower largely as a result of increased non-MCR planned outage days and higher operating costs in 2021. Planned maintenance is expected to occur on Unit 1 in the first half of 2021, on Unit 7 in the second half of 2021 while a Unit 3 outage is expected to begin late first quarter 2021 and be completed early fourth quarter 2021. The average 2021 plant availability percentage, excluding Unit 6, is expected to be in the mid-80 per cent range.

### Capital spending

We invested $0.7 billion in 2020 for our share of Bruce Power's life extension and maintenance capital projects and expect to invest approximately $0.8 billion in 2021.

## BUSINESS RISKS

The following are risks specific to our Power and Storage business. Refer to page 88 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. The contracts on these assets expire in the medium to long term and, as such, 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 Canada. These markets are subject to various federal and provincial 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 impact the value of our assets. 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.

# Corporate

## SIGNIFICANT EVENTS

**Retirement and appointment of our President and CEO**

On September 21, 2020, we announced the retirement of Russ Girling as President and CEO of TC Energy and from our Board of Directors effective December 31, 2020. François Poirier, previously Chief Operating Officer and President, Power & Storage, succeeded Mr. Girling as President and CEO and joined our Board of Directors on January 1, 2021. Mr. Girling will assist Mr. Poirier with the transition through February 28, 2021.

**Acquisition of common units of TC PipeLines, LP**

On December 15, 2020, we announced that we have entered into a definitive agreement and plan of merger to acquire all the outstanding common units of TC PipeLines, LP not beneficially owned by TC Energy or our affiliates in exchange for TC Energy common shares. Pursuant to the agreement, TC PipeLines, LP common unitholders will receive 0.70 common shares of TC Energy for each issued and outstanding publicly-held TC PipeLines, LP common unit. The exchange ratio reflects a value for all publicly-held common units of TC PipeLines, LP of approximately US$1.69 billion, or 38 million TC Energy common shares based on the closing price of TC Energy's common shares on the New York Stock Exchange on January 19, 2021. A vote on the plan of merger by the unitholders of the publicly-held common units is scheduled for February 26, 2021. The transaction is expected to close in late first quarter 2021 subject to approval by the holders of a majority of outstanding common units of TC PipeLines, LP and customary regulatory approvals. Upon closing, TC PipeLines, LP will be wholly owned by TC Energy and will cease to be a publicly-held MLP.

## FINANCIAL RESULTS

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

| year ended December 31<br>(millions of $) | 2020 | 2019 | 2018 |
|---|---|---|---|
| **Comparable EBITDA and EBIT** | **(16)** | (17) | (59) |
| Specific item: | | | |
| Foreign exchange gains/(losses) – inter-affiliate loans[1] | **86** | (53) | 5 |
| **Segmented earnings/(losses)** | **70** | (70) | (54) |

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

Corporate segmented earnings increased by $140 million in 2020 compared to segmented losses of $70 million in 2019. Segmented losses increased by $16 million in 2019 compared to 2018.

Corporate segmented earnings/(losses) included 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 amounts are recorded in Income from equity investments 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.

Comparable EBITDA for Corporate was consistent in 2020 with 2019 and increased by $42 million in 2019 compared to 2018 primarily due to decreased general and administrative costs.

## OTHER INCOME STATEMENT ITEMS

### Interest expense

| year ended December 31<br>(millions of $) | 2020 | 2019 | 2018 |
|---|---|---|---|
| **Interest on long-term debt and junior subordinated notes** | | | |
| Canadian dollar-denominated | **(685)** | (598) | (549) |
| U.S. dollar-denominated | **(1,302)** | (1,326) | (1,325) |
| Foreign exchange impact | **(446)** | (434) | (394) |
| | **(2,433)** | (2,358) | (2,268) |
| Other interest and amortization expense | **(89)** | (161) | (121) |
| Capitalized interest | **294** | 186 | 124 |
| **Interest expense** | **(2,228)** | (2,333) | (2,265) |

Interest expense in 2020 decreased by $105 million compared to 2019 primarily 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 on May 22, 2020, partially offset by lower capitalized interest due to the completion of Napanee construction in first quarter 2020. The increase on Keystone XL is 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 are 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. Refer to the Financial condition section for further details on long-term debt and junior subordinated notes
- foreign exchange impact from a stronger U.S. dollar on translation of U.S. dollar-denominated interest.

Interest expense in 2019 increased by $68 million compared to 2018 mainly due to the net effect of:

- long-term debt and junior subordinated note issuances in 2019 and 2018, net of maturities
- foreign exchange impact from a stronger U.S. dollar on translation of U.S. dollar-denominated interest
- increased levels of short-term borrowings
- higher capitalized interest, largely related to Keystone XL and Napanee.

### Allowance for funds used during construction

| year ended December 31<br>(millions of $) | 2020 | 2019 | 2018 |
|---|---|---|---|
| **Allowance for funds used during construction** | | | |
| Canadian dollar-denominated | **106** | 203 | 103 |
| U.S. dollar-denominated | **182** | 205 | 326 |
| Foreign exchange impact | **61** | 67 | 97 |
| **Allowance for funds used during construction** | **349** | 475 | 526 |

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

AFUDC decreased by $51 million in 2019 compared to 2018 primarily as a result of Columbia Gas and Columbia Gulf growth projects placed in service, partially offset by capital expenditures on our NGTL System and continued investment in our Mexico projects.

### Interest income and other

| year ended December 31<br>(millions of $) | 2020 | 2019 | 2018 |
|---|---|---|---|
| **Interest income and other included in comparable earnings** | **173** | 162 | 177 |
| Specific items: | | | |
| Foreign exchange (losses) / gains – inter-affiliate loan | **(86)** | 53 | (5) |
| Risk management activities | **126** | 245 | (248) |
| **Interest income and other** | **213** | 460 | (76) |

Interest income and other decreased by $247 million in 2020 compared to 2019 and increased by $536 million in 2019 compared to 2018 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) / 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.

Interest income and other included in comparable earnings increased by $11 million in 2020 compared to 2019 primarily 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.

Interest income and other included in comparable earnings decreased by $15 million in 2019 compared to 2018 due to the net effect of:

- higher realized losses in 2019 compared to 2018 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- higher interest income in 2019 related to the peso-denominated inter-affiliate loan receivable from the Sur de Texas joint venture due to increased amounts outstanding.

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 is reflected in Income from equity investments in the Corporate and Mexico Natural Gas Pipelines segments, respectively, resulting in no impact on net income.

## Income tax expense

| year ended December 31<br>(millions of $) | 2020 | 2019 | 2018 |
|---|---|---|---|
| **Income tax expense included in comparable earnings** | **(654)** | (898) | (693) |
| Specific items: | | | |
| Income tax valuation allowance releases | **299** | 195 | — |
| Loss on sale of Ontario natural gas-fired power plants | **131** | 85 | — |
| Gain on partial sale of Coastal GasLink LP | **38** | — | — |
| Loss on sale of Columbia Midstream assets | **18** | (173) | — |
| Gain on partial sale of Northern Courier | **—** | 46 | — |
| Alberta corporate income tax rate reduction | **—** | 32 | — |
| U.S. Northeast power marketing contracts | **—** | 2 | 1 |
| Gain on sale of Coolidge generating station | **—** | (14) | — |
| MLP regulatory liability write-off | **—** | — | 115 |
| U.S. Tax Reform | **—** | — | 52 |
| Bison asset impairment | **—** | — | 44 |
| Sales of U.S. Northeast power generation assets | **—** | — | 27 |
| Tuscarora goodwill impairment | **—** | — | 5 |
| Gain on sale of Cartier Wind power facilities | **—** | — | (27) |
| Bison contract terminations | **—** | — | (8) |
| Risk management activities | **(26)** | (29) | 52 |
| **Income tax expense** | **(194)** | (754) | (432) |

Income tax expense in 2020 decreased by $560 million compared to 2019 and increased by $322 million in 2019 compared to 2018 and included the following specific items which have been removed from our calculation of Income tax expense included in comparable earnings:

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 project
- an $18 million income tax recovery related to state income taxes on the sale of certain Columbia Midstream assets.

In 2019:

- an income tax valuation allowance release of $195 million related to certain prior years' U.S. 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 income tax balances attributable to our Canadian businesses not subject to RRA due to an Alberta corporate income tax rate reduction enacted in June 2019.

In 2018:

- a $115 million deferred income tax recovery from an MLP regulatory liability write-off as a result of changes in the U.S. income tax regulations and the treatment of taxes for rate-making purposes in an MLP
- a $52 million recovery of deferred income taxes as a result of finalizing the impact of U.S. Tax Reform.

In addition, the income tax impacts of the specific items in Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines, Liquids Pipelines, Power and Storage and noted in other sections of this MD&A, were also removed from Income tax expense included in comparable earnings.

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

Income tax expense included in comparable earnings in 2019 increased by $205 million compared to 2018 primarily due to higher comparable earnings before income taxes and lower foreign tax rate differentials, partially offset by lower flow-through income taxes in Canadian rate-regulated pipelines.

### U.S. Tax Reform and FERC Actions

In 2017, U.S. Tax Reform was signed into law and the enacted U.S. federal corporate income tax rate was reduced from 35 per cent to 21 per cent effective January 1, 2018. This resulted in a remeasurement of existing deferred income tax assets and deferred income tax liabilities related to our U.S. businesses to reflect the new lower income tax rate as at December 31, 2017. Given the significance of the legislation, SEC registrants were allowed to record provisional amounts at December 31, 2017 which could be adjusted as additional information became available, prepared or analyzed for a period not to exceed one year. We recognized further adjustments to the provisional amount in 2018.

In accordance with FERC Form 501-G and uncontested rate settlement filings, the accumulated deferred income tax balances for all pipelines held wholly or in part by TC PipeLines, LP were eliminated from their respective rate bases. As a result, net regulatory liabilities recorded for these assets pursuant to U.S. Tax Reform were written off, resulting in a further deferred income tax recovery of $115 million in 2018.

Under U.S. Tax Reform, the U.S. Treasury and the U.S. Internal Revenue Service issued final base erosion and anti-abuse tax regulations in 2019 and final anti-hybrid rules on April 7, 2020. The finalization of these regulations did not have a material impact on our 2020 Consolidated financial statements.

### Mexico Tax Reform

In 2019, Mexico passed tax reform legislation related to, among other things, interest deductibility and tax reporting. These changes did not have a material impact on our 2020 Consolidated financial statements.

### Alberta rate reduction

On December 9, 2020, the Government of Alberta enacted the reduction of the corporate income tax rate to eight per cent effective July 1, 2020. This change did not have a material impact on our 2020 Consolidated financial statements.

## Net (income) / loss attributable to non-controlling interests

| year ended December 31<br>(millions of $) | 2020 | 2019 | 2018 |
|---|---|---|---|
| **Net income attributable to non-controlling interests included in comparable earnings** | **(297)** | (293) | (315) |
| Specific items: | | | |
| Bison asset impairment | **—** | — | 538 |
| Tuscarora goodwill impairment | **—** | — | 59 |
| Bison contract terminations | **—** | — | (97) |
| **Net (income) / loss attributable to non-controlling interests** | **(297)** | (293) | 185 |

Net (income) / loss attributable to non-controlling interests increased by $4 million in 2020 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.

In 2019, Net (income) / loss attributable to non-controlling interests increased by $478 million compared to 2018 primarily due to the net effect of the following items recorded in 2018:

- a $538 million pre-tax charge related to the non-controlling interests' portion of a $722 million Bison asset impairment in TC PipeLines, LP
- a $59 million pre-tax charge related to the non-controlling interests' portion of a $79 million Tuscarora goodwill impairment in TC PipeLines, LP
- $97 million in pre-tax income related to the non-controlling interests' portion of Bison contract termination payments of $130 million received from certain customers in TC PipeLines, LP.

On consolidation, we recorded the non-controlling interests' 74.5 per cent of these transactions which have been excluded in the calculation of comparable earnings. Refer to the Critical accounting estimates section for more information on our goodwill and asset impairment testing.

In 2019, Net income attributable to non-controlling interests included in comparable earnings decreased by $22 million compared to 2018 largely due to lower earnings in TC PipeLines, LP, partially offset by the impact of a stronger U.S. dollar which increased the Canadian dollar equivalent earnings from TC PipeLines, LP.

## Preferred share dividends

| **year ended December 31**<br>(millions of $) | **2020** | **2019** | **2018** |
|---|---|---|---|
| **Preferred share dividends** | **(159)** | (164) | (163) |

Preferred share dividends of $159 million in 2020 were generally consistent with 2019 and 2018.

# Financial condition

We strive to maintain strong financial capacity 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 AIF 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.

We continued to enhance our financial position in 2020 through:

- completion of the sale of the Ontario natural gas-fired power plants for net proceeds of approximately $2.8 billion before post-closing adjustments
- completion of the sale of a 65 per cent equity interest in Coastal GasLink LP for net proceeds of $656 million
- establishment of seven-year senior secured credit facilities for Coastal GasLink LP with current capacity of $6.8 billion. Immediately preceding the equity sale, $1.6 billion was drawn on these facilities and approximately $1.5 billion was paid to TC Energy
- TransCanada PipeLines Limited’s issuance of $2.0 billion of seven-year Medium Term Notes at a fixed rate per annum rate of 3.8 per cent and US$1.25 billion of 10-year Senior Unsecured Notes at a fixed per annum rate of 4.1 per cent
- establishment of a US$4.2 billion Delayed Draw Term Loan at Columbia Pipeline Group, Inc., on which US$4.0 billion was drawn in January 2021 and the total availability under the loan agreement was reduced accordingly
- arrangement of an additional US$2.0 billion of 364-day committed bilateral credit facilities in second quarter 2020 which were extinguished in fourth quarter 2020 as they were no longer required.

In addition, in early January 2021, we put in place a US$4.1 billion project-level credit facility to support the construction of the Keystone XL pipeline that is fully guaranteed by the Government of Alberta and non-recourse to us. We drew US$579 million on the credit facility on January 8, 2021, the proceeds of which were used in part to repurchase a majority of the Government of Alberta's Class A interests. The facility bears interest at a floating rate and matures in January 2024. The suspension of the advancement of the project does not require immediate repayment of the debt as repayment is dependent upon certain other events or decisions specified in the credit facility agreement.

These transactions demonstrate our continued ability to access capital markets under all market conditions, including during periods of stress such as those resulting from COVID-19. Combined with our predictable and growing cash flows from operations, cash on hand, substantial committed credit facilities and various other financing levers available to us, we believe we are well positioned to continue to fund our obligations, capital program and dividends. We do not expect COVID-19 or the recent volatility in commodity prices to have a material impact on our operating cash flows as a significant majority of our revenues are derived from long-term contracts and/or regulated cost of service business models; however, counterparty credit risk has heightened. Refer to the Financial risks section for additional information.

## Balance sheet analysis

At December 31, 2020, our current assets totaled $5.2 billion and current liabilities amounted to $12.0 billion, leaving us with a working capital deficit of $6.8 billion compared to $5.2 billion at December 31, 2019. 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 $6.0 billion of incremental short-term borrowing capacity remains available, net of $4.0 billion backstopping commercial paper balances. We also have arrangements in place for a further $2.4 billion of demand credit facilities of which $1.2 billion remained available as of December 31, 2020
- our access to capital markets, including through incremental credit facilities, portfolio management activities, DRP and Corporate ATM programs, if deemed appropriate.

Our total assets at December 31, 2020 were $100.3 billion compared to $99.3 billion at December 31, 2019 primarily reflecting our 2020 capital spending program, partially offset by depreciation, asset sales and the impact of a weaker U.S. dollar at December 31, 2020 compared to December 31, 2019 on translation of our U.S. dollar-denominated assets.

At December 31, 2020 our total liabilities were $66.8 billion, consistent with December 31, 2019.

Our equity at December 31, 2020 was $33.1 billion compared to $32.4 billion at December 31, 2019. The increase is principally due to net income net of common and preferred dividends paid, partially offset by other comprehensive loss.

## Consolidated capital structure

The following table summarizes the components of our capital structure.

| at December 31<br>(millions of $, unless otherwise noted) | 2020 | Per cent of total | 2019 | Per cent of total |
|---|---|---|---|---|
| Notes payable | **4,176** | **5** | 4,300 | 5 |
| Redeemable non-controlling interest[1] | **633** | **1** | — | — |
| Long-term debt, including current portion | **36,885** | **45** | 36,985 | 46 |
| Cash and cash equivalents | **(1,530)** | **(2)** | (1,343) | (2) |
| Net debt | **40,164** | **49** | 39,942 | 49 |
| Junior subordinated notes | **8,498** | **10** | 8,614 | 11 |
| Redeemable non-controlling interest[2] | **393** | **1** | — | — |
| Preferred shares | **3,980** | **5** | 3,980 | 5 |
| Common shareholders' equity[3] | **29,100** | **35** | 28,417 | 35 |
| | **82,135** | **100** | 80,953 | 100 |

1 Classified in Current liabilities on the Consolidated balance sheet.
2 Classified in mezzanine equity on the Consolidated balance sheet.
3 Includes non-controlling interests.

At February 12, 2021, we had unused capacity of $3.0 billion, $3.0 billion, and US$2.8 billion under our TC Energy equity and TCPL Canadian and U.S. debt 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, 2020.

## Cash flows

The following tables summarize our consolidated cash flows.

| year ended December 31<br>(millions of $) | 2020 | 2019 | 2018 |
|---|---|---|---|
| Net cash provided by operations | **7,058** | 7,082 | 6,555 |
| Net cash used in investing activities | **(6,052)** | (6,872) | (10,019) |
| | **1,006** | 210 | (3,464) |
| Net cash (used in)/provided by financing activities | **(800)** | 693 | 2,748 |
| | **206** | 903 | (716) |
| Effect of foreign exchange rate changes on cash and cash equivalents | **(19)** | (6) | 73 |
| **Increase/(decrease) in cash and cash equivalents** | **187** | 897 | (643) |

## Cash provided by operating activities

| year ended December 31<br>(millions of $) | 2020 | 2019 | 2018 |
|---|---|---|---|
| Net cash provided by operations | **7,058** | 7,082 | 6,555 |
| Increase/(decrease) in operating working capital | **327** | (293) | 102 |
| Funds generated from operations | **7,385** | 6,789 | 6,657 |
| Specific items: | | | |
| Current income tax expense on sale of Columbia Midstream assets | **—** | 320 | — |
| U.S. Northeast power marketing contracts | **—** | 8 | 1 |
| Bison contract terminations | **—** | — | (122) |
| Net gain on sales of U.S. Northeast power generation assets | **—** | — | (14) |
| **Comparable funds generated from operations** | **7,385** | 7,117 | 6,522 |

### Net cash provided by operations

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.

Net cash provided by operations increased by $527 million in 2019 compared to 2018 primarily due to the amount and timing of working capital changes as well as higher funds generated from operations.

### Comparable funds generated from operations

Comparable funds generated from operations increased by $268 million in 2020 compared to 2019 primarily due to the 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.

Comparable funds generated from operations increased by $595 million in 2019 compared to 2018 primarily due the net effect of higher comparable earnings, greater distributions from operating activities of our equity investments and the recovery of higher depreciation on the NGTL System.

## Cash used in investing activities

| year ended December 31<br>(millions of $) | 2020 | 2019 | 2018 |
|---|---|---|---|
| **Capital spending** | | | |
| Capital expenditures | **(8,013)** | (7,475) | (9,418) |
| Capital projects in development | **(122)** | (707) | (496) |
| Contributions to equity investments | **(765)** | (602) | (1,015) |
| | **(8,900)** | (8,784) | (10,929) |
| Proceeds from sales of assets, net of transaction costs | **3,407** | 2,398 | 614 |
| Acquisition | **(88)** | — | — |
| Reimbursement of costs related to capital projects in development | **—** | — | 470 |
| Other distributions from equity investments | **—** | 186 | 121 |
| Payment for unredeemed shares of Columbia Pipeline Group, Inc. | **—** | (373) | — |
| Deferred amounts and other | **(471)** | (299) | (295) |
| **Net cash used in investing activities** | **(6,052)** | (6,872) | (10,019) |

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. shareholders in 2019, discussed below. This was partially offset by the cost to acquire the remaining 50 per cent ownership interest in TC Turbines.

Net cash used in investing activities decreased from $10.0 billion in 2018 to $6.9 billion in 2019 primarily as a result of proceeds received from the sales of certain Columbia Midstream assets and the Coolidge generating station along with lower capital expenditures and contributions to equity investments. This was partially offset by increased spending on capital projects under development, non-recurrence of Coastal GasLink recoveries realized in 2018 as well as a payment to dissenting Columbia Pipeline Group, Inc. shareholders in 2019 for the appraised value of their shares plus interest pursuant to a court decision which affirmed the original share purchase price.

### Capital spending[1]

The following table summarizes capital spending by segment.

| **year ended December 31**<br>(millions of $) | **2020** | **2019** | **2018** |
|---|---:|---:|---:|
| Canadian Natural Gas Pipelines | **3,608** | 3,906 | 2,478 |
| U.S. Natural Gas Pipelines | **2,785** | 2,516 | 5,771 |
| Mexico Natural Gas Pipelines | **173** | 357 | 797 |
| Liquids Pipelines | **1,442** | 954 | 581 |
| Power and Storage | **834** | 1,019 | 1,257 |
| Corporate | **58** | 32 | 45 |
| | **8,900** | 8,784 | 10,929 |

1 Capital spending includes capacity capital expenditures, maintenance capital expenditures, capital projects in development and contributions to equity investments.

#### *Capital expenditures*

Our capital expenditures in 2020 were incurred primarily for the expansion of the NGTL System and Columbia Gas projects, construction of Keystone XL, construction of Coastal GasLink prior to the sale of a 65 per cent equity interest as well as maintenance capital expenditures. Higher capital expenditures in 2020 reflect increased spending on Keystone XL and Columbia Gas projects, partially offset by reduced spending on the NGTL System, Napanee and the adoption of equity accounting for our ownership in Coastal GasLink LP after its partial sale.

#### *Capital projects in development*

Costs incurred during 2020, 2019 and 2018 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 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 decreased in 2019 compared to 2018 mainly due to lower investments in Millennium and Sur de Texas, partially offset by higher investment in Bruce Power.

Contributions to equity investments in 2019 and 2018 include our proportionate share of Sur de Texas debt financing.

### Proceeds from sales of assets

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 Coastal GasLink LP project-level financing which preceded the equity sale.

In 2019, we completed the following 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 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.

In October 2018, we completed the sale of our interests in the Cartier Wind power facilities in Québec for proceeds of approximately $630 million, before post-closing adjustments.

**Acquisition**

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

**Reimbursement of costs related to capital projects in development**

In November 2018, we received $470 million in accordance with provisions in the agreements with the LNG Canada joint venture participants allowing them to reimburse us for their share of pre-FID costs.

**Other distributions from equity investments**

Other distributions from equity investments in 2019 and 2018 primarily reflect our proportionate share of Bruce Power and Northern Border financings undertaken to fund their respective capital programs and to also make distributions to their partners. In 2019 and 2018, we received distributions of $120 million and $121 million, respectively, from Bruce Power in connection with their issuance of senior notes in the capital markets. We also received distributions of $66 million in 2019 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**<br>(millions of $) | **2020** | **2019** | **2018** |
|---|---|---|---|
| Notes payable (repaid) / issued, net | **(220)** | 1,656 | 817 |
| Long-term debt issued, net of issue costs | **5,770** | 3,024 | 6,238 |
| Long-term debt repaid | **(3,977)** | (3,502) | (3,550) |
| Junior subordinated notes issued, net of issue costs | **—** | 1,436 | — |
| Loss on settlement of financial instruments | **(130)** | — | — |
| Dividends and distributions paid | **(3,367)** | (2,174) | (1,954) |
| Contributions from redeemable non-controlling interest | **1,033** | — | — |
| Common shares issued, net of issue costs | **91** | 253 | 1,148 |
| Partnership units of TC PipeLines, LP issued, net of issue costs | **—** | — | 49 |
| **Net cash (used in) / provided by financing activities** | **(800)** | 693 | 2,748 |

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.

Net cash provided by financing activities decreased by $2.1 billion in 2019 compared to 2018 due to lower issuances of long-term debt and common shares, partially offset by junior subordinated notes issued in 2019 and increased notes payable outstanding.

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 2020:

| (millions of Canadian $, unless otherwise noted) | | | | | |
|---|---|---|---|---|---|
| **Company** | **Issue date** | **Type** | **Maturity date** | **Amount** | **Interest rate** |
| **TRANSCANADA PIPELINES LIMITED** | | | | | |
| | April 2020 | Senior Unsecured Notes | April 2030 | US 1,250 | 4.10% |
| | April 2020 | Medium Term Notes | April 2027 | 2,000 | 3.80% |
| **PORTLAND NATURAL GAS TRANSMISSION SYSTEM** | | | | | |
| | October 2020 | Senior Unsecured Notes | October 2030 | US 125 | 2.84% |
| **GAS TRANSMISSION NORTHWEST LLC** | | | | | |
| | June 2020 | Senior Unsecured Notes | June 2030 | US 175 | 3.12% |
| **COASTAL GASLINK PIPELINE LIMITED PARTNERSHIP**[1] | | | | | |
| | April 2020 | Senior Secured Credit Facilities | April 2027 | 1,603 | Floating |

1 On April 28, 2020, Coastal GasLink LP entered into secured long-term project financing credit facilities. On May 22, 2020, TC Energy completed the sale of a 65 per cent equity interest in Coastal GasLink LP and subsequently accounts for its remaining 35 per cent interest using the equity method. Immediately preceding the equity sale, Coastal GasLink LP made an initial draw of $1.6 billion on the credit facilities, of which approximately $1.5 billion was paid to TC Energy.

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.

In addition, on January 4, 2021, we put in place a US$4.1 billion project-level credit facility to support the construction of the Keystone XL pipeline that is fully guaranteed by the Government of Alberta and non-recourse to us. We drew US$579 million on the credit facility on January 8, 2021, the proceeds of which were used in part to repurchase a majority of the Government of Alberta's Class A interests. The facility bears interest at a floating rate and matures in January 2024. The suspension of the advancement of the project does not require immediate repayment of the debt as repayment is dependent upon certain other events or decisions specified in the credit facility agreement. Refer to the notes to our 2020 Consolidated financial statements for additional information.

On December 9, 2020, our subsidiary, Columbia Pipeline Group, Inc., entered into a US$4.2 billion Delayed Draw Term Loan due in June 2022, bearing interest at a floating rate, to be used for general corporate purposes. In January 2021, US$4.0 billion was drawn on the Delayed Draw Term Loan and the total availability under the loan agreement was reduced accordingly.

### Long-term debt retired/repaid

The following table outlines significant long-term debt repaid in 2020 and early 2021:

| (millions of Canadian $, unless otherwise noted)<br>Company | Retirement/<br>repayment date | Type | Amount | Interest rate |
|---|---|---|---|---|
| **TRANSCANADA PIPELINES LIMITED** | | | | |
| | January 2021 | Debentures | US 400 | 9.875% |
| | November 2020 | Debentures | 250 | 11.80% |
| | October 2020 | Senior Unsecured Notes | US 1,000 | 3.80% |
| | March 2020 | Senior Unsecured Notes | US 750 | 4.60% |
| **PORTLAND NATURAL GAS TRANSMISSION SYSTEM** | | | | |
| | October 2020 | Unsecured Loan Facility | US 99 | Floating |
| **COLUMBIA PIPELINE GROUP, INC.** | | | | |
| | June 2020 | Senior Unsecured Notes | US 750 | 3.30% |
| **GAS TRANSMISSION NORTHWEST LLC** | | | | |
| | June 2020 | Senior Unsecured Notes | US 100 | 5.29% |

For more information about long-term debt and junior subordinated notes issued and long-term debt repaid in 2020, 2019 and 2018, refer to the notes to our 2020 Consolidated financial statements.

### Contributions from Redeemable non-controlling interest

During 2020, our Keystone XL subsidiaries issued $1,033 million of Class A Interests to the Government of Alberta. For more information on the redeemable non-controlling interest, refer to the notes to our 2020 Consolidated financial statements.

### Dividend Reinvestment Plan

Under the DRP, eligible holders of common and preferred shares of TC Energy can reinvest their dividends and make optional cash payments to obtain additional TC Energy common shares. From July 1, 2016 to October 31, 2019, common shares were issued from treasury at a discount of two per cent to market prices over a specified period.

Commencing with the dividends declared October 31, 2019, common shares purchased under TC Energy's DRP are no longer satisfied with shares issued from treasury at a discount, but rather are acquired on the open market at 100 per cent of the weighted average purchase price.

### TC Energy Corporate ATM Program

In June 2017, we established an ATM program that allowed us to issue common shares from treasury from time to time, at the prevailing market price. The ATM program, which was effective for a 25-month period, was initially established with an aggregate issuance limit of up to $1.0 billion in common shares or the U.S. dollar equivalent. In June 2018, we replenished the capacity available under the ATM program to allow for the issuance of additional common shares from treasury of up to $1.0 billion for a revised aggregate total of $2.0 billion or the U.S. dollar equivalent.

In 2018, 20 million common shares were issued under the ATM program at an average price of $56.13 per share for proceeds of $1.1 billion, net of approximately $10 million of related commissions and fees.

In July 2019, the ATM program expired with no common shares issued in 2019.

On December 7, 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 new program in 2020.

## TC PipeLines, LP

### ATM equity issuance program

In 2018, TC PipeLines, LP issued 0.7 million common units under its ATM program, which authorized TC PipeLines, LP from time to time to offer and sell, through sales agents, common units representing limited partner interests. In 2018, TC PipeLines, LP's ATM program generated net proceeds of approximately $39 million. In August 2019, this ATM program expired with no common unit issuances in 2019. At December 31, 2020 and 2019, our ownership interest in TC PipeLines, LP was 25.5 per cent.

## Share information

| as at February 12, 2021 | | |
|---|---|---|
| **Common Shares** | **issued and outstanding** | |
| | 940 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 13 | 20 million | Series 14 preferred shares |
| Series 15 | 40 million | Series 16 preferred shares |
| **Options to buy common shares** | **outstanding** | **exercisable** |
| | 9 million | 5 million |

On January 30, 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.

On June 30, 2020, 401,590 Series 3 preferred shares were converted, on a one-for-one basis, into Series 4 preferred shares and 1,865,362 Series 4 preferred shares were converted, on a one-for-one basis, into Series 3 preferred shares.

On December 31, 2019, 173,954 Series 1 preferred shares were converted, on a one-for-one basis, into Series 2 preferred shares and 5,252,715 Series 2 preferred shares were converted, on a one-for-one basis, into Series 1 preferred shares.

For more information on preferred shares refer to the notes to our 2020 Consolidated financial statements.

**Dividends**

| year ended December 31 | 2020 | 2019 | 2018 |
|---|---|---|---|
| **Dividends declared** | | | |
| per common share | **$3.24** | $3.00 | $2.76 |
| per Series 1 preferred share | **$0.86975** | $0.8165 | $0.8165 |
| per Series 2 preferred share | **$0.7099** | $0.89872 | $0.78835 |
| per Series 3 preferred share | **$0.48075** | $0.538 | $0.538 |
| per Series 4 preferred share | **$0.54989** | $0.73872 | $0.62748 |
| per Series 5 preferred share | **$0.56575** | $0.56575 | $0.56575 |
| per Series 6 preferred share | **$0.52537** | $0.7976 | $0.69341 |
| per Series 7 preferred share | **$0.97575** | $0.98181 | $1.00 |
| per Series 9 preferred share | **$0.9405** | $1.032 | $1.0625 |
| per Series 11 preferred share | **$0.92194** | $0.95 | $0.95 |
| per Series 13 preferred share | **$1.375** | $1.375 | $1.375 |
| per Series 15 preferred share | **$1.225** | $1.225 | $1.225 |

On February 17, 2021, we increased the quarterly dividend on our outstanding common shares by 7.4 per cent to $0.87 per common share for the quarter ending March 31, 2021 which equates to an annual dividend of $3.48 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 12, 2021, we had a total of $12.4 billion of committed revolving and demand credit facilities, including:

| 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 2024 | $3.0 billion | $2.4 billion |
| 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 2021 | US$4.5 billion | US$4.1 billion |
| TCPL/TCPL USA/ Columbia/ TransCanada American Investments Ltd. | For general corporate purposes of the borrowers, guaranteed by TCPL | December 2022 | US$1.0 billion | US$1.0 billion |
| **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 billion | $1.1 billion |
| Mexico subsidiary | For Mexico general corporate purposes, guaranteed by TCPL | Demand | MXN$5.0 billion | MXN$3.0 billion |

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

At February 12, 2021, certain of TC Energy's other subsidiaries had an additional $0.8 billion of undrawn capacity on third-party committed credit facilities.

In second quarter 2020, an additional US$2.0 billion of 364-day committed bilateral credit facilities were established. These credit facilities were extinguished in fourth quarter 2020 as they were no longer required.

## 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, 2020<br>(millions of $) | Total | < 1 year | 1 - 3 years | 4 - 5 years | > 5 years |
|---|---|---|---|---|---|
| Notes payable | 4,176 | 4,176 | — | — | — |
| Long-term debt and junior subordinated notes[1] | 45,701 | 1,972 | 3,762 | 2,998 | 36,969 |
| Operating leases[2] | 641 | 86 | 142 | 132 | 281 |
| Purchase obligations | 5,182 | 2,514 | 1,018 | 442 | 1,208 |
| | 55,700 | 8,748 | 4,922 | 3,572 | 38,458 |

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 $4.2 billion at the end of 2020 compared to $4.3 billion at the end of 2019.

### Long-term debt and junior subordinated notes

At December 31, 2020, we had $36.9 billion of long-term debt and $8.5 billion of junior subordinated notes outstanding compared to $37.0 billion of long-term debt and $8.6 billion of junior subordinated notes at December 31, 2019.

We attempt to ladder the maturity profile of our debt. The weighted-average maturity of our long-term debt, excluding call features, and junior subordinated notes is approximately 22 years.

#### *Interest payments*

At December 31, 2020, scheduled interest payments related to our long-term debt and junior subordinated notes were as follows:

| at December 31, 2020<br>(millions of $) | Total | < 1 year | 1 - 3 years | 4 - 5 years | > 5 years |
|---|---|---|---|---|---|
| Long-term debt | 24,363 | 1,808 | 3,370 | 3,095 | 16,090 |
| Junior subordinated notes | 21,532 | 442 | 884 | 885 | 19,321 |
| | 45,895 | 2,250 | 4,254 | 3,980 | 35,411 |

### 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, 2020<br>(millions of $) | Total | < 1 year | 1 - 3 years | 4 - 5 years | > 5 years |
|---|---|---|---|---|---|
| **Canadian Natural Gas Pipelines** | | | | | |
| Transportation by others[1] | 1,690 | 131 | 304 | 286 | 969 |
| Capital spending[2] | 936 | 781 | 154 | 1 | — |
| **U.S. Natural Gas Pipelines** | | | | | |
| Transportation by others[1] | 680 | 119 | 215 | 123 | 223 |
| Capital spending[2] | 254 | 254 | — | — | — |
| **Mexico Natural Gas Pipelines** | | | | | |
| Capital spending[2] | 152 | 76 | 76 | — | — |
| **Liquids Pipelines** | | | | | |
| Capital spending[2] | 880 | 857 | 23 | — | — |
| Other | 12 | 3 | 6 | 3 | — |
| **Power and Storage** | | | | | |
| Capital spending[2] | 279 | 152 | 126 | 1 | — |
| Other[3] | 62 | 14 | 19 | 14 | 15 |
| **Corporate** | | | | | |
| Other | 233 | 123 | 95 | 14 | 1 |
| Capital spending[2] | 4 | 4 | — | — | — |
| | 5,182 | 2,514 | 1,018 | 442 | 1,208 |

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 $20 billion of secured projects and $8 billion of projects under development, which are subject to key commercial or 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

### Northern Courier

As part of our role as operator of the Northern Courier pipeline, we have guaranteed the financial performance of the pipeline related to delivery and terminalling of bitumen and diluent and contingent financial obligations under sub-lease agreements. The guarantees have terms ranging to 2055.

At December 31, 2020, our potential exposure under the Northern Courier guarantees was estimated to be $300 million with a carrying amount of approximately $26 million.

### 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 2021.

At December 31, 2020, our share of potential exposure under the Sur de Texas pipeline guarantees was estimated to be $100 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, 2020, 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, 2020 to be approximately $78 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 expect to make funding contributions of approximately $128 million for the defined benefit pension plans, approximately $6 million for other post-retirement benefit plans and approximately $59 million for the savings plans and defined contribution pension plans. In addition, we expect to provide an additional estimated $13 million letter of credit to the Canadian defined benefit plan for solvency funding requirements.

In 2020, we made funding contributions of $124 million to our defined benefit pension plans, $9 million for other post-retirement benefit plans and $58 million for the savings plan and defined contribution pension plans. We also provided an additional $13 million letter of credit to the Canadian defined benefit plan for funding of solvency requirements.

### Outlook

The next actuarial valuation for our pension and other post-retirement benefit plans will be carried out as at January 1, 2021. Based on current market conditions, we expect funding requirements for these plans to approximate 2021 levels for several years. This will allow us to amortize solvency deficiencies in the plans, in addition to normal service costs. We do not expect COVID-19 to impact our funding requirements.

The net benefit cost for our defined benefit and other post-retirement plans increased to $114 million in 2020 from $83 million in 2019 mainly due to lower discount rates.

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) process which identifies risks that could materially impact the achievement of our strategic objectives, including ESG-related risks.

Our Board of Directors' Governance Committee oversees our ERM activities, which includes ensuring appropriate management systems are in place to identify and manage our risks, ensuring adequate Board oversight of our risk management policies, programs and practices. Other Board committees oversee specific types of risk:

- 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
- 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.

We have discussed the risks that are specific to each of our business segments in their respective sections of this MD&A. The following is a summary of certain general risks that affect our company across all of our operations and are being continuously monitored.

| Risk and Description | Impact | Monitoring and Mitigation |
|---|---|---|
| **Business interruption** | | |
| Operational risks, including equipment malfunctions and breakdowns, labour disputes, a pandemic, natural disasters and other catastrophic events including those related to climate change, acts of terror and sabotage. | 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 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 incident, emergency and crisis management programs to ensure TC Energy can effectively respond to operational risk 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 these risks, but insurance does not cover all events in all circumstances. |
| **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 expectations and concerns important to stakeholders, including those related to climate change, could affect our reputation and our ability to operate and grow, as well as our access to and cost of capital. | Our reputation with stakeholders, including Indigenous communities, can have a significant impact on our operations and projects, infrastructure development and overall reputation. Should investors develop negative perceptions regarding our energy infrastructure business, future access to investment capital could be negatively impacted. | Our four core values – safety, responsibility, collaboration and integrity – guide us in building and maintaining all of 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. |
| **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 keeping them apprised of developments in our business and factually communicating our prospects, risks and challenges, including those related to ESG as well as receiving their feedback. We also conduct research around the ESG preferences of our investors and financial partners, which are considered in our ESG and sustainability approach and reporting. |
| **Capital allocation strategy** | | |
| To be competitive, we must offer integral energy infrastructure services in supply and demand areas, and for 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. |
| **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, ensuring 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, people and process safety, 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 conforms to applicable industry standards and complies with applicable regulatory requirements. It covers our projects and operations and follows a continuous improvement cycle organized into four key areas:

- Plan – risk and regulatory assessment, objective and target setting, including achieving total recordable case rate targets and striving for zero incidents as well as 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 with performance reviewed by management.

The HSSE committee reviews HSSE performance and operational risk management. It receives detailed reports on:

- overall HSSE corporate governance
- operational performance and preventive maintenance metrics
- asset integrity programs
- emergency preparedness, incident response and evaluation
- people and process safety performance metrics
- our Environment Program, which is part of TOMS
- 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
- our Occupational Health and Hygiene Program, which includes physical and mental health
- management's approach to voluntary public disclosure on HSSE matters.

**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 in service only after all necessary requirements, both regulatory and internal, have been satisfied.

In 2020, we spent $1.5 billion for pipeline integrity on the natural gas and liquids pipelines we operate, a $286 million increase from 2019 in part due to increased capital expenditures related to pipeline replacements to address population growth adjacent to our pipeline systems, modifications to facilitate the inline inspection of additional pipeline segments, an increased number of inline inspections and corresponding excavations plus repairs on some pipeline systems. 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 discussion 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 in environmental policy, legislation and regulation, and 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, 2020, accruals related to these obligations totaled $24 million (2019 – $29 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 2020, we incurred $64 million (2019 – $69 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. 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 or other expenses or higher 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 on January 1, 2020. Alberta, British Columbia and Saskatchewan have drafted their own methane regulations that take the place of the federal regulation in those jurisdictions; however, 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 and associated reporting. 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 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. Our assets across Canada are subject to some type of carbon pricing as a result
- new requirements for federally regulated project applications under the Impact Assessment Agency were recently introduced as 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. As well, in August 2020, the CER published a revision to its Filing Manual, integrating the Strategic Assessment of Climate Change, which includes the 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. We are assessing the implications of this requirement as part of our project implementation process

- B.C. 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, B.C. established The CleanBC program for industry 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 existing Carbon Competitive Incentive Regulation (CCIR) has been replaced with the Technology Innovation and Emissions Reduction (TIER) regulation as of January 1, 2020. The CCIR required established industrial facilities with GHG emissions above a certain threshold to reduce their emissions below an intensity baseline. The TIER system follows a similar regulatory framework as the CCIR and 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 natural gas pipeline facilities in Québec are also subject to this program and compliance instruments have been purchased in order to comply with the requirements of this initiative
- Ontario does not currently have carbon pricing regulation. Therefore, TC Energy's electricity and pipeline facilities in this jurisdiction are subject to the Canadian Federal OBPS. The Government of Ontario is in the process of developing a provincial industrial carbon pricing program, the Emissions Performance Standards (EPS). The Ontario EPS system received equivalency status from the Federal Government in August 2020; however, the implementation timeframe and compliance requirements are not finalized. Until that time, Federal OBPS applies to our Canadian Mainline operations in the province and costs under this program are recovered in tolls. At this time, we do not anticipate any material impact to the financial performance of our Ontario natural gas pipeline facilities as a result of this program.

***U.S. jurisdictions***

- *Federal*: On August 13, 2020, the U.S. Environmental Protection Agency (EPA) issued two final rules to lessen the administrative and compliance cost burden on the oil and gas industry related to the New Source Performance Standards (NSPS). One of the rules, the Methane Policy Rule, was a policy amendment which notably removed the transmission and storage sector from the source category and rescinded the NSPS applicable to those sources. The second rule, the Technical Amendment, changed several requirements including monitoring and repair schedules, recordkeeping and reporting requirements plus provided industry with the option to meet certain state requirements in lieu of federal requirements. Lawsuits brought by environmental groups and various state and local governments against both rules are pending in the D.C. Circuit Court of Appeals
- *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 January 1, 2020, thresholds for leak repair were reduced. California also has a GHG cap-and-trade program linked with Quebec's program through the WCI
- *Washington*: In 2016, the Washington Department of Ecology (Ecology) adopted the Clean Air Rule (Rule) which established a cap and reduce program to regulate GHG emissions from major stationary sources, petroleum product producers, importers and distributors and natural gas distributors within Washington. The Rule was challenged in court and on January 16, 2020 the Washington State Supreme Court (Washington Supreme Court) ruled that while Ecology has the authority to regulate actual emitters, it cannot regulate indirect emitters of GHG emissions. As such, it vacated the rule only as it applied to indirect sources of GHGs such as natural gas distributors and fuel suppliers. The Washington Supreme Court remanded the case to the Superior Court to determine how to separate the rule. The impact to our GTN assets is being evaluated
- *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 16, 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 (RENE) and its regulations, which allow for the compilation of information on the emission of compounds and greenhouse gases of the different productive sectors of the country. The LGCC defines the National Inventory of greenhouse gases and compounds as the document that contains the estimate of anthropogenic emissions by sources and absorption by sinks in Mexico
- 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 second quarter 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 greenhouse gas 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 GHG 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 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 in early 2021.

***U.S. jurisdictions***

- *Federal:* On August 6, 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 EPA 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
- *Washington*: In 2019, a law was enacted that committed the state electricity grid to becoming 80 per cent fossil fuel-free by 2030 and 100 per cent by 2045. Ecology has begun rulemaking to further this goal. In Washington's 2020 legislative session, a law was passed committing the state to becoming carbon-neutral by 2050 and strengthening intermediate reduction goals. Additionally, Ecology began rulemaking to implement the Governor's December 2019 directive to strengthen and standardize the consideration of climate change risks, vulnerabilities and impacts in environmental assessments for major industrial and fossil fuel projects with significant environmental impacts. The impact to GTN's assets from regulations furthering these initiatives is still being evaluated
- *California*: Our assets may be affected by the Governor of California's executive order, issued September 23, 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 since a significant number of vehicles in California are currently powered by natural gas. 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. Oregon has begun rulemaking to implement this executive order and we are assessing which of our GTN facilities in Oregon will be impacted. On July 31, 2020, a lawsuit was filed by a coalition of business and trade groups, including Oregon Business & Industry, challenging the executive order

- *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*: On August 14, 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.

## 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 and internal audit 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-term 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 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 exposure to commodity price risk 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 generation business, we manage our exposure to fluctuating commodity prices through long-term contracts and hedging activities including selling and purchasing power 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.

The following risks affect our company across all of our operations and are being continuously monitored.

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 short-term 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 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 LIBOR, of which certain rate settings may cease to be published at the end of 2021 with full cessation expected by mid-2023. We continue to monitor developments and are preparing to address any necessary system and contractual changes while assessing the adoption of the standard market proposed reference rates. This includes identifying and analyzing existing agreements to determine the effect of reference rate reform on our consolidated financial statements.

**Foreign exchange risk**

We generate revenues and incur expenses and capital expenditures that are denominated in currencies other than Canadian dollars. As a result, our earnings and cash flows are exposed to currency fluctuations.

A significant portion of our businesses generate earnings in U.S. dollars, but 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 net income. As our U.S. dollar-denominated operations continue to grow, this exposure increases. A portion of this risk is offset by interest expense on U.S. dollar-denominated debt. The balance of the exposure is actively managed on a rolling two-year basis using foreign exchange derivatives, however, the natural exposure beyond that period remains.

***Average exchange rate – U.S. to Canadian dollars***

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

| | |
|---|---|
| **2020** | **1.34** |
| 2019 | 1.33 |
| 2018 | 1.30 |

The impact of changes in the value of the U.S. dollar on our U.S. and Mexico operations, which are primarily U.S. dollar-denominated, is partially offset by interest on U.S. dollar-denominated debt as set out in the table below. Comparable EBIT is a non-GAAP measure. Refer to the Reconciliation of non-GAAP measures section for more information.

***Significant U.S. dollar-denominated amounts***

| **year ended December 31**<br>(millions of US$) | **2020** | **2019** | **2018** |
|---|---|---|---|
| U.S. Natural Gas Pipelines comparable EBIT | **2,117** | 2,055 | 1,830 |
| Mexico Natural Gas Pipelines comparable EBIT[1] | **579** | 481 | 486 |
| U.S. Liquids Pipelines comparable EBIT | **762** | 1,127 | 876 |
| Interest on U.S. dollar-denominated long-term debt and junior subordinated notes | **(1,302)** | (1,326) | (1,325) |
| Capitalized interest on U.S. dollar-denominated capital expenditures | **131** | 34 | 15 |
| U.S. dollar-denominated allowance for funds used during construction | **182** | 205 | 326 |
| U.S. dollar comparable non-controlling interests and other | **(248)** | (233) | (264) |
| | **2,221** | 2,343 | 1,944 |

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

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

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.

**Counterparty credit risk**

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

- cash and cash equivalents
- accounts receivable
- available-for-sale assets
- the 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 of and communication with those counterparties experiencing greater financial pressures due to recent market events. Although counterparty credit risk has heightened and the long-term impacts of COVID-19 and related disruptions on our customers are difficult to predict, we are not expecting a material negative impact to our 2021 earnings or cash flows as a result of this increased risk.

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, 2020 and 2019, 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 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. There have been periods of heightened global market volatility and reduced liquidity during 2020 but we have taken steps to further strengthen our financial condition and mitigate our exposure to these risks. 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, 2020, 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, 2020, 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, 2020, the internal control over financial reporting was effective.

Our internal control over financial reporting as of December 31, 2020 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their attestation report which is included in this document.

### CEO and CFO certifications

Our President and CEO and our CFO have attested to the quality of the public disclosure in our fiscal 2020 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 2020 and 2019, no impairments were recorded.

In 2018, the following impairments were recorded:

- a $722 million pre-tax impairment of the carrying value of Bison's plant, property and equipment ($140 million after tax and net of non-controlling interests)
- a $79 million pre-tax impairment of the carrying value of Tuscarora's goodwill ($15 million after tax and net of non-controlling interests).

### Long-lived assets

**Bison**

In December 2018, we evaluated our investment in the Bison natural gas pipeline for impairment in connection with the termination of certain customer transportation agreements. With the loss of these contracted future cash flows, and the persistence of unfavourable market conditions which have inhibited system flows on the pipeline, we determined that the asset’s remaining carrying value was no longer recoverable and recognized a non-cash impairment charge of $722 million in the U.S. Natural Gas Pipelines segment. Our share of the impairment charge, after tax and net of non-controlling interests, was $140 million.

### 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. It was determined that it was more likely than not that the fair value of the reporting units exceeded their carrying amounts, including goodwill, and therefore, goodwill was not impaired.

**Tuscarora**

In fourth quarter 2018, we determined that the fair value of Tuscarora did not exceed its carrying value, including goodwill, and recorded a goodwill impairment charge of $79 million within the U.S. Natural Gas Pipelines segment. Our share of the goodwill impairment charge, after tax and net of non-controlling interests, was $15 million. Our share of the remaining goodwill balance related to Tuscarora, net of non-controlling interests, was US$6 million at December 31, 2020 (2019 – US$6 million).

## FINANCIAL 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**<br>(millions of $) | **2020** | **2019** |
|---|---|---|
| Other current assets | **235** | 190 |
| Other long-term assets | **41** | 7 |
| Accounts payable and other | **(72)** | (115) |
| Other long-term liabilities | **(59)** | (81) |
| | **145** | 1 |

### 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, 2020<br>(millions of $) | Total fair value | < 1 year | 1 - 3 years | 4 - 5 years | > 5 years |
|---|---|---|---|---|---|
| **Derivative instruments held for trading** | | | | | |
| Assets | 207 | 188 | 19 | — | — |
| Liabilities | (46) | (42) | — | — | (4) |
| **Derivative instruments in hedging relationships** | | | | | |
| Assets | 69 | 47 | 13 | 9 | — |
| Liabilities | (85) | (30) | (41) | (13) | (1) |
| | 145 | 163 | (9) | (4) | (5) |

### Unrealized and realized (losses) / gains on derivative instruments

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

| year ended December 31<br>(millions of $) | 2020 | 2019 | 2018 |
|---|---|---|---|
| **Derivative instruments held for trading**[1] | | | |
| Amount of unrealized (losses) / gains in the year | | | |
| Commodities | **(23)** | (111) | 28 |
| Foreign exchange | **126** | 245 | (248) |
| Amount of realized gains / (losses) in the year | | | |
| Commodities | **183** | 378 | 351 |
| Foreign exchange | **(33)** | (70) | (24) |
| **Derivative instruments in hedging relationships**[2] | | | |
| Amount of realized gains / (losses) in the year | | | |
| Commodities | **6** | (6) | (1) |
| Interest rate | **(16)** | 2 | (1) |

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 interest rate and foreign exchange held-for-trading derivative instruments are included on a net basis in Interest income and other.

2 There were no gains or losses included in net income relating to discontinued cash flow hedges where it was probable that the anticipated transaction would not occur.

For further details on our non-derivative and derivative financial instruments, including classification assumptions made in the calculation of fair value and additional discussion of exposure to risks and mitigation activities, refer to Note 25, Risk management and financial instruments, of our 2020 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.

***Coastal GasLink LP***

In conjunction with the Coastal GasLink LP equity sale on May 22, 2020, we entered into a subordinated demand revolving credit facility with Coastal GasLink LP, which had a capacity of $200 million at December 31, 2020. This facility provides additional short-term liquidity and funding flexibility to the project and bears interest at a floating market-based rate. At December 31, 2020, there were no amounts outstanding on this facility. Refer to the notes to our 2020 Consolidated financial statements for additional information.

***Sur de Texas***

At December 31, 2020, the Loan receivable from affiliate on our Consolidated balance sheet reflected MXN$20.9 billion or $1.3 billion (2019 – MXN$20.9 billion or $1.4 billion), being our 60 per cent proportionate share of long-term debt financing to the Sur de Texas joint venture. Our Consolidated statement of income reflects the related interest income and foreign exchange impact on this loan receivable which are 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**<br>(millions of $) | **2020** | **2019** | **2018** | **Affected line item in the Consolidated statement of income** |
|---|---|---|---|---|
| Interest income[1] | **110** | 147 | 120 | Interest income and other |
| Interest expense[2] | **(110)** | (147) | (120) | Income from equity investments |
| Foreign exchange (losses) / gains[1] | **(86)** | 53 | (5) | Interest income and other |
| Foreign exchange gains / (losses)[1] | **86** | (53) | 5 | Income from equity investments |

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

## 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 2020 Consolidated financial statements.

## QUARTERLY RESULTS

### Selected quarterly consolidated financial data

(millions of $, except per share amounts)

| 2020 | 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 and diluted | **$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** |

| 2019 | Fourth | Third | Second | First |
|---|---|---|---|---|
| Revenues | 3,263 | 3,133 | 3,372 | 3,487 |
| Net income attributable to common shares | 1,108 | 739 | 1,125 | 1,004 |
| Comparable earnings | 970 | 970 | 924 | 987 |
| Share statistics: | | | | |
| Net income per common share – basic and diluted | $1.18 | $0.79 | $1.21 | $1.09 |
| Comparable earnings per common share | $1.03 | $1.04 | $1.00 | $1.07 |
| Dividends declared per common share | $0.75 | $0.75 | $0.75 | $0.75 |

### Factors affecting quarterly financial information by business segment

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

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

- regulators' 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 net income are based on contracted and uncommitted spot transportation as well as liquids marketing activities. Quarter-over-quarter revenues and net income 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 net income 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 certain financial and commodity price risks. These derivatives generally provide effective economic hedges, but do not meet the criteria for hedge accounting. As a result, the changes in fair value are recorded in net income. As these amounts do not accurately reflect the gains and losses that will be realized at settlement, we do not consider them 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 2020, comparable earnings also excluded:
- an income tax valuation allowance release of $18 million related to certain prior years' U.S. 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
- an incremental after-tax loss of $81 million for the three months ended December 31, 2020 related to the sale of our Ontario natural gas-fired power plants.

In third quarter 2020, comparable earnings also excluded:
- an incremental after-tax loss of $45 million related to the sale of the Ontario natural gas-fired power plants
- a $6 million reduction in the after-tax gain related to the sale of a 65 per cent equity interest in Coastal GasLink LP.

In second quarter 2020, comparable earnings also excluded:
- an after-tax gain for $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 as a result of our decision to proceed with the Keystone XL project
- an incremental after-tax loss of $77 million related to the Ontario natural gas-fired power plant assets held for sale.

In fourth quarter 2019, comparable earnings also excluded:
- an income tax valuation allowance release of $195 million related to certain prior years' U.S. tax losses resulting from our reassessment of deferred tax assets that are more likely than not to be realized
- an incremental after-tax loss of $61 million related to the Ontario natural gas-fired power plant assets held for sale
- an additional $19 million income tax expense related to state income taxes on the sale of certain Columbia Midstream assets.

In third quarter 2019, comparable earnings also excluded:
- an after-tax loss of $133 million related to the Ontario natural gas-fired power plant assets held for sale
- an after-tax loss of $133 million related to the sale of certain Columbia Midstream assets
- an after-tax gain of $115 million related to the partial sale of Northern Courier.

In second quarter 2019, comparable earnings also excluded:

- an after-tax gain of $54 million related to the sale of our Coolidge generating station
- a deferred 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 gain of $6 million related to the remainder of our U.S. Northeast power marketing contracts.

In first quarter 2019, comparable earnings also excluded:

- an after-tax loss of $12 million related to our U.S. Northeast power marketing contracts.

## FOURTH QUARTER 2020 HIGHLIGHTS

### Consolidated results

| **three months ended December 31**<br>(millions of $, except per share amounts) | **2020** | **2019** |
|---|---|---|
| Canadian Natural Gas Pipelines | **350** | 321 |
| U.S. Natural Gas Pipelines | **730** | 666 |
| Mexico Natural Gas Pipelines | **137** | 136 |
| Liquids Pipelines | **300** | 355 |
| Power and Storage | **43** | 102 |
| Corporate | **(150)** | (69) |
| **Total segmented earnings** | **1,410** | 1,511 |
| Interest expense | **(530)** | (586) |
| Allowance for funds used during construction | **95** | 117 |
| Interest income and other | **373** | 210 |
| **Income before income taxes** | **1,348** | 1,252 |
| Income tax expense | **(116)** | (27) |
| **Net income** | **1,232** | 1,225 |
| Net income attributable to non-controlling interests | **(69)** | (76) |
| **Net income attributable to controlling interests** | **1,163** | 1,149 |
| Preferred share dividends | **(39)** | (41) |
| **Net income attributable to common shares** | **1,124** | 1,108 |
| **Net income per common share – basic and diluted** | **$1.20** | $1.18 |

Net income attributable to common shares increased by $16 million or $0.02 per common share for the three months ended December 31, 2020 compared to the same period in 2019. Net income per common share reflects the dilutive impact of common shares issued under our DRP in 2019.

Fourth quarter 2020 results included:

- an income tax valuation allowance release of $18 million related to certain prior years' U.S. 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
- an incremental after-tax loss of $81 million for the three months ended December 31, 2020 related to the sale of our Ontario natural gas-fired power plants on April 29, 2020.

Fourth quarter 2019 results included:

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

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<br>(millions of $, except per share amounts) | 2020 | 2019 |
|---|---|---|
| **Net income attributable to common shares** | **1,124** | 1,108 |
| **Specific items (net of tax):** | | |
| Loss on sale of Ontario natural gas-fired power plants | **81** | 61 |
| Loss on sale of Columbia Midstream assets | **(18)** | 19 |
| Income tax valuation allowance release | **(18)** | (195) |
| Risk management activities[1] | **(89)** | (23) |
| **Comparable earnings** | **1,080** | 970 |
| **Net income per common share** | **$1.20** | $1.18 |
| **Specific items (net of tax):** | | |
| Loss on sale of Ontario natural gas-fired power plants | **0.08** | 0.07 |
| Loss on sale of Columbia Midstream assets | **(0.02)** | 0.02 |
| Income tax valuation allowance release | **(0.02)** | (0.21) |
| Risk management activities[1] | **(0.09)** | (0.03) |
| **Comparable earnings per common share** | **$1.15** | $1.03 |

1

| three months ended December 31<br>(millions of $) | 2020 | 2019 |
|---|---|---|
| Liquids marketing | **(25)** | (36) |
| Canadian power | **(1)** | 1 |
| Natural gas storage | **(5)** | (3) |
| Foreign exchange | **150** | 69 |
| Income taxes attributable to risk management activities | **(30)** | (8) |
| **Total unrealized gains from risk management activities** | **89** | 23 |

## Comparable EBITDA to comparable earnings

Comparable EBITDA represents segmented earnings adjusted for certain aspects of the specific items described above and excludes non-cash charges for depreciation and amortization.

| three months ended December 31<br>(millions of $, except per share amounts) | 2020 | 2019 |
|---|---|---|
| **Comparable EBITDA** | | |
| Canadian Natural Gas Pipelines | **682** | 618 |
| U.S. Natural Gas Pipelines | **919** | 855 |
| Mexico Natural Gas Pipelines | **166** | 165 |
| Liquids Pipelines | **408** | 472 |
| Power and Storage | **161** | 210 |
| Corporate | **(13)** | (5) |
| **Comparable EBITDA** | **2,323** | 2,315 |
| Depreciation and amortization | **(652)** | (625) |
| Interest expense | **(530)** | (586) |
| Allowance for funds used during construction | **95** | 117 |
| Interest income and other included in comparable earnings | **86** | 77 |
| Income tax expense included in comparable earnings | **(134)** | (211) |
| Net income attributable to non-controlling interests | **(69)** | (76) |
| Preferred share dividends | **(39)** | (41) |
| **Comparable earnings** | **1,080** | 970 |
| **Comparable earnings per common share** | **$1.15** | $1.03 |

### Comparable EBITDA – 2020 versus 2019

Comparable EBITDA increased by $8 million for the three months ended December 31, 2020 compared to the same period in 2019 primarily due to the net effect of the following:

- increased earnings from U.S. Natural Gas Pipelines mainly attributable to lower operating costs
- higher comparable EBITDA from Canadian Natural Gas Pipelines due to the impact of increased rate-base earnings, flow-through depreciation from additional facilities placed in service as well as higher financial charges on the NGTL System plus Coastal GasLink development fee revenue recognized in 2020, partially offset by a decrease in flow-through income taxes on the NGTL System and Canadian Mainline
- lower contribution from Liquids Pipelines primarily attributable to reduced margins from our liquids marketing activities
- decreased contribution from Power and Storage primarily due to the net impact of lower Bruce Power earnings in 2020 reflecting the commencement of the Unit 6 MCR program on January 17, 2020, partially offset by fewer outage days on the remaining units, the sale of our Ontario natural gas-fired power plants on April 29, 2020, and improved results from our Alberta cogeneration plants
- foreign exchange impact of a weaker U.S. dollar on the Canadian dollar equivalent earnings from our U.S. dollar-denominated operations.

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

**Comparable earnings – 2020 versus 2019**

Comparable earnings increased by $110 million or $0.12 per common share for the three months ended December 31, 2020 compared to the same period in 2019 and was primarily the net effect of:

- changes in comparable EBITDA described above
- a decrease in income tax expense mainly attributable to lower flow-through income taxes on Canadian rate-regulated pipelines and higher foreign tax rate differentials
- a decrease in interest expense primarily due to higher capitalized interest related to Keystone XL, partially offset by the completion of Napanee construction in first quarter 2020 and the application of equity accounting to our Coastal GasLink LP investment upon the sale of a 65 per cent interest in the project in May 2020. The reduction in interest expense was also a result of lower interest rates on short-term borrowings and the foreign exchange impact of a weaker U.S. dollar on translation of U.S. dollar-denominated interest
- higher Interest income and other primarily related to derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar denominated income
- lower AFUDC primarily due to NGTL System expansion projects placed in service and the suspension of recording AFUDC on the Tula project, partially offset by Columbia Gas growth projects
- higher depreciation in Canadian Natural Gas Pipelines reflecting new assets placed in service as discussed above, partially offset by lower depreciation in Power and Storage mainly due to a 2019 reassessment of the useful life of certain components at our Alberta cogeneration plants.

Comparable earnings per share reflected the dilutive impact of common shares issued under our DRP in 2019.

## Highlights by business segment

**Canadian Natural Gas Pipelines**

Canadian Natural Gas Pipelines segmented earnings increased by $29 million for the three months ended December 31, 2020 compared to the same period in 2019.

Net income for the NGTL System increased by $17 million for the three months ended December 31, 2020 compared to the same period in 2019 mainly due to a higher average investment base resulting from continued system expansions. On August 17, 2020, the CER approved the NGTL System's 2020-2024 Revenue Requirement Settlement Application. This settlement, which is effective from January 1, 2020 to December 31, 2024, includes an ROE of 10.1 per cent on 40 per cent deemed equity, provides the NGTL System the opportunity to increase depreciation rates if tolls fall below pre-determined levels and includes an incentive mechanism for certain operating costs where variances from projected amounts are shared between the NGTL System and its customers. It also includes a mechanism to review the settlement should tolls exceed a pre-determined level, without affecting the equity return. The NGTL System's 2019 results reflected the 2018-2019 Revenue Requirement Settlement that expired on December 31, 2019 which 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 decreased by $2 million for the three months ended December 31, 2020 compared to the same period in 2019.

Comparable EBITDA for Canadian Natural Gas Pipelines increased by $64 million for the three months ended December 31, 2020 compared to the same period in 2019 due to the net effect of:

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

Depreciation and amortization increased by $35 million for the three months ended December 31, 2020 compared to the same period in 2019 mainly due to additional NGTL System facilities placed in service in 2020.

**U.S. Natural Gas Pipelines**

U.S. Natural Gas Pipelines segmented earnings and comparable EBIT increased by $64 million for the three months ended December 31, 2020 compared to the same period in 2019. A weaker U.S. dollar in fourth quarter 2020 had a negative impact on the Canadian dollar equivalent segmented earnings from our U.S. operations compared to the same period in 2019.

U.S. Natural Gas Pipelines comparable EBITDA increased by US$58 million for the three months ended December 31, 2020 compared to the same period in 2019 mainly due to lower operating costs across a number of pipelines.

Depreciation and amortization increased by US$2 million for the three months ended December 31, 2020 compared to the same period in 2019 mainly due to new projects placed in service.

**Mexico Natural Gas Pipelines**

Mexico Natural Gas Pipelines comparable EBIT and segmented earnings increased by $1 million for the three months ended December 31, 2020 compared to the same period in 2019. A weaker U.S. dollar in fourth quarter 2020 had a negative 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 increased by US$3 million for the three months ended December 31, 2020 compared to the same period in 2019 mainly due to increased revenues.

Depreciation and amortization for the three months ended December 31, 2020 was consistent with the same period in 2019.

**Liquids Pipelines**

Liquids Pipelines segmented earnings decreased by $55 million for the three months ended December 31, 2020 compared to the same period in 2019 and included unrealized losses from changes in the fair value of derivatives related to our liquids marketing business which have been excluded from our calculation of comparable EBIT and comparable earnings in both periods. In addition, a weaker U.S. dollar in fourth quarter 2020 had a negative impact on the Canadian dollar equivalent segmented earnings compared to the same period in 2019.

Comparable EBITDA for Liquids Pipelines decreased by $64 million for the three months ended December 31, 2020 compared to the same period in 2019. This was primarily due to lower contributions from liquids marketing activities mainly attributable to lower margins.

Depreciation and amortization for the three months ended December 31, 2020 was comparable to the same period in 2019.

**Power and Storage**

Power and Storage segmented earnings decreased by $59 million for the three months ended December 31, 2020 compared to the same period in 2019 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 (pre-tax loss of $77 million for the three months ended December 31, 2019) related to the sale of our Ontario natural gas-fired power plants
- unrealized 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 decreased by $49 million for the three months ended December 31, 2020 compared to the same period in 2019 primarily due to the net effect of:

- the planned removal from service of Bruce Power Unit 6 on January 17, 2020 for its MCR program, partially offset by fewer planned outage days on the remaining units
- lower Canadian Power earnings largely as a result of the sale of our Ontario natural gas-fired power plants on April 29, 2020, partially offset by improved results from our Alberta cogeneration plants
- higher contributions from Natural Gas Storage and other primarily due to the acquisition of the remaining 50 per cent ownership of TC Turbines on November 13, 2020.

Depreciation and amortization decreased by $10 million for the three months ended December 31, 2020 primarily due to lower depreciation at our Alberta cogeneration plants due to a reassessment of the useful life of certain components performed in 2019.

**Corporate**

Corporate segmented losses increased by $81 million for the three months ended December 31, 2020 compared to the same period in 2019 and included foreign exchange losses on our proportionate share of peso-denominated inter-affiliate loans to the Sur de Texas joint venture from its partners. These amounts are recorded in Income from equity investments and have been excluded from our calculation of comparable EBITDA and EBIT as they are fully offset by corresponding foreign exchange gains on the inter-affiliate loan receivable included in Interest income and other.

Comparable EBITDA for Corporate decreased by $8 million for the three months ended December 31, 2020 compared to the same period in 2019 primarily due to increased corporate expenses.

# 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 |
| FID | Final investment decision |
| 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 |
| LTAA | Long Term Adjustment Account |
| MLP | Master limited partnership |
| 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 |
| TOMS | TC Energy's Operational Management System |
| TSA | Transportation Service Agreement |
| WCSB | Western Canadian Sedimentary basin |

### Accounting terms

| | |
|---|---|
| AFUDC | Allowance for funds used during construction |
| AOCI | Accumulated other comprehensive (loss)/income |
| FASB | Financial Accounting Standards Board (U.S.) |
| 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

| | |
|---|---|
| CCIR | Carbon Competitiveness Incentive Regulation |
| 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) |
| NEB | National Energy Board (Canada) |
| 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 |