Annual report 2020

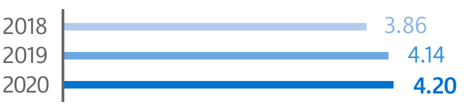
Delivering the energy people need, every day.

TC Energy

Financial highlights

Net income per common share (dollars)

Comparable earnings per common share[1] (dollars)



Dividends declared per common share (dollars)

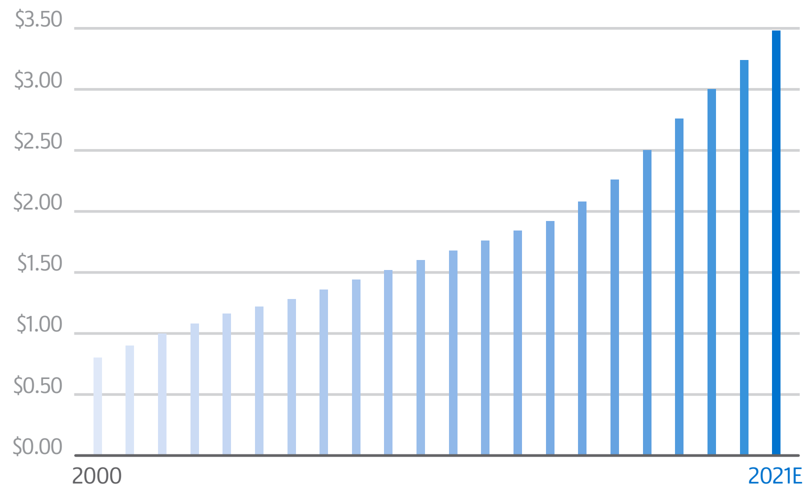
Net income attributable to common shares (millions of dollars)

Comparable earnings[1] (millions of dollars)

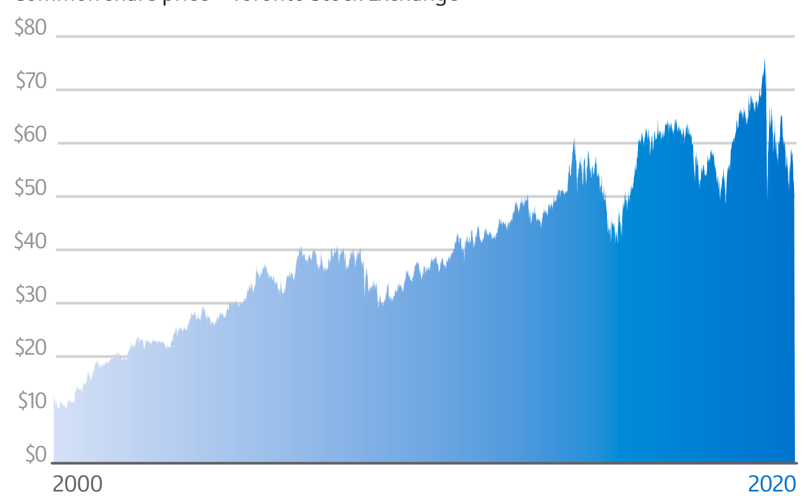
Comparable EBITDA[1] (millions of dollars)

Comparable funds generated from operations[1] (millions of dollars)

Track record of dividend growth



Common share price – Toronto Stock Exchange



12% average annual shareholder return since 2000

(1) Non-GAAP measures which do not have any standardized meanings as prescribed by U.S. generally accepted accounting principles (GAAP). For more information, see the non-GAAP measures section of the Management's Discussion and Analysis of the 2020 Annual Report.

Forward-Looking Information and Non-GAAP Measures
These pages contain certain forward-looking information and also contain references to certain non-GAAP measures that do not have any standardized meaning as prescribed by GAAP and therefore may not be comparable to similar measures presented by other entities. For more information on forward-looking information, the assumptions made, and the risks and uncertainties which could cause actual results to differ from the anticipated results, and reconciliations of non-GAAP measures to directly comparable GAAP measures, refer to TC Energy's 2020 Annual Report filed with Canadian securities regulators, the U.S. Securities and Exchange Commission and available at TCEnergy.com.

About TC Energy

Delivering the energy people need, every day. Safely. Responsibly. Collaboratively. With integrity.

We are a vital part of everyday life — delivering the energy millions of people rely on to power their lives in a sustainable way. Thanks to a safe, reliable network of natural gas and crude oil pipelines, along with power generation and storage facilities, wherever life happens — we're there. Guided by our core values of safety, responsibility, collaboration and integrity, our 7,500 people make a positive difference in the communities where we operate across Canada, the U.S. and Mexico.

TC Energy's common shares trade on the Toronto (TSX) and New York (NYSE) stock exchanges under the symbol TRP.

Our vision

To be the leading energy infrastructure company in North America, focusing on pipeline and power generation opportunities where we have, or can develop, a significant competitive advantage.

ESG at TC Energy

We are committed to providing you with the information you need related to our environmental, social and governance (ESG) approach and performance. Find relevant ESG updates throughout our annual report and also at TCEnergy.com/ESG.

Healthy and resilient in tough times

A message from Russ and Siim

The global healthcare system and economy were tested in new ways in 2020. We were continuously inspired by the sacrifices made by millions of people to support society through all aspects of the COVID-19 pandemic. To everyone doing their part – thank you.

As we all adapted to changes in lifestyle, TC Energy's people and business remained healthy. The critical role our infrastructure plays in providing energy to North America meant our services were deemed essential in every jurisdiction where we operate. Quietly and reliably, energy transported through our systems kept millions of homes, hospitals, businesses and other essential services moving forward to support people and economies across Canada, the U.S. and Mexico.

As a result, our business remained largely unaffected, even during such an extraordinary year. Finding new ways to work together, we:

+ Generated record comparable earnings of $3.9 billion or $4.20 per common share
+ Reported record comparable funds generated from operations of $7.4 billion
+ Reached numerous significant agreements in collaboration with our customers
+ Advanced our $20 billion secured capital program and
+ Placed approximately $5.9 billion of projects into service

These results are a testament to the resourcefulness of our 7,500 people, the resilience of our $100 billion asset base and our low-risk business model.

Enduring economic and societal value

We believe in sharing the benefits of our success with our stakeholders. In 2020, we worked harder than ever to buy locally whenever possible and contributed more than $31 million to community organizations across our footprint. This included $5.2 million for causes related specifically to COVID-19 relief efforts, $8 million for Indigenous organizations and $5.4 million directed by our workforce to causes that are important to them. Our people also found innovative ways to safely log over 22,500 volunteer hours.

Through the pandemic, we remained focused on our goal of zero safety incidents and progressed our operations and projects following COVID-19 protocols to keep our people and communities safe. We invested more than $14 million in research and development activities and advanced over 140 innovation projects focused on pipeline safety and reliability, technological advancement and sustainability.

We also significantly progressed our sustainability program in 2020 and invite you to read our Report on Sustainability and visit our online ESG Directory to learn more. Your valuable feedback continues to help shape our approach.

Sustainable, predictable shareholder returns

For more than two decades, we have remained disciplined in our capital allocation model and focused on a long-term conservative strategy that has delivered consistent shareholder returns through all points of the economic cycle. We've returned approximately 40 per cent of our cash flow to shareholders through a strong and growing dividend, investing the remaining 60 per cent into complementary low-risk assets that continue to drive growth in earnings and cash flow per share and enduring shareholder value.

In 2020, the value of this model was again validated. The utility-like nature of our asset base – which is approximately 95 per cent rate-regulated and/or contracted for the long-term with credit-worthy counterparties – once again did what it was designed to do. For the year ended December 31, 2020, we produced record comparable earnings of $4.20 per common share, a 1.5 per cent increase compared to 2019, while comparable funds generated from operations of $7.4 billion were four per cent higher.

Based on the strength of our financial performance in 2020 and confidence we have in our future, in February 2021 the Board of Directors increased our quarterly common share dividend for the twenty-first consecutive year to $3.48 per share on an annualized basis, an increase of approximately 7.4 per cent.

Looking forward, the demand for energy will continue to grow and the technology employed will also evolve. TC Energy will continue to play a critical role in delivering the energy society needs and capture the investment opportunities that will certainly arise with increased demand and the transition to a lower-carbon future.

Planning for our future

Succession planning is an ongoing process at TC Energy, and one the Board takes very seriously. For several years, the Board has been carefully assessing the skills, experience, performance record and personal attributes required for the Chief Executive Officer role. When Russ announced his intention to retire, we were well prepared for a seamless transition.

We have every confidence in François Poirier's appointment to succeed Russ as President and CEO, which became effective January 1, 2021. François has over 30 years of relevant experience and has played a key role on our executive leadership team for over five years, with involvement in all aspects of our business. He's shown impressive dedication to TC Energy's long-term success and has demonstrated strong vision, leadership and commitment to our core values.

While no one could have anticipated the level of complexity we would face through the year, excellence in leadership requires agility, and both Russ and François worked creatively and unwaveringly to ensure a smooth transition. It's an exciting time to guide TC Energy forward, and we know François' integrity, strategic thinking, commercial acumen and bottom-line focus will serve the company well in the years ahead.

As our company continues to evolve, so does our Board of Directors. We are pleased to welcome Mr. Michael Culbert, Ms. Susan Jones and Mr. David MacNaughton, all of whom were elected as directors at our 2020 Annual Meeting of Shareholders. These three directors bring strong leadership and strategy skills to the Board. Mr. Culbert has extensive knowledge of the energy industry, Ms. Jones has considerable expertise in international business operations including legal and regulatory matters and Mr. MacNaughton brings significant experience in government and policy. They have been excellent additions to our Board and we look forward to their ongoing contributions to TC Energy in the coming years.

We would also like to thank Mr. Steve Williams for his service to the Board as he will not be standing for re-election this year. During his tenure with the Board, Mr. Williams served as a member of the Governance committee and Human Resources committee where his business acumen provided a valuable perspective to the Board.

Looking ahead, the company's discipline and focus on our core priorities will not change. We are confident TC Energy's irreplicable asset base, unmatched human talent and outstanding governance and leadership will serve us well in the future as it has in the past.

We thank you for your continued support,

Russ Girling
President and CEO
(2010-2020)

Siim A. Vanaselja
Chair of
the Board

Three complementary energy infrastructure businesses

Natural Gas Pipelines

25% of North America's demand

Our 93,400-kilometre (58,000-mile) network of natural gas pipelines supplies more than 25 per cent of the daily clean-burning natural gas demand across North America. This pipeline network strategically connects growing supply in the most prolific basins on the continent to key markets across Canada, the U.S. and Mexico. We also operate one of the continent's largest natural gas storage businesses, with 653 billion cubic feet of regulated and non-regulated storage capacity.

Liquids Pipelines

nearly **3 billion** barrels delivered safely

Our 4,900-kilometre (3,000-mile) liquids pipeline system connects growing continental oil supplies to key markets and refineries. The Keystone Pipeline System delivers approximately 20 per cent of western Canadian exports to the U.S. Midwest and Gulf Coast, where it is converted into fuel and other useful petroleum products.

Power and Storage

4 million+ homes powered

We own or have interests in seven power generation facilities with combined capacity of approximately 4,200 megawatts (MW) – enough to power more than four million homes. Approximately 75 per cent of our power capacity is emission-less, and we are leaders in the development and operation of high-efficiency, natural gas–fired generating stations.

The premier energy infrastructure company in North America, now and in the future

A message from François Poirier

> This is an extremely exciting time for our company and I am honoured to take on the role of President and Chief Executive Officer.

Russ was a visionary leader who added tremendous shareholder value. It is my privilege to uphold his culture of excellence and mantra of "doing what's right." Russ, thank you for your invaluable contributions, mentorship and diligence. You've set us on a great path.

Progress that matters to people and our planet

While 2020 presented some of the greatest global challenges in recent history, it was also a year of significant advancement in discussions around diversity, inclusion and climate change. Society expects its energy to be delivered with care for people and our planet. We also demand this of ourselves.

Last year we published 10 new sustainability commitments that contribute to the United Nations Sustainable Development Goals. We set targets in the areas of safety, mental health, community investment, diversity and inclusion, and strengthened our commitment to enhancing long-term relationships with Indigenous communities, landowners, governments and regulators.

In all our operations and projects, we remain focused on managing, reducing or eliminating our GHG emissions where possible. Simultaneously, we are undertaking due diligence to identify potential paths to maximize our GHG emissions reductions by 2050 while ensuring our duty to protect shareholder value is not compromised. We are confident that we can continue to do both.

Uniquely positioned for energy transition

Seventy years ago, the visionaries leading our company saw an opportunity to move high-efficiency natural gas across our continent from where it was produced in abundance in the west to where it was critically needed in the east. As the Canadian Mainline was built, lives changed. Solid fuels like coal and wood were replaced with a steady, reliable source of household heat – high-efficiency natural gas.

You could say our role in the energy transition began with our incorporation in 1951. Since then we've garnered even more expertise across the energy spectrum including liquids, wind, solar, hydro and nuclear. We have also dedicated resources to advance and study opportunities including pumped storage, hydrogen, waste-heat recovery, carbon capture and numerous other energy innovations.

We believe natural gas and oil will remain critical to the global fuel mix for decades to come. Their efficiency, reliability and affordability are necessary to support our standard of living and backstop the intermittency of lower-emission fuel sources. While we continue to watch for signposts and test the resiliency of our asset base against various energy outlooks, we will adhere to our tried-and-tested risk tolerances.

Whatever pace it takes, the energy transition ahead will require expertise and billions of investment dollars. We have both. Looking forward, we believe we will be opportunity-rich and need to carefully allocate our capital to build out an ever more modern, robust and responsible energy system.

Strong platform for growth

While we were disappointed with the action to revoke the Presidential Permit for the Keystone XL pipeline in January 2021, our growth platform remains very strong. Our system of critical energy infrastructure is expected to contribute to the continuous replenishment of our growth portfolio in the years ahead. TC Energy's core business and prospects have never been stronger as the world continues to consume all types of energy.

Today, our $20 billion secured capital program includes projects that expand and modernize our existing system while giving us a clear line of sight to the earnings and cash flow it will generate as projects enter service, largely between now and 2023. Our capital program includes:

+ Expansions to the NGTL System which are reducing western Canada's reliance on coal
+ Progressing Coastal GasLink which, once complete, will displace higher-emission fuel sources in Asia
+ Ongoing upgrades and modernizations that are improving efficiency, accessing LNG export points and reaching new demand centres across our U.S. natural gas pipelines system
+ New and innovative natural gas infrastructure that's displacing fuel oil in Mexico and
+ Growth in our Power and Storage portfolio that includes the life extension program at Bruce Power which provides emission-less power to Ontario

Together with a notable portfolio of other similarly high-quality opportunities under development, this capital program is expected to contribute to strong shareholder returns many years into the future. Based on the confidence we have in our business plans, we expect to grow our common share dividend at an average annual rate of five to seven per cent.

Funding our growth

Because of last year's market volatility, we took significant steps to meaningfully enhance our liquidity and financial position. These included issuing long-term debt and temporarily establishing incremental committed credit facilities, underscoring our continued access to capital markets. Completing the sale of our Ontario natural-gas fired power assets and a 65 per cent equity interest in Coastal GasLink, in conjunction with project-level credit facilities, added to our track record of successfully recycling capital.

These actions, combined with our substantial internally generated cash flow and top credit ratings in our sector, will ensure we are able to prudently fund our capital program.

Strong governance and leadership

A company's ability to weather even the toughest storm is due in large part to the oversight of its Board of Directors, and it's no accident that TC Energy has outperformed through times of historic market volatility. From the onset of the pandemic, we continued every scheduled Board session as planned, engaging in robust discussion in a virtual environment and carefully overseeing the company's business and affairs as our executive leadership team led us through this difficult period. Time and again, this leadership team together with our 7,500 people, have demonstrated their technical expertise, complementary talents and cohesiveness to carefully navigate opportunities and challenges with tenacity and innovative thinking.

I am optimistic about what lies ahead for TC Energy. We are uniquely positioned to be the premier energy infrastructure company in North America not only today, but in the future. Our combination of the right people, the right assets and the right opportunities sets the stage for us to evolve our business to meet societal needs and capture significant shareholder value over the long term.

I look forward to our continued dialogue and welcome your ongoing feedback.

Sincerely,

François Poirier
President and CEO

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

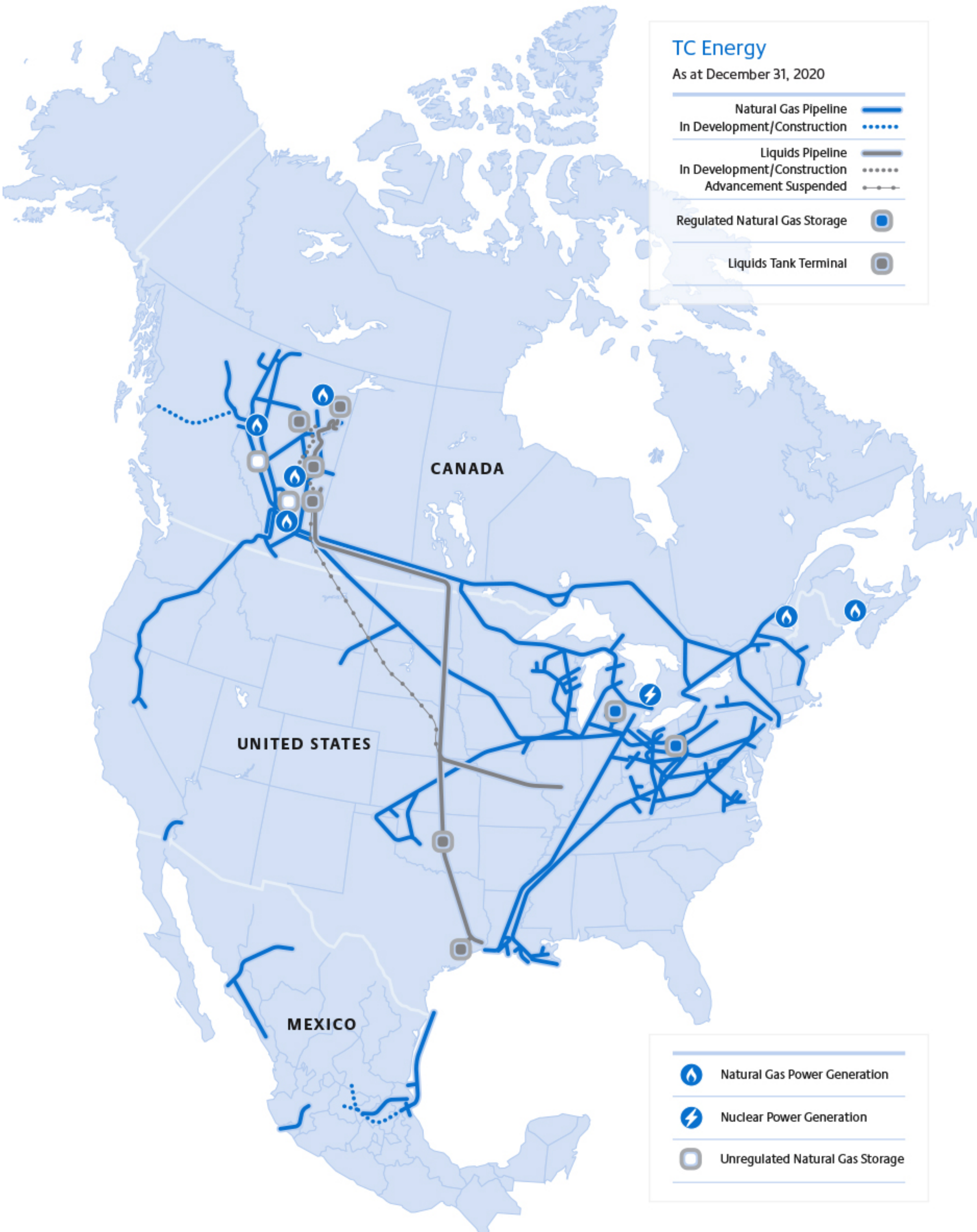
Comparable earnings represents earnings or losses attributable to common shareholders on a consolidated basis, adjusted for specific items. Comparable earnings is comprised of segmented earnings, Interest expense, AFUDC, Interest income and other, Income tax expense, Non-controlling interests and Preferred 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 (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 (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 (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 (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 (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 (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 (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 (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 (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 (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

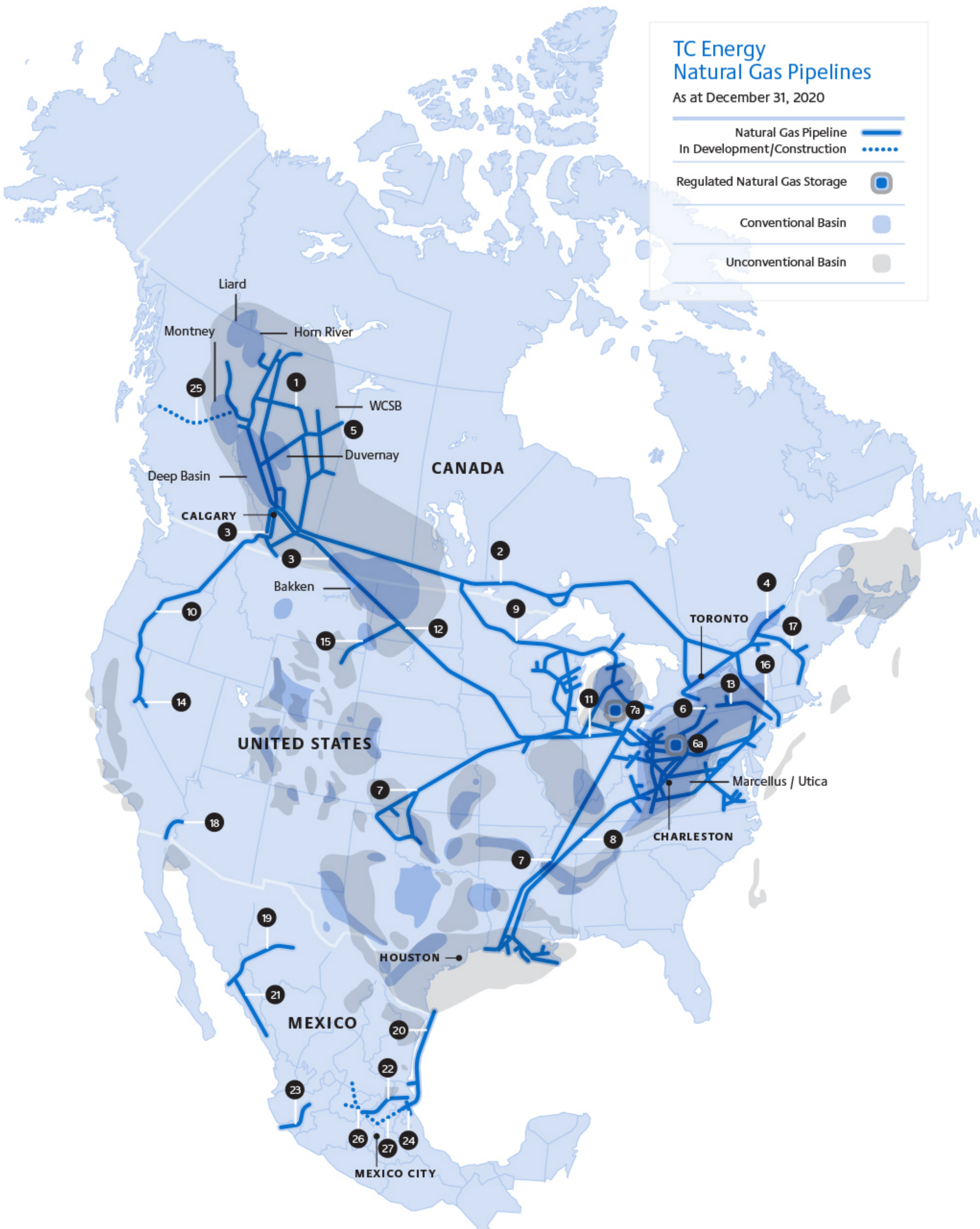
Changes in supply and demand levels and locations have resulted in increased competition to provide transportation services throughout North America. Our well-distributed footprint of natural gas pipelines, particularly in the liquids-rich and low-cost WCSB and the Appalachian basin, both of which are 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
TORONTO
UNITED STATES
Marcellus / Utica
CHARLESTON
HOUSTON
MEXICO
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 (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 (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 (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 (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
TORONTO
CHARLESTON
Anadarko
Permian
HOUSTON
Eagle Ford
MEXICO
MEXICO CITY
1
2
3
4
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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 8	Heartland Pipeline and 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 (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.

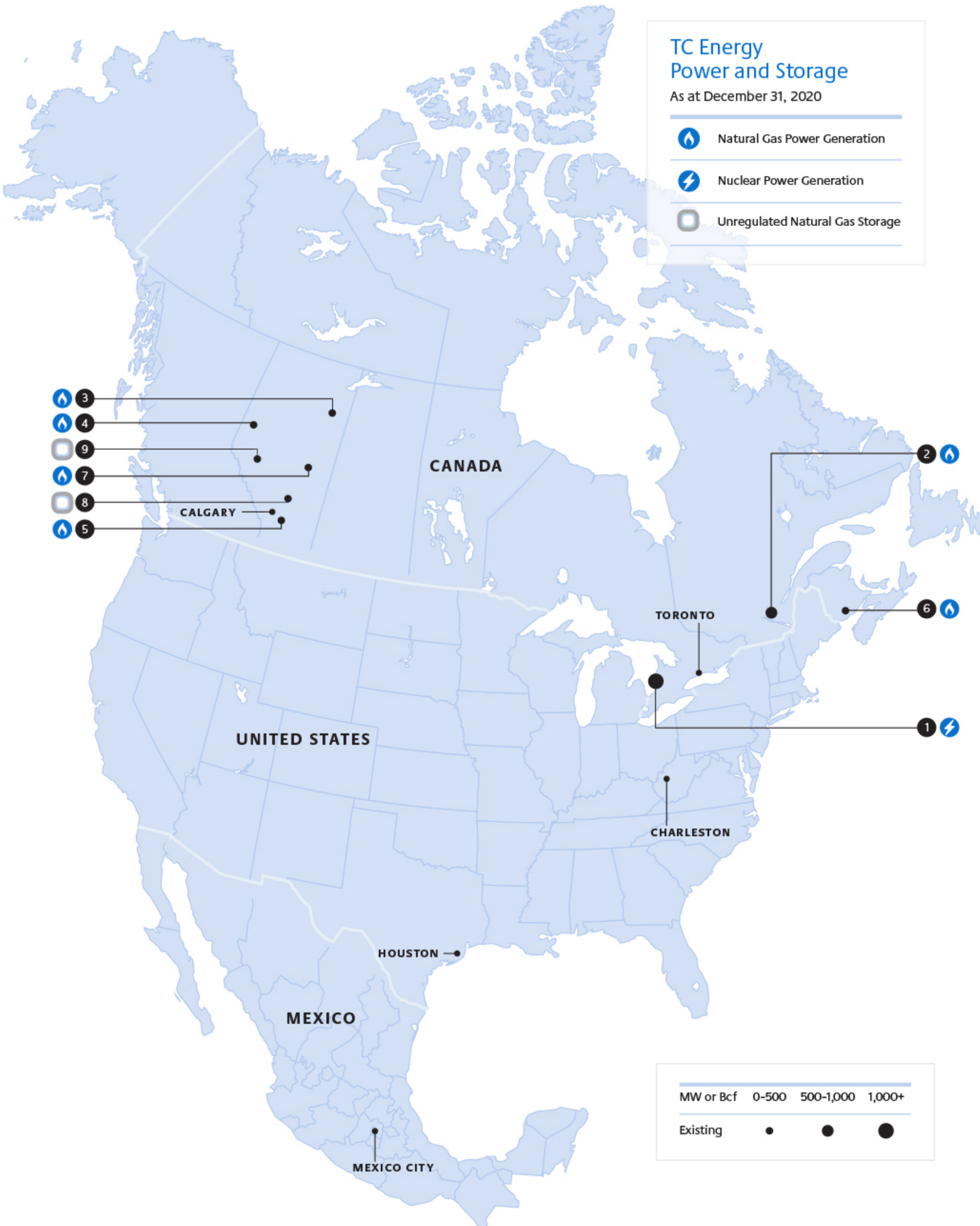
We own and operate approximately 118 Bcf of non-regulated natural gas storage capacity in Alberta.

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
CANADA
CALGARY
TORONTO
UNITED STATES
CHARLESTON
HOUSTON
MEXICO
MEXICO CITY
1
2
3
4
5
6
7
8
9
MW or Bcf
0-500
500-1,000
1,000+
Existing

Power and Storage assets currently have a combined power generation capacity, net to TC Energy, of 4,197 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 (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 (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 (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 (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 (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 (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 (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 (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 (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 (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 (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 (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 (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 (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 (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) Company	Retirement/ 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 (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 (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 (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 (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 (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 (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 (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 (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 (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 (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 (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 (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

Management's Report on Internal Control over Financial Reporting

The consolidated financial statements and Management's Discussion and Analysis (MD&A) included in this Annual Report are the responsibility of the management of TC Energy Corporation (TC Energy or the Company) and have been approved by the Board of Directors of the Company. The consolidated financial statements have been prepared by management in accordance with United States generally accepted accounting principles (GAAP) and include amounts that are based on estimates and judgments. The MD&A is based on the Company's financial results. It compares the Company's financial and operating performance in 2020 to that in 2019, and highlights significant changes between 2019 and 2018. The MD&A should be read in conjunction with the consolidated financial statements and accompanying notes. Financial information contained elsewhere in this Annual Report is consistent with the consolidated financial statements.

Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Company. Management has designed and maintains a system of internal control over financial reporting, including a program of internal audits to carry out its responsibility. Management believes these controls provide reasonable assurance that financial records are reliable and form a proper basis for the preparation of financial statements. The internal control over financial reporting includes management's communication to employees of policies that govern ethical business conduct.

Under the supervision and with the participation of the President and Chief Executive Officer and the Chief Financial Officer, management conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Management concluded, based on its evaluation, that internal control over financial reporting was effective as of December 31, 2020, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes.

The Board of Directors is responsible for reviewing and approving the financial statements and MD&A and ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board of Directors carries out these responsibilities primarily through the Audit Committee, which consists of independent, non-management directors. The Audit Committee meets with management at least five times a year and meets independently with internal and external auditors and as a group to review any significant accounting, internal control and auditing matters in accordance with the terms of the Charter of the Audit Committee, which is set out in the Annual Information Form. The Audit Committee's responsibilities include overseeing management's performance in carrying out its financial reporting responsibilities and reviewing the Annual Report, including the consolidated financial statements and MD&A, before these documents are submitted to the Board of Directors for approval. The internal and independent external auditors have access to the Audit Committee without the requirement to obtain prior management approval.

The Audit Committee approves the terms of engagement of the independent external auditors and reviews the annual audit plan, the Auditors' Report and the results of the audit. It also recommends to the Board of Directors the firm of external auditors to be appointed by the shareholders.

The shareholders have appointed KPMG LLP as independent external auditors to express an opinion as to whether the consolidated financial statements present fairly, in all material respects, the Company's consolidated financial position, results of operations and cash flows in accordance with GAAP. The reports of KPMG LLP outline the scope of its examinations and its opinions on the consolidated financial statements and the effectiveness of the Company's internal control over financial reporting.

Francois L. Poirier
President and
Chief Executive Officer

Donald R. Marchand
Executive Vice-President, Strategy & Corporate Development and
Chief Financial Officer

February 17, 2021

Report of Independent Registered Public Accounting Firm

To the Shareholders of TC Energy Corporation

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of TC Energy Corporation (the Company) as of December 31, 2020 and 2019, the related consolidated statements of income, comprehensive income, cash flows, and equity for each of the years in the three-year period ended December 31, 2020, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2020, and 2019, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2020, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2020, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 17, 2021 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the Audit Committee and that: (1) relates to accounts or disclosures that are material to the consolidated financial statements; and (2) involved our especially challenging, subjective or complex judgment. The communication of a critical audit matter does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Qualitative goodwill impairment indicators

As discussed in Note 12 to the consolidated financial statements, the goodwill balance as of December 31, 2020 was $12,679 million. The Company assesses goodwill for impairment testing annually or more frequently if events or changes in circumstances indicate that the carrying value of a reporting unit might be impaired. In the current year, the Company only performed qualitative assessments to determine whether events or changes in circumstances indicate that goodwill might be impaired. These qualitative assessments were performed as of December 31, 2020.

We identified the evaluation of qualitative goodwill impairment indicators, or qualitative factors, as a critical audit matter. The assessment of the potential impact that these qualitative factors have on a reporting unit's fair value required the application of subjective auditor judgment. Qualitative factors included macroeconomic conditions, industry and market considerations, current valuation multiples and discount rates, cost factors, historical and forecasted financial results and events specific to the reporting units, which required a higher degree of auditor judgment to evaluate. These qualitative factors could have had a significant effect on the Company's qualitative assessment and the potential for the need to perform a quantitative goodwill impairment test.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls related to the Company's goodwill impairment assessment process, including controls related to the assessment of potential qualitative factors. We evaluated the Company's assessment of identified event-specific changes against our knowledge of event-specific changes obtained through other audit procedures. We evaluated information from analyst reports in the energy and utility industries, including global energy consumption forecasts and natural gas production forecasts, which were compared to geopolitical and market considerations used by the Company. We compared current valuation multiples and discount rates, cost factors, historical and forecasted financial results of the reporting units, including the impact of newly approved growth projects to assumptions used in quantitative goodwill impairment tests performed in previous periods. In addition, we involved a valuation professional with specialized skills and knowledge, who assisted in:

- evaluating the Company’s determination of valuation multiples by comparing to independently observed recent market transactions of comparable assets and using publicly available market data for comparable entities;
- evaluating the discount rates used by management in the evaluation, by comparing them against a discount rate range that was independently developed using publicly available market data for comparable entities.

KPMG LLP

Chartered Professional Accountants

We have served as the Company's auditor since 1956.

Calgary, Canada
February 17, 2021

Report of Independent Registered Public Accounting Firm

To the Shareholders and the Board of Directors of TC Energy Corporation

Opinion on Internal Control Over Financial Reporting

We have audited TC Energy Corporation's (the Company) internal control over financial reporting as of December 31, 2020, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2020, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2020 and 2019, the related consolidated statements of income, comprehensive income, cash flows, and equity for each of the years in the three-year period ended December 31, 2020, and the related notes (collectively, the consolidated financial statements), and our report dated February 17, 2021 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

KPMG LLP

Chartered Professional Accountants
Calgary, Canada
February 17, 2021

Consolidated statement of income

year ended December 31 (millions of Canadian $, except per share amounts)	2020	2019	2018
Revenues (Notes 5 and 7)			
Canadian Natural Gas Pipelines	**4,469**	4,010	4,038
U.S. Natural Gas Pipelines	**5,031**	4,978	4,314
Mexico Natural Gas Pipelines	**716**	603	619
Liquids Pipelines	**2,371**	2,879	2,584
Power and Storage	**412**	785	2,124
	12,999	13,255	13,679
Income from Equity Investments (Note 9)	**1,019**	920	714
Operating and Other Expenses			
Plant operating costs and other	**3,878**	3,913	3,593
Commodity purchases resold	**—**	365	1,486
Property taxes	**727**	727	569
Depreciation and amortization	**2,590**	2,464	2,350
Goodwill and other asset impairment charges (Notes 7 and 12)	**—**	—	801
	7,195	7,469	8,799
Net (Loss)/ Gain on Assets Sold/Held for Sale (Note 27)	**(50)**	(121)	170
Financial Charges			
Interest expense (Note 18)	**2,228**	2,333	2,265
Allowance for funds used during construction	**(349)**	(475)	(526)
Interest income and other	**(213)**	(460)	76
	1,666	1,398	1,815
Income before Income Taxes	**5,107**	5,187	3,949
Income Tax Expense (Note 17)			
Current	**252**	699	315
Deferred	**(58)**	55	284
Deferred – U.S. Tax Reform and 2018 FERC Actions	**—**	—	(167)
	194	754	432
Net Income	**4,913**	4,433	3,517
Net income / (loss) attributable to non-controlling interests (Note 20)	**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 (Note 21)			
Basic	**$4.74**	$4.28	$3.92
Diluted	**$4.74**	$4.27	$3.92
Dividends Declared per Common Share	**$3.24**	$3.00	$2.76
Weighted Average Number of Common Shares (millions) (Note 21)			
Basic	**940**	929	902
Diluted	**940**	931	903

The accompanying Notes to the consolidated financial statements are an integral part of these statements.

Consolidated statement of comprehensive income

year ended December 31 (millions of Canadian $)	**2020**	**2019**	**2018**
Net Income	**4,913**	4,433	3,517
Other Comprehensive (Loss) / Income, Net of Income Taxes			
Foreign currency translation gains and losses on net investment in foreign operations	**(609)**	(944)	1,358
Reclassification to net income of foreign currency translation gains on disposal of foreign operations	**—**	(13)	—
Change in fair value of net investment hedges	**36**	35	(42)
Change in fair value of cash flow hedges	**(583)**	(62)	(10)
Reclassification to net income of gains and losses on cash flow hedges	**489**	14	21
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	**12**	(10)	(114)
Reclassification to net income of actuarial gains and losses on pension and other post-retirement benefit plans	**17**	10	15
Other comprehensive (loss) / income on equity investments	**(280)**	(82)	86
Other comprehensive (loss) / income (Note 23)	**(918)**	(1,052)	1,314
Comprehensive Income	**3,995**	3,381	4,831
Comprehensive income / (loss) attributable to non-controlling interests	**259**	194	(13)
Comprehensive Income Attributable to Controlling Interests	**3,736**	3,187	4,844
Preferred share dividends	**159**	164	163
Comprehensive Income Attributable to Common Shares	**3,577**	3,023	4,681

The accompanying Notes to the consolidated financial statements are an integral part of these statements.

Consolidated statement of cash flows

year ended December 31 (millions of Canadian $)	2020	2019	2018
Cash Generated from Operations			
Net income	**4,913**	4,433	3,517
Depreciation and amortization	**2,590**	2,464	2,350
Goodwill and other asset impairment charges (Notes 7 and 12)	**—**	—	801
Deferred income taxes (Note 17)	**(58)**	55	284
Deferred income taxes – U.S. Tax Reform and 2018 FERC Actions (Note 17)	**—**	—	(167)
Income from equity investments (Note 9)	**(1,019)**	(920)	(714)
Distributions received from operating activities of equity investments (Note 9)	**1,123**	1,213	985
Employee post-retirement benefits funding, net of expense (Note 24)	**(19)**	(45)	(35)
Net loss/(gain) on assets sold/held for sale (Note 27)	**50**	121	(170)
Equity allowance for funds used during construction	**(235)**	(299)	(374)
Unrealized (gains)/losses on financial instruments	**(103)**	(134)	220
Foreign exchange losses /(gains) on Loan receivable from affiliate (Note 10)	**86**	(53)	5
Other	**57**	(46)	(45)
(Increase)/decrease in operating working capital (Note 26)	**(327)**	293	(102)
Net cash provided by operations	**7,058**	7,082	6,555
Investing Activities			
Capital expenditures (Note 4)	**(8,013)**	(7,475)	(9,418)
Capital projects in development (Note 4)	**(122)**	(707)	(496)
Contributions to equity investments (Notes 4 and 9)	**(765)**	(602)	(1,015)
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 (Note 13)	**—**	—	470
Other distributions from equity investments (Note 9)	**—**	186	121
Payment for unredeemed shares of Columbia Pipeline Group, Inc. (Note 27)	**—**	(373)	—
Deferred amounts and other	**(471)**	(299)	(295)
Net cash used in investing activities	**(6,052)**	(6,872)	(10,019)
Financing Activities			
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 (Note 25)	**(130)**	—	—
Dividends on common shares	**(2,987)**	(1,798)	(1,571)
Dividends on preferred shares	**(159)**	(160)	(158)
Distributions to non-controlling interests	**(221)**	(216)	(225)
Contributions from redeemable non-controlling interest (Note 20)	**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
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 and Cash Equivalents			
Beginning of year	**1,343**	446	1,089
Cash and Cash Equivalents			
End of year	**1,530**	1,343	446

The accompanying Notes to the consolidated financial statements are an integral part of these statements.

Consolidated balance sheet

at December 31 (millions of Canadian $)		2020	2019
ASSETS			
Current Assets			
Cash and cash equivalents		**1,530**	1,343
Accounts receivable		**2,162**	2,422
Inventories		**629**	452
Assets held for sale (Note 27)		**—**	2,807
Other current assets (Note 6)		**880**	627
		5,201	7,651
Plant, Property and Equipment (Note 7)		**69,775**	65,489
Loan Receivable from Affiliate (Note 10)		**1,338**	1,434
Equity Investments (Note 9)		**6,677**	6,506
Restricted Investments		**1,898**	1,557
Regulatory Assets (Note 11)		**1,753**	1,587
Goodwill (Note 12)		**12,679**	12,887
Other Long-Term Assets (Note 13)		**979**	2,168
		100,300	99,279
LIABILITIES			
Current Liabilities			
Notes payable (Note 14)		**4,176**	4,300
Accounts payable and other (Note 15)		**3,816**	4,544
Redeemable non-controlling interest (Note 20)		**633**	—
Dividends payable		**795**	737
Accrued interest		**595**	613
Current portion of long-term debt (Note 18)		**1,972**	2,705
		11,987	12,899
Regulatory Liabilities (Note 11)		**4,148**	3,772
Other Long-Term Liabilities (Note 16)		**1,475**	1,614
Deferred Income Tax Liabilities (Note 17)		**5,806**	5,703
Long-Term Debt (Note 18)		**34,913**	34,280
Junior Subordinated Notes (Note 19)		**8,498**	8,614
		66,827	66,882
Redeemable Non-Controlling Interest (Note 20)		**393**	—
EQUITY			
Common shares, no par value (Note 21)		**24,488**	24,387
Issued and outstanding:	December 31, 2020 – 940 million shares		
	December 31, 2019 – 938 million shares		
Preferred shares (Note 22)		**3,980**	3,980
Additional paid-in capital		**2**	—
Retained earnings		**5,367**	3,955
Accumulated other comprehensive loss (Note 23)		**(2,439)**	(1,559)
Controlling Interests		**31,398**	30,763
Non-controlling interests (Note 20)		**1,682**	1,634
		33,080	32,397
		100,300	99,279

Commitments, Contingencies and Guarantees (Note 28)
Variable Interest Entities (Note 29)
Subsequent Events (Note 30)

The accompanying Notes to the consolidated financial statements are an integral part of these statements.

On behalf of the Board:

Francois L. Poirier, Director

John E. Lowe, Director

Consolidated statement of equity

year ended December 31 (millions of Canadian $)	2020	2019	2018
Common Shares (Note 21)			
Balance at beginning of year	**24,387**	23,174	21,167
Shares issued:			
On exercise of stock options	**101**	282	34
Under dividend reinvestment and share purchase plan	**—**	931	855
Under at-the-market equity issuance program, net of issue costs	**—**	—	1,118
Balance at end of year	**24,488**	24,387	23,174
Preferred Shares			
Balance at beginning and end of year	**3,980**	3,980	3,980
Additional Paid-In Capital			
Balance at beginning of year	**—**	17	—
Issuance of stock options, net of exercises	**2**	(17)	10
Dilution from TC PipeLines, LP units issued	**—**	—	7
Balance at end of year	**2**	—	17
Retained Earnings			
Balance at beginning of year	**3,955**	2,773	1,623
Net income attributable to controlling interests	**4,616**	4,140	3,702
Common share dividends	**(3,045)**	(2,794)	(2,501)
Preferred share dividends	**(159)**	(164)	(163)
Adjustment related to income tax effects of asset drop-downs to TC PipeLines, LP	**—**	—	95
Reclassification of AOCI to retained earnings resulting from U.S. Tax Reform	**—**	—	17
Balance at end of year	**5,367**	3,955	2,773
Accumulated Other Comprehensive Loss			
Balance at beginning of year	**(1,559)**	(606)	(1,731)
Other comprehensive (loss) / income attributable to controlling interests (Note 23)	**(880)**	(953)	1,142
Reclassification of AOCI to retained earnings resulting from U.S. Tax Reform	**—**	—	(17)
Balance at end of year	**(2,439)**	(1,559)	(606)
Equity Attributable to Controlling Interests	**31,398**	30,763	29,338
Equity Attributable to Non-Controlling Interests			
Balance at beginning of year	**1,634**	1,655	1,852
Net income / (loss) attributable to non-controlling interests	**307**	293	(185)
Other comprehensive (loss) / income attributable to non-controlling interests	**(38)**	(99)	172
Distributions declared to non-controlling interests	**(221)**	(215)	(224)
Issuance of TC PipeLines, LP units			
Proceeds, net of issue costs	**—**	—	49
Decrease in TC Energy's ownership of TC PipeLines, LP	**—**	—	(9)
Balance at end of year	**1,682**	1,634	1,655
Total Equity	**33,080**	32,397	30,993

The accompanying Notes to the consolidated financial statements are an integral part of these statements.

Notes to consolidated financial statements

1. DESCRIPTION OF TC ENERGY'S BUSINESS

TC Energy Corporation (TC Energy or the Company) is a leading North American energy infrastructure company which operates in five business segments: Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines, Mexico Natural Gas Pipelines, Liquids Pipelines and Power and Storage. These segments offer different products and services, including certain natural gas, crude oil and electricity marketing and storage services. The Company also has a Corporate segment, consisting of corporate and administrative functions that provide governance, financing and other support to the Company's business segments.

Canadian Natural Gas Pipelines

The Canadian Natural Gas Pipelines segment primarily consists of the Company's investments in 40,707 km (25,294 miles) of regulated natural gas pipelines.

U.S. Natural Gas Pipelines

The U.S. Natural Gas Pipelines segment primarily consists of the Company's investments in 50,211 km (31,199 miles) of regulated natural gas pipelines, 535 Bcf of regulated natural gas storage facilities and other assets, owned directly and through the Company's investment in TC PipeLines, LP.

Mexico Natural Gas Pipelines

The Mexico Natural Gas Pipelines segment primarily consists of the Company's investments in 2,503 km (1,554 miles) of regulated natural gas pipelines.

Liquids Pipelines

The Liquids Pipelines segment primarily consists of the Company's investments in 4,946 km (3,075 miles) of crude oil pipeline systems which connect Alberta and U.S. crude oil supplies to U.S. refining markets in Illinois, Oklahoma and Texas.

Power and Storage

The Power and Storage segment primarily consists of the Company's investments in seven power generation facilities and 118 Bcf of non-regulated natural gas storage facilities. These assets are located in Alberta, Ontario, Québec and New Brunswick.

2. ACCOUNTING POLICIES

The Company's consolidated financial statements have been prepared by management in accordance with U.S. generally accepted accounting principles. Amounts are stated in Canadian dollars unless otherwise indicated.

Basis of Presentation

These consolidated financial statements include the accounts of TC Energy and its subsidiaries. The Company consolidates variable interest entities (VIEs) for which it is considered to be the primary beneficiary as well as voting interest entities in which it has a controlling financial interest. To the extent there are interests owned by other parties, these interests are included in non-controlling interests, although certain non-controlling interests with redemption features are presented in mezzanine equity. TC Energy uses the equity method of accounting for joint ventures in which the Company is able to exercise joint control and for investments in which the Company is able to exercise significant influence. TC Energy records its proportionate share of undivided interests in certain assets. Certain prior year amounts have been reclassified to conform to current year presentation.

Use of Estimates and Judgments

In preparing these consolidated financial statements, TC Energy is required to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses since the determination of these items may be dependent on future events. The Company uses the most current information available and exercises careful judgment in making these estimates and assumptions.

Certain estimates and judgments have a material impact where the assumptions underlying these accounting estimates relate to matters that are highly uncertain at the time the estimate or judgment is made or are subjective. These estimates and judgments include, but are not limited to:

- recoverability of plant, property and equipment (Notes 7 and 30) and development costs (Notes 13 and 30)
- fair value of reporting units that contain goodwill (Notes 12 and 27) and
- fair value of assets and liabilities acquired in a business combination (Note 27).

Some of the estimates and judgments the Company has to make have a material impact on the consolidated financial statements, but do not involve significant subjectivity or uncertainty. These estimates and judgments include, but are not limited to:

- depreciation rates of plant, property and equipment (Note 7)
- determining whether a contract contains a lease (Note 8)
- fair value of equity investments (Note 9)
- carrying value of regulatory assets and liabilities (Note 11)
- carrying value of asset retirement obligations (Note 16)
- provisions for income taxes, including valuation allowances and releases (Note 17)
- assumptions used to measure retirement and other post-retirement benefit obligations (Note 24)
- fair value of financial instruments (Note 25) and
- provisions for commitments, contingencies and guarantees (Note 28).

Actual results could differ from these estimates.

Regulation

Certain Canadian, U.S. and Mexico natural gas pipeline and storage assets are regulated with respect to construction, operations and the determination of tolls. In Canada, regulated natural gas pipelines and liquids pipelines are subject to the authority of the Canada Energy Regulator (CER), formerly the National Energy Board (NEB), the Alberta Energy Regulator or the B.C. Oil and Gas Commission. In the U.S., regulated natural gas pipelines, liquids pipelines and regulated natural gas storage assets are subject to the authority of the Federal Energy Regulatory Commission (FERC). In Mexico, regulated natural gas pipelines are subject to the authority of the Energy Regulatory Commission (CRE). Rate-regulated accounting (RRA) standards may impact the timing of the recognition of certain revenues and expenses in TC Energy's rate-regulated businesses which may differ from that otherwise recognized in non-rate-regulated businesses to reflect the economic impact of the regulators' decisions regarding revenues and tolls. Regulatory assets represent costs that are expected to be recovered in customer rates in future periods and regulatory liabilities represent amounts that are expected to be returned to customers through future rate-setting processes. An operation qualifies for the use of RRA when it meets three criteria:

- a regulator must establish or approve the rates for the regulated services or activities
- the regulated rates must be designed to recover the cost of providing the services or products, and
- it is reasonable to assume that rates set at levels to recover the cost can be charged to (and collected from) customers because of the demand for services or products and the level of direct or indirect competition.

TC Energy's businesses that apply RRA currently include Canadian, U.S. and Mexico natural gas pipelines, and regulated U.S. natural gas storage. RRA is not applicable to the Company's liquids pipelines as the regulators' decisions regarding operations and tolls on those systems generally do not have an impact on timing of recognition of revenues and expenses.

Revenue Recognition

The total consideration for services and products to which the Company expects to be entitled can include fixed and variable amounts. The Company has variable revenue that is subject to factors outside the Company's influence, such as market prices, actions of third parties and weather conditions. The Company considers this variable revenue to be "constrained" as it cannot be reliably estimated and, therefore, recognizes variable revenue when the service is provided.

Revenues from contracts with customers are recognized net of any commodity taxes collected from customers which are subsequently remitted to governmental authorities. The Company's contracts with customers include natural gas and liquids pipelines capacity arrangements and transportation contracts, power generation contracts, natural gas storage and other contracts.

Canadian Natural Gas Pipelines

Capacity Arrangements and Transportation

Revenues from the Company's Canadian natural gas pipelines are generated from contractual arrangements for committed capacity and from the transportation of natural gas. Revenues earned from firm contracted capacity arrangements are recognized ratably over the term of the contract regardless of the amount of natural gas that is transported. Transportation revenues for interruptible or volumetric-based services are recognized when the service is performed.

Revenues from the Company's Canadian natural gas pipelines under federal jurisdiction are subject to regulatory decisions by the CER. The tolls charged on these pipelines are based on revenue requirements designed to recover the costs of providing natural gas capacity for transportation services, which includes a return of and on capital, as approved by the CER. The Company's Canadian natural gas pipelines are generally not subject to earnings volatility related to variances in revenues and costs. These variances, except as related to incentive arrangements, are generally subject to deferral treatment and are recovered or refunded in future tolls. Revenues recognized prior to a CER decision on rates for that period reflect the CER's last approved return on equity (ROE) assumptions. Adjustments to revenues are recorded when the CER decision is received. Canadian natural gas pipelines' revenues are invoiced and received on a monthly basis. The Company does not take ownership of the natural gas that it transports for customers.

Other

The Company is contracted to provide pipeline construction services to a partially-owned entity for a development fee. The development fee is considered variable consideration due to refund provisions in the contract. The Company recognizes its estimate of the most likely amount of the variable consideration to which it will be entitled. The development fee is recognized over time as the services are provided based on the input method using an estimate of activity level.

U.S. Natural Gas Pipelines

Capacity Arrangements and Transportation

Revenues from the Company's U.S. natural gas pipelines are generated from contractual arrangements for committed capacity and from the transportation of natural gas. Revenues earned from firm contracted capacity arrangements are generally recognized ratably over the term of the contract regardless of the amount of natural gas that is transported. Transportation revenues for interruptible or volumetric-based services are recognized when the service is performed.

The Company's U.S. natural gas pipelines are subject to FERC regulations and, as a result, a portion of revenues collected may be subject to refund if invoiced during an interim period when a rate proceeding is ongoing. Allowances for these potential refunds are recognized using management's best estimate based on the facts and circumstances of the proceeding. Any allowances that are recognized during the proceeding process are refunded or retained at the time a regulatory decision becomes final. U.S. natural gas pipelines' revenues are invoiced and received on a monthly basis. The Company does not take ownership of the natural gas that it transports for customers.

Natural Gas Storage and Other

Revenues from the Company's regulated U.S. natural gas storage services are generated mainly from firm committed capacity storage contracts. The performance obligation in these contracts is the reservation of a specified amount of capacity for storage including specifications with regards to the amount of natural gas that can be injected or withdrawn on a daily basis. Revenues are recognized ratably over the contract period for firm committed capacity regardless of the amount of natural gas that is stored, and when gas is injected or withdrawn for interruptible or volumetric-based services. Natural gas storage services revenues are invoiced and received on a monthly basis. The Company does not take ownership of the natural gas that it stores for customers.

The Company owns mineral rights associated with certain natural gas storage facilities. These mineral rights can be leased or contributed to producers of natural gas in return for a royalty interest which is recognized when natural gas and associated liquids are produced.

During 2019, TC Energy sold certain Columbia Midstream assets that were part of the acquisition of Columbia Pipeline Group, Inc. (Columbia) in 2016. Prior to the sale, revenues from the Company's midstream natural gas services, including gathering, treating, conditioning, processing, compression and liquids handling services, were generated from contractual arrangements and were recognized ratably over the term of the contract. Midstream natural gas service revenues were invoiced and received on a monthly basis. The Company did not take ownership of the natural gas for which it provided midstream services. Refer to Note 27, Acquisitions and dispositions, for additional information regarding the sale of the Columbia Midstream assets.

Net revenues earned from the sale of proprietary natural gas are recognized in the month of delivery.

Mexico Natural Gas Pipelines

Capacity Arrangements and Transportation

Revenues from the Company's Mexico natural gas pipelines are primarily collected based on CRE-approved negotiated firm capacity contracts and are generally recognized ratably over the term of the contract. Transportation revenues related to interruptible or volumetric-based services are recognized when the service is performed. Mexico natural gas pipelines' revenues are invoiced and received on a monthly basis. The Company does not take ownership of the natural gas that it transports for customers.

Other

The Company is contracted to provide operating services to a partially-owned entity for a fee which is recognized over time as services are provided. The Company's construction services to this entity have been performed and the related development fee has been recognized. Net revenues earned from the sale of proprietary natural gas are recognized in the month of delivery.

Liquids Pipelines

Capacity Arrangements and Transportation

Revenues from the Company's liquids pipelines are generated mainly from providing customers with firm capacity arrangements to transport crude oil. The performance obligation in these contracts is the reservation of a specified amount of capacity together with the transportation of crude oil on a monthly basis. Revenues earned from these arrangements are recognized ratably over the term of the contract regardless of the amount of crude oil that is transported. Revenues for interruptible or volumetric-based services are recognized when the service is performed. Liquids pipelines' revenues are invoiced and received on a monthly basis. The Company does not take ownership of the crude oil that it transports for customers.

Other

Net revenues earned from the sale of proprietary crude oil are recognized in the month of delivery.

Power and Storage

Power Generation

Revenues from the Company's Power and Storage business are primarily derived from long-term contractual commitments to provide power capacity to meet the demands of the market, and from the sale of electricity to both centralized markets and to customers. Power generation revenues also include revenues from the sale of steam to customers. Revenues and capacity payments are recognized as the services are provided and as electricity and steam is delivered. Power generation revenues are invoiced and received on a monthly basis.

Natural Gas Storage and Other

Non-regulated natural gas storage contracts include park, loan and term storage arrangements. Revenues are recognized as the services are provided. Term storage revenues are invoiced and received on a monthly basis. Revenues earned from the sale of proprietary natural gas are recognized in the month of delivery. Revenues from ancillary services are recognized as the service is provided. The Company does not take ownership of the natural gas that it stores for customers.

Cash and Cash Equivalents

The Company's Cash and cash equivalents consist of cash and highly liquid short-term investments with original maturities of three months or less and are recorded at cost, which approximates fair value.

Inventories

Inventories primarily consist of materials and supplies including spare parts and fuel, proprietary crude oil in transit and proprietary natural gas inventory in storage. Inventories are carried at the lower of cost and net realizable value.

Assets Held for Sale

The Company classifies assets as held for sale when management approves and commits to a formal plan to actively market a disposal group and expects the sale to close within the next 12 months. Upon classifying an asset as held for sale, the asset is recorded at the lower of its carrying amount or its estimated fair value, net of selling costs, and any losses are recognized in net income. Gains related to the expected sale of these assets are not recognized until the transaction closes. Once an asset is classified as held for sale, depreciation expense is no longer recorded.

Plant, Property and Equipment

Natural Gas Pipelines

Plant, property and equipment for natural gas pipelines is carried at cost. Depreciation is calculated on a straight-line basis once the assets are ready for their intended use. Pipeline and compression equipment are depreciated at annual rates ranging from 0.6 per cent to seven per cent, and metering and other plant equipment are depreciated at various rates reflecting their estimated useful lives. The cost of major overhauls of equipment is capitalized and depreciated over the estimated service lives of the overhauls. The cost of regulated natural gas pipelines includes an allowance for funds used during construction (AFUDC) consisting of a debt component and an equity component based on the rate of return on rate base approved by regulators. AFUDC is reflected as an increase in the cost of the assets in Plant, property and equipment with a corresponding credit recognized in Allowance for funds used during construction in the Consolidated statement of income. The equity component of AFUDC is a non-cash expenditure. Interest is capitalized during construction of non-regulated natural gas pipelines.

Natural gas pipelines' linepack and natural gas storage base gas are valued at cost and are maintained to ensure adequate pressure exists to transport natural gas through pipelines and deliver natural gas held in storage. Linepack and base gas are not depreciated.

When rate-regulated natural gas pipelines retire plant, property and equipment from service, the original book cost is removed from the gross plant amount and recorded as a reduction to accumulated depreciation with no amount recorded to net income. Costs incurred to remove plant, property and equipment from service, net of any salvage proceeds, are also recorded in accumulated depreciation.

Other

The Company participates as a working interest partner in the development of certain Marcellus and Utica acreage. The working interest allows the Company to invest in drilling activities in addition to receiving a royalty interest in well production. The Company uses the successful efforts method of accounting for natural gas and crude oil resulting from its portion of drilling activities. Capitalized well costs are depleted based on the units of production method.

Prior to its sale in 2019, plant, property and equipment for Columbia Midstream was carried at cost. Depreciation was calculated on a straight-line basis once the assets were ready for their intended use. Gathering and processing facilities were depreciated at annual rates ranging from 1.7 per cent to 2.5 per cent, and other plant and equipment were depreciated at various rates reflecting their estimated useful lives. When these assets were retired from plant, property and equipment, the original book cost and related accumulated depreciation were derecognized and any gain or loss was recorded in net income. Refer to Note 27, Acquisitions and dispositions, for additional information.

Liquids Pipelines

Plant, property and equipment for liquids pipelines is carried at cost. Depreciation is calculated on a straight-line basis once the assets are ready for their intended use. Pipeline and pumping equipment are depreciated at annual rates ranging from two per cent to 2.5 per cent, and other plant and equipment are depreciated at various rates reflecting their estimated useful lives. The cost of these assets includes interest capitalized during construction. When liquids pipelines retire plant, property and equipment from service, the original book cost and related accumulated depreciation are derecognized and any gain or loss is recorded in net income.

Power and Storage

Plant, property and equipment for Power and Storage assets are recorded at cost and, once the assets are ready for their intended use, depreciated by major component on a straight-line basis over their estimated service lives at average annual rates ranging from two per cent to 20 per cent. Other equipment is depreciated at various rates reflecting their estimated useful lives. The cost of major overhauls of equipment is capitalized and depreciated over the estimated service lives of the overhauls. Interest is capitalized on facilities under construction. When these assets are retired from plant, property and equipment, the original book cost and related accumulated depreciation are derecognized and any gain or loss is recorded in net income.

Natural gas storage base gas, which is valued at original cost, represents gas volumes that are maintained to ensure adequate reservoir pressure exists to deliver gas held in storage. Base gas is not depreciated.

Corporate

Corporate plant, property and equipment is recorded at cost and depreciated on a straight-line basis over its estimated useful life at average annual rates ranging from four per cent to 20 per cent.

Capital Projects in Development

The Company capitalizes project costs once advancement of the project to a construction stage is probable or costs are otherwise likely to be recoverable. The Company also capitalizes interest costs for non-regulated projects in development and AFUDC for regulated projects in development. Capital projects in development are included in Other long-term assets on the Consolidated balance sheet. These represent larger projects that generally require regulatory or other approvals before physical construction can begin. Once approvals are received, projects are moved to plant, property and equipment under construction.

Leases

On January 1, 2019, the Company adopted the FASB's new lease guidance using optional transition relief. Results reported for 2020 and 2019 reflect the application of the new guidance while the 2018 comparative results were prepared and reported under previous lease guidance.

Lessee Accounting Policy

The Company determines if an arrangement is a lease at inception of the contract. Operating leases are recognized as right-of-use (ROU) assets and included in Plant, property, and equipment while corresponding liabilities are included in Accounts payable and other and Other long-term liabilities on the Consolidated balance sheet.

Operating lease ROU assets and operating lease liabilities are recognized based on the present value of the future minimum lease payments over the lease term at the commencement date of the lease agreement. Lease terms may include options to extend or terminate the lease when it is reasonably certain that the Company will exercise that option. As the Company's lease contracts do not provide an implicit interest rate, the Company uses its incremental borrowing rate based on the information available at commencement date in determining the present value of future payments. Operating lease expense is recognized on a straight-line basis over the lease term and included in Plant operating costs and other in the Consolidated statement of income.

The Company applies the practical expedients to not recognize ROU assets or lease liabilities for leases that qualify for the short-term lease recognition exemption and to not separate lease and non-lease components for all leases for which the Company is a lessee.

Lessor Accounting Policy

The Company is the lessor within certain contracts and these are accounted for as operating leases. The Company recognizes lease payments as income over the lease term on a straight-line basis. Variable lease payments are recognized as income in the period in which they occur.

The Company applies the practical expedient to not separate lease and non-lease components for facility and liquids tank terminals for which the Company is the lessor.

Impairment of Long-Lived Assets

The Company reviews long-lived assets such as plant, property and equipment, equity investments and capital projects in development for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable. If the total of the estimated undiscounted future cash flows for an asset within plant, property and equipment, or the estimated selling price of any long-lived asset is less than the carrying value of an asset, an impairment loss is recognized for the excess of the carrying value over the estimated fair value of the asset.

Acquisitions and Goodwill

The Company accounts for business combinations using the acquisition method of accounting and, accordingly, the assets and liabilities of the acquired entities are primarily measured at their estimated fair values at the date of acquisition. The excess of the fair value of the consideration transferred over the estimated fair value of the net assets acquired is classified as goodwill. Goodwill is not amortized and is tested for impairment on an annual basis, or more frequently if events or changes in circumstances indicate that it might be impaired.

The annual review for goodwill impairment is performed at the reporting unit level which is one level below the Company's operating segments. The Company can initially assess qualitative factors to determine whether events or changes in circumstances indicate that goodwill might be impaired. The factors the Company considers 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, and events specific to that reporting unit. If the Company concludes that it is not more likely than not that the fair value of the reporting unit is greater than its carrying value, the Company will then perform a quantitative goodwill impairment test. The Company can elect to proceed directly to the quantitative goodwill impairment test for any of its reporting units. If the quantitative goodwill impairment test is performed, the Company compares 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. A goodwill impairment test will be completed for both the goodwill disposed and the portion of the goodwill that will be retained.

Loans and Receivables

Loans receivable from affiliates and accounts receivable are measured at amortized cost.

Impairment of Financial Assets

The Company reviews 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. TC Energy uses historical credit loss and recovery data, adjusted for management's judgment regarding current economic and credit conditions, along with supportable forecasts to determine any impairment, which is recognized in Plant operating costs and other.

Power Purchase Arrangements

A power purchase arrangement (PPA) is a long-term contract for the purchase or sale of power on a predetermined basis. TC Energy has PPAs for the sale of power that are accounted for as operating leases where TC Energy is the lessor.

Restricted Investments

The Company has certain investments that are restricted as to their withdrawal and use. These restricted investments are classified as available for sale and are recorded at fair value on the Consolidated balance sheet.

As a result of the CER's Land Matters Consultation Initiative (LMCI), TC Energy is required to collect funds to cover estimated future pipeline abandonment costs for larger CER-regulated Canadian pipelines. Funds collected are placed in trusts that hold and invest the funds and are accounted for as restricted investments (LMCI restricted investments). LMCI restricted investments may only be used to fund the abandonment of the CER-regulated pipeline facilities, therefore, a corresponding regulatory liability is recorded on the Consolidated balance sheet. The Company also has other restricted investments that have been set aside to fund insurance claim losses to be paid by the Company's wholly-owned captive insurance subsidiary.

Income Taxes

The Company uses the asset and liability method of accounting for income taxes. This method requires the recognition of deferred income tax assets and liabilities for future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred income tax assets and liabilities are measured using enacted tax rates at the balance sheet date that are anticipated to apply to taxable income in the years in which temporary differences are expected to be reversed or settled. Changes to these balances are recognized in net income in the period in which they occur, except for changes in balances related to regulated natural gas pipelines which are deferred until they are refunded or recovered in tolls, as permitted by the regulator. Deferred income tax assets and liabilities are classified as non-current on the Consolidated balance sheet.

Canadian income taxes are not provided on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future.

Asset Retirement Obligations

The Company recognizes the fair value of a liability for asset retirement obligations (ARO) in the period in which it is incurred, when a legal obligation exists and a reasonable estimate of fair value can be made. The fair value is added to the carrying amount of the associated asset and the liability is accreted through charges to Plant operating costs and other in the Consolidated statement of income.

In determining the fair value of ARO, the following assumptions are used:
- the expected retirement date
- the scope and cost of abandonment and reclamation activities that are required, and
- appropriate inflation and discount rates.

The Company's AROs are substantively related to its power generation facilities. The scope and timing of asset retirements related to the Company's natural gas and liquids pipelines and storage facilities are indeterminable because the Company intends to operate them as long as there is supply and demand. As a result, the Company has not recorded an amount for ARO related to these assets.

Environmental Liabilities

The Company records liabilities on an undiscounted basis for environmental remediation efforts that are likely to occur and where the cost can be reasonably estimated. These estimates, including associated legal costs, are based on available information using existing technology and enacted laws and regulations, and are subject to revision in future periods based on actual costs incurred or new circumstances. Amounts expected to be recovered from other parties, including insurers, are recorded as an asset separate from the associated liability.

Emission allowances or credits purchased for compliance are recorded on the Consolidated balance sheet at historical cost and expensed when they are utilized or cancelled/retired by government agencies. Compliance costs are expensed when incurred. Allowances granted to or internally generated by TC Energy are not attributed a value for accounting purposes. When required, TC Energy accrues emission liabilities on the Consolidated balance sheet using the best estimate of the amount required to settle the compliance obligation. Allowances and credits not used for compliance are sold and any gain or loss is recorded in Revenues.

Stock Options and Other Compensation Programs

TC Energy's Stock Option Plan permits options for the purchase of common shares to be awarded to certain employees, including officers. Stock options granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value as calculated using a binomial model and is recognized on a straight-line basis over the vesting period with an offset to Additional paid-in capital. Forfeitures are accounted for when they occur. Upon exercise of stock options, amounts originally recorded against Additional paid-in capital are reclassified to Common shares on the Consolidated balance sheet.

The Company has medium-term incentive plans under which payments are made to eligible employees. The expense related to these incentive plans is accounted for on an accrual basis. Under these plans, benefits vest when certain conditions are met, including the employees' continued employment during a specified period and achievement of specified corporate performance targets.

Employee Post-Retirement Benefits

The Company sponsors defined benefit pension plans (DB Plans), defined contribution plans (DC Plans), savings plans and other post-retirement benefit plans. Contributions made by the Company to the DC Plans and savings plans are expensed in the period in which contributions are made. The cost of the DB Plans and other post-retirement benefits received by employees is actuarially determined using the projected benefit method pro-rated based on service, and management's best estimate of expected plan investment performance, salary escalation, retirement age of employees and expected health care costs.

The DB Plans' assets are measured at fair value at December 31 of each year. The expected return on the DB Plans' assets is determined using market-related values based on a five-year moving average value for all of the DB Plans' assets. Past service costs are amortized over the expected average remaining service life (EARSL) of the employees. Adjustments arising from plan amendments are amortized on a straight-line basis over the EARSL of employees active at the date of amendment. The Company recognizes the overfunded or underfunded status of its DB Plans as an asset or liability, respectively, on its Consolidated balance sheet and recognizes changes in that funded status through Other comprehensive (loss)/ income (OCI) in the year in which the change occurs. The excess of net actuarial gains or losses over 10 per cent of the greater of the benefit obligation and the market-related value of the DB Plans' assets, if any, is amortized out of Accumulated other comprehensive income /(loss) (AOCI) and into net income over the EARSL of the active employees. When the restructuring of a benefit plan gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement.

For certain regulated operations, post-retirement benefit amounts are recoverable through tolls as benefits are funded. The Company records any unrecognized gains or losses or changes in actuarial assumptions related to these post-retirement benefit plans as either regulatory assets or liabilities. The regulatory assets or liabilities are amortized on a straight-line basis over the EARSL of active employees.

Foreign Currency Transactions and Translation

Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which the Company or reporting subsidiary operates. This is referred to as the functional currency. Transactions denominated in foreign currencies are translated into the functional currency using the exchange rate prevailing at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency using the rate of exchange in effect at the balance sheet date whereas non-monetary assets and liabilities are translated at the historical rate of exchange in effect on the date of the transaction. Exchange gains and losses resulting from translation of monetary assets and liabilities are recorded in net income except for exchange gains and losses on any foreign currency debt related to Canadian regulated natural gas pipelines, which are deferred until they are refunded or recovered in tolls, as permitted by the CER.

Gains and losses arising from translation of foreign operations' functional currencies to the Company's Canadian dollar reporting currency are reflected in OCI until the operations are sold, at which time the gains and losses are reclassified to net income. Asset and liability accounts are translated at the period-end exchange rates while revenues, expenses, gains and losses are translated at the exchange rates in effect at the time of the transaction. The Company's U.S. dollar-denominated debt and certain derivative hedging instruments have been designated as a hedge of the net investment in foreign subsidiaries and, as a result, the unrealized foreign exchange gains and losses on the U.S. dollar-denominated debt and derivatives are also reflected in OCI.

Derivative Instruments and Hedging Activities

All derivative instruments are recorded on the Consolidated balance sheet at fair value, unless they qualify for and are designated under a normal purchase and normal sales exemption, or are considered to meet other permitted exemptions.

The Company applies hedge accounting to arrangements that qualify for and are designated for hedge accounting treatment. This includes fair value and cash flow hedges and hedges of foreign currency exposures of net investments in foreign operations. Hedge accounting is discontinued prospectively if the hedging relationship ceases to be effective or the hedging or hedged items cease to exist as a result of maturity, expiry, sale, termination, cancellation or exercise.

In a fair value hedging relationship, the carrying value of the hedged item is adjusted for changes in fair value attributable to the hedged risk and these changes are recognized in net income. Changes in the fair value of the hedged item, to the extent that the hedging relationship is effective, are offset by changes in the fair value of the hedging item, which are also recorded in net income. Changes in the fair value of foreign exchange and interest rate fair value hedges are recorded in Interest income and other and Interest expense, respectively. If hedge accounting is discontinued, the carrying value of the hedged item is no longer adjusted and the cumulative fair value adjustments to the carrying value of the hedged item are amortized to net income over the remaining term of the original hedging relationship.

In a cash flow hedging relationship, the change in the fair value of the hedging derivative is recognized in OCI. When hedge accounting is discontinued, the amounts recognized previously in AOCI are reclassified to Revenues, Interest expense and Interest income and other, as appropriate, during the periods when the variability in cash flows of the hedged item affects net income or as the original hedged item settles. Gains and losses on derivatives are reclassified immediately to net income from AOCI when the hedged item is sold or terminated early, or when it becomes probable that the anticipated transaction will not occur. Termination payments on interest rate derivatives are classified as a financing activity on the Consolidated statement of cash flows.

In hedging the foreign currency exposure of a net investment in a foreign operation, the foreign exchange gains and losses on the hedging instruments are recognized in OCI. The amounts recognized previously in AOCI are reclassified to net income in the event the Company reduces its net investment in a foreign operation.

In some cases, derivatives do not meet the specific criteria for hedge accounting treatment. In these instances, the changes in fair value are recorded in net income in the period of change.

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 refunded or recovered through the tolls charged by the Company. As a result, these gains and losses are deferred as regulatory assets or liabilities and are refunded to or collected from ratepayers in subsequent periods when the derivative settles.

Derivatives embedded in other financial instruments or contracts (host instrument) are recorded as separate derivatives. Embedded derivatives are measured at fair value if their economic characteristics are not clearly and closely related to those of the host instrument, their terms are the same as those of a stand-alone derivative and the total contract is not held for trading or accounted for at fair value. When changes in the fair value of embedded derivatives are measured separately, they are included in net income.

Long-Term Debt Transaction Costs and Issuance Costs

The Company records long-term debt transaction costs and issuance costs as a deduction from the carrying amount of the related debt liability and amortizes these costs using the effective interest method except those related to the Canadian natural gas regulated pipelines, which continue to be amortized on a straight-line basis in accordance with the provisions of regulatory tolling mechanisms.

Guarantees

Upon issuance, the Company records the fair value of certain guarantees entered into by the Company on behalf of a partially-owned entity or by partially-owned entities for which contingent payments may be made. The fair value of these guarantees is estimated by discounting the cash flows that would be incurred by the Company if letters of credit were used in place of the guarantees as appropriate in the circumstances. Guarantees are recorded as an increase to Equity investments or Plant, property and equipment and a corresponding liability is recorded in Other long-term liabilities. The release from the obligation is recognized either over the term of the guarantee or upon expiration or settlement of the guarantee.

3. ACCOUNTING CHANGES

Changes in Accounting Policies for 2020

Measurement of credit losses on financial instruments

In June 2016, the FASB issued new guidance that changes how entities measure credit losses for most financial assets and certain other financial instruments that are not measured at fair value through net income. The new guidance amends the impairment model of financial instruments, basing it on expected losses rather than incurred losses. These expected credit losses will be recognized as an allowance rather than as a direct write-down of the amortized cost basis. The new guidance was effective January 1, 2020 and was applied using a modified retrospective approach. The adoption of this new guidance did not have a material impact on the Company's consolidated financial statements.

Implementation costs of cloud computing arrangements

In August 2018, the FASB issued new guidance requiring an entity in a hosting arrangement that is a service contract to follow the guidance for internal-use software to determine which implementation costs should be capitalized as an asset and which costs should be expensed. The guidance also requires the entity to amortize the capitalized implementation costs of a hosting arrangement over the term of the arrangement. This guidance was effective January 1, 2020 and was applied prospectively. The adoption of this new guidance did not have a material impact on the Company's consolidated financial statements.

Consolidation

In October 2018, the FASB issued new guidance for determining whether fees paid to decision makers and service providers are variable interests for indirect interests held through related parties under common control. This new guidance was effective January 1, 2020 and was applied on a retrospective basis. The adoption of this new guidance did not have an impact on the Company's consolidated financial statements.

Defined benefit plans

In August 2018, the FASB issued new guidance which amends and clarifies disclosure requirements related to defined benefit pension and other post-retirement benefit plans. This new guidance was effective for annual disclosure requirements at December 31, 2020 and applied on a retrospective basis. The adoption of this new guidance, which is limited to disclosures only, did not have a material impact on the Company's consolidated financial statements.

Reference rate reform

In response to the expected cessation of the London Interbank Offered Rate (LIBOR), of which certain rate settings may cease to be published at the end of 2021 with full cessation expected by mid-2023, the FASB issued new optional guidance in March 2020 that eases the potential burden in accounting for such reference rate reform. The new guidance provides optional expedients for contracts and hedging relationships that are affected by reference rate reform if certain criteria are met. Each of the expedients can be applied as of January 1, 2020 through December 31, 2022. For eligible hedging relationships existing as of January 1, 2020 and prospectively, the Company has applied an optional expedient allowing an entity to assume that the hedged forecasted transaction in a cash flow hedge is probable of occurring. The Company is continuing to identify and analyze existing agreements to determine the effect of reference rate reform on its consolidated financial statements. The Company will continue to evaluate the timing and potential impact of adoption for other optional expedients when deemed necessary.

Future Accounting Changes

Income taxes

In December 2019, the FASB issued new guidance that simplified the accounting for income taxes and clarified existing guidance. This new guidance is effective January 1, 2021, and is not expected to have a material impact on the Company's consolidated financial statements.

4. SEGMENTED INFORMATION

year ended December 31, 2020 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Storage	Corporate[1]	Total
Revenues	4,469	5,031	716	2,371	412	—	12,999
Intersegment revenues	—	165	—	—	20	(185) [2]	—
	4,469	5,196	716	2,371	432	(185)	12,999
Income from equity investments	12	264	127	75	455	86 [3]	1,019
Plant operating costs and other	(1,631)	(1,485)	(57)	(654)	(220)	169 [2]	(3,878)
Property taxes	(284)	(337)	—	(101)	(5)	—	(727)
Depreciation and amortization	(1,273)	(801)	(117)	(332)	(67)	—	(2,590)
Net gain / (loss) on sale of assets	364	—	—	—	(414)	—	(50)
Segmented earnings	1,657	2,837	669	1,359	181	70	6,773
Interest expense							(2,228)
Allowance for funds used during construction							349
Interest income and other[3]							213
Income before income taxes							5,107
Income tax expense							(194)
Net income							4,913
Net income attributable to non-controlling interests							(297)
Net income attributable to controlling interests							4,616
Preferred share dividends							(159)
Net income attributable to common shares							4,457
Capital spending							
Capital expenditures	3,503	2,785	173	1,315	179	58	8,013
Capital projects in development	—	—	—	122	—	—	122
Contributions to equity investments	105	—	—	5	655	—	765
	3,608	2,785	173	1,442	834	58	8,900

1 Includes intersegment eliminations.

2 The Company records intersegment sales at contracted rates. For segmented reporting, these transactions are included as Intersegment revenues in the segment providing the service and Plant operating costs and other in the segment receiving the service. These transactions are eliminated on consolidation. Intersegment profit is recognized when the product or service has been provided to third parties or otherwise realized.

3 Income from equity investments includes the Company's proportionate share of Sur de Texas foreign exchange gains and losses on the peso-denominated loans from affiliates which are fully offset in Interest income and other by the corresponding foreign exchange losses and gains on the affiliate receivable balance. Refer to Note 10, Loans receivable from affiliates, for additional information.

year ended December 31, 2019 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Storage	Corporate[1]	Total
Revenues	4,010	4,978	603	2,879	785	—	13,255
Intersegment revenues	—	164	—	—	19	(183) [2]	—
	4,010	5,142	603	2,879	804	(183)	13,255
Income / (loss) from equity investments	12	264	56	70	571	(53) [3]	920
Plant operating costs and other	(1,473)	(1,581)	(54)	(728)	(243)	166 [2]	(3,913)
Commodity purchases resold	—	—	—	—	(365)	—	(365)
Property taxes	(275)	(345)	—	(101)	(6)	—	(727)
Depreciation and amortization	(1,159)	(754)	(115)	(341)	(95)	—	(2,464)
Net gain / (loss) on assets sold/held for sale	—	21	—	69	(211)	—	(121)
Segmented earnings / (losses)	1,115	2,747	490	1,848	455	(70)	6,585
Interest expense							(2,333)
Allowance for funds used during construction							475
Interest income and other[3]							460
Income before income taxes							5,187
Income tax expense							(754)
Net income							4,433
Net income attributable to non-controlling interests							(293)
Net income attributable to controlling interests							4,140
Preferred share dividends							(164)
Net income attributable to common shares							3,976
Capital spending							
Capital expenditures	3,900	2,500	323	239	481	32	7,475
Capital projects in development	6	—	—	701	—	—	707
Contributions to equity investments	—	16	34	14	538	—	602
	3,906	2,516	357	954	1,019	32	8,784

1 Includes intersegment eliminations.

2 The Company records intersegment sales at contracted rates. For segmented reporting, these transactions are included as Intersegment revenues in the segment providing the service and Plant operating costs and other in the segment receiving the service. These transactions are eliminated on consolidation. Intersegment profit is recognized when the product or service has been provided to third parties or otherwise realized.

3 Income / (loss) from equity investments includes the Company's proportionate share of Sur de Texas foreign exchange losses and gains on the peso-denominated loans from affiliates which are fully offset in Interest income and other by the corresponding foreign exchange gains and losses on the affiliate receivable balance. Refer to Note 10, Loans receivable from affiliates, for additional information.

year ended December 31, 2018 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Storage	Corporate[1]	Total
Revenues	4,038	4,314	619	2,584	2,124	—	13,679
Intersegment revenues	—	162	—	—	56	(218) [2]	—
	4,038	4,476	619	2,584	2,180	(218)	13,679
Income from equity investments	12	256	22	64	355	5 [3]	714
Plant operating costs and other	(1,405)	(1,368)	(34)	(630)	(315)	159 [2]	(3,593)
Commodity purchases resold	—	—	—	—	(1,486)	—	(1,486)
Property taxes	(266)	(199)	—	(98)	(6)	—	(569)
Depreciation and amortization	(1,129)	(664)	(97)	(341)	(119)	—	(2,350)
Goodwill and other asset impairment charges	—	(801)	—	—	—	—	(801)
Net gain on sale of assets	—	—	—	—	170	—	170
Segmented earnings / (losses)	1,250	1,700	510	1,579	779	(54)	5,764
Interest expense							(2,265)
Allowance for funds used during construction							526
Interest income and other[3]							(76)
Income before income taxes							3,949
Income tax expense							(432)
Net income							3,517
Net loss attributable to non-controlling interests							185
Net income attributable to controlling interests							3,702
Preferred share dividends							(163)
Net income attributable to common shares							3,539
Capital spending							
Capital expenditures	2,442	5,591	463	110	767	45	9,418
Capital projects in development	36	1	—	459	—	—	496
Contributions to equity investments	—	179	334	12	490	—	1,015
	2,478	5,771	797	581	1,257	45	10,929

1 Includes intersegment eliminations.

2 The Company records intersegment sales at contracted rates. For segmented reporting, these transactions are included as Intersegment revenues in the segment providing the service and Plant operating costs and other in the segment receiving the service. These transactions are eliminated on consolidation. Intersegment profit is recognized when the product or service has been provided to third parties or otherwise realized.

3 Income from equity investments includes the Company's proportionate share of Sur de Texas foreign exchange gains and losses on the peso-denominated loans from affiliates which are fully offset in Interest income and other by the corresponding foreign exchange losses and gains on the affiliate receivable balance. Refer to Note 10, Loans receivable from affiliates, for additional information.

at December 31 (millions of Canadian $)	2020	2019
Total Assets by segment		
Canadian Natural Gas Pipelines	**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	**5,062**	7,788
Corporate	**5,210**	4,743
	100,300	99,279

Geographic Information

year ended December 31 (millions of Canadian $)	2020	2019	2018
Revenues			
Canada – domestic	**4,392**	4,059	4,187
Canada – export	**1,059**	1,035	1,075
United States	**6,832**	7,558	7,798
Mexico	**716**	603	619
	12,999	13,255	13,679

at December 31 (millions of Canadian $)	2020	2019
Plant, Property and Equipment		
Canada	**24,092**	23,362
United States	**39,698**	36,184
Mexico	**5,985**	5,943
	69,775	65,489

5. REVENUES

Disaggregation of Revenues

year ended December 31, 2020 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Storage	Total
Revenues from contracts with customers						
Capacity arrangements and transportation	**4,408**	**4,301**	**607**	**2,206**	**—**	**11,522**
Power generation	**—**	**—**	**—**	**—**	**192**	**192**
Natural gas storage and other[1]	**61**	**654**	**109**	**3**	**106**	**933**
	4,469	**4,955**	**716**	**2,209**	**298**	**12,647**
Other revenues[2,3]	**—**	**76**	**—**	**162**	**114**	**352**
	4,469	**5,031**	**716**	**2,371**	**412**	**12,999**

1 Includes $138 million of fee revenues from affiliates, of which $77 million is related to the construction of the Sur de Texas pipeline which is 60 per cent owned by TC Energy and $61 million is related to development and construction of the Coastal GasLink pipeline project which is 35 per cent owned by TC Energy as at December 31, 2020. Refer to Note 27, Acquisitions and dispositions, for additional information.

2 Other revenues include income from the Company's marketing activities, financial instruments and lease arrangements. Refer to Note 8, Leases, and Note 25, Risk management and financial instruments, for additional information on income from lease arrangements and financial instruments, respectively.

3 Other revenues from U.S. Natural Gas Pipelines include the amortization of the net regulatory liabilities resulting from U.S. Tax Reform. Refer to Note 17, Income taxes, for additional information.

year ended December 31, 2019 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Storage	Total
Revenues from contracts with customers						
Capacity arrangements and transportation	4,010	4,245	601	2,423	—	11,279
Power generation	—	—	—	—	662	662
Natural gas storage and other	—	650	2	4	73	729
	4,010	4,895	603	2,427	735	12,670
Other revenues[1,2]	—	83	—	452	50	585
	4,010	4,978	603	2,879	785	13,255

1 Other revenues include income from the Company's marketing activities, financial instruments and lease arrangements. Refer to Note 8, Leases, and Note 25, Risk management and financial instruments, for additional information on income from lease arrangements and financial instruments, respectively.

2 Other revenues from U.S. Natural Gas Pipelines include the amortization of the net regulatory liabilities resulting from U.S. Tax Reform. Refer to Note 17, Income taxes, for additional information.

year ended December 31, 2018 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Storage	Total
Revenues from contracts with customers						
Capacity arrangements and transportation	4,038	3,549	614	2,079	—	10,280
Power generation	—	—	—	—	1,771	1,771
Natural gas storage and other	—	654	5	3	81	743
	4,038	4,203	619	2,082	1,852	12,794
Other revenues[1,2]	—	111	—	502	272	885
	4,038	4,314	619	2,584	2,124	13,679

1 Other revenues include income from the Company's marketing activities, financial instruments and lease arrangements. Refer to Note 8, Leases, and Note 25, Risk management and financial instruments, for additional information on income from lease arrangements and financial instruments, respectively.

2 Other revenues from U.S. Natural Gas Pipelines include the amortization of the net regulatory liabilities resulting from U.S. Tax Reform. Refer to Note 17, Income taxes, for additional information.

Contract Balances

at December 31 (millions of Canadian $)	2020	2019	Affected line item on Consolidated balance sheet
Receivables from contracts with customers	**1,330**	1,458	Accounts receivable
Contract assets (Note 6)	**132**	153	Other current assets
Long-term contract assets (Note 13)	**192**	102	Other long-term assets
Contract liabilities[1] (Note 15)	**129**	61	Accounts payable and other
Long-term contract liabilities (Note 16)	**203**	226	Other long-term liabilities

1 During the year ended December 31, 2020, $18 million (2019 – $6 million) of revenues were recognized that were included in contract liabilities at the beginning of the year.

Contract assets and long-term contract assets primarily relate to the Company’s right to revenues for services completed but not invoiced at the reporting date on long-term committed capacity natural gas pipelines contracts. The change in contract assets is primarily related to the transfer to Accounts receivable when these rights become unconditional and the customer is invoiced, as well as the recognition of additional revenues that remain to be invoiced. Contract liabilities and long-term contract liabilities primarily relate to force majeure fixed capacity payments received on long-term capacity arrangements in Mexico.

Future Revenues from Remaining Performance Obligations

As at December 31, 2020, future revenues from long-term pipeline capacity arrangements and transportation as well as natural gas storage and other contracts extending through 2047 are approximately $25.5 billion, of which approximately $3.7 billion is expected to be recognized in 2021.

A significant portion of the Company's revenues are considered constrained and therefore not included in the future revenue amounts above as the Company uses the following practical expedients:

- right to invoice practical expedient – applied to all U.S. and certain Mexico rate-regulated natural gas pipeline capacity arrangements and flow-through revenues
- variable consideration practical expedient – applied to the following variable revenues:
  - interruptible transportation service revenues as volumes cannot be estimated
  - liquids pipelines capacity revenues based on volumes transported
  - power generation revenues related to market prices that are subject to factors outside the Company's influence
- contracts for a duration of one year or less.

In addition, future revenues from the Company's Canadian natural gas pipelines' regulated firm capacity contracts include fixed revenues only for the time periods that approved tolls under current rate settlements are in effect and certain, which is currently one year.

6. OTHER CURRENT ASSETS

at December 31 (millions of Canadian $)	2020	2019
Fair value of derivative contracts (Note 25)	**235**	190
Cash provided as collateral	**142**	52
Contract assets (Note 5)	**132**	153
Regulatory assets (Note 11)	**131**	43
Prepaid expenses	**126**	60
Other	**114**	129
	880	627

7. PLANT, PROPERTY AND EQUIPMENT

at December 31	2020			2019		
(millions of Canadian $)	Cost	Accumulated Depreciation	Net Book Value	Cost	Accumulated Depreciation	Net Book Value
Canadian Natural Gas Pipelines						
NGTL System						
Pipeline	**14,190**	**5,278**	**8,912**	11,556	4,846	6,710
Compression	**5,421**	**1,906**	**3,515**	4,205	1,771	2,434
Metering and other	**1,393**	**648**	**745**	1,296	609	687
	21,004	**7,832**	**13,172**	17,057	7,226	9,831
Under construction	**1,402**	**—**	**1,402**	3,181	—	3,181
	22,406	**7,832**	**14,574**	20,238	7,226	13,012
Canadian Mainline						
Pipeline	**10,297**	**7,443**	**2,854**	10,145	7,109	3,036
Compression	**3,930**	**3,000**	**930**	3,867	2,823	1,044
Metering and other	**637**	**239**	**398**	643	219	424
	14,864	**10,682**	**4,182**	14,655	10,151	4,504
Under construction	**150**	**—**	**150**	60	—	60
	15,014	**10,682**	**4,332**	14,715	10,151	4,564
Other Canadian Natural Gas Pipelines[1]						
Other	**1,885**	**1,508**	**377**	1,861	1,455	406
Under construction[2]	**42**	**—**	**42**	1,276	—	1,276
	1,927	**1,508**	**419**	3,137	1,455	1,682
	39,347	**20,022**	**19,325**	38,090	18,832	19,258
U.S. Natural Gas Pipelines						
Columbia Gas						
Pipeline	**10,198**	**557**	**9,641**	9,708	389	9,319
Compression	**4,287**	**276**	**4,011**	4,094	206	3,888
Metering and other	**3,388**	**185**	**3,203**	3,244	125	3,119
	17,873	**1,018**	**16,855**	17,046	720	16,326
Under construction	**1,070**	**—**	**1,070**	425	—	425
	18,943	**1,018**	**17,925**	17,471	720	16,751
ANR						
Pipeline	**1,685**	**512**	**1,173**	1,594	472	1,122
Compression	**2,146**	**489**	**1,657**	2,050	436	1,614
Metering and other	**1,289**	**388**	**901**	1,245	355	890
	5,120	**1,389**	**3,731**	4,889	1,263	3,626
Under construction	**431**	**—**	**431**	252	—	252
	5,551	**1,389**	**4,162**	5,141	1,263	3,878

at December 31 (millions of Canadian $)	2020 Cost	2020 Accumulated Depreciation	2020 Net Book Value	2019 Cost	2019 Accumulated Depreciation	2019 Net Book Value
Other U.S. Natural Gas Pipelines						
Columbia Gulf	**2,638**	**151**	**2,487**	2,597	114	2,483
GTN	**2,330**	**1,008**	**1,322**	2,257	969	1,288
Great Lakes	**2,117**	**1,223**	**894**	2,090	1,208	882
Other[3]	**1,568**	**578**	**990**	1,530	616	914
	8,653	**2,960**	**5,693**	8,474	2,907	5,567
Under construction	**389**	**—**	**389**	164	—	164
	9,042	**2,960**	**6,082**	8,638	2,907	5,731
	33,536	**5,367**	**28,169**	31,250	4,890	26,360
Mexico Natural Gas Pipelines						
Pipeline	**2,952**	**411**	**2,541**	2,988	340	2,648
Compression	**480**	**69**	**411**	486	54	432
Metering and other	**624**	**133**	**491**	643	124	519
	4,056	**613**	**3,443**	4,117	518	3,599
Under construction	**2,525**	**—**	**2,525**	2,321	—	2,321
	6,581	**613**	**5,968**	6,438	518	5,920
Liquids Pipelines						
Keystone Pipeline System						
Pipeline	**9,254**	**1,579**	**7,675**	9,378	1,403	7,975
Pumping equipment	**1,025**	**228**	**797**	1,035	204	831
Tanks and other	**3,522**	**644**	**2,878**	3,488	556	2,932
	13,801	**2,451**	**11,350**	13,901	2,163	11,738
Under construction[4]	**2,870**	**—**	**2,870**	47	—	47
	16,671	**2,451**	**14,220**	13,948	2,163	11,785
Intra-Alberta Pipelines						
Pipeline	**142**	**6**	**136**	138	2	136
Tanks and other	**56**	**3**	**53**	56	2	54
	198	**9**	**189**	194	4	190
	16,869	**2,460**	**14,409**	14,142	2,167	11,975
Power and Storage						
Natural Gas	**1,255**	**569**	**686**	1,256	522	734
Natural Gas Storage and Other	**780**	**194**	**586**	742	181	561
	2,035	**763**	**1,272**	1,998	703	1,295
Under construction	**11**	**—**	**11**	6	—	6
	2,046	**763**	**1,283**	2,004	703	1,301
Corporate	**993**	**372**	**621**	883	208	675
	99,372	**29,597**	**69,775**	92,807	27,318	65,489

1 Includes Foothills, Ventures LP and Great Lakes Canada.
2 Includes the Coastal GasLink pipeline project at December 31, 2019. On May 22, 2020, the Company completed the sale of a 65 per cent equity interest in Coastal GasLink Pipeline Limited Partnership and subsequently commenced accounting for its remaining investment using the equity method. Refer to Note 27, Acquisitions and dispositions, for additional information.
3 Includes Portland, North Baja, Tuscarora, Crossroads and mineral rights.
4 On March 31, 2020, TC Energy announced that it would proceed with construction of the Keystone XL pipeline. As a result, related capitalized development costs of $1.7 billion were transferred to Plant, property and equipment from Capital projects in development within Other long-term assets on the Consolidated balance sheet. On January 20, 2021, the Presidential Permit for the Keystone XL pipeline was revoked. Refer to Note 30, Subsequent events, for additional information.

Bison Impairment

At December 31, 2018, the Company evaluated its investment in its Bison natural gas pipeline for impairment in connection with the termination of certain customer transportation agreements which released the Company from providing any future services. With the loss of these future cash flows and the persistence of unfavourable market conditions which have inhibited system flows on the pipeline, the Company determined that the asset's remaining carrying value was no longer recoverable and recognized a non-cash impairment charge of $722 million pre tax in its U.S. Natural Gas Pipelines segment. The non-cash charge was recorded in Goodwill and other asset impairment charges in the Consolidated statement of income. As Bison is a TC PipeLines, LP asset, in which the Company had a 25.5 per cent interest, the Company's share of the impairment charge, after tax and net of non-controlling interests, was $140 million.

The termination of the transportation agreements resulted in the receipt of $130 million in termination payments which were recorded in Revenues in 2018. The Company's share of this amount, after tax and net of non-controlling interests, was $25 million.

8. LEASES

As a Lessee

The Company has operating leases for corporate offices, other various premises, equipment and land. Some leases have an option to renew for periods of one to 25 years, and some may include options to terminate the lease within one year. Payments due under lease contracts include fixed payments plus, for many of the Company's leases, variable payments such as a proportionate share of the buildings' property taxes, insurance and common area maintenance. The Company subleases some of the leased premises.

Operating lease cost was as follows:

year ended December 31 (millions of Canadian $)	2020	2019
Operating lease cost[1]	**124**	117
Sublease income	**(13)**	(11)
Net operating lease cost	**111**	106

1 Includes short-term leases and variable lease costs.

Net rental expense on operating leases in 2018 was $84 million.

Other information related to operating leases is noted in the following tables:

year ended December 31 (millions of Canadian $)	2020	2019
Cash paid for amounts included in the measurement of operating lease liabilities	**77**	76
ROU assets obtained in exchange for new operating lease liabilities	**14**	9

at December 31	2020	2019
Weighted average remaining lease term	**10 years**	10 years
Weighted average discount rate	**3.5%**	3.5%

Maturities of operating lease liabilities are as follows:

(millions of Canadian $)	2020	2019
Less than one year	**72**	73
One to two years	**61**	69
Two to three years	**59**	59
Three to four years	**58**	58
Four to five years	**54**	57
More than five years	**269**	323
Total operating lease payments	**573**	639
Imputed interest	**(90)**	(107)
Operating lease liabilities	**483**	532

The amounts recognized on TC Energy's Consolidated balance sheet for its operating lease liabilities were as follows:

at December 31 (millions of Canadian $)	**2020**	**2019**
Accounts payable and other	**56**	56
Other long-term liabilities (Note 16)	**427**	476
	483	532

As at December 31, 2020, the carrying value of the ROU assets recorded under operating leases was $473 million (2019 – $530 million) and is included in Plant, property and equipment on the Consolidated balance sheet.

As a Lessor

The Grandview and Bécancour power plants in the Power and Storage segment are accounted for as operating leases. In addition, the Company has long-term PPAs for the sale of power for the Power and Storage lease assets which expire between 2024 and 2026.

The Northern Courier pipeline in the Liquids Pipelines segment was accounted for as an operating lease prior to the July 2019 sale of an 85 per cent equity interest in Northern Courier. The Company uses the equity method to account for its remaining 15 per cent interest in the Company's consolidated financial statements. Refer to Note 27, Acquisitions and dispositions, for additional information.

Some leases contain variable lease payments that are based on operating hours and the reimbursement of variable costs, and options to purchase the underlying asset at fair value or based on a formula considering the remaining fixed payments. Lessees have rights under some leases to terminate under certain circumstances.

The Company also leases liquids tanks which are accounted for as operating leases.

The fixed portion of the operating lease income recorded by the Company for the year ended December 31, 2020 was $130 million (2019 – $180 million). Operating lease income in 2018 was $373 million.

Future lease payments to be received under operating leases are as follows:

(millions of Canadian $)	**2020**	**2019**
Less than one year	**119**	123
One to two years	**111**	116
Two to three years	**109**	111
Three to four years	**109**	109
Four to five years	**94**	109
More than five years	**70**	164
	612	732

The cost and accumulated depreciation for facilities accounted for as operating leases was $858 million and $327 million, respectively, at December 31, 2020 (2019 – $834 million and $301 million, respectively).

9. EQUITY INVESTMENTS

(millions of Canadian $)	Ownership Interest at December 31, 2020	Income / (Loss) from Equity Investments year ended December 31			Equity Investments at December 31	
		2020	**2019**	**2018**	**2020**	**2019**
Canadian Natural Gas Pipelines						
TQM[1]	50.0%	**12**	12	12	**90**	79
Coastal GasLink[1,2]	35.0%	**—**	—	—	**211**	—
U.S. Natural Gas Pipelines						
Northern Border[3]	50.0%	**100**	91	87	**521**	549
Millennium	47.5%	**96**	92	75	**482**	496
Iroquois[4]	50.0%	**52**	54	60	**197**	241
Pennant Midstream[5]	nil	**—**	12	17	**—**	—
Other	Various	**16**	15	17	**120**	112
Mexico Natural Gas Pipelines						
Sur de Texas[6]	60.0%	**213**	3	27	**680**	600
Liquids Pipelines						
Grand Rapids[1,7]	50.0%	**53**	56	65	**998**	1,028
Northern Courier[1,8]	15.0%	**22**	14	—	**53**	62
HoustonLink Pipeline[1]	50.0%	**—**	—	(1)	**19**	19
Power and Storage						
Bruce Power[1,9]	48.4%	**439**	527	311	**3,306**	3,256
Portlands Energy Centre[1,10]	nil	**12**	35	36	**—**	—
TransCanada Turbines[11]	100.0%	**4**	9	8	**—**	64
		1,019	920	714	**6,677**	6,506

1 Classified as a non-consolidated VIE. Refer to Note 29, Variable interest entities, for additional information.

2 On May 22, 2020, TC Energy completed the sale of a 65 per cent equity interest in Coastal GasLink Pipeline Limited Partnership and subsequently applied the equity method to account for its 35 per cent retained equity interest in the jointly controlled entity. Refer to Note 27, Acquisitions and dispositions, for additional information. At December 31, 2020, the difference between the carrying value of the investment and the underlying equity in the net assets of Coastal GasLink Pipeline Limited Partnership was $188 million due mainly to the fair value assessment of assets at the time of partial monetization.

3 At December 31, 2020, the difference between the carrying value of the investment and the underlying equity in the net assets of Northern Border was US$116 million (2019 – US$116 million) due mainly to the fair value assessment of assets at the time of acquisition.

4 At December 31, 2020, the difference between the carrying value of the investment and the underlying equity in the net assets of Iroquois was US$39 million (2019 – US$40 million) due mainly to the fair value assessment of the assets at the times of acquisition.

5 In August 2019, TC Energy completed the sale of certain Columbia Midstream assets, including the Company's investment in Pennant Midstream. Refer to Note 27, Acquisitions and dispositions, for additional information.

6 Sur de Texas was placed into service in September 2019. TC Energy has a 60 per cent equity interest and, as a jointly controlled entity, applies the equity method of accounting. Income from equity investments recorded in the Corporate segment reflects the Company's proportionate share of Sur de Texas foreign exchange gains and losses on the peso-denominated loans from affiliates which are fully offset in Interest income and other in the Consolidated statement of income. At December 31, 2020, the difference between the carrying value of the investment and the underlying equity in the net assets of Sur de Texas was US$79 million (2019 – nil) due mainly to fees earned from the successful construction of the pipeline.

7 At December 31, 2020, the difference between the carrying value of the investment and the underlying equity in the net assets of Grand Rapids was $98 million (2019 – $101 million) due mainly to interest capitalized during construction.

8 In July 2019, TC Energy completed the sale of an 85 per cent equity interest in Northern Courier, and subsequently applied the equity method to account for its 15 per cent retained equity interest in the jointly controlled entity. Refer to Note 27, Acquisitions and dispositions, for additional information. At December 31, 2020, the difference between the carrying value of the investment and the underlying equity in the net assets of Northern Courier was $56 million (2019 – $62 million) due mainly to the fair value of guarantees and the fair value assessment of assets at the time of partial monetization.

9 At December 31, 2020, the difference between the carrying value of the investment and the underlying equity in the net assets of Bruce Power was $796 million (2019 – $829 million) due mainly to capitalized interest and the fair value assessment of assets at the time of acquisition.

10 Investment in Portlands Energy Centre was reclassed to Assets held for sale in July 2019 and sold on April 29, 2020. At December 31, 2019, the difference between the carrying value of the investment and the underlying equity in the net assets of Portlands Energy Centre was $76 million due mainly to capitalized interest. Refer to Note 27, Acquisitions and dispositions, for additional information.

11 On November 13, 2020, TC Energy purchased the remaining 50 per cent ownership in TransCanada Turbines which was subsequently consolidated. Refer to Note 27, Acquisitions and dispositions, for additional information.

Distributions and Contributions

Distributions received from equity investments for the year ended December 31, 2020 were $1,123 million (2019 – $1,399 million; 2018 – $1,106 million). For 2020, all distributions received were included in Cash generated from operations in the Consolidated statement of cash flows. Of the total distributions received in 2019 and 2018, $186 million and $121 million, respectively, were included in Investing activities in the Consolidated statement of cash flows with regard to distributions received from Bruce Power and Northern Border from their respective financing programs.

Contributions made to equity investments for the year ended December 31, 2020 were $765 million (2019 – $602 million; 2018 – $1,015 million) and were included in Investing activities in the Consolidated statement of cash flows. For 2019 and 2018, contributions of $32 million and $179 million, respectively, related to TC Energy's proportionate share of the Sur de Texas debt financing requirements.

Summarized Financial Information of Equity Investments

year ended December 31 (millions of Canadian $)	**2020**	**2019**	**2018**
Income			
Revenues	**5,838**	5,693	4,836
Operating and other expenses	**(3,341)**	(3,408)	(3,545)
Net income	**2,047**	1,990	1,515
Net income attributable to TC Energy	**1,019**	920	714

at December 31 (millions of Canadian $)	**2020**	**2019**
Balance Sheet		
Current assets	**2,911**	2,305
Non-current assets	**26,957**	21,865
Current liabilities	**(3,727)**	(2,060)
Non-current liabilities	**(15,309)**	(11,461)

10. 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 Pipeline Limited Partnership

In conjunction with the equity sale on May 22, 2020, the Company entered into a subordinated demand revolving credit facility with Coastal GasLink Pipeline Limited Partnership (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 Note 27, Acquisitions and dispositions, for additional information.

Sur de Texas

TC Energy holds a 60 per cent equity interest in a joint venture with IEnova to own the Sur de Texas pipeline, for which TC Energy is the operator. In 2017, TC Energy entered into a MXN$21.3 billion unsecured revolving credit facility with the joint venture, which bears interest at a floating rate and matures in March 2022. At December 31, 2020, Loan receivable from affiliate on the Company's Consolidated balance sheet reflected a MXN$20.9 billion or $1.3 billion (2019 – MXN$20.9 billion or $1.4 billion) loan receivable from the Sur de Texas joint venture which represents TC Energy's proportionate share of long-term debt financing to the joint venture.

The Company's Consolidated statement of income reflects the related interest income and foreign exchange impact on this loan receivable which were fully offset upon consolidation with corresponding amounts included in TC Energy's proportionate share of Sur de Texas equity earnings as follows:

year ended December 31 (millions of Canadian $)	**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 the Corporate segment.
2 Included in the Mexico Natural Gas Pipelines segment.

11. RATE-REGULATED BUSINESSES

TC Energy's businesses that apply RRA currently include almost all of the Canadian, U.S. and Mexico natural gas pipelines and certain U.S. natural gas storage operations. Rate-regulated businesses account for and report assets and liabilities consistent with the resulting economic impact of the regulators' established rates, provided the rates are designed to recover the costs of providing the regulated service and the competitive environment makes it probable that such rates can be charged and collected. Certain revenues and expenses subject to utility regulation or rate determination that would otherwise be reflected in the statement of income are deferred on the balance sheet and are expected to be recovered from or refunded to customers in future service rates.

Canadian Regulated Operations

The majority of TC Energy's Canadian natural gas pipelines are regulated by the CER under the Canadian Energy Regulator Act (CER Act). In August 2019, the CER and CER Act replaced the NEB and the National Energy Board Act (NEB Act), respectively. The impact assessment and decision-making for designated major transboundary pipeline projects also changed at that time with the implementation of the new Impact Assessment Act which required designated projects, on a prospective basis, to be assessed by the Impact Assessment Agency of Canada. TC Energy projects submitted to the NEB for review prior to August 28, 2019 will continue to be assessed under the previous NEB Act in accordance with the transitional rules under the CER Act.

The CER regulates the construction and operation of facilities, and the terms and conditions of services, including rates, for the Company's Canadian regulated natural gas transmission systems under federal jurisdiction.

TC Energy's Canadian natural gas transmission services are supplied under natural gas transportation tariffs that provide for cost recovery, including return of and return on capital as approved by the CER or NEB. Rates charged for these services are typically set through a process that involves filing an application with the regulator wherein forecasted operating costs, including a return of and on capital, determine the revenue requirement for the upcoming year or multiple years. To the extent actual costs and revenues are more or less than forecasted costs and revenues, the regulators generally allow the difference to be deferred to a future period and recovered or refunded in rates at that time. Differences between actual and forecasted costs that the regulator does not allow to be deferred are included in the determination of net income in the year they occur. The Company's most significant regulated Canadian natural gas pipelines, based on total operated pipe length, are described below.

NGTL System

The NGTL System currently operates under the terms of the 2020-2024 Revenue Requirement Settlement approved by the CER on August 17, 2020. The settlement, effective January 1, 2020, includes an ROE of 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.

NGTL System's 2019 and 2018 results reflect the terms of the 2018-2019 Revenue Requirement Settlement 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 operating, maintenance and administration amount and flow-through treatment of all other costs.

Canadian Mainline

The Canadian Mainline currently operates under the terms of the 2015-2030 Tolls Application approved in 2014 (the NEB 2014 Decision). The terms in the 2015-2020 six-year settlement of the NEB 2014 Decision, which ended December 31, 2020, included an ROE of 10.1 per cent on deemed common equity of 40 per cent, an incentive mechanism that had 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 the Company's 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, an NEB decision was received on the 2018-2020 Tolls Review (NEB 2018 Decision) 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.

On April 17, 2020, the CER approved the six-year unanimous negotiated settlement (2021-2026 Mainline Settlement) filed in December 2019. Similar to previous settlements, the 2021-2026 Mainline Settlement maintains a base equity return of 10.1 per cent on 40 per cent deemed common equity and includes an incentive to either achieve cost efficiencies and/or increase revenues on the pipeline with a beneficial sharing mechanism to both the shippers and TC Energy. An estimate of the remaining LTAA balance at the end of 2020 was included as an adjustment in the calculation of Mainline fixed tolls and amortized over the settlement term. Going forward, similar to the LTAA, the short-term adjustment accounts (STAA) captures the surplus or shortfall between system revenues and cost of service each year under the 2021-2026 Mainline Settlement.

U.S. Regulated Operations

TC Energy's U.S. regulated natural gas pipelines operate under the provisions of the Natural Gas Act (NGA)of 1938, the Natural Gas Policy Act of 1978 and the Energy Policy Act of 2005, and are subject to the jurisdiction of FERC. The NGA grants FERC authority over the construction and operation of pipelines and related facilities, including the regulation of tariffs which incorporates maximum and minimum rates for services and allows U.S. regulated natural gas pipelines to discount or negotiate rates on a non-discriminatory basis. The Company's most significant regulated U.S. natural gas pipelines, based on effective ownership and total operated pipe length, are described below.

In 2018, FERC prescribed changes (2018 FERC Actions) related to H.R.1, the Tax Cuts and Jobs Act (U.S. Tax Reform), and income taxes for rate-making purposes in a master limited partnership (MLP) that impact future earnings and cash flows of FERC-regulated pipelines. As part of the 2018 FERC Actions, FERC issued a Revised Policy Statement which created a presumption that entities whose earnings are not taxed through a corporation should not be permitted to recover an income tax allowance in their cost-of-service rates. In addition, FERC established that, to the extent an entity's income tax allowance should be eliminated from rates, it must also eliminate existing accumulated deferred income tax (ADIT) asset and liability balances from its rate base.

These 2018 FERC Actions also established a process and schedule by which all FERC-regulated interstate pipelines and natural gas storage facilities had to either (i) file a new uncontested rate settlement or (ii) file a FERC Form 501-G that quantified the isolated impact of U.S. Tax Reform and provided four options to address the impact for rate-making purposes.

Columbia Gas
Columbia Gas' natural gas transportation and storage services are provided under a tariff at rates subject to FERC approval. A FERC-approved modernization settlement provided for cost recovery and return on investment of up to US$1.5 billion from 2013-2017 to modernize the Columbia Gas system thereby improving system integrity and enhancing service reliability and flexibility. An extension of this settlement was approved by FERC in 2016 which allows for the cost recovery and return on additional expanded scope investment of US$1.1 billion over a three-year period through 2020.

Columbia Gas filed a general NGA Section 4 Rate Case with FERC on July 31, 2020 requesting an increase to Columbia Gas's maximum transportation rates expected to become effective February 1, 2021, subject to refund. The rate case continues to progress as expected, and the Company intends to pursue a collaborative process to reach a mutually beneficial outcome with its customers through settlement negotiations.

ANR Pipeline
ANR Pipeline operates under rates established through a FERC-approved rate settlement in 2016. Under terms of the 2016 settlement, ANR Pipeline is no longer under a rate moratorium and is required to file for new rates to be effective no later than August 1, 2022.

On August 10, 2020, FERC terminated ANR Pipeline's 501-G proceeding and ruled that ANR Pipeline has complied with the one-time reporting requirement. Additionally, FERC stated it will not exercise its right to initiate a NGA Section 5 investigation into ANR's effective rates at this time but may in the future, if warranted.

Columbia Gulf
Columbia Gulf reached a rate settlement with its customers, which was approved by FERC in December 2019, increasing Columbia Gulf's recourse rates to take effect on August 1, 2020. This settlement establishes a rate case and tariff filing moratorium through August 1, 2022 and Columbia Gulf is required to file a general rate case under Section 4 of the NGA no later than January 31, 2027, with new rates to be effective August 1, 2027.

TC PipeLines, LP
TC Energy owns 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. As TC PipeLines, LP is an MLP, all pipelines it owns wholly or in part were impacted by the 2018 FERC Actions which required these pipelines to eliminate their existing ADIT balance from rate base. Refer to Note 17, Income taxes, for additional information regarding the impact of these changes to TC Energy.

Great Lakes
Great Lakes reached a rate settlement with its customers, which was approved by FERC in February 2018, decreasing Great Lakes' maximum transportation rates by 27 per cent effective October 2017. This settlement does not contain a moratorium and Great Lakes will be required to file for new rates no later than March 31, 2022, with new rates to be effective October 1, 2022. In 2018, as a result of the 2018 FERC Actions noted above, Great Lakes made a limited NGA Section 4 filing which had the effect of reducing rates by two per cent from what was in place previously. The reduction in rates became effective on February 1, 2019 after the limited Section 4 filing was accepted by FERC.

On May 11, 2020, FERC terminated Great Lakes' 501-G proceeding and ruled that Great Lakes has complied with the one-time reporting requirement. Additionally, FERC also stated that rate reductions provided for in its 2017 settlement and the two per cent rate reduction from the limited Section 4 rate reduction proceeding have provided substantial rate relief for Great Lakes' shippers and, as a result, it will not exercise its right to institute a NGA Section 5 investigation to determine if Great Lakes is over-recovering on its current tariff rates.

Mexico Regulated Operations
TC Energy's Mexico natural gas pipelines are regulated by CRE and operate in accordance with CRE-approved tariffs. The rates in effect on TC Energy's Mexico natural gas pipelines were established based on CRE-approved contracts that provide for cost recovery, including a return of and on invested capital.

Regulatory Assets and Liabilities

at December 31 (millions of Canadian $)	2020	2019	Remaining Recovery/ Settlement Period (years)
Regulatory Assets			
Deferred income taxes[1]	**1,287**	1,088	n/a
Operating and debt-service regulatory assets[2]	**54**	2	1
Pensions and other post-retirement benefits[1,3]	**401**	417	n/a
Foreign exchange on long-term debt[1,4]	**7**	16	1-9
Other	**135**	107	n/a
	1,884	1,630	
Less: Current portion included in Other current assets (Note 6)	**131**	43	
	1,753	1,587	
Regulatory Liabilities			
Operating and debt-service regulatory liabilities[2]	**48**	139	1
Pensions and other post-retirement benefits[3]	**18**	35	n/a
ANR-related post-employment and retirement benefits other than pension[5]	**40**	41	n/a
Long-term adjustment account[6,7]	**227**	660	6
Bridging amortization account[6]	**537**	428	10
Pipeline abandonment trust balances[8]	**1,842**	1,462	n/a
Cost of removal[9]	**246**	253	n/a
Deferred income taxes[1]	**115**	151	n/a
Deferred income taxes – U.S. Tax Reform[10]	**1,170**	1,239	n/a
Other	**58**	60	n/a
	4,301	4,468	
Less: Current portion included in Accounts payable and other (Note 15)	**153**	696	
	4,148	3,772	

1 These regulatory assets and liabilities are underpinned by non-cash transactions or are recovered without an allowance for return as approved by the regulator. Accordingly, these regulatory assets or liabilities are not included in rate base and do not yield a return on investment during the recovery period.

2 Operating and debt-service regulatory assets and liabilities represent the accumulation of cost and revenue variances to be included in determination of rates in the following year.

3 These balances represent the regulatory offset to pension plan and other post-retirement benefit obligations to the extent the amounts are expected to be collected from or refunded to customers in future rates.

4 Foreign exchange on long-term debt of the NGTL System represents the variance resulting from revaluing foreign currency-denominated debt instruments to the current foreign exchange rate from the historical foreign exchange rate at the time of issue. Foreign exchange gains and losses realized when foreign debt matures or is redeemed early are expected to be recovered or refunded through the determination of future tolls.

5 This balance represents the amount ANR estimates would be required to refund to its customers for post-retirement and post-employment benefit amounts collected through its FERC-approved rates that have not been used to pay benefits to its employees. Pursuant to a FERC-approved rate settlement, the $40 million (US$32 million) balance at December 31, 2020 is subject to resolution through future regulatory proceedings and, accordingly, a settlement period cannot be determined at this time.

6 These regulatory accounts are used to capture Canadian Mainline revenue and cost variances plus toll-stabilization adjustments during the 2015-2030 settlement term.

7 Under the terms of the 2021-2026 Mainline Settlement, $223 million will be amortized over the six-year settlement term and the residual of $4 million will be transferred to the STAA.

8 This balance represents the amounts collected in tolls from shippers and included in the LMCI restricted investments to fund future abandonment of the Company's CER-regulated pipeline facilities.

9 This balance represents anticipated costs of removal that have been, and continue to be, included in depreciation rates and collected in the service rates of certain rate-regulated operations for future costs to be incurred.

10 These balances represent the impact of U.S. Tax Reform. The regulatory liabilities will be amortized over varying terms that approximate the expected reversal of the underlying deferred tax liabilities that gave rise to the regulatory liabilities under the Reverse South Georgia Methodology.

12. GOODWILL

The Company has recorded the following Goodwill on its acquisitions:

(millions of Canadian $)	U.S. Natural Gas Pipelines
Balance at January 1, 2019	14,178
Sale of Columbia Midstream assets	(595)
Foreign exchange rate changes	(696)
Balance at December 31, 2019	12,887
Foreign exchange rate changes	**(208)**
Balance at December 31, 2020	**12,679**

As part of the annual goodwill impairment assessment at December 31, 2020, the Company evaluated qualitative factors impacting the fair value of the underlying 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.

Sale of Columbia Midstream Assets

In August 2019, TC Energy completed the sale of certain Columbia Midstream assets. As these assets constituted a business, and there was goodwill within this reporting unit, $595 million of Columbia's goodwill allocated to these assets was released and netted in the pre-tax gain on sale. The amount released was determined based on the relative fair values of the assets sold and the portion of the reporting unit retained. The fair value of the reporting unit was determined using a discounted cash flow analysis. Refer to Note 27, Acquisitions and dispositions, for additional details.

Tuscarora

In 2018, the Company recorded a goodwill impairment charge of $79 million pre-tax within the U.S. Natural Gas Pipelines segment. The fair value of the reporting unit was determined using a discounted cash flow analysis. This non-cash charge was recorded in Goodwill and other asset impairment charges in the Consolidated statement of income. As Tuscarora is a TC PipeLines, LP asset, the Company's share of this amount, after tax and net of non-controlling interests, was $15 million. The gross goodwill and accumulated impairment losses related to Tuscarora were US$82 million and US$59 million, respectively, on the Consolidated balance sheet at December 31, 2020 and 2019.

13. OTHER LONG-TERM ASSETS

at December 31 (millions of Canadian $)	2020	2019
Capital projects in development	**231**	1,715
Employee post-retirement benefits (Note 24)	**207**	162
Long-term contract assets (Note 5)	**192**	102
Deferred income tax assets (Note 17)	**177**	37
Fair value of derivative contracts (Note 25)	**41**	7
Other	**131**	145
	979	2,168

Capital Projects in Development

Keystone XL

On March 31, 2020, TC Energy announced that it would proceed with construction of the Keystone XL pipeline and, as a result, $1.7 billion of related capitalized development costs were transferred to Plant, property and equipment. At December 31, 2019, the amount included in Capital projects in development for this project was $1.5 billion.

Reimbursement of Coastal GasLink pipeline project costs

In November 2018, in accordance with provisions in the agreements with the LNG Canada joint venture participants, all five parties elected to collectively reimburse TC Energy $470 million representing costs incurred prior to receiving the Final Investment Decision (FID) on the Coastal GasLink pipeline project (Coastal GasLink). These payments were recorded as a reduction of the carrying value of Coastal GasLink costs which, subsequent to the FID, were reported in Plant, property and equipment until the sale of a 65 per cent equity interest in Coastal GasLink LP on May 22, 2020, at which point TC Energy's remaining investment was recorded in Equity investments. Refer to Note 27, Acquisitions and dispositions, for additional information.

14. NOTES PAYABLE

(millions of Canadian $, unless otherwise noted)	2020 Outstanding at December 31	2020 Weighted Average Interest Rate per Annum at December 31	2019 Outstanding at December 31	2019 Weighted Average Interest Rate per Annum at December 31
Canada[1]	**2,836**	**0.4%**	4,034	2.1%
U.S. (2020 – US$900; 2019 – nil)	**1,149**	**0.4%**	—	—
Mexico (2020 – US$150; 2019 – US$205)[2]	**191**	**1.7%**	266	2.7%
	4,176		4,300	

1 At December 31, 2020, Notes payable consisted of Canadian dollar-denominated notes of $656 million (2019 – $1,353 million) and U.S. dollar-denominated notes of US$1,709 million (2019 – US$2,068 million).

2 The demand senior unsecured revolving credit facility for the Company's Mexico subsidiary can be drawn in either Mexican pesos or U.S. dollars, up to the total facility amount of MXN$5.0 billion or the U.S. dollar equivalent.

At December 31, 2020 and 2019, Notes payable reflects short-term borrowings in Canada by TransCanada PipeLines Limited (TCPL) and in Mexico by a wholly-owned Mexican subsidiary. At December 31, 2020, Notes payable also includes short-term borrowings in the U.S. by TransCanada PipeLine USA Ltd. (TCPL USA).

At December 31, 2020, total committed revolving and demand credit facilities were $12.4 billion (2019 – $12.6 billion). When drawn, interest on these lines of credit is charged at negotiated floating rates of Canadian and U.S. banks, and at other negotiated financial bases. These unsecured credit facilities included the following:

at December 31 (billions of Canadian $, unless otherwise noted) Borrower	Description	Matures	2020 Total Facilities	2020 Unused Capacity[1]	2019 Total Facilities
Committed, syndicated, revolving, extendible, senior unsecured credit facilities[2]:					
TCPL	Supports TCPL's Canadian dollar commercial paper program and for general corporate purposes	December 2024	**3.0**	**2.3**	3.0
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**	**US 1.9**	US 4.5
TCPL/TCPL USA/Columbia/ TransCanada American Investments Ltd.	For general corporate purposes of the borrowers, guaranteed by TCPL	December 2022	**US 1.0**	**US 1.0**	US 1.0
Demand senior unsecured revolving credit facilities[2]:					
TCPL/TCPL USA	Supports the issuance of letters of credit and provides additional liquidity; TCPL USA facility guaranteed by TCPL	Demand	**2.1** [3]	**1.1**	2.1 [3]
Mexico subsidiary	For Mexico general corporate purposes, guaranteed by TCPL	Demand	**MXN5.0** [3]	**MXN2.0**	MXN5.0 [3]

1 Net of commercial paper outstanding and facility draws.

2 Provisions of various credit arrangements with the Company's subsidiaries can restrict their ability to declare and pay dividends or make distributions under certain circumstances. If such restrictions apply, they may, in turn, have an impact on the Company's ability to declare and pay dividends on common and preferred shares. These credit arrangements also require the Company to comply with various affirmative and negative covenants and maintain certain financial ratios. At December 31, 2020, the Company was in compliance with all debt covenants.

3 Or the U.S. dollar equivalent.

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.

For the year ended December 31, 2020, the cost to maintain the above facilities was $21 million (2019 – $11 million; 2018 – $12 million).

At December 31, 2020, certain of the Company's other subsidiaries had an additional $0.8 billion (2019 – $0.8 billion) of undrawn capacity on third-party committed credit facilities.

15. ACCOUNTS PAYABLE AND OTHER

at December 31 (millions of Canadian $)	**2020**	**2019**
Trade payables	**3,057**	3,314
Regulatory liabilities (Note 11)	**153**	696
Contract liabilities (Note 5)	**129**	61
Fair value of derivative contracts (Note 25)	**72**	115
Other	**405**	358
	3,816	4,544

16. OTHER LONG-TERM LIABILITIES

at December 31 (millions of Canadian $)	**2020**	**2019**
Employee post-retirement benefits (Note 24)	**503**	540
Operating lease obligations (Note 8)	**427**	476
Long-term contract liabilities (Note 5)	**203**	226
Fair value of derivative contracts (Note 25)	**59**	81
Asset retirement obligations	**54**	62
Guarantees	**30**	32
Other	**199**	197
	1,475	1,614

17. INCOME TAXES

Provision for Income Taxes

year ended December 31 (millions of Canadian $)	2020	2019	2018
Current			
Canada	**(54)**	84	65
Foreign[1]	**306**	615	250
	252	699	315
Deferred			
Canada	**(224)**	(29)	49
Foreign	**166**	84	235
Foreign – U.S. Tax Reform and 2018 FERC Actions	**—**	—	(167)
	(58)	55	117
Income Tax Expense	**194**	754	432

1 The 2019 current foreign income tax expense mainly relates to the sale of certain Columbia Midstream assets in August 2019. Refer to Note 27, Acquisitions and dispositions, for additional information.

Geographic Components of Income before Income Taxes

year ended December 31 (millions of Canadian $)	2020	2019	2018
Canada	**691**	1,144	433
Foreign	**4,416**	4,043	3,516
Income before Income Taxes	**5,107**	5,187	3,949

Reconciliation of Income Tax Expense

year ended December 31 (millions of Canadian $)	2020	2019	2018
Income before income taxes	**5,107**	5,187	3,949
Federal and provincial statutory tax rate	**24.0%**	26.5%	27.0%
Expected income tax expense	**1,226**	1,375	1,066
Valuation allowance releases	**(400)**	(259)	—
Foreign income tax rate differentials	**(258)**	(180)	(432)
Income tax differential related to regulated operations	**(228)**	(159)	(54)
(Income) / loss from non-controlling interests and equity investments	**(141)**	(78)	50
Alberta tax rate reduction	**—**	(32)	—
Non-taxable portion of capital gains	**(62)**	(28)	(11)
Non-deductible goodwill on the Columbia Midstream asset disposition	**—**	154	—
U.S. Tax Reform and 2018 FERC Actions	**—**	—	(167)
Other	**57**	(39)	(20)
Income Tax Expense	**194**	754	432

Deferred Income Tax Assets and Liabilities

at December 31 (millions of Canadian $)	2020	2019
Deferred Income Tax Assets		
Tax loss and credit carryforwards	**1,389**	1,046
Regulatory and other deferred amounts	**532**	692
Difference in accounting and tax bases of impaired assets and assets held for sale	**537**	538
Unrealized foreign exchange losses on long-term debt	**154**	260
Financial instruments	**48**	23
Other	**70**	70
	2,730	2,629
Less: Valuation allowance	**243**	673
	2,487	1,956
Deferred Income Tax Liabilities		
Difference in accounting and tax bases of plant, property and equipment	**6,661**	6,197
Equity investments	**1,087**	1,087
Taxes on future revenue requirement	**287**	232
Other	**81**	106
	8,116	7,622
Net Deferred Income Tax Liabilities	**5,629**	5,666

The above deferred tax amounts have been classified on the Consolidated balance sheet as follows:

at December 31 (millions of Canadian $)	2020	2019
Deferred Income Tax Assets		
Other long-term assets (Note 13)	**177**	37
Deferred Income Tax Liabilities		
Deferred income tax liabilities	**5,806**	5,703
Net Deferred Income Tax Liabilities	**5,629**	5,666

At December 31, 2020, the Company has recognized the benefit of non-capital loss carryforwards of $3,671 million (2019 – $1,929 million) for federal and provincial purposes in Canada, which expire from 2030 to 2040. The Company has not yet recognized the benefit of capital loss carryforwards of $253 million (2019 – $598 million) for federal and provincial purposes in Canada, with no expiry date. The Company also has Ontario minimum tax credits of $106 million (2019 – $102 million), which expire from 2026 to 2040.

At December 31, 2020, the Company has fully recognized the benefit of net operating loss carryforwards of US$849 million (2019 – US$1,098 million) for federal purposes in the U.S., which expire from 2029 to 2037.

At December 31, 2020, the Company has recognized the benefit of net operating loss carryforwards of US$13 million (2019 – US$4 million) in Mexico, which expire from 2024 to 2030.

TC Energy recorded an income tax valuation allowance of $243 million and $673 million against the deferred income tax asset balances at December 31, 2020 and 2019, respectively. The decrease in the valuation allowance in 2020 is primarily a result of the foreign exchange movement on unrecognized capital losses, realized capital gains and valuation allowance releases. At each reporting date, the Company considers new evidence, both positive and negative, that could affect its view of the future realization of deferred tax assets. As at December 31, 2020, the Company determined there was sufficient positive evidence to conclude that it is more likely than not that the net deferred tax assets will be realized.

The Company recorded $400 million in valuation allowance releases in 2020 primarily a result of the final investment decision to proceed with the construction of the Keystone XL pipeline, the sale of the Ontario natural gas-fired power plants and the sale of a 65 per cent equity interest in Coastal GasLink LP. Refer to Note 27, Acquisitions and dispositions, for additional information on the sale of the Ontario natural gas-fired power plants and Coastal GasLink LP equity sale, and refer to Note 30, Subsequent events, for additional information on the Keystone XL pipeline.

Unremitted Earnings of Foreign Investments

Income taxes have not been provided on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future. Deferred income tax liabilities would have increased at December 31, 2020 by approximately $684 million (2019 – $648 million) if there had been a provision for these taxes.

Income Tax Payments

Income tax payments of $252 million, net of refunds, were made in 2020 (2019 – payments, net of refunds, of $713 million; 2018 – payments, net of refunds, of $338 million).

Reconciliation of Unrecognized Tax Benefit

Below is the reconciliation of the annual changes in the total unrecognized tax benefit:

at December 31 (millions of Canadian $)	**2020**	**2019**	**2018**
Unrecognized tax benefit at beginning of year	**29**	19	15
Gross increases – tax positions in prior years	**26**	13	13
Gross decreases – tax positions in prior years	**(2)**	(1)	(5)
Gross increases – tax positions in current year	**1**	—	—
Lapse of statutes of limitations	**(2)**	(2)	(4)
Unrecognized Tax Benefit at End of Year	**52**	29	19

Subject to the results of audit examinations by taxing authorities and other legislative amendments, TC Energy does not anticipate further adjustments to the unrecognized tax benefits during the next 12 months that would have a material impact on its financial statements.

TC Energy and its subsidiaries are subject to either Canadian federal and provincial income tax, U.S. federal, state and local income tax or the relevant income tax in other international jurisdictions. The Company has substantially concluded all Canadian federal and provincial income tax matters for the years through 2012. Substantially all material U.S. federal, state and local income tax matters have been concluded for years through 2014. Substantially all material Mexico income tax matters have been concluded for years through 2013.

TC Energy's practice is to recognize interest and penalties related to income tax uncertainties in Income tax expense. Income tax expense for the year ended December 31, 2020 reflects $4 million of interest expense (2019 – $4 million of interest expense; 2018 – $1 million of interest recovery). At December 31, 2020, the Company had accrued $11 million in interest expense (December 31, 2019 – $7 million). The Company incurred no penalties associated with income tax uncertainties related to Income tax expense for the years ended December 31, 2020, 2019 and 2018 and no penalties were accrued as at December 31, 2020 and 2019.

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 the Company's 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. The Company recognized further adjustments to the provisional amount in 2018.

In accordance with FERC Form 501-G and uncontested rate settlement filings, the ADIT 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 the Company's consolidated financial statements at December 31, 2020.

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 the Company's consolidated financial statements at December 31, 2020.

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 the Company's consolidated financial statements at December 31, 2020.

18. LONG-TERM DEBT

Outstanding amounts (millions of Canadian $, unless otherwise noted)	Maturity Dates	2020 Outstanding at December 31	2020 Interest Rate[1]	2019 Outstanding at December 31	2019 Interest Rate[1]
TRANSCANADA PIPELINES LIMITED					
Debentures					
Canadian		—	—	250	11.8%
U.S. (2020 and 2019 – US$400)	2021	**510**	**9.9%**	518	9.9%
Medium Term Notes					
Canadian	2021 to 2049	**11,491**	**4.5%**	9,491	4.6%
Senior Unsecured Notes					
U.S. (2020 – US$14,292; 2019 – US$14,792)	2022 to 2049	**18,227**	**5.3%**	19,174	5.2%
		30,228		29,433	
NOVA GAS TRANSMISSION LTD.					
Debentures and Notes					
Canadian	2024	**100**	**9.9%**	100	9.9%
U.S. (2020 and 2019 – US$200)	2023	**255**	**7.9%**	259	7.9%
Medium Term Notes					
Canadian	2025 to 2030	**504**	**7.4%**	504	7.4%
U.S. (2020 and 2019 – US$33)	2026	**42**	**7.5%**	42	7.5%
		901		905	
COLUMBIA PIPELINE GROUP, INC.					
Senior Unsecured Notes					
U.S. (2020 – US$1,500; 2019 – US$2,250)[2]	2025 to 2045	**1,913**	**4.9%**	2,916	4.4%
TC PIPELINES, LP					
Unsecured Term Loan					
U.S. (2020 and 2019 – US$450)	2022	**574**	**1.4%**	583	2.9%
Senior Unsecured Notes					
U.S. (2020 and 2019 – US$1,200)	2021 to 2027	**1,530**	**4.4%**	1,556	4.4%
		2,104		2,139	
ANR PIPELINE COMPANY					
Senior Unsecured Notes					
U.S. (2020 and 2019 – US$672)	2021 to 2026	**858**	**7.2%**	872	7.2%
GAS TRANSMISSION NORTHWEST LLC					
Senior Unsecured Notes					
U.S. (2020 - US$325; 2019 – US$250)	2030 to 2035	**415**	**4.3%**	324	5.6%
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP					
Senior Unsecured Notes					
U.S. (2020 – US$198; 2019 – US$219)	2021 to 2030	**253**	**7.6%**	284	7.7%

Outstanding amounts (millions of Canadian $, unless otherwise noted)	Maturity Dates	2020 Outstanding at December 31	2020 Interest Rate[1]	2019 Outstanding at December 31	2019 Interest Rate[1]
PORTLAND NATURAL GAS TRANSMISSION SYSTEM					
Unsecured Loan Facility					
U.S. (2020 – US$25; 2019 – US$39)	2023	**32**	**1.3%**	51	3.0%
Senior Unsecured Notes					
U.S. (2020 – US$125 ; 2019 – nil)	2030	**159**	**2.8%**	—	—
		191		51	
TUSCARORA GAS TRANSMISSION COMPANY					
Unsecured Term Loan					
U.S. (2020 and 2019 – US$23)	2021	**29**	**2.2%**	30	2.8%
NORTH BAJA PIPELINE, LLC					
Unsecured Term Loan					
U.S. (2020 and 2019 – US$50)	2021	**64**	**1.2%**	65	2.8%
		36,956		37,019	
Current portion of long-term debt		**(1,972)**		(2,705)	
Unamortized debt discount and issue costs		**(238)**		(228)	
Fair value adjustments[3]		**167**		194	
		34,913		34,280	

1 Interest rates are the effective interest rates except for those pertaining to long-term debt issued for the Company's Canadian regulated natural gas operations, in which case the weighted average interest rate is presented as approved by the regulators. The effective interest rate is calculated by discounting the expected future interest payments, adjusted for loan fees, premiums and discounts. Weighted average and effective interest rates are stated as at the respective outstanding dates.

2 Certain subsidiaries of Columbia have guaranteed the principal payments of Columbia's senior unsecured notes. Each guarantor of Columbia's obligations is required to comply with covenants under the debt indenture and in the event of default, the guarantors would be obligated to pay the principal and related interest.

3 The fair value adjustments include $167 million (2019 – $193 million) related to the acquisition of Columbia. In 2019, these adjustments also included an increase of $1 million related to hedged interest rate risk. Refer to Note 25, Risk management and financial instruments, for additional information.

Principal Repayments

At December 31, 2020, principal repayments for the next five years on the Company's long-term debt are approximately as follows:

(millions of Canadian $)	2021	2022	2023	2024	2025
Principal repayments on long-term debt	1,972	1,901	1,861	286	2,712

Long-Term Debt Issued

The Company issued long-term debt over the three years ended December 31, 2020 as follows:

(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%
	September 2019	Medium Term Notes	September 2029	700	3.00%
	September 2019	Medium Term Notes	July 2048	300	4.18% [1]
	April 2019	Medium Term Notes	October 2049	1,000	4.34%
	October 2018	Senior Unsecured Notes	March 2049	US 1,000	5.10%
	October 2018	Senior Unsecured Notes	May 2028	US 400	4.25% [2]
	July 2018	Medium Term Notes	July 2048	800	4.18%
	July 2018	Medium Term Notes	March 2028	200	3.39% [3]
	May 2018	Senior Unsecured Notes	May 2028	US 1,000	4.25%
	May 2018	Senior Unsecured Notes	May 2048	US 1,000	4.875%
	May 2018	Senior Unsecured Notes	May 2038	US 500	4.75%
PORTLAND NATURAL GAS TRANSMISSION SYSTEM					
	October 2020	Senior Unsecured Notes	October 2030	US 125	2.84%
	April 2018	Unsecured Loan Facility	April 2023	US 19	Floating
GAS TRANSMISSION NORTHWEST LLC					
	June 2020	Senior Unsecured Notes	June 2030	US 175	3.12%
COASTAL GASLINK PIPELINE LIMITED PARTNERSHIP[4]					
	April 2020	Senior Secured Credit Facilities	April 2027	1,603	Floating
NORTHERN COURIER PIPELINE LIMITED PARTNERSHIP[5]					
	July 2019	Senior Secured Notes	June 2042	1,000	3.365%
NORTH BAJA PIPELINE, LLC					
	December 2018	Unsecured Term Loan	December 2021	US 50	Floating

1 Reflects coupon rate on re-opening of a pre-existing Medium Term Notes (MTN) issue. The MTNs were issued at a premium to par, resulting in a re-issuance yield of 3.991 per cent.

2 Reflects coupon rate on re-opening of a pre-existing senior unsecured notes issue. The notes were issued at a discount to par, resulting in a re-issuance yield of 4.439 per cent.

3 Reflects coupon rate on re-opening of a pre-existing MTN issue. The MTNs were issued at a discount to par, resulting in a re-issuance yield of 3.41 per cent.

4 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. Refer to Note 27, Acquisitions and dispositions, for additional information.

5 In July 2019, subsequent to the Senior Secured Notes issuance, TC Energy completed the sale of an 85 per cent equity interest in Northern Courier and subsequently accounts for its remaining 15 per cent interest using the equity method. Refer to Note 27, Acquisitions and dispositions, for additional information.

Long-Term Debt Retired/Repaid

The Company retired/repaid long-term debt over the three years ended December 31, 2020 as follows:

(millions of Canadian $, unless otherwise noted) Company	Retirement/ Repayment Date	Type	Amount	Interest Rate
TRANSCANADA PIPELINES LIMITED				
	November 2020	Debentures	250	11.80%
	October 2020	Senior Unsecured Notes	US 1,000	3.80%
	March 2020[1]	Senior Unsecured Notes	US 750	4.60%
	November 2019	Senior Unsecured Notes	US 700	2.125%
	November 2019	Senior Unsecured Notes	US 550	Floating
	May 2019	Medium Term Notes	13	9.35%
	March 2019	Debentures	100	10.50%
	January 2019	Senior Unsecured Notes	US 750	7.125%
	January 2019	Senior Unsecured Notes	US 400	3.125%
	August 2018	Senior Unsecured Notes	US 850	6.50%
	March 2018	Debentures	150	9.45%
	January 2018	Senior Unsecured Notes	US 500	1.875%
	January 2018	Senior Unsecured Notes	US 250	Floating
PORTLAND NATURAL GAS TRANSMISSION SYSTEM				
	October 2020	Unsecured Loan Facility	US 99	Floating
	May 2018	Senior Secured Notes	US 18	5.90%
COLUMBIA PIPELINE GROUP, INC.				
	June 2020	Senior Unsecured Notes	US 750	3.30%
	June 2018	Senior Unsecured Notes	US 500	2.45%
GAS TRANSMISSION NORTHWEST LLC				
	June 2020	Senior Unsecured Notes	US 100	5.29%
	May 2019	Unsecured Term Loan	US 35	Floating
TC PIPELINES, LP				
	June 2019	Unsecured Term Loan	US 50	Floating
	December 2018	Unsecured Term Loan	US 170	Floating
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP				
	March 2018	Senior Unsecured Notes	US 9	6.73%

1 Related unamortized debt issue costs of $8 million were included in Interest expense in the Consolidated statement of income for the year ended December 31, 2020.

Interest Expense

year ended December 31 (millions of Canadian $)	2020	2019	2018
Interest on long-term debt	**1,963**	1,931	1,877
Interest on junior subordinated notes	**470**	427	391
Interest on short-term debt	**46**	106	73
Capitalized interest	**(294)**	(186)	(124)
Amortization and other financial charges[1]	**43**	55	48
	2,228	2,333	2,265

1 Amortization and other financial charges includes amortization of transaction costs and debt discounts calculated using the effective interest method and losses on derivatives used to manage the Company's exposure to changes in interest rates.

The Company made interest payments of $2,203 million in 2020 (2019 – $2,295 million; 2018 – $2,156 million) on long-term debt, junior subordinated notes and short-term debt, net of interest capitalized.

19. JUNIOR SUBORDINATED NOTES

Outstanding loan amount (millions of Canadian $, unless otherwise noted)	Maturity Date	2020 Outstanding at December 31	2020 Effective Interest Rate[1]	2019 Outstanding at December 31	2019 Effective Interest Rate[1]
TRANSCANADA PIPELINES LIMITED					
US$1,000 notes issued 2007 at 6.35%[2]	2067	**1,275**	**4.1%**	1,296	5.1%
US$750 notes issued 2015 at 5.875%[3,4]	2075	**957**	**5.0%**	972	6.0%
US$1,200 notes issued 2016 at 6.125%[3,4]	2076	**1,530**	**5.8%**	1,556	6.7%
US$1,500 notes issued 2017 at 5.55%[3,4]	2077	**1,913**	**4.7%**	1,944	5.7%
$1,500 notes issued 2017 at 4.90%[3,4]	2077	**1,500**	**4.5%**	1,500	5.4%
US$1,100 notes issued 2019 at 5.75%[3,4]	2079	**1,403**	**5.4%**	1,426	6.3%
		8,578		8,694	
Unamortized debt discount and issue costs		**(80)**		(80)	
		8,498		8,614	

1 The effective interest rate is calculated by discounting the expected future interest payments using the coupon rate and any estimated future rate resets, adjusted for issue costs and discounts.

2 Junior subordinated notes of US$1 billion were issued in 2007 at a fixed rate of 6.35 per cent and converted in 2017 to a floating interest rate that is reset quarterly to the three-month LIBOR plus 2.21 per cent.

3 The Junior subordinated notes were issued to TransCanada Trust, a financing trust subsidiary wholly owned by TCPL. While the obligations of TransCanada Trust are fully and unconditionally guaranteed by TCPL on a subordinated basis, the Trust is not consolidated in TC Energy's financial statements since TCPL does not have a variable interest in the Trust and the only substantive assets of the Trust are junior subordinated notes of TCPL.

4 The coupon rate is initially a fixed interest rate for the first 10 years and converts to a floating rate thereafter.

The Junior subordinated notes are subordinated in right of payment to existing and future senior indebtedness or other obligations of TCPL.

In September 2019, TransCanada Trust (the Trust) issued US$1.1 billion of Trust Notes – Series 2019-A to investors with a fixed interest rate of 5.50 per cent for the first 10 years converting to a floating rate thereafter. All of the proceeds of the issuance by the Trust were loaned to TCPL for US$1.1 billion of junior subordinated notes of TCPL at an initial fixed rate of 5.75 per cent, including a 0.25 per cent administration charge. The rate will reset commencing September 2029 until September 2049 to the then three-month LIBOR plus 4.404 per cent per annum; from September 2049 until September 2079, the interest rate will reset to the then three-month LIBOR plus 5.154 per cent per annum. Refer to Note 25, Risk management and financial instruments, for additional information regarding the expected impact to the Company with certain rate settings of LIBOR which may cease to be published at the end of 2021 with full cessation expected by mid-2023. The junior subordinated notes are callable at TCPL's option at any time on or after September 15, 2029 at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption.

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

20. REDEEMABLE NON-CONTROLLING INTEREST AND NON-CONTROLLING INTERESTS

Redeemable Non-Controlling Interest

On March 31, 2020, TC Energy announced that it would proceed with construction of the Keystone XL pipeline. As part of the funding plan, the Government of Alberta agreed to invest up to US$1.1 billion as equity in certain Keystone XL subsidiaries of TC Energy. In the year ended December 31, 2020, the Government of Alberta invested $1,033 million in the form of Class A Interests which rank above TC Energy's equity investment in Keystone XL and have certain voting rights.

TC Energy has a call right exercisable at any time to repurchase the Class A Interests from the Government of Alberta. In turn, the Government of Alberta has a put right to sell its Class A Interests to the Company exercisable upon and following the in-service date of the Keystone XL pipeline if certain conditions are met. As a result of these redemption features, the Company classified the Class A Interests as Redeemable non-controlling interest in mezzanine equity on the Consolidated balance sheet. These Class A Interests are entitled to a return in accordance with contractual terms. This return accrues on a quarterly basis and adjusts the carrying value of the Class A Interests accordingly. Refer to Note 30, Subsequent events, for additional information.

At December 31, 2020, TC Energy had reclassified $630 million related to Class A Interests to Current liabilities on the Consolidated balance sheet to reflect the expectation that the Company would exercise its call right in January 2021 in accordance with contractual terms. Redeemable non-controlling interest in Current liabilities of $633 million also included $3 million of return accrued that was recorded in Interest expense in the Consolidated statement of income.

On January 4, 2021, the Company put in place a US$4.1 billion project-level credit facility to support construction of the Keystone XL pipeline, that is fully guaranteed by the Government of Alberta and non-recourse to the Company. The Company drew US$579 million on the credit facility on January 8, 2021, of which US$497 million was used 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 changes in Redeemable non-controlling interest classified in mezzanine equity were as follows:

year ended December 31 (millions of Canadian $)	**2020**
Balance at beginning of year	—
Class A Interests issued	**1,033**
Net loss attributable to redeemable non-controlling interest[1]	**(10)**
Class A Interests transferred to Current liabilities	**(630)**
Balance at end of year	**393**

1 Includes a return accrual and a foreign currency translation loss on Class A Interests, both of which were presented within Net income / (loss) attributable to non-controlling interests in the Consolidated statement of income.

Non-Controlling Interests

TC PipeLines, LP

During 2020 and 2019, the non-controlling interests in TC PipeLines, LP remained at 74.5 per cent and in 2018 ranged between 74.3 per cent and 74.5 per cent due to periodic issuances of common units in TC PipeLines, LP to third parties under an at-the-market issuance program. Refer to Note 28, Commitments, contingencies and guarantees, for additional information on the acquisition of common units of TC PipeLines, LP.

The Company's Non-controlling interests included on the Consolidated balance sheet were as follows:

at December 31 (millions of Canadian $)	**2020**	**2019**
Non-controlling interests in TC PipeLines, LP	**1,682**	1,634

The Company's Net income / (loss) attributable to non-controlling interests included in the Consolidated statement of income were as follows:

year ended December 31 (millions of Canadian $)	2020	2019	2018
Non-controlling interests in TC PipeLines, LP	**307**	293	(185)
Redeemable non-controlling interest	**(10)**	—	—
	297	293	(185)

21. COMMON SHARES

	Number of Shares (thousands)	Amount (millions of Canadian $)
Outstanding at January 1, 2018	881,376	21,167
At-the-market equity issuance program[1]	20,050	1,118
Dividend reinvestment and share purchase plan	15,937	855
Exercise of options	734	34
Outstanding at December 31, 2018	918,097	23,174
Dividend reinvestment and share purchase plan	15,165	931
Exercise of options	5,138	282
Outstanding at December 31, 2019	938,400	24,387
Exercise of options	**1,664**	**101**
Outstanding at December 31, 2020	**940,064**	**24,488**

1 Net of issue costs and deferred income taxes.

Common Shares Issued and Outstanding

The Company is authorized to issue an unlimited number of common shares without par value.

TC Energy Corporation At-the-Market Equity Issuance Program

In June 2017, the Company established an At-the-Market Equity Issuance Program (ATM program) that allowed, from time to time, for the issuance of common shares from treasury at the prevailing market price when sold through the Toronto Stock Exchange, the New York Stock Exchange or any other existing trading market for TC Energy common shares in Canada or the United States. This ATM program was effective for a 25-month period and was utilized as appropriate to assist in managing the Company's capital structure. Under the initial ATM program, the Company could issue up to $1.0 billion in common shares or the U.S. dollar equivalent. In June 2018, the Company replenished the capacity available under the program which allowed for the issuance of additional common shares from treasury 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 above 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, this ATM program expired with no common shares issued under it in 2019.

On December 7, 2020, the Company established a new ATM program that allows for the issuance of up to $1.0 billion in common shares or the U.S. dollar equivalent under substantially similar terms and trading platforms. This ATM program is effective for a 25-month period and will be utilized as appropriate to assist in managing the Company's capital structure. No common shares were issued under this program in 2020.

Dividend Reinvestment and Share Purchase Plan

Under the Company's Dividend Reinvestment and Share Purchase Plan (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 under the DRP were issued from treasury at a two per cent discount to market prices over a specified period.

Commencing with the dividends declared October 31, 2019, common shares purchased with reinvested cash dividends under the Company's DRP are acquired on the open market at 100 per cent of the weighted average purchase price.

Basic and Diluted Net Income per Common Share

Net income per common share is calculated by dividing Net income attributable to common shares by the weighted average number of common shares outstanding. The weighted average number of shares for the diluted earnings per share calculation includes options exercisable under TC Energy's Stock Option Plan and shares issuable under the DRP up to October 31, 2019 when participation was satisfied with common shares issued from treasury.

Weighted Average Common Shares Outstanding (millions)	**2020**	**2019**	**2018**
Basic	**940**	929	902
Diluted	**940**	931	903

Stock Options

	Number of Options (thousands)	**Weighted Average Exercise Prices**	**Weighted Average Remaining Contractual Life** (years)
Options outstanding at January 1, 2020	**9,094**	**$55.77**	
Options granted	**1,714**	**$75.06**	
Options exercised	**(1,664)**	**$54.47**	
Options forfeited/expired	**(148)**	**$63.95**	
Options Outstanding at December 31, 2020	**8,996**	**$59.55**	**3.8**
Options Exercisable at December 31, 2020	**5,395**	**$55.74**	**2.8**

At December 31, 2020, an additional 6,396,168 common shares were reserved for future issuance from treasury under TC Energy's Stock Option Plan. The contractual life of options granted is seven years. Options may be exercised at a price determined at the time the option is awarded and vest equally on the anniversary date in each of the three years following the award. Forfeiture of stock options results from their expiration and, if not previously vested, upon resignation or termination of the option holder's employment.

The Company used a binomial model for determining the fair value of options granted applying the following weighted average assumptions:

year ended December 31	**2020**	**2019**	**2018**
Weighted average fair value	**$7.73**	$6.37	$5.80
Expected life (years)[1]	**5.7**	5.7	5.7
Interest rate	**1.5%**	1.9%	2.1%
Volatility[2]	**17%**	19%	16%
Dividend yield	**4.2%**	5.0%	4.2%

1 Expected life is based on historical exercise activity.

2 Volatility is derived based on the average of both the historical and implied volatility of the Company's common shares.

The amount expensed for stock options, with a corresponding increase in Additional paid-in capital, was $12 million in 2020 (2019 – $13 million; 2018 – $13 million). At December 31, 2020, unrecognized compensation costs related to non-vested stock options were $14 million. The cost is expected to be fully recognized over a weighted average period of 1.7 years.

The following table summarizes additional stock option information:

year ended December 31 (millions of Canadian $, unless otherwise noted)	**2020**	**2019**	**2018**
Total intrinsic value of options exercised	**31**	75	10
Total fair value of options that have vested	**101**	143	101
Total options vested	**2.0 million**	2.1 million	2.1 million

As at December 31, 2020, the aggregate intrinsic value of the total options exercisable was $5 million and the aggregate intrinsic value of options outstanding was $5 million.

Shareholder Rights Plan

TC Energy's Shareholder Rights Plan is designed to provide the Board of Directors with sufficient time to explore and develop alternatives for maximizing shareholder value in the event of a takeover offer for the Company and to encourage the fair treatment of shareholders in connection with any such offer. Attached to each common share is one right that, under certain circumstances, entitles certain holders to purchase an additional common share of the Company.

22. PREFERRED SHARES

at December 31, 2020	Number of Shares Outstanding	Current Yield	Annual Dividend Per Share[1,2]	Redemption Price Per Share	Redemption and Conversion Option Date	Right to Convert Into	Carrying Value December 31[3] 2020	2019	2018
	(thousands)						(millions of Canadian $)		
Cumulative First Preferred Shares									
Series 1	14,577	3.479%	$0.86975	$25.00	December 31, 2024	Series 2	**360**	360	233
Series 2	7,423	Floating [4]	Floating	$25.00	December 31, 2024	Series 1	**179**	179	306
Series 3	9,997	1.694% [5]	$0.4235	$25.00	June 30, 2025	Series 4	**246**	209	209
Series 4	4,003	Floating [4]	Floating	$25.00	June 30, 2025	Series 3	**97**	134	134
Series 5	12,714	2.263%	$0.56575	$25.00	January 30, 2021	Series 6	**310**	310	310
Series 6	1,286	Floating [4]	Floating	$25.00	January 30, 2021	Series 5	**32**	32	32
Series 7	24,000	3.903% [6]	$0.97575	$25.00	April 30, 2024	Series 8	**589**	589	589
Series 9	18,000	3.762% [6]	$0.9405	$25.00	October 30, 2024	Series 10	**442**	442	442
Series 11	10,000	3.351% [7]	$0.83775	$25.00	November 28, 2025	Series 12	**244**	244	244
Series 13	20,000	5.50%	$1.375	$25.00	May 31, 2021	Series 14	**493**	493	493
Series 15	40,000	4.90%	$1.225	$25.00	May 31, 2022	Series 16	**988**	988	988
							3,980	3,980	3,980

1 Each of the even-numbered series of preferred shares, if in existence, will be entitled to receive floating rate cumulative quarterly preferential dividends per share at an annualized rate equal to the 90-day Government of Canada Treasury bill rate (T-bill rate) plus 1.92 per cent (Series 2), 1.28 per cent (Series 4), 1.54 per cent (Series 6), 2.38 per cent (Series 8), 2.35 per cent (Series 10), 2.96 per cent (Series 12), 4.69 per cent (Series 14) or 3.85 per cent (Series 16). These rates reset quarterly with the then current T-Bill rate.

2 The odd-numbered series of preferred shares, if in existence, will be entitled to receive fixed rate cumulative quarterly preferential dividends, which will reset on the redemption and conversion option date and every fifth year thereafter, at an annualized rate equal to the then five-year Government of Canada bond yield plus 1.92 per cent (Series 1), 1.28 per cent (Series 3), 1.54 per cent (Series 5), 2.38 per cent (Series 7), 2.35 per cent (Series 9), 2.96 per cent (Series 11), 4.69 per cent, subject to a minimum of 5.50 per cent (Series 13) or 3.85 per cent, subject to a minimum of 4.90 per cent (Series 15).

3 Net of underwriting commissions and deferred income taxes.

4 The floating quarterly dividend rate for the Series 2 preferred shares is 2.029 per cent for the period starting December 31, 2020 to, but excluding, March 31, 2021. The floating quarterly dividend rate for the Series 4 preferred shares is 1.389 per cent for the period starting December 31, 2020 to, but excluding, March 31, 2021. The floating quarterly dividend rate for the Series 6 preferred shares is 1.676 per cent for the period starting October 30, 2020 to, but excluding, January 30, 2021. These rates will reset each quarter going forward.

5 The fixed rate dividend for Series 3 preferred shares decreased from 2.152 per cent to 1.694 per cent on June 30, 2020 and is due to reset on every fifth anniversary thereafter.

6 No Series 7 or 9 preferred shares were converted on the April 30, 2019 or October 30, 2019 conversion option dates, respectively. The fixed rate dividend decreased for Series 7 from 4.00 per cent to 3.903 per cent on April 30, 2019 and for Series 9 from 4.250 per cent to 3.762 per cent on October 30, 2019, and are due to reset on every fifth anniversary thereafter.

7 No Series 11 were converted on the November 30, 2020 conversion option date. The fixed rate dividend for Series 11 preferred shares decreased from 3.8 per cent to 3.351 per cent on November 30, 2020 and is due to reset on every fifth anniversary thereafter.

The holders of preferred shares are entitled to receive a fixed cumulative quarterly preferential dividend as and when declared by the Board with the exception of Series 2, Series 4 and Series 6 preferred shares. The holders of Series 2, Series 4 and Series 6 preferred shares are entitled to receive quarterly floating rate cumulative preferential dividends as and when declared by the Board. The holders will have the right, subject to certain conditions, to convert their first preferred shares of a specified series into first preferred shares of another specified series on the conversion option date and every fifth anniversary thereafter as indicated in the table above.

TC Energy may, at its option, redeem all or a portion of the outstanding preferred shares for the redemption price per share, plus all accrued and unpaid dividends on the applicable redemption option date and on every fifth anniversary thereafter. In addition, Series 2, Series 4 and Series 6 preferred shares are redeemable by TC Energy at any time other than on a designated date for $25.50 per share plus all accrued and unpaid dividends on such redemption date.

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.

23. OTHER COMPREHENSIVE (LOSS) / INCOME AND ACCUMULATED OTHER COMPREHENSIVE LOSS (AOCI)

Components of other comprehensive (loss) / income, including the portion attributable to non-controlling interests and related tax effects, were as follows:

year ended December 31, 2020 (millions of Canadian $)	**Before Tax Amount**	**Income Tax Recovery/ (Expense)**	**Net of Tax Amount**
Foreign currency translation losses on net investment in foreign operations	**(647)**	**38**	**(609)**
Change in fair value of net investment hedges	**48**	**(12)**	**36**
Change in fair value of cash flow hedges	**(771)**	**188**	**(583)**
Reclassification to net income of gains and losses on cash flow hedges	**649**	**(160)**	**489**
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	**15**	**(3)**	**12**
Reclassification to net income of actuarial gains and losses on pension and other post-retirement benefit plans	**23**	**(6)**	**17**
Other comprehensive loss on equity investments	**(373)**	**93**	**(280)**
Other Comprehensive Loss	**(1,056)**	**138**	**(918)**

year ended December 31, 2019 (millions of Canadian $)	**Before Tax Amount**	**Income Tax Recovery/ (Expense)**	**Net of Tax Amount**
Foreign currency translation losses on net investment in foreign operations	(914)	(30)	(944)
Reclassification to net income of foreign currency translation gains on disposal of foreign operations	(13)	—	(13)
Change in fair value of net investment hedges	46	(11)	35
Change in fair value of cash flow hedges	(78)	16	(62)
Reclassification to net income of gains and losses on cash flow hedges	19	(5)	14
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	(15)	5	(10)
Reclassification to net income of actuarial gains and losses on pension and other post-retirement benefit plans	14	(4)	10
Other comprehensive loss on equity investments	(114)	32	(82)
Other Comprehensive Loss	(1,055)	3	(1,052)

year ended December 31, 2018 (millions of Canadian $)	**Before Tax Amount**	**Income Tax Recovery/ (Expense)**	**Net of Tax Amount**
Foreign currency translation gains on net investment in foreign operations	1,323	35	1,358
Change in fair value of net investment hedges	(57)	15	(42)
Change in fair value of cash flow hedges	(14)	4	(10)
Reclassification to net income of gains and losses on cash flow hedges	27	(6)	21
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	(153)	39	(114)
Reclassification to net income of actuarial gains and losses on pension and other post-retirement benefit plans	20	(5)	15
Other comprehensive income on equity investments	113	(27)	86
Other Comprehensive Income	1,259	55	1,314

The changes in AOCI by component were as follows:

	Currency Translation Adjustments	Cash Flow Hedges	Pension and Other Post-Retirement Benefit Plan Adjustments	Equity Investments	Total[1]
AOCI balance at January 1, 2018	(1,043)	(31)	(203)	(454)	(1,731)
Other comprehensive income / (loss) before reclassifications[2]	1,150	(9)	(114)	72	1,099
Amounts reclassified from AOCI	—	16	15	12	43
Net current period other comprehensive income / (loss)	1,150	7	(99)	84	1,142
Reclassification of AOCI to retained earnings resulting from U.S. Tax Reform	—	1	(12)	(6)	(17)
AOCI balance at December 31, 2018	107	(23)	(314)	(376)	(606)
Other comprehensive loss before reclassifications[2]	(824)	(49)	(10)	(86)	(969)
Amounts reclassified from AOCI	(13)	14	10	5	16
Net current period other comprehensive loss	(837)	(35)	—	(81)	(953)
AOCI balance at December 31, 2019	(730)	(58)	(314)	(457)	(1,559)
Other comprehensive (loss) / income before reclassifications[2]	**(543)**	**(567)**	**12**	**(292)**	**(1,390)**
Amounts reclassified from AOCI[3]	**—**	**482**	**17**	**11**	**510**
Net current period other comprehensive (loss) / income	**(543)**	**(85)**	**29**	**(281)**	**(880)**
AOCI balance at December 31, 2020	**(1,273)**	**(143)**	**(285)**	**(738)**	**(2,439)**

1 All amounts are net of tax. Amounts in parentheses indicate losses recorded to OCI.

2 In 2020, other comprehensive (loss) / income before reclassifications on currency translation adjustments, cash flow hedges and equity investments are net of non-controlling interest losses of $30 million (2019 – $85 million losses; 2018 – $166 million gains), losses of $16 million (2019 – $13 million losses; 2018 – $1 million losses) and gains of $1 million (2019 – $1 million losses; 2018 – nil), respectively.

3 Losses related to cash flow hedges reported in AOCI and expected to be reclassified to net income in the next 12 months are estimated to be $37 million ($28 million, net of tax) at December 31, 2020. These estimates assume constant commodity prices, interest rates and foreign exchange rates over time, however, the amounts reclassified will vary based on the actual value of these factors at the date of settlement.

Details about reclassifications out of AOCI into the Consolidated statement of income were as follows:

year ended December 31 (millions of Canadian $)	Amounts Reclassified From AOCI 2020	2019	2018	Affected Line Item in the Consolidated Statement of Income[1]
Cash flow hedges				
Commodities	**(1)**	(7)	(4)	Revenues (Power and Storage)
Interest rate	**(28)**	(12)	(18)	Interest expense
Interest rate	**(613)**	—	—	Net (loss)/gain on assets sold/held for sale[2]
	(642)	(19)	(22)	Total before tax
	160	5	6	Income tax expense
	(482)	(14)	(16)	Net of tax[3]
Pension and other post-retirement benefit plan adjustments				
Amortization of actuarial losses	**(23)**	(14)	(16)	Plant operating costs and other[4]
Settlement charge	**—**	—	(4)	Plant operating costs and other[4]
	(23)	(14)	(20)	Total before tax
	6	4	5	Income tax expense
	(17)	(10)	(15)	Net of tax
Equity investments				
Equity income	**(15)**	(8)	(16)	Income from equity investments
	4	3	4	Income tax expense
	(11)	(5)	(12)	Net of tax[3]
Currency translation adjustments				
Foreign currency translation gains on disposal of foreign operations	**—**	13	—	Net (loss)/gain on assets sold/held for sale
	—	—	—	Income tax expense
	—	13	—	Net of tax

1 Amounts in parentheses indicate expenses to the Consolidated statement of income.

2 Represents a loss of $613 million ($459 million, net of tax) related to a contractually required derivative instrument used to hedge the interest rate risk associated with project-level financing of the Coastal GasLink construction. The derivative instrument was derecognized as part of the sale of a 65 per cent equity interest in Coastal GasLink LP. Refer to Note 27, Acquisitions and dispositions, for additional information.

3 Amounts reclassified from AOCI on cash flow hedges and equity investments are net of non-controlling interest losses of $7 million (2019 – nil; 2018 – $5 million gains) and nil (2019 – nil; 2018 – $2 million gains), respectively.

4 These AOCI components are included in the computation of net benefit cost. Refer to Note 24, Employee post-retirement benefits, for additional information.

24. EMPLOYEE POST-RETIREMENT BENEFITS

The Company sponsors DB Plans for certain of its employees. Pension benefits provided under the DB Plans are generally based on years of service and highest average earnings over three consecutive years of employment. Effective January 1, 2019, there were certain amendments made to the Canadian DB Plan for new members whereby, subsequent to that date, benefits provided for these new members are based on years of service and highest average earnings over five consecutive years of employment. Upon commencement of retirement, pension benefits in the Canadian DB Plan increase annually by a portion of the increase in the Consumer Price Index. The Company's U.S. DB Plan is closed to non-union new entrants and all non-union hires participate in the DC Plan. Net actuarial gains or losses are amortized out of AOCI over the EARSL of plan participants, which is approximately nine years at December 31, 2020 (2019 and 2018 – nine years).

The Company also provides its employees with savings plans in Canada and Mexico, DC Plans consisting of a 401(k) Plan in the U.S. and post-employment benefits other than pensions, including termination benefits and life insurance and medical benefits beyond those provided by government-sponsored plans. Net actuarial gains or losses for the plans are amortized out of AOCI over the EARSL of employees, which was approximately 11 years at December 31, 2020 (2019 – 11 years; 2018 – 12 years). In 2020, the Company expensed $58 million (2019 – $61 million; 2018 – $59 million) for the savings and DC Plans.

Total cash contributions by the Company for employee post-retirement benefits were as follows:

year ended December 31 (millions of Canadian $)	**2020**	**2019**	**2018**
DB Plans	**124**	122	103
Other post-retirement benefit plans	**9**	22	23
Savings and DC Plans	**58**	61	59
	191	205	185

Current Canadian pension legislation allows for partial funding of solvency requirements over a number of years through letters of credit in lieu of cash contributions, up to certain limits. As such, in addition to the cash contributions noted above, the Company provided a $13 million letter of credit to the Canadian DB Plan in 2020 (2019 – $12 million; 2018 – $17 million), resulting in a total of $302 million provided to the Canadian DB Plan under letters of credit at December 31, 2020.

The most recent actuarial valuation of the pension plans for funding purposes was as at January 1, 2020 and the next required valuation will be as at January 1, 2021.

In December 2018, the Company recorded a settlement resulting from lump sum payments made in 2018 to certain terminated non-union vested participants in the Company's U.S. DB Plan related to voluntary cash settlement options available to these participants. The impact of the settlement was determined using assumptions consistent with those employed at December 31, 2017. The settlement reduced the Company's U.S. DB Plan's unrealized actuarial losses by $4 million, which was included in OCI, and resulted in a settlement charge of $4 million which was recorded in net benefit costs in 2018. Effective December 1, 2018, the plan was amended to include this unlimited lump sum payment option for certain union employees who were not previously eligible.

The Company's funded status at December 31 was comprised of the following:

at December 31	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
(millions of Canadian $)	**2020**	**2019**	**2020**	**2019**
Change in Benefit Obligation[1]				
Benefit obligation – beginning of year	**4,058**	3,653	**427**	430
Service cost	**155**	126	**6**	5
Interest cost	**133**	142	**14**	17
Employee contributions	**6**	5	**—**	—
Benefits paid	**(249)**	(213)	**(21)**	(24)
Actuarial loss	**242**	394	**36**	13
Foreign exchange rate changes	**(19)**	(49)	**(5)**	(14)
Benefit obligation – end of year	**4,326**	4,058	**457**	427
Change in Plan Assets				
Plan assets at fair value – beginning of year	**3,693**	3,321	**406**	376
Actual return on plan assets	**485**	505	**56**	52
Employer contributions[2]	**124**	122	**9**	22
Employee contributions	**6**	5	**—**	—
Benefits paid	**(249)**	(212)	**(21)**	(24)
Foreign exchange rate changes	**(21)**	(48)	**(9)**	(20)
Plan assets at fair value – end of year	**4,038**	3,693	**441**	406
Funded Status – Plan Deficit	**(288)**	(365)	**(16)**	(21)

1 The benefit obligation for the Company's pension benefit plans represents the projected benefit obligation. The benefit obligation for the Company's other post-retirement benefit plans represents the accumulated post-retirement benefit obligation.

2 Excludes a $13 million letter of credit provided to the Canadian DB Plan for funding purposes (2019 – $12 million).

The actuarial loss realized on the defined benefit plan obligation is primarily attributable to a decrease in the weighted average discount rate from 3.20 per cent in 2019 to 2.70 per cent in 2020.

The actuarial loss realized on the other post-retirement benefit plan obligation is primarily due to the decrease in the weighted average discount rate from 3.35 per cent in 2019 to 2.75 per cent in 2020.

The amounts recognized on the Company's Consolidated balance sheet for its DB Plans and other post-retirement benefits plans were as follows:

at December 31	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
(millions of Canadian $)	**2020**	**2019**	**2020**	**2019**
Other long-term assets (Note 13)	**29**	—	**178**	162
Accounts payable and other	**—**	—	**(8)**	(8)
Other long-term liabilities (Note 16)	**(317)**	(365)	**(186)**	(175)
	(288)	(365)	**(16)**	(21)

Included in the above benefit obligation and fair value of plan assets were the following amounts for plans that were not fully funded:

at December 31 (millions of Canadian $)	Pension Benefit Plans 2020	Pension Benefit Plans 2019	Other Post-Retirement Benefit Plans 2020	Other Post-Retirement Benefit Plans 2019
Projected benefit obligation[1]	**(3,292)**	(4,058)	**(194)**	(182)
Plan assets at fair value	**2,975**	3,693	**—**	—
Funded Status – Plan Deficit	**(317)**	(365)	**(194)**	(182)

1 The projected benefit obligation for the pension benefit plans differs from the accumulated benefit obligation in that it includes an assumption with respect to future compensation levels.

The funded status based on the accumulated benefit obligation for all DB Plans was as follows:

at December 31 (millions of Canadian $)	2020	2019
Accumulated benefit obligation	**(3,957)**	(3,719)
Plan assets at fair value	**4,038**	3,693
Funded Status – Plan Surplus / (Deficit)	**81**	(26)

Included in the above accumulated benefit obligation and fair value of plan assets are the following amounts in respect of DB Plans that were not fully funded:

at December 31 (millions of Canadian $)	2020[1]	2019
Accumulated benefit obligation	**—**	(2,397)
Plan assets at fair value	**—**	2,351
Funded Status – Plan Deficit	**—**	(46)

1 The Company's DB Plans with respect to the accumulated benefit obligation and fair value of plan assets were fully funded at December 31, 2020.

The Company pension plans' weighted average asset allocations and target allocations by asset category were as follows:

at December 31	Percentage of Plan Assets 2020	Percentage of Plan Assets 2019	Target Allocations 2020
Debt securities	**33%**	32%	**25% to 45%**
Equity securities	**57%**	58%	**35% to 65%**
Alternatives	**10%**	10%	**10% to 20%**
	100%	100%	

Debt and equity securities include the Company's debt and common shares as follows:

at December 31 (millions of Canadian $)	2020	2019	Percentage of Plan Assets 2020	Percentage of Plan Assets 2019
Debt securities	**13**	9	**0.3%**	0.2%
Equity securities	**5**	15	**0.1%**	0.4%

Pension plan assets are managed on a going concern basis, subject to legislative restrictions, and are diversified across asset classes to maximize returns at an acceptable level of risk. Asset mix strategies consider plan demographics and may include traditional equity and debt securities as well as alternative assets such as infrastructure, private equity, real estate and derivatives to diversify risk. Derivatives are not used for speculative purposes and the use of leveraged derivatives is prohibited.

All investments are measured at fair value using market prices. Where the fair value cannot be readily determined by reference to generally available price quotations, the fair value is determined by considering the discounted cash flows on a risk-adjusted basis and by comparison to similar assets which are publicly traded. In Level I, the fair value of assets is determined by reference to quoted prices in active markets for identical assets that the Company has the ability to access at the measurement date. In Level II, the fair value of assets is determined using valuation techniques such as option pricing models and extrapolation using significant inputs which are observable directly or indirectly. In Level III, the fair value of assets is determined using a market approach based on inputs that are unobservable and significant to the overall fair value measurement.

The following table presents plan assets for DB Plans and other post-retirement benefits measured at fair value, which have been categorized into the three categories based on a fair value hierarchy. For additional information on the fair value hierarchy, refer to Note 25, Risk management and financial instruments.

at December 31	Quoted Prices in Active Markets (Level I)		Significant Other Observable Inputs (Level II)		Significant Unobservable Inputs (Level III)		Total		Percentage of Total Portfolio	
(millions of Canadian $)	2020	2019	2020	2019	2020	2019	2020	2019	2020	2019
Asset Category										
Cash and Cash Equivalents	**87**	58	**—**	—	**—**	—	**87**	58	**2**	1
Equity Securities:										
Canadian	**276**	402	**177**	189	**—**	—	**453**	591	**10**	14
U.S.	**594**	523	**211**	156	**—**	—	**805**	679	**18**	17
International	**114**	46	**380**	320	**—**	—	**494**	366	**11**	9
Global	**116**	136	**368**	297	**—**	—	**484**	433	**11**	11
Emerging	**35**	8	**125**	126	**—**	—	**160**	134	**4**	3
Fixed Income Securities:										
Canadian Bonds:										
Federal	**—**	—	**207**	198	**—**	—	**207**	198	**5**	5
Provincial	**—**	—	**283**	246	**—**	—	**283**	246	**6**	6
Municipal	**—**	—	**13**	12	**—**	—	**13**	12	**—**	—
Corporate	**—**	—	**151**	125	**—**	—	**151**	125	**3**	3
U.S. Bonds:										
Federal	**444**	421	**14**	7	**—**	—	**458**	428	**10**	11
Municipal	**—**	—	**2**	1	**—**	—	**2**	1	**—**	—
Corporate	**72**	67	**143**	120	**—**	—	**215**	187	**5**	5
International:										
Government	**8**	7	**6**	4	**—**	—	**14**	11	**—**	—
Corporate	**—**	—	**48**	52	**—**	—	**48**	52	**1**	1
Mortgage backed	**47**	46	**4**	7	**—**	—	**51**	53	**1**	1
Other Investments:										
Real estate	**—**	—	**—**	—	**213**	196	**213**	196	**5**	5
Infrastructure	**—**	—	**—**	—	**203**	181	**203**	181	**5**	4
Private equity funds	**—**	—	**—**	—	**1**	2	**1**	2	**—**	—
Derivatives	**—**	—	**(8)**	—	**—**	—	**(8)**	—	**—**	—
Funds held on deposit	**145**	146	**—**	—	**—**	—	**145**	146	**3**	4
	1,938	1,860	**2,124**	1,860	**417**	379	**4,479**	4,099	**100**	100

The following table presents the net change in the Level III fair value category:

(millions of Canadian $, pre-tax)	
Balance at December 31, 2018	362
Purchases and sales	35
Realized and unrealized losses	(18)
Balance at December 31, 2019	379
Purchases and sales	**42**
Realized and unrealized losses	**(4)**
Balance at December 31, 2020	**417**

The Company's expected funding contributions in 2021 are approximately $128 million for the DB Plans, approximately $6 million for the other post-retirement benefit plans and approximately $59 million for the savings plans and DC Plans. The Company expects to provide an additional estimated $13 million letter of credit to the Canadian DB Plan for the funding of solvency requirements.

The following are estimated future benefit payments, which reflect expected future service:

(millions of Canadian $)	Pension Benefits	Other Post-Retirement Benefits
2021	208	25
2022	210	25
2023	213	25
2024	215	25
2025	217	25
2026 to 2030	1,115	120

The rate used to discount pension and other post-retirement benefit plan obligations was developed based on a yield curve of primarily corporate AA bond yields at December 31, 2020. This yield curve is used to develop spot rates that vary based on the duration of the obligations. The estimated future cash flows for the pension and other post-retirement benefit obligations were matched to the corresponding rates on the spot rate curve to derive a weighted average discount rate.

The significant weighted average actuarial assumptions adopted in measuring the Company's benefit obligations were as follows:

	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
at December 31	**2020**	**2019**	**2020**	**2019**
Discount rate	**2.70%**	3.20%	**2.75%**	3.35%
Rate of compensation increase	**2.60%**	3.00%	**—**	—

The significant weighted average actuarial assumptions adopted in measuring the Company's net benefit plan costs were as follows:

	Pension Benefit Plans			Other Post-Retirement Benefit Plans		
year ended December 31	**2020**	**2019**	**2018**	**2020**	**2019**	**2018**
Discount rate	**3.20%**	3.90%	3.60%	**3.35%**	4.10%	3.70%
Expected long-term rate of return on plan assets	**6.40%**	6.60%	6.70%	**3.50%**	4.30%	4.00%
Rate of compensation increase	**3.00%**	3.00%	3.00%	**—**	—	—

The overall expected long-term rate of return on plan assets is based on historical and projected rates of return for the portfolio in aggregate and for each asset class in the portfolio. Assumed projected rates of return are selected after analyzing historical experience and estimating future levels and volatility of returns. Asset class benchmark returns, asset mix and anticipated benefit payments from plan assets are also considered in determining the overall expected rate of return. The discount rate is based on market interest rates of high-quality bonds that match the timing and benefits expected to be paid under each plan.

A 6.30 per cent weighted-average annual rate of increase in the per capita cost of covered health care benefits was assumed for 2021 measurement purposes. The rate was assumed to decrease gradually to 4.80 per cent by 2028 and remain at this level thereafter.

The net benefit cost recognized for the Company's pension benefit plans and other post-retirement benefit plans was as follows:

at December 31	Pension Benefit Plans			Other Post-Retirement Benefit Plans		
(millions of Canadian $)	**2020**	**2019**	**2018**	**2020**	**2019**	**2018**
Service cost[1]	**155**	126	121	**6**	5	4
Other components of net benefit cost[1]						
Interest cost	**133**	142	134	**14**	17	14
Expected return on plan assets	**(230)**	(222)	(221)	**(14)**	(15)	(16)
Amortization of actuarial loss	**21**	12	15	**2**	2	1
Amortization of regulatory asset	**25**	14	18	**2**	2	—
Settlement charge – AOCI	**—**	—	4	**—**	—	—
	(51)	(54)	(50)	**4**	6	(1)
Net Benefit Cost Recognized	**104**	72	71	**10**	11	3

1 Service cost and other components of net benefit cost are included in Plant operating costs and other in the Consolidated statement of income.

Pre-tax amounts recognized in AOCI were as follows:

at December 31	2020		2019		2018	
(millions of Canadian $)	**Pension Benefits**	**Other Post-Retirement Benefits**	**Pension Benefits**	**Other Post-Retirement Benefits**	**Pension Benefits**	**Other Post-Retirement Benefits**
Net loss	**358**	**22**	398	20	364	53

Pre-tax amounts recognized in OCI were as follows:

at December 31	2020		2019		2018	
(millions of Canadian $)	**Pension Benefits**	**Other Post-Retirement Benefits**	**Pension Benefits**	**Other Post-Retirement Benefits**	**Pension Benefits**	**Other Post-Retirement Benefits**
Amortization of net loss from AOCI to net income	**(21)**	**(2)**	(12)	(2)	(15)	(1)
Settlement	**—**	**—**	—	—	(4)	—
Funded status adjustment	**(18)**	**3**	52	(37)	110	43
	(39)	**1**	40	(39)	91	42

25. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

Risk Management Overview

TC Energy has exposure to market risk and counterparty credit risk, and has strategies, policies and limits in place to manage the impact of these risks on earnings, cash flows and, ultimately, shareholder value.

Risk management strategies, policies and limits are designed to ensure TC Energy's risks and related exposures are in line with the Company's business objectives and risk tolerance. Market risk and counterparty credit risk are managed within limits that are established by the Company's Board of Directors, implemented by senior management and monitored by the Company's risk management and internal audit groups. The 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

The Company constructs and invests in energy infrastructure projects, purchases and sells commodities, issues short-term and long-term debt, including amounts in foreign currencies, and invests in foreign operations. Certain of these activities expose the Company to market risk from changes in commodity prices, foreign exchange rates and interest rates, which may affect the Company's earnings and the value of its financial assets and liabilities. The Company assesses contracts used to manage market risk to determine whether all, or a portion, meets the definition of a derivative.

Derivative contracts the Company uses 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 the Company's non-regulated businesses:

- in the Company's natural gas marketing business, TC Energy enters into natural gas transportation and storage contracts as well as natural gas purchase and sale agreements. The Company manages exposure on these contracts using financial instruments and hedging activities to offset market price volatility
- in the Company's liquids marketing business, TC Energy enters into pipeline and storage terminal capacity contracts as well as crude oil purchase and sale agreements. The Company fixes a portion of the exposure on these contracts by entering into financial instruments to manage variable price fluctuations that arise from physical liquids transactions
- in the Company's power generation business, TC Energy manages the exposure to fluctuating commodity prices through long-term contracts and hedging activities including selling and purchasing power and natural gas in forward markets
- in the Company's non-regulated natural gas storage business, TC Energy's 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.

In May 2019, TC Energy sold its remaining U.S. Power marketing contracts completing the divestiture of its U.S. Northeast power business which began in 2017, greatly reducing its exposure to electricity price risk.

Interest rate risk

TC Energy utilizes short-term and long-term debt to finance its operations which exposes the Company to interest rate risk. TC Energy typically pays fixed rates of interest on its long-term debt and floating rates on its commercial paper programs and amounts drawn on its credit facilities. A small portion of TC Energy's long-term debt bears interest at floating rates. In addition, the Company is exposed to interest rate risk on financial instruments and contractual obligations containing variable interest rate components. The Company actively manages its interest rate risk using interest rate derivatives.

Many of TC Energy's 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. The Company continues to monitor developments and is preparing to address any necessary system and contractual changes while assessing the adoption of the standard market proposed reference rates.

Foreign exchange risk

TC Energy generates revenues and incurs expenses and capital expenditures that are denominated in currencies other than Canadian dollars. As a result, the Company's earnings and cash flows are exposed to currency fluctuations.

A significant portion of TC Energy's businesses generate earnings in U.S. dollars, but since the Company reports its financial results in Canadian dollars, changes in the value of the U.S. dollar against the Canadian dollar can affect its net income. As the Company's 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.

A small portion of the Company's 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 the Company's net income. This exposure is managed using foreign exchange derivatives.

Net investment hedges

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

The fair values and notional amounts for the derivatives designated as a net investment hedge were as follows:

at December 31 (millions of Canadian $, unless otherwise noted)	2020 Fair Value[1,2]	 Notional Amount	2019 Fair Value[1,2]	 Notional Amount
U.S. dollar foreign exchange options (maturing 2021)	**45**	**US 2,200**	10	US 3,000
U.S. dollar cross-currency interest rate swaps (maturing 2022 to 2025)[3]	**23**	**US 400**	3	US 100
	68	**US 2,600**	13	US 3,100

1 Fair value equals carrying value.
2 No amounts have been excluded from the assessment of hedge effectiveness.
3 In 2020, Net income includes net realized gains of $1 million (2019 – nil) related to the interest component of cross-currency swap settlements which are reported within Interest expense.

The notional amounts and fair value of U.S. dollar-denominated debt designated as a net investment hedge were as follows:

at December 31 (millions of Canadian $, unless otherwise noted)	2020	2019
Notional amount	**27,700 (US 21,800)**	29,300 (US 22,600)
Fair value	**33,800 (US 26,500)**	33,400 (US 25,700)

Counterparty Credit Risk

TC Energy's exposure to counterparty credit risk consists of its cash and cash equivalents, accounts receivable, available-for-sale assets, the fair value of derivative assets and 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 TC Energy's customers. While the majority of the Company's credit exposure is to large creditworthy entities, TC Energy has increased its monitoring of and communication with those counterparties experiencing greater financial pressures due to recent market events.

At times, the Company's 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 TC Energy's 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 TC Energy operations
- competitive position of the Company's assets and the demand for the Company's services, and
- potential recovery of unpaid amounts through bankruptcy and similar proceedings.

The Company reviews 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. TC Energy uses historical credit loss and recovery data, adjusted for management's 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, there were no significant credit losses, no significant credit risk concentrations and no significant amounts past due or impaired.

TC Energy has 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 the Company's exposure to counterparties and provide liquidity in commodity, foreign exchange and interest rate derivative markets.

Fair Value of Non-Derivative Financial Instruments

Available-for-sale assets are recorded at fair value which is calculated using quoted market prices where available. Certain non-derivative financial instruments included in Cash and cash equivalents, Accounts receivable, Other current assets, Loan receivable from affiliate, Restricted investments, Other long-term assets, Notes payable, Accounts payable and other, Redeemable non-controlling interest, Dividends payable, Accrued interest and Other long-term liabilities have carrying amounts that approximate their fair value due to the nature of the item or the short time to maturity. Each of these instruments are classified in Level II of the fair value hierarchy, except for the Company's LMCI equity securities which are classified in Level I.

Credit risk has been taken into consideration when calculating the fair value of non-derivative financial instruments.

Balance Sheet Presentation of Non-Derivative Financial Instruments

The following table details the fair value of non-derivative financial instruments, excluding those where carrying amounts approximate fair value, and would be classified in Level II of the fair value hierarchy:

at December 31 (millions of Canadian $)	**2020**		**2019**	
	Carrying Amount	**Fair Value**	**Carrying Amount**	**Fair Value**
Long-term debt, including current portion[1,2] (Note 18)	**(36,885)**	**(46,054)**	(36,985)	(43,187)
Junior subordinated notes (Note 19)	**(8,498)**	**(8,908)**	(8,614)	(8,777)
	(45,383)	**(54,962)**	(45,599)	(51,964)

1 Long-term debt is recorded at amortized cost, except for US$200 million at December 31, 2019 that was attributed to hedged risk and recorded at fair value.

2 Net income in 2020 included unrealized losses of nil (2019 – losses of $3 million) for fair value adjustments attributable to the hedged interest rate risk associated with interest rate swap fair value hedging relationships on US$200 million of long-term debt that matured in March 2020 (2019 – US$200 million). There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

Available-for-Sale Assets Summary

The following tables summarize additional information about the Company's restricted investments that were classified as available-for-sale assets:

at December 31 (millions of Canadian $)	2020		2019	
	LMCI Restricted Investments	Other Restricted Investments[1]	LMCI Restricted Investments	Other Restricted Investments[1]
Fair value of fixed income securities[2,3]				
Maturing within 1 year	**—**	**17**	—	6
Maturing within 1-5 years	**—**	**66**	26	100
Maturing within 5-10 years	**985**	**—**	801	—
Maturing after 10 years	**85**	**—**	61	—
Fair value of equity securities[2,4]	**736**	**—**	556	—
	1,806	**83**	1,444	106

1 Other restricted investments have been set aside to fund insurance claim losses to be paid by the Company's wholly-owned captive insurance subsidiary.
2 Available-for-sale assets are recorded at fair value and included in Other current assets and Restricted investments on the Company's Consolidated balance sheet.
3 Classified in Level II of the fair value hierarchy.
4 Classified in Level I of the fair value hierarchy.

year ended December 31 (millions of Canadian $)	2020		2019		2018	
	LMCI restricted investments[1]	Other restricted investments[2]	LMCI restricted investments[1]	Other restricted investments[2]	LMCI restricted investments[1]	Other restricted investments[2]
Net unrealized gains	**130**	**1**	32	3	11	—
Net realized gains / (losses)[3]	**20**	**1**	60	—	(4)	—

1 Gains and losses arising from changes in the fair value of LMCI restricted investments impact the subsequent amounts to be collected through tolls to cover future pipeline abandonment costs. As a result, the Company records these gains and losses as regulatory assets or liabilities.
2 Gains and losses on other restricted investments are included in Interest income and other in the Company's Consolidated statement of income.
3 Realized gains and losses on the sale of LMCI restricted investments are determined using the average cost basis.

Fair Value of Derivative Instruments

The fair value of foreign exchange and interest rate derivatives has been calculated using the income approach which uses year-end market rates and applies a discounted cash flow valuation model. The fair value of commodity derivatives has been calculated using quoted market prices where available. In the absence of quoted market prices, third-party broker quotes or other valuation techniques have been used. The fair value of options has been calculated using the Black-Scholes pricing model. Credit risk has been taken into consideration when calculating the fair value of derivative instruments. Unrealized gains and losses on derivative instruments are not necessarily representative of the amounts that will be realized on settlement.

In some cases, even though the derivatives are considered to be effective economic hedges, they do not meet the specific criteria for hedge accounting treatment or are not designated as a hedge and are accounted for at fair value with changes in fair value recorded in net income in the period of change. This may expose the Company to increased variability in reported earnings because the fair value of the 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 the Company. 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 classification of the fair value of derivative instruments as at December 31, 2020 was as follows:

at December 31, 2020 (millions of Canadian $)	**Cash Flow Hedges**	**Net Investment Hedges**	**Held for Trading**	**Total Fair Value of Derivative Instruments**[1]
Other current assets (Note 6)				
Commodities[2]	—	—	13	13
Foreign exchange	—	47	175	222
	—	47	188	235
Other long-term assets (Note 13)				
Foreign exchange	—	22	19	41
	—	22	19	41
Total Derivative Assets	—	69	207	276
Accounts payable and other (Note 15)				
Commodities[2]	(8)	—	(32)	(40)
Foreign exchange	—	(1)	(10)	(11)
Interest rate[3]	(21)	—	—	(21)
	(29)	(1)	(42)	(72)
Other long-term liabilities (Note 16)				
Commodities[2]	(6)	—	(4)	(10)
Interest rate[3]	(49)	—	—	(49)
	(55)	—	(4)	(59)
Total Derivative Liabilities	(84)	(1)	(46)	(131)
Total Derivatives	(84)	68	161	145

1 Fair value equals carrying value.

2 Includes purchases and sales of power, natural gas and liquids.

3 For the year ended December 31, 2020, a $130 million payment to settle a loss on financial instruments was included in Net cash (used in)/provided by financing activities in the Consolidated statement of cash flows.

The balance sheet classification of the fair value of derivative instruments as at December 31, 2019 was as follows:

at December 31, 2019 (millions of Canadian $)	**Cash Flow Hedges**	**Fair Value Hedges**	**Net Investment Hedges**	**Held for Trading**	**Total Fair Value of Derivative Instruments**[1]
Other current assets (Note 6)					
Commodities[2]	—	—	—	118	118
Foreign exchange	—	—	10	61	71
Interest rate	—	1	—	—	1
	—	1	10	179	190
Other long-term assets (Note 13)					
Foreign exchange	—	—	5	—	5
Interest rate	2	—	—	—	2
	2	—	5	—	7
Total Derivative Assets	2	1	15	179	197
Accounts payable and other (Note 15)					
Commodities[2]	(4)	—	—	(104)	(108)
Foreign exchange	—	—	(1)	(3)	(4)
Interest rate	(3)	—	—	—	(3)
	(7)	—	(1)	(107)	(115)
Other long-term liabilities (Note 16)					
Commodities[2]	(6)	—	—	(11)	(17)
Foreign exchange	—	—	(1)	—	(1)
Interest rate	(63)	—	—	—	(63)
	(69)	—	(1)	(11)	(81)
Total Derivative Liabilities	(76)	—	(2)	(118)	(196)
Total Derivatives	(74)	1	13	61	1

1 Fair value equals carrying value.
2 Includes purchases and sales of power, natural gas and liquids.

The majority of derivative instruments held for trading have been entered into for risk management purposes and all are subject to the Company's risk management strategies, policies and limits. These include derivatives that have not been designated as hedges or do not qualify for hedge accounting treatment but have been entered into as economic hedges to manage the Company's exposures to market risk.

Derivatives in fair value hedging relationships

The following table details amounts recorded on the Consolidated balance sheet in relation to cumulative adjustments for fair value hedges included in the carrying amount of the hedged liabilities:

at December 31	**Carrying amount**		**Fair value hedging adjustments**[1]	
(millions of Canadian $)	**2020**	**2019**	**2020**	**2019**
Long-term debt	—	(260)	—	(1)

1 At December 31, 2020 and 2019, adjustments for discontinued hedging relationships included in these balances were nil.

Notional and Maturity Summary

The maturity and notional amount or quantity outstanding related to the Company's derivative instruments excluding hedges of the net investment in foreign operations was as follows:

at December 31, 2020	Power	Natural Gas	Liquids	Foreign Exchange	Interest Rate
Purchases[1]	**185**	**13**	**26**	**—**	**—**
Sales[1]	**1,786**	**14**	**30**	**—**	**—**
Millions of U.S. dollars	**—**	**—**	**—**	**4,432**	**1,100**
Millions of Mexican pesos	**—**	**—**	**—**	**1,700**	**—**
Maturity dates	**2021-2025**	**2021-2027**	**2021**	**2021-2022**	**2022-2026**

1 Volumes for power, natural gas and liquids derivatives are in GWh, Bcf and MMBbls, respectively.

at December 31, 2019	Power	Natural Gas	Liquids	Foreign Exchange	Interest Rate
Purchases[1]	492	14	39	—	—
Sales[1]	2,089	22	53	—	—
Millions of U.S. dollars	—	—	—	3,153	1,600
Millions of Mexican pesos	—	—	—	800	—
Maturity dates	2020-2024	2020-2027	2020	2020	2020-2030

1 Volumes for power, natural gas and liquids derivatives are in GWh, Bcf and MMBbls, respectively.

Unrealized and Realized (Losses) / Gains on Derivative Instruments

The following summary does not include hedges of the net investment in foreign operations:

year ended December 31 (millions of Canadian $)	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 foreign exchange held-for-trading derivative instruments are included on a net basis in Interest income and other.

2 In 2020, 2019 and 2018, 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.

Derivatives in cash flow hedging relationships

The components of OCI (Note 23) related to the change in fair value of derivatives in cash flow hedging relationships before tax and including the portion attributable to non-controlling interests were as follows:

year ended December 31 (millions of Canadian $, pre-tax)	2020	2019	2018
Change in fair value of derivative instruments recognized in OCI[1]			
Commodities	**(5)**	(15)	(1)
Interest rate	**(766)**	(63)	(13)
	(771)	(78)	(14)

1 No amounts have been excluded from the assessment of hedge effectiveness. Amounts in parentheses indicate losses recorded to OCI and AOCI.

Effect of fair value and cash flow hedging relationships

The following table details amounts presented in the Consolidated statement of income in which the effects of fair value or cash flow hedging relationships were recorded:

year ended December 31 (millions of Canadian $)	2020	2019	2018
Fair Value Hedges			
Interest rate contracts[1]			
Hedged items	**(3)**	(19)	(71)
Derivatives designated as hedging instruments	**1**	1	(4)
Cash Flow Hedges			
Reclassification of losses on derivative instruments from AOCI to net income[2,3]			
Interest rate contracts[1]	**(648)**	(12)	(22)
Commodity contracts[4]	**(1)**	(7)	(5)

1 Presented within Interest expense in the Consolidated statement of income, except for a loss of $613 million related to a contractually required derivative instrument used to hedge the interest rate risk associated with project-level financing for the Coastal GasLink construction. This derivative instrument was derecognized as part of the sale of a 65 per cent equity interest in Coastal GasLink LP. The loss is included in Net (loss)/ gain on assets sold/held for sale. Refer to Note 27, Acquisitions and dispositions, for additional information.

2 Refer to Note 23, Other comprehensive (loss)/ income and accumulated other comprehensive loss, for the components of OCI related to derivatives in cash flow hedging relationships including the portion attributable to non-controlling interests.

3 There are no amounts recognized in earnings that were excluded from effectiveness testing.

4 Presented within Revenues (Power and Storage) in the Consolidated statement of income.

Offsetting of derivative instruments

The Company enters into derivative contracts with the right to offset in the normal course of business as well as in the event of default. TC Energy has no master netting agreements, however, similar contracts are entered into containing rights to offset. The Company has elected to present the fair value of derivative instruments with the right to offset on a gross basis on the Consolidated balance sheet. The following tables show the impact on the presentation of the fair value of derivative instrument assets and liabilities had the Company elected to present these contracts on a net basis:

at December 31, 2020 (millions of Canadian $)	Gross Derivative Instruments	Amounts Available for Offset[1]	Net Amounts
Derivative instrument assets			
Commodities	**13**	**(7)**	**6**
Foreign exchange	**263**	**(11)**	**252**
	276	**(18)**	**258**
Derivative instrument liabilities			
Commodities	**(50)**	**7**	**(43)**
Foreign exchange	**(11)**	**11**	**—**
Interest rate	**(70)**	**—**	**(70)**
	(131)	**18**	**(113)**

1 Amounts available for offset do not include cash collateral pledged or received.

at December 31, 2019 (millions of Canadian $)	Gross Derivative Instruments	Amounts Available for Offset[1]	Net Amounts
Derivative instrument assets			
Commodities	118	(76)	42
Foreign exchange	76	(5)	71
Interest rate	3	(1)	2
	197	(82)	115
Derivative instrument liabilities			
Commodities	(125)	76	(49)
Foreign exchange	(5)	5	—
Interest rate	(66)	1	(65)
	(196)	82	(114)

1 Amounts available for offset do not include cash collateral pledged or received.

With respect to the derivative instruments presented above, the Company provided cash collateral of $54 million and letters of credit of $15 million at December 31, 2020 (2019 – $58 million and $25 million, respectively) to its counterparties. At December 31, 2020, the Company held no cash collateral and no letters of credit (2019 – nil and nil, respectively) from counterparties on asset exposures.

Credit-risk-related contingent features of derivative instruments

Derivative contracts entered into to manage market risk often contain financial assurance provisions that allow parties to the contracts to manage credit risk. These provisions may require collateral to be provided if a credit-risk-related contingent event occurs, such as a downgrade in the Company's credit rating to non-investment grade. The Company may also need to provide collateral if the fair value of its derivative financial instruments exceeds pre-defined exposure limits.

Based on contracts in place and market prices at December 31, 2020, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $4 million (2019 – $4 million), for which the Company has provided no collateral in the normal course of business. If the credit-risk-related contingent features in these agreements were triggered on December 31, 2020, the Company would have been required to provide collateral equal to the fair value of the related derivative instruments discussed above. Collateral may also need to be provided should the fair value of derivative instruments exceed pre-defined contractual exposure limit thresholds.

The Company has sufficient liquidity in the form of cash and undrawn committed revolving credit facilities to meet these contingent obligations should they arise.

Fair Value Hierarchy

The Company's financial assets and liabilities recorded at fair value have been categorized into three categories based on a fair value hierarchy.

Levels	How fair value has been determined
Level I	Quoted prices in active markets for identical assets and liabilities that the Company has the ability to access at the measurement date. An active market is a market in which frequency and volume of transactions provides pricing information on an ongoing basis.
Level II	This category includes interest rate and foreign exchange derivative assets and liabilities where fair value is determined using the income approach and commodity derivatives where fair value is determined using the market approach. Inputs include published exchange rates, interest rates, interest rate swap curves, yield curves and broker quotes from external data service providers.
Level III	This category mainly includes long-dated commodity transactions in certain markets where liquidity is low and the Company uses the most observable inputs available or, if not available, long-term broker quotes to estimate the fair value for these transactions. There is uncertainty caused by using unobservable market data which may not accurately reflect possible future changes in fair value.

The fair value of the Company's derivative assets and liabilities measured on a recurring basis, including both current and non-current portions, were categorized as follows:

at December 31, 2020 (millions of Canadian $)	**Quoted Prices in Active Markets (Level I)**	**Significant Other Observable Inputs (Level II)**[1]	**Significant Unobservable Inputs (Level III)**[1]	**Total**
Derivative instrument assets				
Commodities	**3**	**10**	**—**	**13**
Foreign exchange	**—**	**263**	**—**	**263**
Derivative instrument liabilities				
Commodities	**(15)**	**(31)**	**(4)**	**(50)**
Foreign exchange	**—**	**(11)**	**—**	**(11)**
Interest rate	**—**	**(70)**	**—**	**(70)**
	(12)	**161**	**(4)**	**145**

1 There were no transfers from Level II to Level III for the year ended December 31, 2020.

at December 31, 2019 (millions of Canadian $)	Quoted Prices in Active Markets (Level I)	Significant Other Observable Inputs (Level II)[1]	Significant Unobservable Inputs (Level III)[1]	Total
Derivative instrument assets				
Commodities	81	37	—	118
Foreign exchange	—	76	—	76
Interest rate	—	3	—	3
Derivative instrument liabilities				
Commodities	(77)	(41)	(7)	(125)
Foreign exchange	—	(5)	—	(5)
Interest rate	—	(66)	—	(66)
	4	4	(7)	1

1 There were no transfers from Level II to Level III for the year ended December 31, 2019.

The following table presents the net change in fair value of derivative assets and liabilities classified in Level III of the fair value hierarchy:

(millions of Canadian $, pre-tax)	2020	2019
Balance at beginning of year	**(7)**	(4)
Transfers out of Level III	**—**	4
Total gains / (losses) included in Net income	**3**	(3)
Total losses included in OCI	**—**	(4)
Balance at end of year[1]	**(4)**	(7)

1 Revenues include unrealized gains of $3 million attributed to derivatives in the Level III category that were still held at December 31, 2020 (2019 – unrealized losses of $3 million).

26. CHANGES IN OPERATING WORKING CAPITAL

year ended December 31 (millions of Canadian $)	2020	2019	2018
Decrease / (increase) in Accounts receivable	**129**	31	(69)
Increase in Inventories	**(55)**	(42)	(49)
(Increase) / decrease in Other current assets	**(221)**	(15)	45
(Decrease) / increase in Accounts payable and other	**(162)**	352	(70)
(Decrease) / increase in Accrued interest	**(18)**	(33)	41
(Increase) / Decrease in Operating Working Capital	**(327)**	293	(102)

27. ACQUISITIONS AND DISPOSITIONS

Canadian Natural Gas Pipelines

Coastal GasLink LP

On May 22, 2020, TC Energy completed the sale of a 65 per cent equity interest in Coastal GasLink LP to third parties for net proceeds of $656 million before post-closing adjustments resulting in a pre-tax gain of $364 million ($402 million after tax). The pre-tax gain includes $231 million related to the required remeasurement of the Company's retained 35 per cent equity interest to fair value which was based on the proceeds realized for the 65 per cent equity interest, and also incorporates the reclassification from AOCI to income of the fair value of a derivative instrument used to hedge the interest rate risk associated with project-level financing for the Coastal GasLink construction. The $402 million after-tax gain also reflects the utilization of previously unrecognized tax loss benefits. The pre-tax gain is included in Net (loss)/ gain on assets sold/held for sale in the Consolidated statement of income. As part of this transaction, TC Energy has been contracted by Coastal GasLink LP to construct and operate the pipeline. TC Energy uses the equity method to account for its remaining 35 per cent equity interest in the Company's consolidated financial statements.

In conjunction with the equity sale, Coastal GasLink LP entered into secured long-term project financing credit facilities with a current total capacity of $6.8 billion to 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.

Along with this sale, TC Energy has provided an opportunity to the 20 First Nations that have executed agreements with Coastal GasLink LP to invest in the project through an option to acquire a 10 per cent equity interest.

U.S. Natural Gas Pipelines

Columbia Midstream Assets

In August 2019, TC Energy completed the sale of certain Columbia Midstream assets to a third party for approximately US$1.3 billion before post-closing adjustments.

The Company recorded a pre-tax gain on sale of $21 million ($152 million after-tax loss) including the impact of $4 million of foreign currency translation gains that were reclassified from AOCI to net income and the release of $595 million of Columbia goodwill allocated to these assets that is not deductible for income tax purposes. The pre-tax gain is included in Net (loss)/ gain on assets sold/held for sale in the Consolidated statement of income. This sale did not include any interest in Columbia Energy Ventures Company, the Company's minerals business in the Appalachian basin.

In 2020, upon finalizing its 2019 annual tax returns for its U.S. operations, the Company recorded an $18 million income tax recovery related to the sale.

Columbia Pipeline Group, Inc.

At the time of the July 2016 acquisition of Columbia, certain Columbia shareholders dissented from the transaction and did not tender their shares. In October 2019, TC Energy made a payment to the dissenting Columbia shareholders in the amount of $373 million (US$284 million), representing the appraised value of their shares pursuant to a court decision, which affirmed the original Columbia share purchase price of US$25.50 per share plus accrued interest.

Liquids Pipelines

Northern Courier

In July 2019, TC Energy completed the sale of an 85 per cent equity interest in Northern Courier pipeline to a third party for gross proceeds of $144 million before post-closing adjustments resulting in a pre-tax gain of $69 million after recording the Company's remaining 15 per cent interest at fair value. The pre-tax gain is included in Net (loss)/ gain on assets sold/held for sale in the Consolidated statement of income. On an after-tax basis, the gain of $115 million reflects the utilization of previously unrecognized tax loss benefits. Preceding the equity sale, Northern Courier pipeline issued $1.0 billion of long-term, non-recourse debt with all proceeds paid to TC Energy.

TC Energy remains the operator of the Northern Courier pipeline and uses the equity method to account for its remaining 15 per cent interest in the Company's consolidated financial statements.

Power and Storage

TransCanada Turbines Ltd.

On November 13, 2020, TC Energy acquired the remaining 50 per cent ownership interest in TransCanada Turbines Ltd. (TC Turbines) for cash consideration of US$67 million. TC Turbines provides industrial gas turbine maintenance, parts, repair and overhaul services. The acquisition was accounted for as a business combination and the evaluation of assigned fair value of acquired assets and liabilities did not result in recognition of goodwill. TC Energy previously accounted for its 50 per cent interest in TC Turbines as an equity investment but commenced full consolidation of TC Turbines as of the date of acquisition, which did not have a material impact on Revenues and Net income of the Company. In addition, the pro forma incremental impact on the Company's Revenues and Net income for each of the periods presented was not material.

Ontario natural gas-fired power plants

On April 29, 2020, the Company completed the sale of the Halton Hills and Napanee power plants as well as its 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 on the sale 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 and the after-tax loss also reflects utilization of previously unrecognized tax loss benefits. The pre-tax loss is included in Net (loss)/ gain on assets sold/held for sale in the Consolidated statement of income. This loss may be amended in the future upon the settlement of existing insurance claims.

Coolidge Generating Station

In December 2018, the Company entered into an agreement to sell its Coolidge generating station in Arizona to SWG Coolidge Holdings, LLC (SWG). Salt River Project Agriculture Improvement and Power District (SRP), the PPA counterparty, subsequently exercised its contractual right of first refusal (ROFR) on a sale to a third party and the Company terminated the agreement with SWG.

In May 2019, the Company completed the sale to SRP, as per the terms of their ROFR, for proceeds of US$448 million before post-closing adjustments. As a result, the Company recorded a pre-tax gain on sale of $68 million ($54 million after tax) including the impact of $9 million of foreign currency translation gains which were reclassified from AOCI to net income. The pre-tax gain is included in Net (loss)/ gain on assets sold/held for sale in the Consolidated statement of income.

Cartier Wind

In October 2018, the Company completed the sale of its 62 per cent interest in the Cartier Wind power facilities to Innergex Renewable Energy Inc. for proceeds of $630 million before post-closing adjustments. As a result, the Company recorded a gain on sale of $170 million ($143 million after tax) which is included in Net (loss)/ gain on assets sold/held for sale in the Consolidated statement of income.

28. COMMITMENTS, CONTINGENCIES AND GUARANTEES

Commitments

TC Energy and its affiliates have long-term natural gas transportation and natural gas purchase arrangements as well as other purchase obligations, all of which are transacted at market prices and in the normal course of business. Purchases under these contracts in 2020 were $224 million (2019 – $236 million; 2018 – $207 million).

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. At December 31, 2020, TC Energy had the following capital expenditure commitments:

- approximately $0.9 billion for its Canadian natural gas pipelines, primarily related to construction costs associated with NGTL System expansion projects
- approximately $0.3 billion for its U.S. natural gas pipelines, primarily related to construction costs associated with ANR and Columbia Gulf pipeline projects
- approximately $0.2 billion for its Mexico natural gas pipelines, primarily related to construction of the Tula and Villa de Reyes pipeline projects
- approximately $0.9 billion for its Liquids pipelines, primarily related to the construction of Keystone XL
- approximately $0.3 billion for its Power and Storage business, primarily related to the Company's proportionate share of commitments for Bruce Power's life extension program.

Acquisition of common units of TC PipeLines, LP

On December 14, 2020, the Company 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 its 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 an equivalent of approximately 38 million TC Energy common shares for all publicly-held common units of TC PipeLines, LP. 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.

If the transaction closes, the expected changes in the Company's ownership interest in TC PipeLines, LP will be accounted for as an equity transaction as the Company will continue to control TC PipeLines, LP and no gain or loss will be recognized in the Consolidated statement of income resulting from the transaction.

Contingencies

TC Energy is subject to laws and regulations governing environmental quality and pollution control. As at December 31, 2020, the Company had accrued approximately $24 million (2019 – $30 million) related to operating facilities, which represents the present value of the estimated future amount it expects to spend to remediate the sites. However, additional liabilities may be incurred as assessments take place and remediation efforts continue.

TC Energy and its subsidiaries are subject to various legal proceedings, arbitrations and actions arising in the normal course of business. The amounts involved in such proceedings are not reasonably estimable as the final outcome of such legal proceedings cannot be predicted with certainty. It is the opinion of management that the ultimate resolution of such proceedings and actions will not have a material impact on the Company's consolidated financial position or results of operations.

Guarantees

As part of its role as operator of the Northern Courier pipeline, TC Energy has guaranteed the financial performance of the pipeline related to delivery and terminalling of bitumen and diluent and contingent financial obligations under sub-lease agreements.

TC Energy and its 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.

TC Energy and its 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 and contractor and supplier services.

The Company and its partners in certain other jointly-owned entities have either (i) jointly and severally, (ii) jointly or (iii) severally guaranteed the financial performance of these entities. Such agreements include guarantees and letters of credit which are primarily related to construction services and the payment of liabilities. For certain of these entities, any payments made by TC Energy under these guarantees in excess of its ownership interest are to be reimbursed by its partners.

The carrying value of these guarantees has been recorded in Accounts payable and other and Other long-term liabilities on the Consolidated balance sheet. Information regarding the Company's guarantees were as follows:

		2020		2019	
at December 31 (millions of Canadian $)	**Term**	**Potential Exposure**[1]	**Carrying Value**	**Potential Exposure**[1]	**Carrying Value**
Northern Courier pipeline	to 2055	**300**	**26**	300	27
Sur de Texas	to 2021	**100**	**—**	109	—
Bruce Power	to 2023	**88**	**—**	88	—
Other jointly-owned entities	to 2043	**78**	**4**	100	10
		566	**30**	597	37

1 TC Energy's share of the potential estimated current or contingent exposure.

29. VARIABLE INTEREST ENTITIES

A VIE is a legal entity that does not have sufficient equity at risk to finance its activities without additional subordinated financial support or is structured such that equity investors lack the ability to make significant decisions relating to the entity's operations through voting rights or do not substantively participate in the gains and losses of the entity.

In the normal course of business, the Company consolidates VIEs in which it has a variable interest and for which it is considered to be the primary beneficiary. VIEs in which the Company has a variable interest but is not the primary beneficiary are considered non-consolidated VIEs and are accounted for as equity investments.

Consolidated VIEs

The Company's consolidated VIEs consist of legal entities where the Company is the primary beneficiary. As the primary beneficiary, the Company has the power, through voting or similar rights, to direct the activities of the VIE that most significantly impact economic performance including purchasing or selling significant assets; maintenance and operations of assets; incurring additional indebtedness; or determining the strategic operating direction of the entity. In addition, the Company has the obligation to absorb losses or the right to receive benefits from the consolidated VIE that could potentially be significant to the VIE.

A significant portion of the Company's assets are held through VIEs in which the Company holds a 100 per cent voting interest, the VIE meets the definition of a business and the VIE's assets can be used for general corporate purposes. The consolidated VIEs whose assets cannot be used for purposes other than for the settlement of the VIE's obligations, or are not considered a business, were as follows:

at December 31 (millions of Canadian $)	2020	2019
ASSETS		
Current Assets		
Cash and cash equivalents	**254**	106
Accounts receivable	**61**	88
Inventories	**26**	27
Other	**11**	8
	352	229
Plant, Property and Equipment	**3,325**	3,050
Equity Investments	**714**	785
Goodwill	**424**	431
Other Long-Term Assets	**8**	—
	4,823	4,495
LIABILITIES		
Current Liabilities		
Accounts payable and other	**109**	70
Redeemable non-controlling interest	**633**	—
Accrued interest	**21**	21
Current portion of long-term debt	**579**	187
	1,342	278
Regulatory Liabilities	**60**	45
Other Long-Term Liabilities	**11**	9
Deferred Income Tax Liabilities	**12**	9
Long-Term Debt	**2,468**	2,694
	3,893	3,035

Certain consolidated VIEs have a redeemable non-controlling interest that ranks above the Company's equity interest. Refer to Note 20, Redeemable non-controlling interest and non-controlling interests and Note 30, Subsequent events, for additional information.

Non-Consolidated VIEs

The Company's non-consolidated VIEs consist of legal entities where the Company is not the primary beneficiary as it does not have the power to direct the activities that most significantly impact the economic performance of these VIEs or where this power is shared with third parties. The Company contributes capital to these VIEs and receives ownership interests that provide it with residual claims on assets after liabilities are paid.

The carrying value of these VIEs and the maximum exposure to loss as a result of the Company's involvement with these VIEs were as follows:

at December 31 (millions of Canadian $)	**2020**	**2019**
Balance sheet		
Equity investments		
Bruce Power	**3,306**	3,256
Pipeline equity investments and other[1]	**1,371**	1,464
Off-balance sheet[2]		
Bruce Power	**1,183**	1,521
Pipeline equity investments	**1,506**	425
Maximum exposure to loss	**7,366**	6,666

1 Includes equity investment in Portlands Energy Centre classified as Assets held for sale as at December 31, 2019 and sold on April 29, 2020. Refer to Note 27, Acquisitions and dispositions, for additional information.

2 Includes maximum potential exposure to guarantees plus future expected and contingent funding commitments.

30. SUBSEQUENT EVENTS

Columbia Pipeline Group, Inc. Debt Issuance

On December 9, 2020, the Company's subsidiary, Columbia, entered into a US$4.2 billion Delayed Draw Term Loan due in June 2022, bearing interest at a floating rate. 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.

Keystone XL Presidential Permit Revocation

On January 20, 2021, U.S. President Biden revoked the Presidential Permit for the Keystone XL pipeline. As a result and as of this date, the Company suspended the advancement of the Keystone XL pipeline project while it assesses the implications of the revocation and considers its options along with its partner, the Government of Alberta, and other stakeholders. The Company ceased capitalizing costs, including interest during construction, and also ceased accruing a return on the Government of Alberta Class A Interests, effective January 20, 2021. The decision to suspend advancement of the Keystone XL pipeline also represents a triggering event under GAAP requiring the Company to evaluate the Keystone XL capitalized project costs for impairment. Given the uncertainty related to the Keystone XL project, the Company expects to record a predominantly non-cash impairment charge in first quarter 2021. The carrying value of plant, property and equipment for Keystone XL, including capitalized interest, was $2.8 billion at December 31, 2020.

Accounting implications, in the first quarter of 2021 and beyond, will depend on the assessment and consideration of options as noted above, including the impacts that this has on contractual arrangements. As a result, the magnitude of the impairment charge and related recoveries cannot be quantified at this time.

The following factors will be considered in determining the amount and timing of the impairment charge and related recoveries, although these will be dependent on future decisions and developments:

- the viability of projects currently associated with the Keystone XL pipeline, including Heartland Pipeline, TC Terminals and Keystone Hardisty Terminal, is also being reviewed. The carrying value of these projects in Other long-term assets on the Consolidated balance sheet at December 31, 2020 was $0.2 billion
- incremental liabilities incurred for contractual commitments
- specified contractual recoveries
- recoverable value of the project's tangible assets
- income tax impact of the above items, including the assessment of any income tax valuation allowances and deferred income tax assets recorded at December 31, 2020.

Any principal outstanding under the project-level credit facility is fully guaranteed by the Government of Alberta without recourse to the Company. 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. While the credit facility remains outstanding, the Company continues to be responsible for ongoing interest charges. For further discussion of subsequent events related to the project-level credit facility, refer to Note 20, Redeemable non-controlling interest and non-controlling interests.

Shareholder information

TC Energy welcomes questions from shareholders and investors.
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