2022 Year in review

Annual report

TC Energy

About TC Energy

DELIVERING THE ENERGY PEOPLE NEED, EVERY DAY.

We're a team of 7,000+ energy problem solvers working to move, generate and store the energy North America relies on. Today, we're taking action to make that energy more sustainable and more secure. We're innovating and modernizing to reduce emissions from our business. And, we're delivering new energy solutions – from natural gas and renewables to carbon capture and hydrogen – to help other businesses and industries decarbonize too. Along the way, we invest in communities and partner with our neighbours, customers and governments to build the energy system of the future.

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

Our values

SAFETY
INNOVATION
RESPONSIBILITY
COLLABORATION
INTEGRITY

OUR SUSTAINABILITY & ESG COMMITMENTS

The world is facing an ambitious and critically important challenge: the need to evolve to a lower-carbon, lower-emission energy economy while continuing to meet the growing global demand for safe, reliable and affordable energy. At TC Energy, the need for responsible energy solutions is clear, as is our obligation, ability and opportunity to bring solutions forward. We are working every day to address this challenge for ourselves, our customers and the communities where we live and work.

Our 2022 Report on Sustainability and 2022 ESG Data Sheet provide a fulsome overview of our 2021 ESG performance metrics and our commitment to increased transparency and accountability of our ESG priorities. Additional details can be found at TCEnergy.com/ESG.

LAND ACKNOWLEDGEMENT

Embedded in the lands on which TC Energy operates are the histories, cultures and traditions of Indigenous groups across North America. TC Energy thanks the original stewards of these lands — generations past, present and future — for sharing their homelands with us.

Forward-looking information

These pages contain certain forward-looking information. 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 refer to TC Energy's 2022 Annual Report filed with Canadian securities regulators, the U.S. Securities and Exchange Commission and available at TCEnergy.com

A CONTINENTAL ENERGY COMPANY

NATURAL GAS PIPELINES

25%

of North America's demand

Our 93,700-kilometre (58,200-mile) network serves the largest, most competitive resource basins and the highest-value demand markets. Spanning Canada, the U.S. and Mexico, we safely supply more than 25 per cent of the natural gas required to meet North America's energy needs. Our U.S. natural gas system currently moves approximately 30 per cent of liquified natural gas (LNG) feed-gas and we are constructing the first direct link for Western Canadian Sedimentary Basin (WCSB) gas to reach LNG markets through the Coastal GasLink pipeline.

Natural gas is a secure and reliable fuel that has an important role to play in the energy transition as the world reduces dependence on higher-carbon energy sources. It is an abundant and cleaner burning fuel that will continue to backstop the intermittency of renewable power sources.

LIQUIDS PIPELINES

20%

of demand for Canadian crude oil

Our 4,900-kilometre (3,000-mile) liquids pipeline system directly connects one of the largest global oil reserves, the WCSB, to the largest refining markets (totaling ~14 million bbl/d of capacity) in the U.S. Midwest and Gulf Coast. Underpinned by long-term commercial structures and 96 per cent investment-grade or equivalent customers, this irreplaceable system serves a highly strategic corridor.

North American oil production is expected to remain a robust and important part of the fuel mix for decades to come. Stable and reliable WCSB crude oil supply is forecast to grow by 600,000 bbl/d through the end of the decade, with refining utilizations in our key markets forecast to remain strong through 2050.

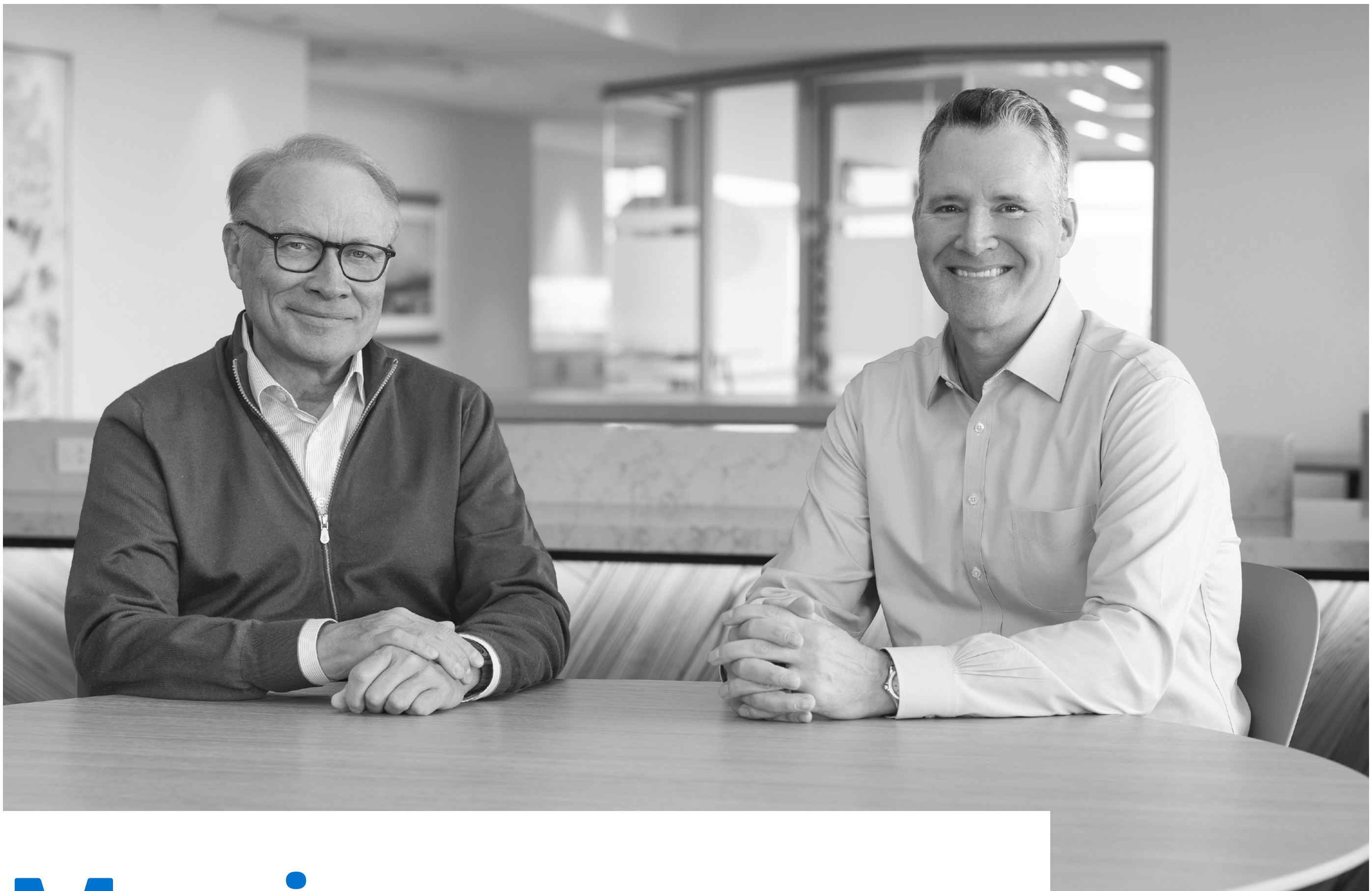
POWER AND ENERGY SOLUTIONS

30+

years of experience

We own or have interests in facilities providing approximately 4,300 megawatts (MW) of capacity, approximately 75 per cent of which is emission-less. Our power portfolio is over 92 per cent underpinned by long-term contracts and we have secured 600 MW in the U.S. and 416 MW in Canada of power purchase agreements from wind and solar facilities. We continue to progress numerous energy transition growth initiatives, including opportunities to increase capacity and extend the life of our Bruce Power nuclear facility while also continuing to explore or invest in renewables, hydrogen, pumped storage and carbon capture and storage (CCUS).

Rising power demand requires an all-of-the-above solution that TC Energy is well-positioned to serve. Our strong foundational business is growing via customer-led opportunities and our incumbent position enables access to high barrier-to-entry markets.



Moving energy, delivering solutions

A MESSAGE FROM FRANÇOIS AND SIIM

Social and political factors are in constant motion, and how we adapt is key.

In 2022, geopolitical events highlighted energy security around the world as well as the importance of balancing energy security and sustainability when planning for the future. Our role in contributing to local and global energy transition solutions is significant, and in 2022, we continued to leverage our vast infrastructure to deliver affordable, reliable and more sustainable energy as demand rose in the communities we serve. Our team and, by extension, our assets performed extraordinarily well, setting new records for energy delivered throughout the year, most recently during cold weather when our NGTL System set a new record for delivery of 16.4 Bcf on December 19 and our U.S. natural gas systems experienced an all-time peak delivery record of 36.6 Bcf on December 23. Further, during cold days in February and March, we reached 100 per cent power availability in Alberta – delivering energy when people needed it most.

In addition to meeting domestic energy demand, our unique footprint plays an indispensable role in delivering approximately 30 per cent of the natural gas destined for LNG export from the U.S. to markets around the world. We anticipate continued growth in LNG exports as global energy demand continues to rise.

Once again, we leveraged the value of our more than $100 billion asset base and delivered solid results for our shareholders by:

- Generating comparable EBITDA[1] of $9.9 billion
- Achieving comparable earnings[1] of $4.3 billion or $4.30 per common share[1]
- Producing comparable funds generated from operations[1] of $7.4 billion
- Placing approximately $5.8 billion of assets into service while advancing our $34 billion secured capital program

In addition to managing external factors, we also continue to look inwards to ensure safe and efficient operations to maximize value for all of our stakeholders.

A FOCUS ON SAFETY AND OPERATIONAL EXCELLENCE

Operational excellence starts with safety, and our goals are clear: keep people, the environment and our assets safe every day. Serious or critical incidents are never acceptable. In the rare instance when an incident occurs, we are committed to doing what is right throughout the response, recovery, and remediation. We take this responsibility seriously, including resolving the recent Milepost 14 incident on the Keystone Pipeline System in Washington County, Kansas. By February 2023, we recovered 90 per cent of the released volume. We continue to diligently work to restore the area to its original condition, while investigating the root cause of the incident and applying learnings going forward.

As part of our focus on operational excellence, we continue to look for new ways to maximize the value from our operating assets by optimizing system availability and throughput and optimizing commercial terms with our customers. We are also scrutinizing our organization to find additional cost efficiencies – getting the best value possible for dollars we spend and reducing costs without compromising on safety.

CREATING A MORE SUSTAINABLE AND EQUITABLE ENERGY FUTURE

Though progress is not always linear, we are making the necessary changes to continue driving meaningful change. In 2022, we reported our progress against our targets including how we:

- Established a corporate emissions intensity key performance indicator to provide more insight into the progress on our climate goals
- Formed an Indigenous Advisory Council to advise our senior leadership on Indigenous matters
- Signed a 10 per cent equity interest option agreement with 16 Indigenous communities along the Coastal GasLink project corridor
- Exceeded our gender target for Board composition – through the ongoing retirement and nomination process, our Board composition now has 38 per cent female representation

1 Comparable EBITDA, Comparable earnings, Comparable earnings per share and Comparable funds generated from operations are non-GAAP measures and do not have any standardized meaning under U.S. GAAP and therefore may not be comparable to similar measures presented by other entities. The most directly comparable U.S. GAAP measures are Segmented earnings, Net income attributable to common shares, Net income per common share and Net cash provided by operations, respectively. Refer to the About this document – Non-GAAP measures section of our 2022 Annual MD&A (incorporated by reference herein) for more information and a reconciliation to the U.S. GAAP equivalent.

- Linked compensation to progress on our ESG priorities through the corporate scorecard

Anchored in our values, our multi-year sustainability strategy is driven by the belief that natural gas will play a pivotal role in the world's energy future and liquids will remain an important part while low-carbon power generation grows.

SUSTAINABLE CASH FLOW GROWTH AND RESILIENCY OF OUR DIVIDEND GROWTH

Our strategy has been steadfast, and our commitments have been consistent for decades. We offer a unique value proposition that has delivered steady and reliable long-term value to our shareholders including 23 years of consecutive dividend increases.

Our map highlights our industry-leading position that spans North America like no other infrastructure company in our peer group. We have one of the largest natural gas networks. Our natural gas and liquids pipelines are strategically positioned, connecting the lowest-cost basins to the largest demand markets. We have over 30 years of experience in the power business, and within North America, we are uniquely situated at the intersection of molecules and electrons, allowing us to capitalize on energy transition opportunities as GHG emission reductions will come primarily from electrification over the next decade.

The North American energy mix is continuing to evolve and requires an all-of-the-above solution to maintain affordability and reliability and deliver GHG emissions reductions. Our infrastructure provides the backbone for this evolving continental energy system. Our core principles have not changed, but where we plan to invest capital will evolve over time, as it always has. We continue to expand our capabilities and investments in renewable and low-carbon energy solutions, such as hydrogen, CCUS and renewable natural gas.

Importantly, our strategy has been tested against multiple energy outlooks including an accelerated energy transition scenario. Our assets are expected to remain highly utilized and useful across a broad range of energy transition pathways. TC Energy remains opportunity-rich. This past year, we sanctioned $8.8 billion in new projects, including several energy transition initiatives, along with expanding, extending and modernizing our natural gas systems. We have a $34 billion industry-leading portfolio of diverse and fully sanctioned capital projects. Our goal is to sanction $5+ billion of projects every year that are consistent with our risk and return preferences. This means underpinning our assets with long-term take-or-pay contracts or rate regulation and capturing a spread above our cost of capital to maximize shareholder value.

Combined, this unique value proposition is what supports the certainty of our cash flow and demonstrates the resilience of our portfolio, over time, and at all points of the economic cycle. And this is why we can confidently say we have the ability to reinvest and continue to grow our business. We have delivered 23 consecutive years of dividend growth and expect to continue growing our dividend at an annual rate of three to five per cent.

A CLEARLY DEFINED FUNDING PLAN

Our unmatched growth portfolio is a differentiator for us. Being opportunity-rich means we have access to a significant runway of future projects. We are exercising strategic discipline with the opportunities we pursue and how we will fund this growth.

Capital rotation has always been a powerful tool in our toolkit. We are proceeding with the sale of discrete non-core assets and/or minority interests and plan to realize $5+ billion of proceeds in 2023. And, we will continue to use capital rotation beyond 2023 as a mechanism to create long-term shareholder value.

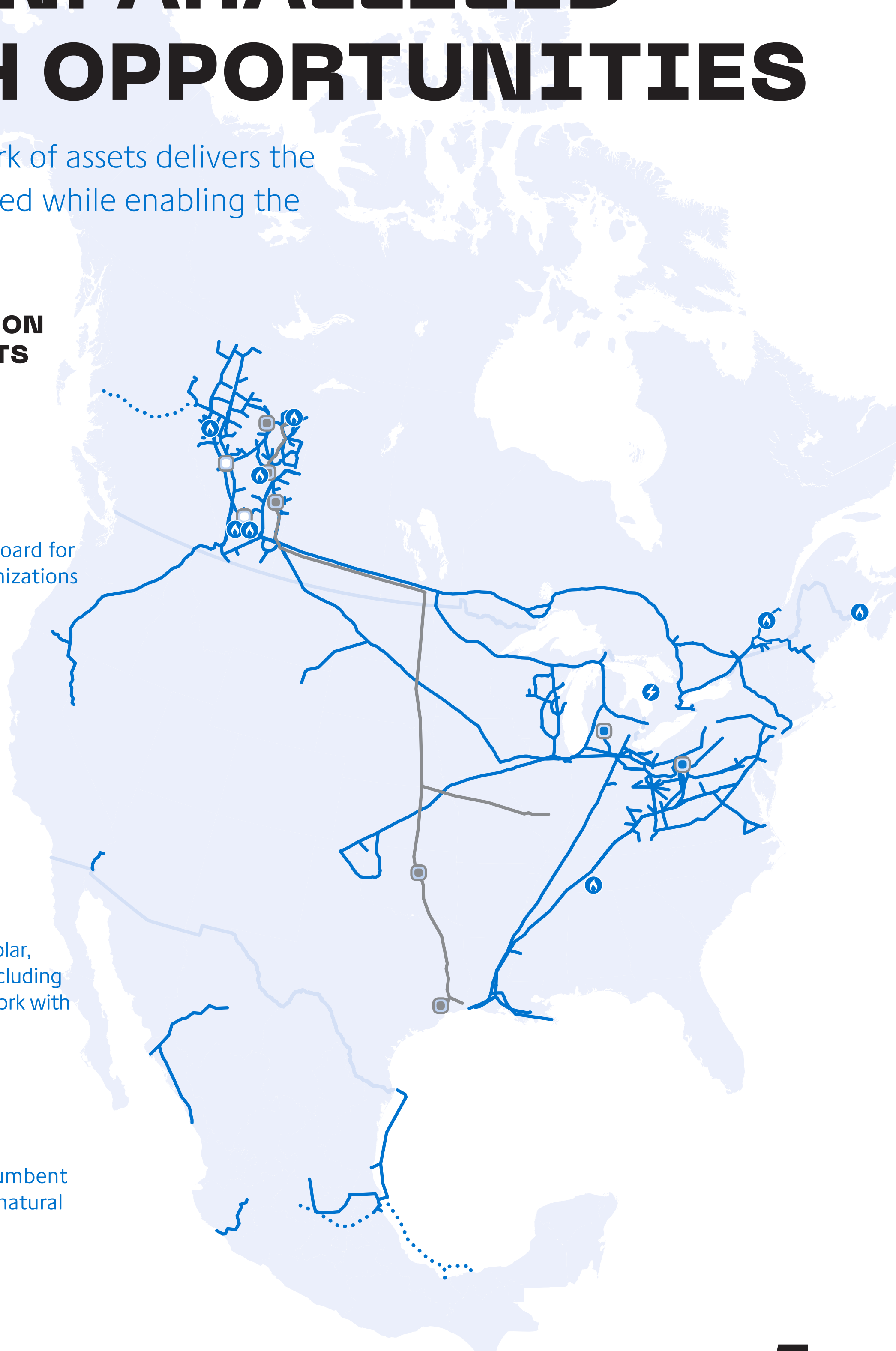
The objectives of our 2023 $5+ billion capital rotation target are to:

- Accelerate our deleveraging target
- Execute on our vast opportunity set
- Provide a self-funding source for high-value growth opportunities

We believe that executing these steps will strengthen our balance sheet to ensure we remain competitively positioned to capitalize on future opportunities. Looking forward, we will continue to grow earnings, cash flow and dividends per share by prudently investing in high-quality, low-risk energy infrastructure assets that deliver the affordable and reliable energy people need, every day.

SYNERGIES ACROSS BUSINESS SEGMENTS OFFER UNPARALLELED GROWTH OPPORTUNITIES

Our well-connected network of assets delivers the energy North Americans need while enabling the technologies of the future.



① IMPROVING RETURN ON OUR EXISTING ASSETS

Identifying innovation and efficiencies.

② LEVERAGING OUR FOOTPRINT

North America-wide assets are a springboard for ongoing expansions, extensions, modernizations and for low-carbon energy solutions.

③ LIQUEFIED NATURAL GAS (LNG)

Increasing market share of LNG supply transported through our systems to reach global markets.

④ EMISSION-LESS ENERGY

Developing or operating nuclear, hydro, solar, wind and large-scale energy storage — including solutions to power our own pipeline network with renewables.

⑤ DECARBONIZATION OPPORTUNITIES

Customer-led opportunities and our incumbent position enable initiatives in renewable natural gas, hydrogen and CCUS.

FOCUSED ON TODAY, PREPARING FOR THE FUTURE

It is our team of more than 7,000 energy problem solvers who make these achievements possible as we continue to move, store and generate the energy North America, and ultimately the world, relies on today – while finding new, more secure and sustainable solutions for tomorrow. We believe an all-of-the-above strategy is required, as are innovation, collaboration and world-class expertise. These essential skills are widespread throughout our organization and, when combined with our robust strategy, continue to position us for long-term success.

Guiding these efforts is our increasingly diverse Board of Directors, who bring a variety of perspectives, backgrounds and experiences. As part of our continual succession planning, we welcomed Dheeraj Verma and Cheryl Campbell to the Board. Appointed in April 2022, Dheeraj brings considerable expertise in capital market transactions and energy investment. Cheryl, who was appointed in June 2022, brings extensive experience in the midstream energy sector, with expertise in operations in both regulated and unregulated environments, as well as in sustainability and risk management. We look forward to their continued valuable contributions to our corporate strategy and governance.

We enter 2023 excited to develop and expand our portfolio of energy solutions. Our unique blend of deep experience and strong relationships with partners and customers positions us to help solve the global challenge of meeting rising energy demand while reducing emissions. And our financial discipline and recently announced capital rotation program will enable us to prudently fund and manage our assets and opportunities across our existing footprint.

Our company-wide emphasis on safe, efficient and disciplined operations will deliver results for our employees, our customers and our shareholders, while setting a strong foundation for robust and sustainable growth that will secure our place in the energy future.

To our valued shareholders, thank you for your continued support.

Sincerely,

François Poirier
President and
CEO

Siim A. Vanaselja
Chair of
the Board

ADVANCING A CLEANER ENERGY FUTURE

Our unparalleled footprint provides significant opportunities to advance a lower-carbon energy future. By decarbonizing our energy consumption and innovating across our assets, we will achieve our climate targets and support global goals for emissions reduction.

DECARBONIZING OUR OPERATIONS

By equipping pipelines with zero-emission electric compressors, advancing carbon capture technology, and shifting the company fleet to electric vehicles, we're reducing emissions from our operations.

INVESTING IN LOW-CARBON TECHNOLOGIES

Using our deep energy expertise and vast infrastructure, we're investing in nuclear, solar, pumped storage, hydrogen and renewable natural gas technologies that will be critical components of a sustainable energy future.

MODERNIZING OUR SYSTEMS AND ASSETS

We're using data and machine learning to make our systems smarter, safer and more efficient so that every piece of our footprint can be part of the solution for emissions reduction.

STRONG FOCUS ON ESG

To us, evolving to a lower-carbon energy future is a serious obligation, it is not an imposition or an obstacle – it is an incredible opportunity, serving as a catalyst for future growth for our company with investments that are strongly aligned with our corporate strategic objectives, traditional risk preferences and our core values.

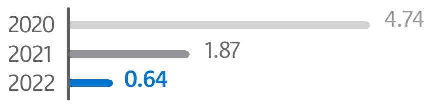
We have both an extraordinary opportunity and an accountability to play a vital role in the energy transition. We are confident we can make a difference thanks in large part to our innovative workforce, our asset footprint and the trusted relationships we have built with stakeholders, rightsholders and partners.

Financial highlights

23
YEARS OF ANNUAL DIVIDEND INCREASES

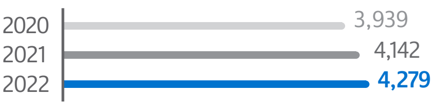
Comparable earnings per common share[3] (dollars)

Net income per common share (dollars)

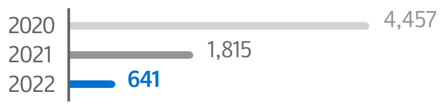


Comparable EBITDA[3] (millions of dollars)

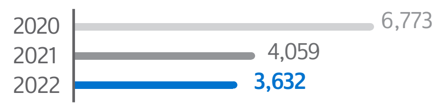
Comparable earnings[3] (millions of dollars)



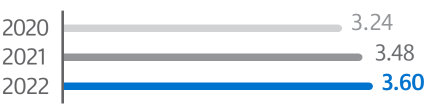
Net income attributable to common shares (millions of dollars)



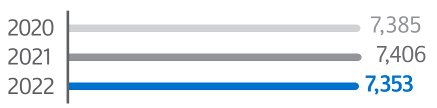
Total segmented earnings (millions of dollars)



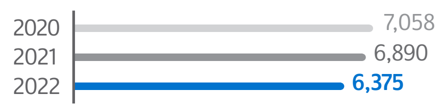
Dividends declared per common share (dollars)



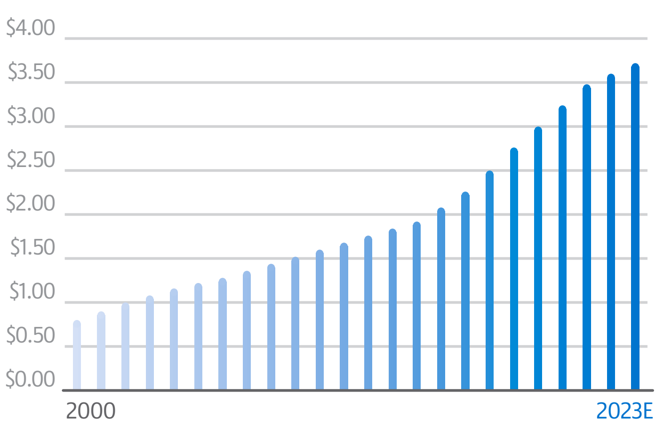
Comparable funds generated from operations[3] (millions of dollars)



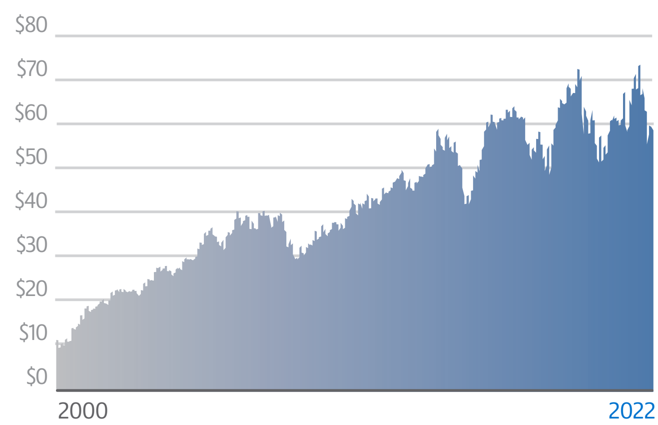
Net cash provided by operations (millions of dollars)



Track record of dividend growth



Common share price — Toronto Stock Exchange



3 Non-GAAP measures which do not have any standardized meanings as prescribed by U.S. generally accepted accounting principles (GAAP) and therefore may not be comparable to similar measures presented by other entities. Refer to the About this document – Non-GAAP measures section of our 2022 Annual MD&A (incorporated by reference herein) for more information and a reconciliation to the U.S. GAAP equivalents.

Management's discussion and analysis

February 13, 2023

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, 2022.

This MD&A should also be read in conjunction with our December 31, 2022 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 134. All information is as of February 13, 2023 and all amounts are in Canadian dollars, unless noted otherwise.

FORWARD-LOOKING INFORMATION

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

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

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

- our financial and operational performance, including the performance of our subsidiaries
- expectations about strategies and goals for growth and expansion, including acquisitions
- expected cash flows and future financing options available along with portfolio management, including our expectations regarding the size, timing and outcome of the asset divestiture program
- expected dividend growth
- expected duration of discounted DRP
- expected access to and cost of capital
- expected energy demand levels
- expected costs and schedules for planned projects, including projects under construction and in development
- expected capital expenditures, contractual obligations, commitments and contingent liabilities, including environmental remediation costs
- expected regulatory processes and outcomes
- statements related to our GHG emissions reduction goals
- expected outcomes with respect to legal proceedings, including arbitration and insurance claims
- the expected impact of future tax and accounting changes
- the commitments and targets contained in our 2022 Report on Sustainability and GHG Emissions Reduction Plan
- expected industry, market and economic conditions, including their impact on our customers and suppliers.

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

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

Assumptions

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

Risks and uncertainties

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

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

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

FOR MORE INFORMATION

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

NON-GAAP MEASURES

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

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

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

Comparable measures

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

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

- gains or losses on sales of assets or assets held for sale
- income tax refunds, valuation allowances and adjustments resulting from changes in legislation and enacted tax rates
- unrealized fair value adjustments related to risk management activities and Bruce Power funds invested for post-retirement benefits
- expected credit loss provisions on net investment in leases and certain contract assets
- legal, contractual, bankruptcy and other settlements
- impairment of goodwill, plant, property and equipment, equity investments and other assets
- acquisition and integration costs
- restructuring costs.

We exclude from comparable measures the unrealized gains and losses from changes in the fair value of derivatives related to financial and commodity price risk management activities. These derivatives generally provide effective economic hedges but do not meet the criteria for hedge accounting. Beginning in first quarter 2022, with consistent presentation of prior periods, we excluded from comparable measures our proportionate share of the unrealized gains and losses from changes in the fair value of Bruce Power's funds invested for post-retirement benefits and derivatives related to its risk management activities. These changes in fair value are recorded in net income. As these amounts do not accurately reflect the gains and losses that will be realized at settlement, we do not consider them reflective of our underlying operations.

In third quarter 2022, Transportadora de Gas Natural de la Huasteca (TGNH) and the CFE executed agreements which consolidate a number of operating and in-development natural gas pipelines in central and southeast Mexico under one TSA. As this TSA contains a lease, we have recognized amounts in net investment in leases on our Consolidated balance sheet. In accordance with the requirements of U.S. GAAP, we have recognized an expected credit loss provision related to net investment in leases and certain contract assets. The amount of this provision will fluctuate from period to period based on changing economic assumptions and forward-looking information. The provision is an estimate of losses that may occur over the duration of the TSA through 2055. As this provision, as well as a provision related to certain contract assets in Mexico, do not reflect losses or cash outflows that were incurred under this lease arrangement in the current period or from our underlying operations, we have excluded any unrealized changes from comparable measures. Refer to Note 28, Risk management and financial instruments, of our 2022 Consolidated financial statements for additional information on expected credit loss provisions.

We also excluded from comparable measures the unrealized foreign exchange gains and losses on the peso-denominated loan receivable from an affiliate as well as the corresponding proportionate share of Sur de Texas foreign exchange gains and losses, as the amounts do not accurately reflect the gains and losses that will be realized at settlement. These amounts offset within each reporting period, resulting in no impact on net income. This peso-denominated loan was fully repaid in first quarter 2022.

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

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

Comparable EBITDA and comparable EBIT

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

Comparable earnings and comparable earnings per common share

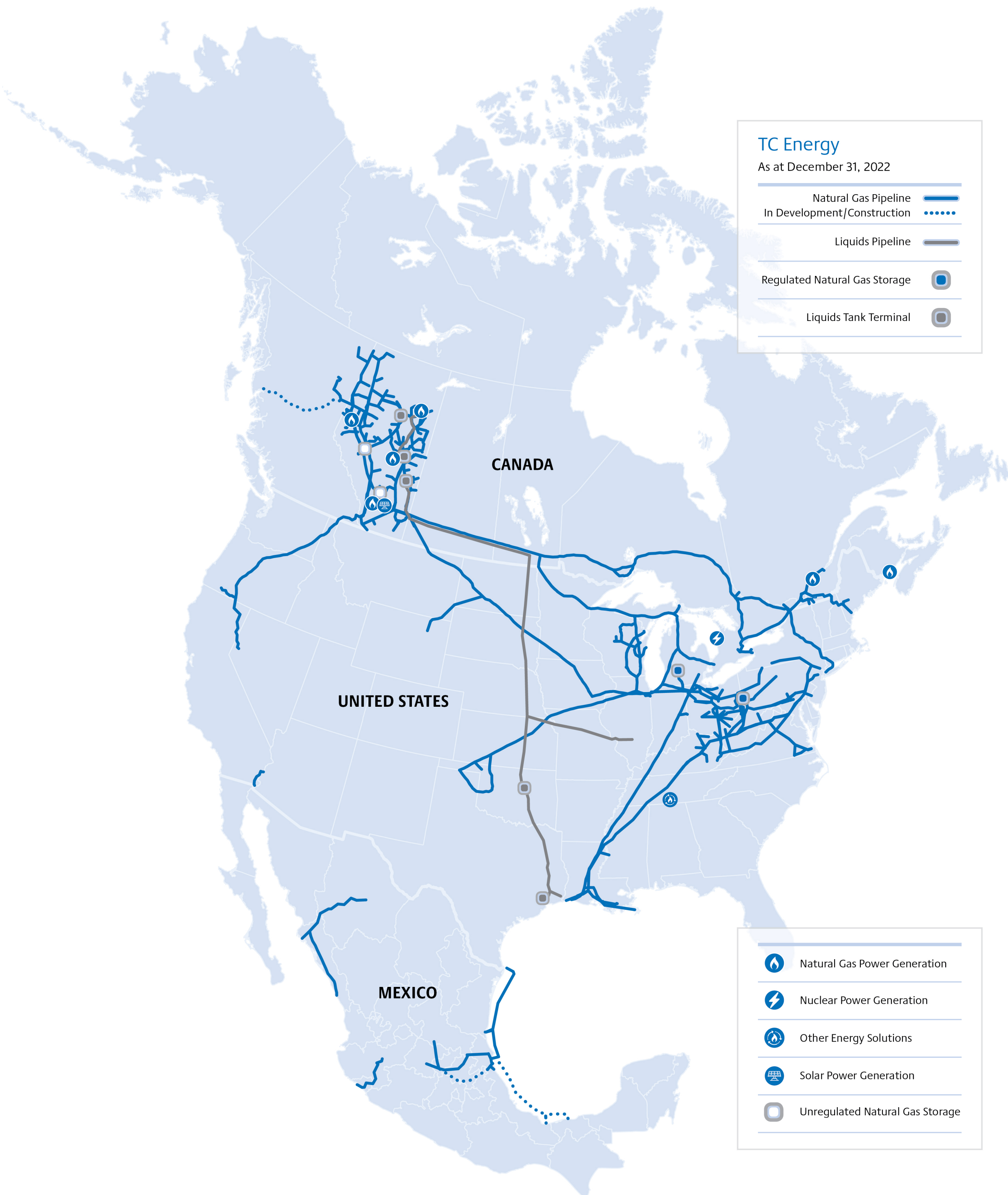
Comparable earnings represents earnings attributable to common shareholders on a consolidated basis, adjusted for specific items. Comparable earnings is comprised of segmented earnings, Interest expense, AFUDC, Foreign exchange (loss)/gain, net, Interest income and other, Income tax expense, Non-controlling 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. The components of changes in working capital are disclosed in Note 29, Changes in operating working capital, of our 2022 Consolidated financial statements. We believe funds generated from operations is a useful measure of our consolidated operating cash flows because it excludes fluctuations from working capital balances, which do not necessarily reflect underlying operations in the same period, and is used to provide a consistent measure of the cash-generating ability of our businesses. Comparable funds generated from operations is adjusted for the cash impact of specific items noted above. Refer to the Financial Condition section for a reconciliation to Net cash provided by operations.

About our business

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



THREE CORE BUSINESSES

We operate in three core businesses – Natural Gas Pipelines, Liquids Pipelines and Power and Energy Solutions. 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 Energy Solutions. 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 $)	2022	2021
Total assets by segment		
Canadian Natural Gas Pipelines	**27,456**	25,452
U.S. Natural Gas Pipelines	**50,038**	45,502
Mexico Natural Gas Pipelines	**9,231**	7,547
Liquids Pipelines	**15,587**	14,951
Power and Energy Solutions	**8,272**	6,563
Corporate	**3,764**	4,203
	114,348	104,218

year ended December 31 (millions of $)	2022	2021
Total revenues by segment		
Canadian Natural Gas Pipelines	**4,764**	4,519
U.S. Natural Gas Pipelines	**5,933**	5,233
Mexico Natural Gas Pipelines	**688**	605
Liquids Pipelines	**2,668**	2,306
Power and Energy Solutions	**924**	724
	14,977	13,387

year ended December 31 (millions of $)	2022	2021
Comparable EBITDA by segment[1]		
Canadian Natural Gas Pipelines	**2,806**	2,675
U.S. Natural Gas Pipelines	**4,089**	3,856
Mexico Natural Gas Pipelines	**753**	666
Liquids Pipelines	**1,366**	1,526
Power and Energy Solutions	**907**	669
Corporate	**(20)**	(24)
	9,901	9,368

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

OUR STRATEGY

Our vision is to be the premier energy infrastructure company in North America today and in the future by safely generating, storing and delivering the energy people need every day. Our goal is to develop, build and operate a portfolio of infrastructure assets that enable us to prosper irrespective of the pace and direction of energy transition. We are a team of energy problem solvers working to deliver this energy in a more affordable, reliable and sustainable manner while developing lower carbon energy solutions to drive energy transition ranging from natural gas and renewables to carbon capture and hydrogen.

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

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

Allocation of comparable EBITDA[1]

year ended December 31	2022	2021
Comparable EBITDA by segment		
Canadian Natural Gas Pipelines	**28%**	29%
U.S. Natural Gas Pipelines	**41%**	41%
Mexico Natural Gas Pipelines	**8%**	7%
Liquids Pipelines	**14%**	16%
Power and Energy Solutions	**9%**	7%
	100%	100%

1 Refer to Note 4, Segmented information, of our 2022 Consolidated financial statements for an allocation of segmented earnings by business segment.

Our asset mix will continue to evolve to align with the North American energy mix as energy transition unfolds with the following anticipated shifts in capital allocation:

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

Key components of our strategy

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

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

2 Commercially develop and build new asset investment programs

- We are developing high quality, long-life assets under our current capital program, comprised of approximately $34 billion in secured projects. As well, our projects under development are, or are expected to be, largely commercially supported. We expect that these investments will contribute to incremental earnings and cash flows as they are placed in service
- Our existing extensive footprint offers significant in-corridor growth opportunities. This includes possible future opportunities to deploy low-emission infrastructure technologies such as renewables, hydrogen and carbon capture, which will help reduce the carbon footprint of our customers and us, and also support extending the longevity of our existing assets
- We continue to develop projects and manage construction risk in a disciplined manner that maximizes capital efficiency and returns to shareholders
- As part of our growth strategy, we rely on our experience and our regulatory, commercial, financial, legal and operational expertise to successfully permit, fund, build and integrate new pipeline and other energy facilities
- Safety, executability, profitability and responsible ESG performance are fundamental to our investments.

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

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

4 Maximize our competitive strengths

- We continually seek to enhance our core competencies in safety, operational excellence, investment opportunity origination, project execution and stakeholder relations as well as key sustainability and ESG areas to ensure we deliver shareholder value
- The use of a disciplined approach to capital allocation supports our ability to maximize value over the short, medium and long term. We allocate capital in a manner that improves the breadth and cost competitiveness of the services we provide, extends the life of our assets, increases diversification and strengthens the carbon-competitiveness of our assets
- We believe that our high-quality, diversified portfolio of incumbent assets results in predictable, low risk cash flows and positions us well to succeed under an energy transition scenario
- A strong focus on talent management ensures that we have the necessary capabilities to execute and deliver on our strategy.

Our competitive advantage

The need for secure, reliable and sustainable energy solutions has become increasingly important. 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. We will do this safely, responsibly, collaboratively and with integrity through:

- strong leadership and governance: we maintain rigorous governance over our approach to business ethics, enterprise risk management, competitive behaviour, operating capabilities and strategy development as well as regulatory, legal, commercial, stakeholder and financing support
- a high-quality portfolio: our low-risk and enduring utility-like business model offers the scale and presence to provide essential and highly competitive infrastructure services that enable us to maximize the full-life value of our long-life assets and commercial positions throughout all points of the business cycle. Our incumbent portfolio of assets and synergistic footprint support transporting both molecules and electrons, providing us flexibility to allocate capital towards electrification or other emerging low-carbon technologies in support of any energy transition scenario. For example, we are working with an industry partner on the Alberta Carbon Grid (ACG) – a world scale carbon capture and storage system in development to help the province's industrial sectors sequester their emissions
- 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 investments balanced with common share dividend growth while preserving financial flexibility, including asset divestitures, 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, re-purposing the underutilized Canadian Mainline pipeline capacity from natural gas to crude oil service, installing electric compression and/or switching gas compression to electrification such as the proposed Valhalla North and Berland River (VNBR) and WR projects in Canada and the U.S., respectively, and currently leveraging our complementary asset mix with the objective of reducing emissions on our Liquids pipelines through our Power and Energy Solutions business
- 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. As part of our 2022 Report on Sustainability, we published our emissions intensity on a corporate-wide basis, providing more transparency and insight into our goals as we progress toward our 2030 target to reduce GHG emissions intensity from our operations by 30 per cent. We continue to make steady progress on 10 sustainability commitments from last year. In alignment with our pursuit of meaningful partnerships that will endeavour to solve critical global sustainability challenges, TC Energy became an official participant of the UNGC in 2022
- open communication: we carefully manage relationships with our customers and stakeholders and offer clear, candid communication to investors in order to build trust and support.

Our risk preferences

The following is an overview of our risk philosophy:

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

2022 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 23 and 89 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)	2022	2021	2020
Income			
Revenues	**14,977**	13,387	12,999
Net income attributable to common shares	**641**	1,815	4,457
per common share – basic	**$0.64**	$1.87	$4.74
Comparable EBITDA[1]	**9,901**	9,368	9,342
Comparable earnings	**4,279**	4,142	3,939
per common share	**$4.30**	$4.26	$4.19
Cash flows			
Net cash provided by operations	**6,375**	6,890	7,058
Comparable funds generated from operations	**7,353**	7,406	7,385
Capital spending[2]	**8,961**	7,134	8,900
Proceeds from sales of assets, net of transaction costs	**—**	35	3,407
Balance sheet[3]			
Total assets	**114,348**	104,218	100,300
Long-term debt, including current portion	**41,543**	38,661	36,885
Junior subordinated notes	**10,495**	8,939	8,498
Redeemable non-controlling interest[4]	**—**	—	393
Preferred shares	**2,499**	3,487	3,980
Non-controlling interests	**126**	125	1,682
Common shareholders' equity	**31,491**	29,784	27,418
Dividends declared			
per common share	**$3.60**	$3.48	$3.24
Basic common shares (millions)			
– weighted average for the year	**995**	973	940
– issued and outstanding at end of year	**1,018**	981	940

1 Additional information on Segmented earnings, the most directly comparable GAAP measure, can be found on page 21.
2 Includes Capital expenditures, Capital projects in development and Contributions to equity investments. Refer to Note 4, Segmented information, of our 2022 Consolidated financial statements for the financial statement line items that comprise total capital spending.
3 As at December 31.
4 At December 31, 2020, redeemable non-controlling interest was classified in mezzanine equity and subsequently repurchased in 2021.

Consolidated results

year ended December 31 (millions of $, except per share amounts)	2022	2021	2020
Canadian Natural Gas Pipelines	**(1,440)**	1,449	1,657
U.S. Natural Gas Pipelines	**2,617**	3,071	2,837
Mexico Natural Gas Pipelines	**491**	557	669
Liquids Pipelines	**1,123**	(1,600)	1,359
Power and Energy Solutions	**833**	628	181
Corporate	**8**	(46)	70
Total segmented earnings	**3,632**	4,059	6,773
Interest expense	**(2,588)**	(2,360)	(2,228)
Allowance for funds used during construction	**369**	267	349
Foreign exchange (loss)/gain, net	**(185)**	10	28
Interest income and other	**146**	190	185
Income before income taxes	**1,374**	2,166	5,107
Income tax expense	**(589)**	(120)	(194)
Net income	**785**	2,046	4,913
Net income attributable to non-controlling interests	**(37)**	(91)	(297)
Net income attributable to controlling interests	**748**	1,955	4,616
Preferred share dividends	**(107)**	(140)	(159)
Net income attributable to common shares	**641**	1,815	4,457
Net income per common share – basic	**$0.64**	$1.87	$4.74

Net income attributable to common shares in 2022 was $0.6 billion or $0.64 per share (2021 – $1.8 billion or $1.87 per share; 2020 – $4.5 billion or $4.74 per share), a decrease of $1.2 billion or $1.23 per share compared to 2021. The significant decrease for the year ended December 31, 2022 compared to 2021 as well as the significant decrease in Net income per common share of $2.87 in 2021 compared to 2020 is primarily due to the net effect of specific items mentioned below. Net income per common share in both years also reflects the impact of common shares issued for the acquisition of TC PipeLines, LP in first quarter 2021 and common shares issued in 2022.

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

2022

- an after-tax impairment charge of $2.6 billion related to our equity investment in Coastal GasLink Pipeline Limited Partnership (Coastal GasLink LP). Refer to Note 7, Coastal GasLink, of our 2022 Consolidated financial statements for additional information
- an after-tax goodwill impairment charge of $531 million related to Great Lakes. Refer to the Other Information – Critical accounting estimates section for additional information
- a $196 million income tax expense for the settlement related to prior years' income tax assessments in Mexico
- $114 million after-tax expected credit loss provision related to the TGNH net investment in leases and certain contract assets in Mexico
- $20 million after-tax charge due to the CER decision on Keystone issued in December 2022 in respect of a tolling-related complaint pertaining to amounts reflected in 2021 and 2020
- preservation and other costs for Keystone XL pipeline project assets of $19 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge
- a $5 million after-tax net expense related to the 2021 Keystone XL asset impairment charge and other due to a U.S. minimum tax, partially offset by the gain on the sale of Keystone XL project assets and reduction to the estimate for contractual and legal obligations related to termination activities.

2021

- a $2.1 billion after-tax asset impairment charge, net of expected contractual recoveries and other contractual and legal obligations, related to the termination of the Keystone XL pipeline project following the January 2021 revocation of the Presidential Permit
- a $48 million after-tax expense with respect to transition payments incurred as part of the Voluntary Retirement Program (VRP)
- preservation and other costs for Keystone XL pipeline project assets of $37 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge, as well as interest expense on the Keystone XL project-level credit facility prior to its termination
- an after-tax gain of $19 million related to the sale of the remaining 15 per cent interest in Northern Courier
- a $7 million after-tax recovery primarily related to certain costs from the IESO associated with the Ontario natural gas-fired power plants sold in April 2020.

2020

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

Refer to the Financial 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 years included unrealized gains and losses on our proportionate share of Bruce Power's fair value adjustment on funds invested for post-retirement benefits and derivatives related to its risk management activities, as well as unrealized gains and losses from changes in our risk management activities, all of which we exclude along with the above noted items, to arrive at comparable earnings. A reconciliation of Net income attributable to common shares to comparable earnings is shown in the following table.

Reconciliation of net income attributable to common shares to comparable earnings

year ended December 31 (millions of $, except per share amounts)	2022	2021	2020
Net income attributable to common shares	**641**	1,815	4,457
Specific items (net of tax):			
Coastal GasLink LP impairment charge	**2,643**	—	—
Great Lakes goodwill impairment charge	**531**	—	—
Settlement of Mexico prior years' income tax assessments	**196**	—	—
Expected credit loss provision on net investment in leases and certain contract assets	**114**	—	—
Keystone CER decision	**20**	—	—
Keystone XL preservation and other	**19**	37	—
Bruce Power unrealized fair value adjustments	**13**	(11)	(6)
Keystone XL asset impairment charge and other	**5**	2,134	—
Voluntary Retirement Program	**—**	48	—
Gain on sale of Northern Courier	**—**	(19)	—
(Gain)/loss on sale of Ontario natural gas-fired power plants	**—**	(7)	283
Gain on partial sale of Coastal GasLink LP	**—**	—	(402)
Income tax valuation allowance releases	**—**	—	(299)
Gain on sale of Columbia Midstream assets	**—**	—	(18)
Risk management activities[1]	**97**	145	(76)
Comparable earnings	**4,279**	4,142	3,939
Net income per common share	**$0.64**	$1.87	$4.74
Coastal GasLink LP impairment charge	**2.66**	—	—
Great Lakes goodwill impairment charge	**0.53**	—	—
Settlement of Mexico prior years' income tax assessments	**0.20**	—	—
Expected credit loss provision on net investment in leases and certain contract assets	**0.11**	—	—
Keystone CER decision	**0.02**	—	—
Keystone XL preservation and other	**0.02**	0.04	—
Bruce Power unrealized fair value adjustments	**0.01**	(0.01)	(0.01)
Keystone XL asset impairment charge and other	**0.01**	2.19	—
Voluntary Retirement Program	**—**	0.05	—
Gain on sale of Northern Courier	**—**	(0.02)	—
(Gain)/loss on sale of Ontario natural gas-fired power plants	**—**	(0.01)	0.30
Gain on partial sale of Coastal GasLink LP	**—**	—	(0.43)
Income tax valuation allowance releases	**—**	—	(0.32)
Gain on sale of Columbia Midstream assets	**—**	—	(0.02)
Risk management activities	**0.10**	0.15	(0.07)
Comparable earnings per common share	**$4.30**	$4.26	$4.19

1

year ended December 31 (millions of $)	2022	2021	2020
U.S. Natural Gas Pipelines	**(15)**	6	—
Liquids Pipelines	**20**	(3)	(9)
Canadian Power	**4**	12	(2)
Natural Gas Storage	**11**	(6)	(13)
Foreign exchange	**(149)**	(203)	126
Income tax attributable to risk management activities	**32**	49	(26)
Total unrealized (losses)/gains from risk management activities	**(97)**	(145)	76

Comparable EBITDA to comparable earnings

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

year ended December 31 (millions of $, except per share amounts)	2022	2021	2020
Comparable EBITDA			
Canadian Natural Gas Pipelines	**2,806**	2,675	2,566
U.S. Natural Gas Pipelines	**4,089**	3,856	3,638
Mexico Natural Gas Pipelines	**753**	666	786
Liquids Pipelines	**1,366**	1,526	1,700
Power and Energy Solutions	**907**	669	668
Corporate	**(20)**	(24)	(16)
Comparable EBITDA	**9,901**	9,368	9,342
Depreciation and amortization	**(2,584)**	(2,522)	(2,590)
Interest expense included in comparable earnings	**(2,588)**	(2,354)	(2,228)
Allowance for funds used during construction	**369**	267	349
Foreign exchange (loss)/gain, net included in comparable earnings	**(8)**	254	(12)
Interest income and other	**146**	190	185
Income tax expense included in comparable earnings	**(813)**	(830)	(651)
Net income attributable to non-controlling interests	**(37)**	(91)	(297)
Preferred share dividends	**(107)**	(140)	(159)
Comparable earnings	**4,279**	4,142	3,939
Comparable earnings per common share	**$4.30**	$4.26	$4.19

Comparable EBITDA – 2022 versus 2021

Comparable EBITDA in 2022 increased by $533 million compared to 2021 primarily due to the net result of the following:

- increased Power and Energy Solutions EBITDA primarily attributable to higher contributions from Bruce Power due to a higher contract price, higher earnings from Canadian Power related to higher realized power prices and increased contributions from Natural Gas Storage and Other as a result of higher realized spreads in 2022
- higher EBITDA in U.S. Natural Gas Pipelines largely due to incremental earnings from growth projects placed in service, increased earnings from our mineral rights business as well as Columbia Gas following the FERC-approved settlement for higher transportation rates effective February 2021, partially offset by higher property taxes on Columbia Gas
- increased EBITDA from Canadian Natural Gas Pipelines largely attributable to the impact of higher flow-through costs and increased rate-base earnings on the NGTL System, higher Canadian Mainline incentive earnings and flow-through costs
- higher EBITDA from Mexico Natural Gas Pipelines primarily related to the north section of the Villa de Reyes pipeline (VdR North) and east section of the Tula pipeline (Tula East) that were placed in commercial service in third quarter 2022
- decreased EBITDA from Liquids Pipelines as a result of lower rates on lower contracted volumes on the U.S. Gulf Coast section of the Keystone Pipeline System as well as reduced contributions from liquids marketing activities due to lower margins and volumes
- the positive foreign exchange impact of a stronger U.S. dollar on the Canadian dollar equivalent comparable EBITDA in our U.S. dollar-denominated operations. As detailed on page 27, U.S. dollar-denominated comparable EBITDA decreased by US$63 million compared to 2021; however, this was translated to Canadian dollars at an average rate of 1.30 in 2022 versus 1.25 in 2021. Refer to the Foreign exchange discussion below for additional information.

Comparable EBITDA – 2021 versus 2020

Comparable EBITDA in 2021 increased by $26 million compared to 2020 primarily due to the net result of the following:

- increased earnings in U.S. Natural Gas Pipelines from higher Columbia Gas transportation rates effective February 1, 2021 as a result of the subsequently uncontested rate case settlement, improved earnings across our U.S. natural gas pipelines following the cold weather events of 2021 impacting many of the U.S. markets in which we operate, increased earnings from our mineral rights business and increased capitalization of pipeline integrity costs, partially offset by higher property taxes
- higher comparable EBITDA from Canadian Natural Gas Pipelines largely as a result of the impact of increased flow-through costs along with higher rate-base earnings on the NGTL System, full-year recognition of Coastal GasLink development fee revenue and higher Canadian Mainline incentive earnings, partially offset by lower flow-through costs
- consistent Power and Energy Solutions results mainly attributable to increased Canadian Power earnings primarily due to higher realized margins in 2021, contributions from trading activities and a full year of earnings from our MacKay River cogeneration facility following its return to service in May 2020, partially offset by the sale of our Ontario natural gas-fired power plants in April 2020 and decreased earnings at Bruce Power in 2021 due to lower volumes resulting from greater planned outage days and higher operating expenses
- decreased earnings from Liquids Pipelines attributable to lower volumes on the U.S. Gulf Coast section of the Keystone Pipeline System, partially offset by increased contributions from liquids marketing activities reflecting higher margins and volumes
- lower contribution from Mexico Natural Gas Pipelines mainly due to US$55 million of fees recognized in 2020 associated with the successful completion of the Sur de Texas pipeline
- the negative foreign exchange impact of a weaker U.S. dollar on the Canadian dollar equivalent segmented earnings in our U.S. dollar-denominated operations. As detailed on page 27, U.S. dollar-denominated comparable EBITDA of US$4.6 billion increased by US$226 million compared to 2020; however, this was translated to Canadian dollars at an average rate of 1.25 in 2021 versus 1.34 in 2020. Refer to the Foreign exchange discussion below for additional information.

The net impact of U.S. dollar movements on comparable earnings, after considering natural offsets and economic hedges, was not significant. Refer to the Foreign exchange discussion below for additional information.

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

Comparable earnings – 2022 versus 2021

Comparable earnings in 2022 were $137 million or $0.04 per common share higher than in 2021, and were primarily the net result of:

- changes in comparable EBITDA described above
- net realized losses in 2022 compared to net realized gains in 2021 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income, foreign exchanges losses in 2022 compared to gains in 2021 on the revaluation of peso-denominated net monetary liabilities, partially offset by higher realized gains in 2022 compared to 2021 on derivatives used to manage our exposure to these net liabilities in Mexico that give rise to foreign exchange gains and losses
- increased Interest expense primarily due to higher interest rates on increased levels of short-term borrowings, long-term debt and junior subordinated note issuances, net of maturities, as well as the foreign exchange impact of a stronger U.S. dollar in 2022
- lower Interest income and other due to the repayment of the inter-affiliate loan receivable by the Sur de Texas joint venture on July 29, 2022
- higher AFUDC predominantly due to the reactivation of AFUDC on the TGNH assets under construction following the new TSA with the CFE completed in third quarter 2022 and capital expenditures on the Southeast Gateway pipeline project, partially offset by the impact of decreased capital expenditures and projects placed in service on our U.S. natural gas pipeline projects
- higher Depreciation and amortization mainly in U.S. Natural Gas Pipelines reflecting new assets placed in service and a stronger U.S. dollar in 2022
- lower Net income attributable to non-controlling interests following the March 2021 acquisition of all outstanding common units of TC PipeLines, LP not beneficially owned by TC Energy
- decreased Income tax expense primarily due to lower flow-through income taxes and higher foreign tax rate differentials, partially offset by higher earnings subject to tax and other various valuation allowances
- lower Preferred share dividends due to the redemption of preferred shares in 2022 and 2021.

Comparable earnings – 2021 versus 2020

Comparable earnings in 2021 were $203 million or $0.07 per common share higher than in 2020, and were primarily the net result of:

- changes in comparable EBITDA described above
- net foreign exchange gain in 2021 compared to net foreign exchange loss in 2020 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- decreased Net income attributable to non-controlling interests following the March 2021 acquisition of all outstanding common units of TC PipeLines, LP not beneficially owned by TC Energy
- lower Depreciation and amortization on our U.S. dollar-denominated assets primarily as a result of the weaker U.S. dollar and in Canadian Natural Gas Pipelines due to one section of the Canadian Mainline being fully depreciated in 2021
- higher Income tax expense mainly due to increased pre-tax earnings and higher flow-through income taxes on our Canadian rate-regulated pipelines
- higher Interest expense primarily due to lower capitalized interest as a result of the cessation for the Keystone XL pipeline project following the revocation of the Presidential Permit on January 2021, the change to equity accounting for our Coastal GasLink investment upon the sale of a 65 per cent interest in Coastal GasLink LP and the completion of the Napanee power plant in 2020, partially offset by the foreign exchange impact from a weaker U.S. dollar on translation of U.S. dollar-denominated interest
- lower AFUDC, predominantly due to the suspension of recording AFUDC on the Villa de Reyes project effective January 2021 as a result of ongoing project delays, partially offset by the NGTL System and U.S. natural gas pipeline expansion projects.

Comparable earnings per common share for the year ended December 31, 2022 and 2021 reflect the dilutive effect of common shares issued in 2022 and the impact of common shares issued for the acquisition of the remaining ownership interests in TC PipeLines, LP in March 2021, respectively. Refer to the Financial Condition section for further information on common share issuances.

Foreign exchange

Certain of our businesses generate all or most of their earnings in U.S. dollars and, since we report our financial results in Canadian dollars, changes in the value of the U.S. dollar against the Canadian dollar directly affect our comparable EBITDA and may also impact comparable earnings. As our U.S. dollar-denominated operations continue to grow, this exposure increases. A portion of the U.S. dollar-denominated comparable EBITDA exposure is naturally offset by U.S. dollar-denominated amounts below comparable EBITDA within Depreciation and amortization, Interest expense and other income statement line items. The balance of the exposure is actively managed on a rolling forward basis up to three years using foreign exchange derivatives; however, the natural exposure beyond that period remains. The net impact of the U.S. dollar movements on comparable earnings during the year ended December 31, 2022 after considering natural offsets and economic hedges was not significant.

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

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

year ended December 31 (millions of US$)	**2022**	**2021**	**2020**
Comparable EBITDA			
U.S. Natural Gas Pipelines	**3,142**	3,075	2,714
Mexico Natural Gas Pipelines[1]	**602**	602	666
Liquids Pipelines	**754**	884	955
	4,498	4,561	4,335
Depreciation and amortization	**(952)**	(911)	(877)
Interest on long-term debt and junior subordinated notes	**(1,267)**	(1,259)	(1,302)
Allowance for funds used during construction	**161**	101	182
Non-controlling interests and other	**(101)**	(66)	(117)
	2,339	2,426	2,221
Average exchange rate – U.S. to Canadian dollars	**1.30**	1.25	1.34

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

A 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 comparable earnings. In addition, foreign exchange gains or losses calculated for Mexico income tax purposes on the revaluation of the U.S. dollar-denominated monetary assets and liabilities result in a peso-denominated income tax exposure for these entities, leading to fluctuations in Income from equity investments and Income tax expense. As our U.S. dollar-denominated monetary assets and liabilities continue to grow, this exposure increases. These exposures are partially managed using foreign exchange derivatives, with the gains and losses on the derivatives recorded in Foreign exchange loss/(gain), net in our Consolidated statement of income.

Cash flows

Net cash provided by operations of $6.4 billion in 2022 was seven per cent lower than 2021 primarily due to the amount and timing of working capital changes and lower funds generated from operations. Comparable funds generated from operations in 2022 and 2021 were $7.4 billion.

Funds used in investing activities

Capital spending[1]

year ended December 31 (millions of $)	2022	2021	2020
Canadian Natural Gas Pipelines	**4,719**	2,737	3,608
U.S. Natural Gas Pipelines	**2,137**	2,820	2,785
Mexico Natural Gas Pipelines	**1,027**	129	173
Liquids Pipelines	**143**	571	1,442
Power and Energy Solutions	**894**	842	834
Corporate	**41**	35	58
	8,961	7,134	8,900

1 Capital spending includes Capital expenditures, Capital projects in development and Contributions to equity investments. Refer to Note 4, Segmented information, of our 2022 Consolidated financial statements for the financial statement line items that comprise total capital spending.

In 2022 and 2021, we invested $9.0 billion and $7.1 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 2022 and 2021 included contributions of $2.2 billion and $1.2 billion, respectively, to our equity investments, predominantly related to Coastal GasLink LP and Bruce Power.

Proceeds from sales of assets

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

In 2020, we completed the following asset divestiture 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.

Balance sheet

We continue to maintain a solid financial position while growing our total assets by $10.1 billion in 2022. At December 31, 2022, common shareholders' equity, including non-controlling interests, represented 35 per cent (2021 – 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 14 per cent (2021 – 15 per cent). Refer to the Financial Condition section for more information about our capital structure.

Dividends

We increased the quarterly dividend on our outstanding common shares by 3.3 per cent to $0.93 per common share for the quarter ending March 31, 2023 which equates to an annual dividend of $3.72 per common share. This was the twenty-third consecutive year we have increased the dividend on our common shares and is consistent with our goal of growing our common share dividend at an average annual rate of three to five per cent.

Dividend reinvestment and share purchase 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. To prudently fund our growth program that includes increased project costs on the NGTL System and following our July 2022 obligation to make an equity contribution of $1.9 billion to Coastal GasLink LP, we reinstated the issuance of common shares from treasury at a two per cent discount under our DRP, commencing with the dividends declared on July 27, 2022. On dividends declared in 2022, the participation rate by common shareholders was approximately 33 per cent, resulting in $607 million reinvested in common equity under the program. The discounted DRP is expected to be in place through the dividend declarations for the quarter ending June 30, 2023.

Cash dividends paid

year ended December 31 (millions of $)	2022	2021	2020
Common shares	**3,192**	3,317	2,987
Preferred shares	**106**	141	159

OUTLOOK

Comparable EBITDA and comparable earnings

We expect our 2023 comparable EBITDA to be higher than 2022 and our 2023 comparable earnings per common share are expected to be modestly higher than 2022 due to the net impact of the following:

- growth in the NGTL System from advancement of expansion programs
- higher contributions from our Mexico Natural Gas Pipelines segment primarily related to the new TGNH TSA with the CFE
- full-year impact from assets placed in service in 2022 and new projects anticipated to be placed in service in 2023, net of incremental depreciation expense
- modestly lower contributions from the Keystone Pipeline System including liquids marketing, primarily as a result of the de-rate associated with the Milepost 14 incident and continuing lower margins
- higher Interest expense as a result of long-term debt issuances, net of maturities and higher floating interest rates
- higher AFUDC related to the Southeast Gateway pipeline.

We continue to monitor developments in energy markets, our construction projects, regulatory proceedings and our asset divestiture program for any potential impacts on the above outlook.

Consolidated capital spending and equity investments

We expect to spend approximately $11.5 to $12.0 billion in 2023 on growth projects, maintenance capital expenditures and contributions to equity investments. The majority of the 2023 capital program is focused on NGTL System expansions, advancement of the Southeast Gateway Pipeline and the Coastal GasLink pipeline project, U.S. Natural Gas Pipelines projects, the Bruce Power life extension program and normal course maintenance capital expenditures.

Refer to the relevant business segment's outlook and Financial condition sections for additional details on expected earnings and capital spending for 2023.

CAPITAL PROGRAM

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

Our capital program consists of approximately $34 billion of secured projects that represent commercially supported, committed projects that are either under construction or are in or preparing to commence the permitting stage.

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

During 2022, we placed approximately $5.8 billion of primarily Canadian, U.S. and Mexico natural gas pipelines capacity capital projects in service and approximately $1.9 billion of maintenance capital expenditures were incurred.

All projects are subject to cost and timing adjustments due to factors including weather, market conditions, route refinement, land acquisition, permitting conditions, scheduling and timing of regulatory permits, as well as other potential restrictions and uncertainties, including inflationary pressures on labour and materials. Amounts exclude capitalized interest and AFUDC, where applicable.

Secured projects

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

(billions of $)	Expected in-service date	Estimated project cost	Project costs incurred as at December 31, 2022
Canadian Natural Gas Pipelines			
NGTL System[1]	2023	3.1	1.4
	2024	0.5	0.2
	2025+	0.6	—
Coastal GasLink[2]	2023	5.4	1.6
Regulated maintenance capital expenditures	2023-2025	2.2	—
U.S. Natural Gas Pipelines			
Modernization III (Columbia Gas)	2023-2024	US 1.2	US 0.6
Delivery market projects	2025	US 1.5	US 0.1
Other capital	2023-2028	US 1.8	US 0.2
Regulated maintenance capital expenditures	2023-2025	US 2.4	—
Mexico Natural Gas Pipelines			
Villa de Reyes – lateral and south sections[3]	2023	US 0.6	US 0.6
Tula – central and west sections[4]	—	US 0.5	US 0.4
Southeast Gateway	2025	US 4.5	US 0.8
Liquids Pipelines			
Other capacity capital	2023	US 0.1	US 0.1
Recoverable maintenance capital expenditures	2023-2025	0.1	—
Power and Energy Solutions			
Bruce Power – life extension[5]	2023-2027	4.3	2.2
Other capacity capital	2023	0.1	—
Other			
Non-recoverable maintenance capital expenditures[6]	2023-2025	0.7	0.2
		29.6	8.4
Foreign exchange impact on secured projects[7]		4.4	1.0
Total secured projects (Cdn$)		34.0	9.4

1 Estimated project costs include $0.7 billion, primarily reflected in 2023, for the Foothills portion of the West Path Delivery Program.

2 Subsequent to revised project agreements executed between Coastal GasLink LP and LNG Canada and amended agreements with our partners in Coastal GasLink LP, the estimated project cost noted above represents our share of anticipated partner equity contributions to the project. Mechanical completion is targeted for the end of 2023 and commercial in-service of the Coastal GasLink pipeline will occur after completion of commissioning the pipeline. Refer to the Canadian Natural Gas Pipelines – Significant events section for additional information.

3 We are currently working with the CFE on completing the remaining sections of the Villa de Reyes pipeline, expecting commercial in-service in 2023. Refer to the Mexico Natural Gas Pipelines – Significant events section for additional information.

4 With the CFE, we are assessing the completion of the central section of the Tula pipeline, subject to an FID. We are also working together to advance the completion of the west section. Refer to the Mexico Natural Gas Pipelines – Significant events section for additional information.

5 Reflects our expected share of cash contributions for the Bruce Power Unit 6 Major Component Replacement (MCR) program, expected to be in service in 2023, and the Unit 3 MCR, expected to be in service in 2026, as well as amounts to be invested under the Asset Management program through 2027 and the incremental uprate initiative. Refer to the Power and Energy Solutions – Significant events section for additional information.

6 Includes non-recoverable maintenance capital expenditures from all segments and is primarily comprised of our proportionate share of maintenance capital expenditures for Bruce Power and other Power and Energy Solutions assets.

7 Reflects U.S./Canada foreign exchange rate of 1.35 at December 31, 2022.

Projects under development

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

Canadian Natural Gas Pipelines

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

U.S. Natural Gas Pipelines

Delivery Market Projects

Projects are in development that are expected to replace, upgrade and expand certain U.S. Natural Gas Pipelines facilities while reducing emissions along portions of our pipeline systems in principal delivery markets. The enhanced facilities are expected to improve reliability of our systems and allow for additional transportation services under long-term contracts to address growing demand in the U.S. Midwest and the Mid-Atlantic regions, while reducing direct carbon dioxide equivalent emissions.

Renewable Natural Gas Hub Development

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

Other Opportunities

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

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

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

Mexico Natural Gas Pipelines

On August 4, 2022, we announced a strategic alliance with the CFE, Mexico's state-owned electric utility, to accelerate the development of natural gas infrastructure in the central and southeast regions of Mexico. Along with the assets currently under construction, we are assessing the completion of the central section of Tula, subject to an FID in the first half of 2023.

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

Liquids Pipelines

We remain focused on maximizing the value of our liquids assets by finding solutions to enable flexible and tailored solutions for our customers. We continue to seek ways of optimizing our existing assets by extending connectivity between supply and delivery markets. We are pursuing selective growth opportunities to add incremental value to our business and expansions that leverage latent capacity on our existing infrastructure. We remain disciplined in our approach and will position our business development activities strategically to capture opportunities within our risk preferences.

Power and Energy Solutions

Bruce Power

Life Extension Program

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

Uprate Initiative

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

Development-Stage Projects

Ontario Pumped Storage

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

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

Canyon Creek Pumped Storage

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

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

Renewable Energy Contracts and/or Investment Opportunities

We continue to pursue potential contracts and/or investment opportunities in wind, solar and energy storage projects to meet the electricity needs of the U.S. portion of the Keystone Pipeline System and supply renewable energy products and services to industrial and oil and gas sectors proximate to our in-corridor demand. To date, we have contracted approximately 600 MW from wind and solar projects.

Other Opportunities

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

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

Other Energy Solutions

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

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

Alberta Carbon Grid

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

Hydrogen Hubs

We have entered into individual Joint Development Agreements (JDAs) with Nikola Corporation (Nikola) and Hyzon Motors Inc. (Hyzon) to support customer-driven hydrogen production for long-haul transportation, power generation, large industrials and heating customers across the U.S. and Canada. Under their JDA, Nikola will be a long-term anchor customer for hydrogen production infrastructure supporting hydrogen-fueled, zero-emission, heavy-duty trucks and the co-development of large-scale green and blue hydrogen production hubs. The Hyzon JDA is expected to support the development of hydrogen production facilities focused on zero-to-negative carbon intensity hydrogen from RNG, biogas and other sustainable sources. These facilities are expected to be located close to demand, supporting Hyzon’s back-to-base vehicle deployments.

Our significant pipeline, storage and power assets can potentially be leveraged to lower the cost and increase the speed of development of these hubs. This may include exploring the integration of pipeline assets to enable hydrogen distribution and storage via pipeline and/or to deliver carbon dioxide to permanent sequestration sites to decarbonize the hydrogen production process. In April 2022, we announced a plan to evaluate a hydrogen production hub that would produce an estimated 60 tonnes of hydrogen per day, with the capacity to increase to 150 tonnes of hydrogen per day in the future, on 140 acres in Crossfield, Alberta, where we currently operate a natural gas storage facility. We expect an FID in 2024, subject to customary regulatory approvals.

NATURAL GAS PIPELINES BUSINESS

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

- wholly-owned natural gas pipelines – 88,472 km (54,973 miles)
- partially-owned natural gas pipelines – 5,259 km (3,267 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 532 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

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

Our key areas of focus include:

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

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

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

Recent highlights

Canadian Natural Gas Pipelines

- approximately $3.2 billion of projects placed in service in 2022, primarily related to the NGTL System expansions
- sanctioned the $0.6 billion VNBR project on the NGTL System
- received remaining primary regulatory approvals on the NGTL System/Foothills West Path Delivery Program
- advanced construction of the Coastal GasLink pipeline project
- announced the signing of option agreements to sell a 10 per cent equity interest in Coastal GasLink LP to Indigenous communities across the project corridor.

U.S. Natural Gas Pipelines

- placed approximately US$2.1 billion of capital projects into service including Louisiana XPress on Columbia Gulf in addition to Elwood Power and Wisconsin Access on ANR
- sanctioned an additional US$1.3 billion of growth projects including the greenfield pipeline Gillis Access project, the KO Transmission acquisition by Columbia Gas and Ventura XPress on ANR
- ANR uncontested rate case settlement filed with FERC and Great Lakes rate case settlement approved by FERC
- achieved record throughput volumes on a number of our pipelines.

Mexico Natural Gas Pipelines

- announced a strategic alliance with Mexico's state-owned electric utility, the CFE, resolving previous international arbitrations related to the Villa de Reyes and Tula pipelines
- sanctioned the Southeast Gateway pipeline under our alliance with the CFE, a 1.3 Bcf/d, 715 km (444 mile) offshore natural gas pipeline that will serve the southeast region of Mexico with an expected in-service by mid-2025
- the lateral section of the Villa de Reyes pipeline was mechanically completed in second quarter 2022. We placed the north section of Villa de Reyes and the east section of Tula in service in third quarter 2022. In addition, we are working with the CFE to advance the construction of the remaining sections of both pipelines
- continued feasibility assessments with the CFE on potential alternatives to complete the central section of the Tula pipeline, subject to an FID in the first half of 2023
- overall pipeline 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 40 shows our extensive pipeline network in North America that connects major supply sources and markets. The highlights shown on the map include:

Canadian Natural Gas Pipelines

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

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

U.S. Natural Gas Pipelines

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

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

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

Other U.S. Natural Gas Pipelines: We have ownership interests in eight wholly-owned or partially-owned natural gas pipelines serving major markets in the U.S. that were previously held by our subsidiary, TC PipeLines, LP.

Mexico Natural Gas Pipelines

Sur de Texas: This offshore pipeline transports natural gas from Texas to power and industrial markets in the eastern and central regions of Mexico. The average volumes transported by this pipeline in 2022 supplied approximately 15 per cent of Mexico's total natural gas imports via pipelines. We own a 60 per cent equity interest and are the operator of this pipeline.

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

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

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

Regulation of tolls and cost recovery

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

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

Business environment and strategic priorities

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

We have significant pipeline footprints that serve two of the most prolific supply regions of North America – the WCSB and the Appalachian basin. Our pipelines also source natural gas from other significant basins including the Rockies, Williston, Haynesville, Fayetteville and Anadarko basins as well as the Gulf of Mexico. We expect continued growth in North American natural gas production to meet demand within growing domestic markets, particularly in the electric generation and industrial sectors which benefit from a relatively low natural gas price. In addition, North American supply is expected to benefit from increased natural gas demand in Mexico and growing access to international markets via LNG exports. We expect North American natural gas demand, including LNG exports, of approximately 125 Bcf/d by 2027, reflecting an increase of approximately 16 Bcf/d from 2022 levels.

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

Changing demand
The abundant supply of natural gas has supported increased demand, particularly in the following areas:
- natural gas-fired power generation
- global LNG exports
- petrochemical and industrial facilities
- Alberta oil sands.

Natural gas producers continue to progress opportunities to sell natural gas to global markets which involves connecting natural gas supplies to LNG export terminals, both operating and proposed, along the U.S. Gulf Coast, and the east and west coasts of Canada, the U.S. and Mexico. The increasing export of natural gas to Mexico is driven by the CFE's need to serve existing markets and requires pipelines to serve new regions. We are forecasting significant gas demand growth in the future to support economic expansion and industrial load growth, conversion to lower carbon fuels for industrial and power generation use, and LNG export prospects. The demand created by the addition of these new markets provides additional opportunities for us to build new pipeline infrastructure and to increase throughput on our existing pipelines. We believe that natural gas is a key energy transition fuel for Mexico.

The growing focus on ESG is expected to result in shifting market dynamics as both energy demand and pressure for accelerated climate action increase simultaneously.

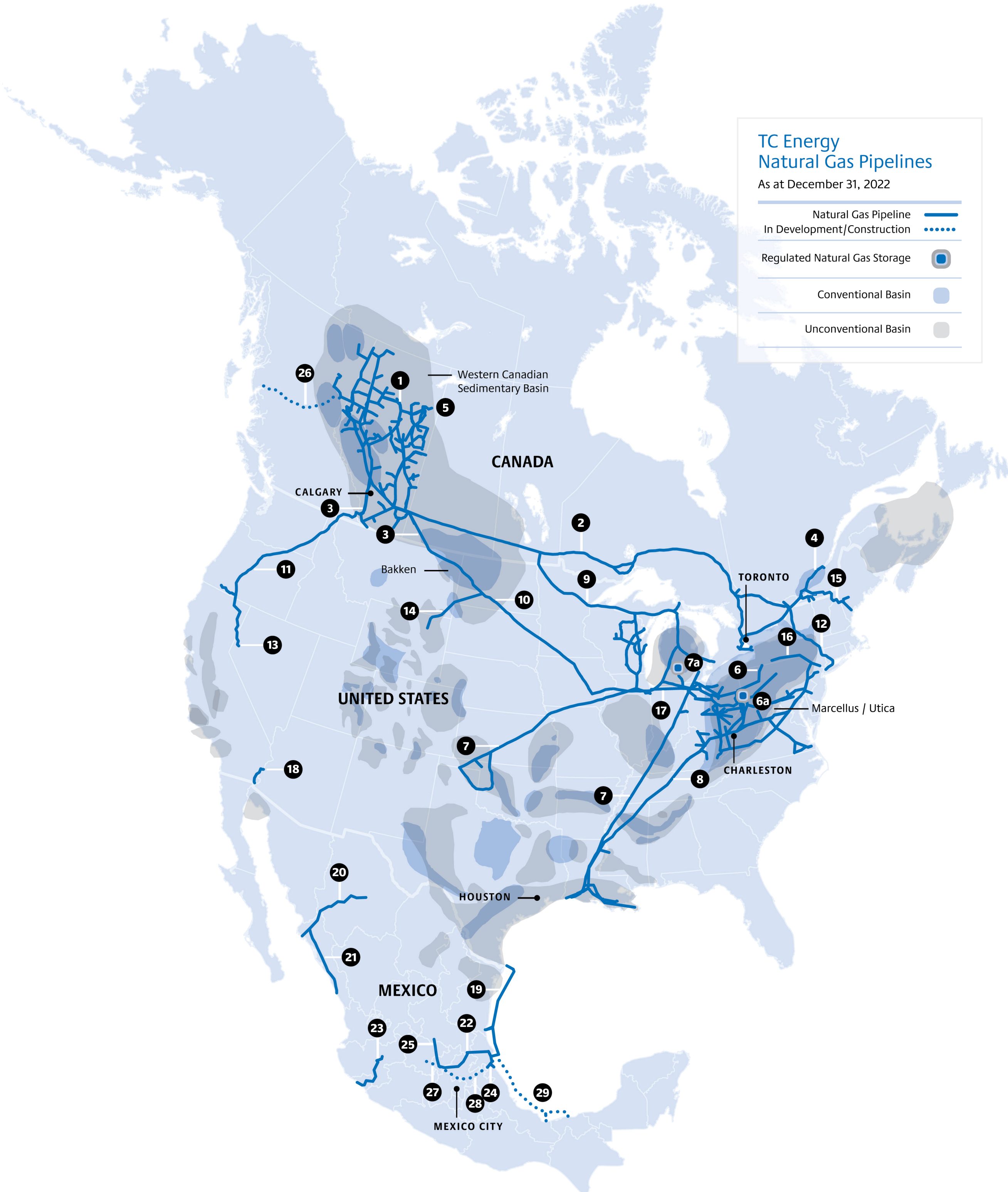
Commodity prices
In general, the profitability of our natural gas pipelines business is not directly tied to commodity prices given we are a transporter of the commodity and the transportation tolls are not tied to the price of natural gas. However, the cyclical supply and demand nature of commodities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

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

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

In 2023, we will continue to focus on the execution of our existing capital program that includes progressing construction on our Southeast Gateway pipeline in Mexico, further investment in the NGTL System, mechanical completion of the Coastal GasLink pipeline as well as the completion and initiation of new pipeline projects in the United States. We will also continue to pursue the next wave of growth opportunities. Our goal is to place all of our projects into service on time and on budget while ensuring the safety of our people, of the environment and the general public impacted by the construction and operation of these facilities.

Our marketing entities will complement our natural gas 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, 2022
Natural Gas Pipeline
In Development/Construction
Regulated Natural Gas Storage
Conventional Basin
Unconventional Basin
Western Canadian
Sedimentary Basin
CANADA
CALGARY
Bakken
UNITED STATES
TORONTO
Marcellus / Utica
CHARLESTON
HOUSTON
MEXICO
MEXICO CITY
1
2
3
3
4
5
6
6a
7
7
7a
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28
29

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

		Length	Description	Ownership
	Canadian pipelines			
1	NGTL System	24,631 km (15,305 miles)	Receives, transports and delivers natural gas within Alberta and British Columbia, and connects with Canadian Mainline, Foothills and third-party pipelines.	100%
2	Canadian Mainline	14,082 km (8,750 miles)	Transports natural gas from the Alberta/Saskatchewan border and the Ontario/U.S. border to serve eastern Canada and interconnects to the U.S.	100%
3	Foothills	1,237 km (769 miles)	Transports natural gas from central Alberta to the U.S. border for export to the U.S. Midwest, Pacific Northwest, California and Nevada.	100%
4	Trans Québec & Maritimes (TQM)	649 km (403 miles)	Connects with the Canadian Mainline near the Ontario/Québec border to transport natural gas to the Montréal to Québec City corridor and interconnects with Portland.	50%
5	Ventures LP	133 km (83 miles)	Transports natural gas to the oil sands region near Fort McMurray, Alberta.	100%
	Great Lakes Canada[1]	60 km (37 miles)	Transports natural gas from the Great Lakes system in the U.S. to a point near Dawn, Ontario through a connection at the U.S. border underneath the St. Clair River.	100%
	U.S. pipelines and gas storage assets			
6	Columbia Gas	18,768 km (11,662 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	247 Bcf	Provides regulated underground natural gas storage service from several facilities (not all shown) to customers in key mid-western markets.	
8	Columbia Gulf	5,419 km (3,367 miles)	Transports natural gas to various markets and pipeline interconnects in the southern U.S. and U.S. Gulf Coast.	100%
9	Great Lakes	3,404 km (2,115 miles)	Connects with the Canadian Mainline near Emerson, Manitoba and to Great Lakes Canada near St Clair, Ontario, plus interconnects with ANR at Crystal Falls and Farwell in Michigan, to transport natural gas to eastern Canada and the U.S. Midwest.	100%
10	Northern Border	2,272 km (1,412 miles)	Transports WCSB, Bakken and Rockies natural gas from connections with Foothills and Bison to U.S. Midwest markets.	50%
11	Gas Transmission Northwest (GTN)	2,216 km (1,377 miles)	Transports WCSB and Rockies natural gas to Washington, Oregon and California. Connects with Tuscarora and Foothills.	100%
12	Iroquois	669 km (416 miles)	Connects with the Canadian Mainline and serves markets in New York.	50%
13	Tuscarora	491 km (305 miles)	Transports natural gas from GTN at Malin, Oregon to markets in northeastern California and northwestern Nevada.	100%
14	Bison	488 km (303 miles)	Transports natural gas from the Powder River basin in Wyoming to Northern Border in North Dakota.	100%
15	Portland	475 km (295 miles)	Connects with TQM near East Hereford, Québec to deliver natural gas to customers in the U.S. Northeast and Canadian Maritimes.	61.7%

		Length	Description	Ownership
16	Millennium	424 km (263 miles)	Transports natural gas primarily sourced from the Marcellus shale play to markets across southern New York and the lower Hudson Valley as well as to New York City through its pipeline interconnections.	47.5%
17	Crossroads	325 km (202 miles)	Interstate natural gas pipeline operating in Indiana and Ohio with multiple interconnects to other pipelines.	100%
18	North Baja	138 km (86 miles)	Transports natural gas between Arizona and California and connects with a third-party pipeline on the California/Mexico border.	100%
	Mexico pipelines			
19	Sur de Texas	770 km (478 miles)	Offshore pipeline that transports natural gas from the U.S./Mexican border near Brownsville, Texas, to Mexican power plants in Altamira, Tamaulipas and Tuxpan, Veracruz, where it interconnects with the Tamazunchale and Tula pipelines and other third-party facilities.	60%
20	Topolobampo	572 km (355 miles)	Transports natural gas to El Oro and Topolobampo, Sinaloa, from interconnects with third-party pipelines in El Encino, Chihuahua and El Oro.	100%
21	Mazatlán	430 km (267 miles)	Transports natural gas from El Oro to Mazatlán, Sinaloa and connects to the Topolobampo Pipeline at El Oro.	100%
22	Tamazunchale	370 km (230 miles)	Transports natural gas from Naranjos, Veracruz to Tamazunchale, San Luis Potosi and on to El Sauz, Querétaro in central Mexico.	100%
23	Guadalajara	313 km (194 miles)	Bidirectional pipeline that connects imported LNG supply near Manzanillo and continental gas supply near Guadalajara to power plants and industrial customers in the states of Colima and Jalisco.	100%
24	Tula – east section	114 km (71 miles)	The east section of the Tula pipeline transports natural gas from Sur de Texas to power plants in Tuxpan, Veracruz.	100%
25	Villa de Reyes – north section	206 km (128 miles)	The north section of the Villa de Reyes pipeline is interconnected to our Tamazunchale pipeline and third-party systems, supporting gas deliveries to a power plant in Villa de Reyes, San Luis Potosí.	100%
	Under construction			
	Canadian pipelines			
26	Coastal GasLink	670 km (416 miles)	A greenfield project to deliver natural gas from the Montney gas producing region to LNG Canada's liquefaction facility under construction near Kitimat, British Columbia.	35%
	NGTL System 2023 Facilities[1,2]	168 km (105 miles)	Components of each of the 2021 NGTL System Expansion Program, 2022 NGTL System Expansion Program, NGTL System/Foothills West Path Delivery Program and 2023 NGTL System Intra-Basin Expansion, along with other facilities, with expected in-service dates in 2023.	100%
	U.S. pipelines			
	North Baja XPress[3]	n/a	An expansion project on North Baja to meet increased customer demand in Arizona and California, with expected in-service in 2023.	100%
	Alberta XPress[3]	n/a	An expansion project of ANR through compressor station modifications and additions, placed in service in January 2023.	100%

	Under construction (continued)	Length	Description	Ownership
	Mexico pipelines			
27	Villa de Reyes – lateral and south sections	230 km (143 miles)	These pipeline sections will connect to the operational north section of the Villa de Reyes pipeline and Tula pipeline. The lateral section was mechanically completed in 2022.	100%
28	Tula – central and west sections	200 km (124 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%
29	Southeast Gateway	715 km (444 miles)	Offshore pipeline that will connect to the Tula pipeline and transport gas to delivery points in Coatzacoalcos, Veracruz and Paraíso, Tabasco in Mexico's southeast region.	100%
	Permitting and pre-construction phase			
	NGTL System 2023/2024/2025+ Facilities[1,2]	96 km (60 miles)	Components of each of the NGTL System/Foothills West Path Delivery Program and the 2023 NGTL System Intra-Basin Expansion with expected in-service dates commencing in 2023, along with the VNBR project expected to be placed in service in 2026.	100%
	U.S. pipelines			
	VR Project[3]	n/a	A delivery market project on Columbia Gas that will replace and upgrade certain facilities while improving reliability and reducing emissions with expected in-service in 2025.	100%
	WR Project[3]	n/a	A delivery market project on ANR that will replace and upgrade certain facilities while improving reliability and reducing emissions with expected in-service in 2025.	100%
	GTN XPress[3]	n/a	An expansion project of GTN through compressor station modifications and additions with expected in-service in 2023 and 2024.	100%
	Virginia Electrification Project[3]	n/a	A delivery market project on Columbia Gas that will replace and upgrade certain facilities while improving reliability and reducing emissions, including electrification, with expected in-service in 2024.	100%
	Ventura XPress Project[3]	n/a	A project on ANR that will replace and upgrade certain facilities improving base system reliability with expected in-service in 2025.	100%
	Gillis Access Project[1,2]	68 km (42 miles)	A greenfield pipeline system project that will connect supplies from the Haynesville basin at Gillis, Louisiana to markets elsewhere in Louisiana with expected in-service in 2024.	100%
	East Lateral XPress[1,3]	n/a	An expansion project on Columbia Gulf through compressor station modifications and additions with expected in-service in 2025.	100%

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

Canadian Natural Gas Pipelines

UNDERSTANDING OUR CANADIAN NATURAL GAS PIPELINES SEGMENT

The Canadian Natural Gas Pipelines 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 the Coastal GasLink pipeline, which is currently under construction.

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

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

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

SIGNIFICANT EVENTS

Coastal GasLink

The 670 km (416 mile) Coastal GasLink pipeline project is currently under construction and will have an initial capacity of approximately 2.2 PJ/d (2.1 Bcf/d). Once complete, the pipeline will transport natural gas from a receipt point in the Dawson Creek area of British Columbia to a natural gas liquefaction facility near Kitimat, British Columbia. The LNG facility, which is owned by LNG Canada, is also currently under construction. Transportation service on the pipeline is underpinned by 25-year TSAs (with renewal provisions) with each of the five LNG Canada participants. We hold a 35 per cent ownership interest in Coastal GasLink LP, the partnership entity that owns the pipeline and that has been contracted to develop, construct and operate the pipeline.

The Coastal GasLink pipeline project is approximately 84 per cent complete. The entire route has been cleared, grading is more than 96 per cent complete and more than 510 km of pipeline has been welded, lowered and backfilled with restoration activities underway in many areas.

On July 28, 2022, Coastal GasLink LP executed definitive agreements with LNG Canada, TC Energy and the other Coastal GasLink LP partners (collectively, the July 2022 agreements) that amended existing project agreements to address and resolve disputes over certain incurred and anticipated costs of the Coastal GasLink pipeline project. The revised agreements incorporated a target date for mechanical completion of December 31, 2023 and a new capital cost for the project to reflect, among other changes, scope increases and the impacts of COVID-19, weather and other events outside the control of Coastal GasLink LP.

Subsequent to execution of the July 2022 agreements, the project has faced material cost pressures that reflect challenging conditions in the Western Canadian labour market, shortages of skilled labour, impacts of contractor underperformance and disputes, as well as other unexpected events, including drought conditions and erosion and sediment control challenges. A comprehensive cost and schedule risk analysis (CSRA) was conducted to assess current market conditions and potential risks and uncertainties facing the remaining project scope. As a result of the CSRA, the estimate of the cost to complete the pipeline has increased to approximately $14.5 billion. This estimate excludes potential cost recoveries and incorporates contingencies for certain factors that may be outside the control of Coastal GasLink LP, such as labour conditions, contractor underperformance and weather-related events. The work plan continues to target mechanical completion by year-end 2023, with commissioning and restoration work continuing into 2024 and 2025. TC Energy expects to fund the incremental project costs and is actively pursuing cost mitigants and recoveries that may partially offset a portion of these costs, some of which may not be conclusively determined until after the pipeline is in service. The CSRA review also considered the potential impact of an extension of construction well into 2024. In that event, costs would increase further by up to $1.2 billion.

This increase in the capital cost estimate for the project and our corresponding funding requirements were indicators that a decrease in the value of our equity investment had occurred.

As a result, we completed a valuation assessment and concluded that the fair value of our investment was below its carrying value at December 31, 2022. We determined that this was an other-than-temporary impairment of our equity investment in Coastal GasLink LP and, as a result, we recognized a pre-tax impairment of $3.0 billion ($2.6 billion after tax) in fourth quarter 2022. The pre-impairment carrying value of our investment in Coastal GasLink LP at December 31, 2022 consisted of amounts in Equity investments ($2.8 billion) and Loans receivable from affiliates ($250 million), which were reduced to a nil balance. Due to the funding provisions of the July 2022 agreements, we expect to fund an additional $3.3 billion related to the revised estimated capital cost to complete the Coastal GasLink pipeline, and a significant portion of this future investment in Coastal GasLink LP is expected to be impaired. We will continue to assess for other-than-temporary declines in the fair value of our investment and the extent of any additional impairment charges will depend on our valuation assessment performed at the respective reporting date. Refer to Note 7, Coastal GasLink, of our 2022 Consolidated financial statements for additional information.

Going forward, project costs will be funded in part by existing project-level credit facilities with a revised total capacity of $8.4 billion following an expansion of these facilities by $1.6 billion in third quarter 2022. Additional equity financing required to fund construction of the pipeline will initially be provided through a subordinated loan agreement between TC Energy and Coastal GasLink LP, which was originally put in place in fourth quarter 2021 and amended in July 2022. Following this amendment, draws by Coastal GasLink LP on this loan will be repaid with funds from equity contributions to the partnership by the Coastal GasLink LP partners, including us, subsequent to the in-service date of the Coastal GasLink pipeline when final project costs are known. We expect that, in accordance with contractual terms, the additional equity contributions required as a result of the increase in capital cost will be predominantly funded by us, except under certain conditions, but will not result in a change to our 35 per cent ownership. Committed capacity under this subordinated loan agreement was $1.3 billion at December 31, 2022 with an outstanding balance of $250 million, prior to the above impairment. The committed capacity under this loan will increase as required in the future to support the estimated $3.3 billion of additional equity financing requirements through completion of construction of the Coastal GasLink pipeline. We currently estimate our portion of the equity contributions to Coastal GasLink LP over the project life to be approximately $5.4 billion, including contributions recognized to the end of 2022.

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

NGTL System

In the year ended December 31, 2022, the NGTL System placed approximately $3.0 billion of capacity projects in service.

2021 NGTL System Expansion Program

The 2021 NGTL System Expansion Program consists of 344 km (214 miles) of new pipeline, three new compressor units and associated facilities and is expected to add 1.59 PJ/d (1.45 Bcf/d) of incremental capacity to the NGTL System. Construction of the expansion program is nearing completion with an estimated capital cost of the program of $3.5 billion due to regulatory and weather delays, along with inflationary pressures throughout construction. As of December 31, 2022, $3.0 billion of the program's facilities have been placed in service, adding 1.4 PJ/d (1.3 Bcf/d) of incremental capacity to the NGTL System. The facilities required to declare the remaining capacity are expected to be placed in service in first quarter 2023.

2022 NGTL System Expansion Program

The 2022 NGTL System Expansion Program consists of approximately 166 km (103 miles) of new pipeline, one compressor unit and associated facilities and is expected to provide incremental capacity of approximately 773 TJ/d (722 MMcf/d) to meet firm-receipt and intra-basin delivery requirements with eight-year minimum terms. Inflationary pressures and regulatory delays have contributed to an increased estimated program cost of $1.5 billion. As of December 31, 2022, $0.6 billion of facilities have been placed in service, with the remaining facilities expected to be placed in service in the first half of 2023.

NGTL System/Foothills West Path Delivery Program

The NGTL System/Foothills West Path Delivery Program is a multi-year expansion of the NGTL System and Foothills system to facilitate incremental contracted export capacity connecting to the GTN pipeline system. The combined NGTL System and Foothills program consists of approximately 107 km (66 miles) of pipeline and associated facilities and is underpinned by 275 TJ/d (258 MMcf/d) of new firm-service contracts with terms that exceed 30 years. In 2022, construction was initiated on three of the six pipeline segments with one pipeline segment being placed in service in fourth quarter 2022 and construction continuing into 2023 on the other two segments. The primary regulatory approvals have been received with certain required ancillary permits still outstanding and are anticipated in the first half of 2023. Terrain complexity, inflationary pressures, permitting delays and additional permitting conditions have contributed to an estimated program cost of $1.6 billion. As of December 31, 2022, $0.3 billion of facilities have been placed in service, with all remaining facilities forecasted to be placed in service throughout 2023, subject to receiving timely approval of outstanding ancillary permits.

2023 NGTL System Intra-Basin Expansion

The NGTL System Intra-Basin Expansion consists of 23 km (14 miles) of new pipeline and two new compressor stations and is underpinned by approximately 255 TJ/d (238 MMcf/d) of new firm-service contracts with 15-year terms. The estimated capital cost of the expansion is $0.6 billion. Construction activities commenced in 2022 with anticipated in-service dates commencing in late 2023.

Valhalla North and Berland River Project

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

Canadian Mainline

In the year ended December 31, 2022, the Canadian Mainline placed approximately $0.2 billion of capacity projects in service.

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 $)	**2022**	**2021**	**2020**
NGTL System	**1,853**	1,649	1,509
Canadian Mainline	**770**	838	911
Other Canadian pipelines[1]	**183**	188	146
Comparable EBITDA	**2,806**	2,675	2,566
Depreciation and amortization	**(1,198)**	(1,226)	(1,273)
Comparable EBIT	**1,608**	1,449	1,293
Specific items:			
Coastal GasLink LP impairment charge	**(3,048)**	—	—
Gain on partial sale of Coastal GasLink LP	**—**	—	364
Segmented (losses)/earnings	**(1,440)**	1,449	1,657

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 (losses)/earnings decreased by $2,889 million in 2022 compared to 2021 and decreased by $208 million in 2021 compared to 2020 and included the following specific items which have been excluded from our calculation of comparable EBIT and comparable earnings:

- a pre-tax impairment charge of $3.0 billion in 2022 related to our equity investment in Coastal GasLink LP. Refer to Note 7, Coastal GasLink, of our 2022 Consolidated financial statements for additional information
- a pre-tax gain of $364 million in 2020 related to the sale of a 65 per cent equity interest in Coastal GasLink LP.

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 $)	**2022**	**2021**	**2020**
Net income			
NGTL System	**708**	631	565
Canadian Mainline	**223**	213	160
Average investment base			
NGTL System	**17,493**	15,560	14,070
Canadian Mainline	**3,735**	3,724	3,673

Net income for the NGTL System increased by $77 million in 2022 compared to 2021 and $66 million in 2021 compared to 2020 mainly due to a higher average investment base resulting from continued system expansions. The NGTL System is operating under the 2020-2024 Revenue Requirement Settlement which includes an approved ROE of 10.1 per cent on 40 per cent deemed common equity. This settlement provides the NGTL System the opportunity to increase depreciation rates if tolls fall below specified levels and an incentive mechanism for certain operating costs where variances from projected amounts are shared with our customers.

Net income for the Canadian Mainline increased by $10 million in 2022 compared to 2021 as a result of higher incentive earnings. Net income in 2021 increased by $53 million compared to 2020 mainly as a result of higher incentive earnings and the elimination of a $20 million after-tax annual TC Energy contribution included in the previous settlement ended in 2020. The Canadian Mainline is operating under the 2021-2026 Mainline Settlement which includes an approved ROE of 10.1 per cent on 40 per cent deemed common equity and an incentive to decrease costs and increase revenues on the pipeline under a beneficial sharing mechanism with our customers. In 2020, the Canadian Mainline operated under the terms of the 2015-2030 Tolls Application approved in 2014. The terms of the previous settlement included an ROE of 10.1 per cent on deemed common equity of 40 per cent, an incentive mechanism with both upside and downside risk and a $20 million after-tax annual TC Energy contribution to reduce the revenue requirement.

Comparable EBITDA

Comparable EBITDA for Canadian Natural Gas Pipelines was $131 million higher in 2022 compared to 2021 primarily due to the net effect of:

- higher flow-through financial charges and depreciation as well as increased rate-base earnings on the NGTL System
- lower flow-through depreciation partially offset by higher flow-through income taxes and financial charges and increased incentive earnings on the Canadian Mainline
- lower Coastal GasLink development fee revenue due to timing of revenue recognition.

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

- higher flow-through depreciation and income taxes as well as increased rate-base earnings on the NGTL System
- Coastal GasLink development fee revenue which commenced in second quarter 2020
- lower flow-through depreciation and financial charges, partially offset by higher flow-through income taxes, increased incentive earnings and elimination of the TC Energy contribution on the Canadian Mainline.

Depreciation and amortization

Depreciation and amortization was $28 million lower in 2022 compared to 2021 and $47 million lower in 2021 compared to 2020 due to one section of the Canadian Mainline being fully depreciated in 2021, partially offset by higher depreciation on the NGTL System from expansion facilities that were placed in service.

OUTLOOK

Comparable EBITDA and comparable earnings

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

Canadian Natural Gas Pipelines comparable EBITDA and earnings in 2023 are expected to be higher than 2022 mainly due to continued growth of the NGTL System as we advance expansion programs which extend and expand supply facilities, enhance delivery facilities in Alberta and provide incremental service at our major border delivery locations in response to requests for firm service on the system. Due to the flow-through treatment of certain costs on our Canadian rate-regulated pipelines, changes in these costs can impact our comparable EBITDA despite having no significant effect on comparable earnings.

Capital spending

We spent a total of $3.3 billion in 2022 in our Canadian Natural Gas Pipelines business on growth projects and maintenance capital expenditures. We expect to spend approximately $2.8 billion in 2023, primarily on NGTL System expansion projects and maintenance capital expenditures, all of which are immediately reflected in investment base and related earnings.

We also contributed $1.4 billion to our investment in Coastal GasLink LP in 2022, and are obligated to contribute an additional $0.5 billion in 2023, primarily related to installments of partner equity contributions in accordance with the July 2022 agreements with Coastal GasLink LP. We also expect to make further contributions related to the revised estimated capital cost of the project in 2023. Refer to the Canadian Natural Gas Pipelines – Significant events section for additional information on Coastal GasLink.

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. interstate natural gas business. FERC approves maximum transportation rates that are cost-based and are designed to recover the pipeline's investment, operating expenses and a reasonable return for our investors. In the U.S., we have the ability to contract for negotiated or discounted rates with shippers.

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

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

PHMSA compliance regulation

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

In 2016, PHMSA proposed new rules to revise the U.S. Federal Pipeline Safety Regulations and issued a Notice of Proposed Rulemaking (NPRM) for onshore natural gas transmission and gathering lines that impose more stringent inspection, reporting and integrity management requirements on operators. The rulemaking is commonly referred to as the Gas Mega Rule, and was subsequently issued in three separate parts focusing on the following: 1) confirmation of maximum allowable operating pressure and expanded integrity assessments in areas outside of HCAs, known as moderate consequence areas; 2) additional integrity management repair criteria, corrosion inspections and corrosion control; and 3) expanded jurisdictional gathering line definition. The first and largest of the three parts, addressing the confirmation of maximum allowable operating pressure, was published as a final rule in October 2019. Part one was followed by the gathering line definition rule (part three) which was issued as final in November 2021. Lastly, part two, with additional integrity management repair criteria and corrosion inspections, completed the Gas Mega Rule with its issuance in August 2022. With all parts of the Gas Mega Rule promulgated, we continue to assess the cumulative operational and financial impacts related to its numerous revisions and newly introduced language, with a specific focus on those aspects associated with the 15-year implementation window related to part one that began in July 2020 and, for which, we seek cost recovery.

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

Lastly, the requirement of valve installation and minimum rupture detection standards rulemaking was published as a final rule in April 2022. The non-retroactive rupture detection and mitigation rule defines when the installation of automatic shutoff valves, remote-controlled valves or manual valves is required on newly constructed pipelines or certain pipe replacements six inches and larger in diameter and meeting a cumulative length requirement. The rule primarily targets Class 3 and 4 locations and HCAs but also includes more stringent mandates on the timeliness of response and the ability for the Supervisory Control and Data Acquisition System to detect, locate and alert gas controllers of a potential rupture. In addition, PHMSA mandates emergency response protocols including a 30-minute requirement to have a gas release fully isolated from the time it was identified as a rupture.

SIGNIFICANT EVENTS

Columbia Gas Section 4 Rate Case

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

ANR Section 4 Rate Case

ANR filed a Section 4 rate case with FERC in January 2022 requesting an increase to ANR's maximum transportation rates effective August 1, 2022, subject to refund upon completion of the rate proceeding. In November 2022, ANR notified FERC that it reached a settlement-in-principle with its customers. In January 2023, the presiding Administrative Law Judge certified the settlement as uncontested and recommended it for approval by FERC. While there is no timeframe in which FERC must act on the settlement, in line with other recent rate case settlement approval timelines, we expect to receive FERC approval of the settlement in early 2023.

Great Lakes Rate Settlement

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

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

KO Transmission Enhancement Acquisition

On April 28, 2022, we approved the approximately US$80 million acquisition of KO Transmission assets to be integrated into our Columbia Gas pipeline. The expanded footprint is expected to provide additional last-mile connectivity of Columbia Gas into northern Kentucky and southern Ohio to growing LDC markets and a platform for future capital investments including future conversions of coal-fueled power plants in the region. FERC approval for the acquisition was received in November 2022 and the transaction closed in February 2023.

Renewable Natural Gas Hub Development

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

Alberta XPress Project

The Alberta XPress project, an expansion project on ANR that utilizes existing capacity on the Great Lakes and the Canadian Mainline systems to connect growing supply from the WCSB to U.S. Gulf Coast LNG export markets, was placed in service in January 2023.

Louisiana XPress Project

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

Elwood Power and Wisconsin Access Projects

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

Gillis Access Project

In November 2022, we sanctioned the development of the Gillis Access project, a 1.5 Bcf/d greenfield pipeline system that will connect supplies from the Haynesville basin at Gillis to markets elsewhere in Louisiana. The 68 km (42 mile) Louisiana header system will also enable the rapidly growing Louisiana LNG export market to access Haynesville-sourced gas production as well as create a platform for further growth into the southeast Louisiana markets. The project has an anticipated in-service date in 2024 and a total estimated cost of US$0.4 billion.

In February 2023, we approved a 63 km (39 mile), 1.4 Bcf/d extension of the Gillis Access project to further connect supplies from the Haynesville basin at Gillis. Subject to customer FID, the project has an anticipated in-service date in 2025 and a total estimated cost of US$0.3 billion.

Ventura XPress Project

In December 2022, we approved the Ventura XPress project, a set of ANR projects designed to improve base system reliability and allow for additional long-term contracted transportation services to a point of delivery on the Northern Border pipeline at Ventura, Iowa. The project has an anticipated in-service date in 2025 and a total estimated cost of US$0.2 billion.

FINANCIAL RESULTS

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

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

year ended December 31 (millions of US$, unless otherwise noted)	**2022**	**2021**	**2020**
Columbia Gas	**1,511**	1,529	1,305
ANR	**582**	592	512
Columbia Gulf	**207**	220	195
GTN[1,2]	**184**	139	—
Great Lakes[1,3]	**178**	158	91
Other U.S. pipelines[1,4]	**441**	313	117
TC PipeLines, LP[1,5]	**—**	24	119
Non-controlling interests[5]	**39**	100	375
Comparable EBITDA	**3,142**	3,075	2,714
Depreciation and amortization	**(681)**	(630)	(597)
Comparable EBIT	**2,461**	2,445	2,117
Foreign exchange impact	**742**	620	720
Comparable EBIT (Cdn$)	**3,203**	3,065	2,837
Specific items:			
Great Lakes goodwill impairment charge	**(571)**	—	—
Risk management activities	**(15)**	6	—
Segmented earnings (Cdn$)	**2,617**	3,071	2,837

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

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

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

4 Reflects comparable EBITDA from our ownership in our mineral rights business (CEVCO), Crossroads and our share of equity income from Millennium and Hardy Storage, our U.S. natural gas marketing business as well as general and administrative and business development costs related to our U.S. natural gas pipelines. For the period subsequent to our March 2021 acquisition of TC PipeLines, LP, results also include 100 per cent of Bison, North Baja and Tuscarora, 61.7 per cent of Portland plus our equity income from Northern Border and Iroquois.

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

U.S. Natural Gas Pipelines segmented earnings in 2022 decreased by $454 million compared to 2021 and increased by $234 million in 2021 compared to 2020 and included the following specific items which have been excluded from our calculation of comparable EBIT and comparable earnings:

- a pre-tax goodwill impairment charge of $571 million related to Great Lakes in first quarter 2022. Refer to the Other Information – Critical accounting estimates section for additional information
- unrealized gains and losses from changes in the fair value of derivatives used in our U.S. natural gas marketing business.

A stronger U.S. dollar in 2022 had a positive impact on the Canadian dollar equivalent segmented earnings from our U.S. operations compared to 2021, while a weaker U.S. dollar in 2021 had a negative impact on the Canadian dollar equivalent segmented earnings from our U.S. operations compared to 2020.

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

Comparable EBITDA for U.S. Natural Gas Pipelines was US$67 million higher in 2022 than 2021 primarily due to the net effect of:

- incremental earnings from growth projects placed in service
- increased earnings from our mineral rights business due to higher commodity prices
- a net increase in earnings from Columbia Gas following the FERC-approved settlement for higher transportation rates effective February 2021, partially offset by higher property taxes as a result of projects placed in service
- decreased earnings due to the impact of cold weather events and other discrete items recognized in 2021
- a decrease in earnings as a result of certain fourth quarter 2022 adjustments related to regulatory deferrals, partially offset by an increase in earnings due to higher transportation rates effective August 1, 2022, both pursuant to the ANR uncontested rate settlement. Refer to the U.S. Natural Gas Pipelines – Significant events section for additional information.

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

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

The positive impact on comparable earnings following the TC PipeLines, LP acquisition noted above is reflected through a reduction in Net income attributable to non-controlling interests in the Consolidated statement of income.

Depreciation and amortization

Depreciation and amortization was US$51 million higher in 2022 compared to 2021 and US$33 million higher in 2021 compared to 2020 mainly due to new projects placed in service.

OUTLOOK

Comparable EBITDA

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

U.S. Natural Gas Pipelines comparable EBITDA in 2023 is expected to be consistent with 2022. This is due to, among other factors, completion of expansion projects in 2022 and 2023 on the ANR and Columbia Gulf systems as well as higher revenues on ANR due to the full-year implementation of higher transportation rates as part of the uncontested Section 4 rate case settlement filed with FERC. Our pipeline systems continue to see historically strong demand for service and we anticipate our assets will maintain the high utilization levels experienced in 2022. These positive results are expected to be partially offset by higher operational costs, reflective of increased system utilization across our footprint, and an anticipated increase in property taxes from capital projects placed in service.

Capital spending

We spent a total of US$1.7 billion in 2022 on our U.S. natural gas pipelines and expect to spend approximately US$1.9 billion in 2023 primarily on our Gillis Access, North Baja and Columbia Gas expansion projects and our Columbia Gas Modernization III program, as well as Columbia Gas and ANR maintenance capital expenditures, the return on and recovery of which is expected to be reflected in future tolls.

Mexico Natural Gas Pipelines

UNDERSTANDING OUR MEXICO NATURAL GAS PIPELINES SEGMENT

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

SIGNIFICANT EVENTS

Strategic Alliance with the CFE

On August 4, 2022, we announced a strategic alliance with Mexico’s state-owned electric utility, the CFE, for the development of new natural gas infrastructure in central and southeast Mexico. This alliance consolidates previous TSAs executed between TC Energy’s Mexico-based subsidiary TGNH and the CFE in connection with our natural gas pipeline assets in central Mexico (including the Tamazunchale, Villa de Reyes and Tula pipelines) under a single, U.S. dollar-denominated, take-or-pay contract that extends through 2055. This agreement also resolved and terminated previous international arbitrations with the CFE related to the Villa de Reyes and Tula pipelines.

In connection with the strategic alliance, we reached an FID to develop and construct the Southeast Gateway pipeline, a 1.3 Bcf/d, 715 km (444 mile) offshore natural gas pipeline to serve the southeast region of Mexico with an expected in-service by mid-2025 and an estimated project cost of US$4.5 billion.

The lateral section of the Villa de Reyes pipeline was mechanically completed in second quarter 2022, while VdR North and Tula East were placed in commercial service in third quarter 2022. We are working with the CFE, and expect the lateral and the south sections of the Villa de Reyes pipeline to begin commercial service in 2023. Additionally, we have agreed to jointly develop and complete the central segment of the Tula pipeline, subject to an FID in the first half of 2023. Finally, we are working with the CFE on the Tula pipeline’s west section to procure necessary land access and resolve legal claims.

Subject to regulatory approvals from Mexico’s economic competition commission and the Regulatory Energy Commission, the strategic alliance provides the CFE with the ability to hold an equity interest in TGNH, which is conditional upon the CFE contributing capital, acquiring land and supporting permitting on the TGNH projects. Upon in-service of the Southeast Gateway pipeline, the CFE’s equity interest in TGNH will equal 15 per cent, and will increase to approximately 35 per cent upon expiry of the contract in 2055. Regulatory approvals related to the CFE's equity participation in TGNH are expected to take up to 24 months.

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$, unless otherwise noted)	**2022**	**2021**	**2020**
TGNH[1]	**164**	118	120
Topolobampo	**161**	161	159
Sur de Texas[2]	**112**	113	171
Guadalajara	**73**	71	64
Mazatlán	**67**	70	70
Comparable EBITDA	**577**	533	584
Depreciation and amortization	**(76)**	(86)	(87)
Comparable EBIT	**501**	447	497
Foreign exchange impact	**153**	110	172
Comparable EBIT (Cdn$)	**654**	557	669
Specific item:			
Expected credit loss provision on net investment in leases and certain contract assets	**(163)**	—	—
Segmented earnings (Cdn$)	**491**	557	669

1 TGNH includes the operating sections of the Tamazunchale, Villa de Reyes and Tula pipelines.

2 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 2022 decreased by $66 million compared to 2021 and includes the impact of an expected credit loss provision of $163 million relating to the TGNH net investment in leases and certain contract assets. In accordance with the requirements of U.S. GAAP, an expected credit loss provision must be recognized on the TGNH net investment in leases. The provision is an estimate of losses that may occur over the duration of the TSA through 2055. As this provision, as well as a provision related to certain contract assets in Mexico, do not reflect actual losses or cash outflows that were incurred under the lease arrangement in the current period or from our underlying operations, we have excluded these unrealized changes from our calculation of comparable EBITDA and comparable EBIT. Refer to Note 28, Risk management and financial instruments, of our 2022 Consolidated financial statements for additional information on expected credit loss provisions. A stronger U.S. dollar in 2022 had a positive impact on the Canadian dollar equivalent segmented earnings from our Mexico operations compared to 2021.

Mexico Natural Gas Pipelines segmented earnings decreased by $112 million in 2021 compared to 2020. A weaker U.S. dollar in 2021 had a negative impact on the Canadian dollar equivalent segmented earnings from our Mexico operations compared to 2020.

Comparable EBITDA for Mexico Natural Gas Pipelines increased by US$44 million in 2022 compared to 2021 primarily due to higher revenues related to the commercial in-service of VdR North and Tula East in third quarter 2022.

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

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

In 2017, we entered into a MXN$21.3 billion unsecured revolving credit facility with the Sur de Texas joint venture. This peso-denominated inter-affiliate loan was fully repaid upon maturity on March 15, 2022 and replaced with a new U.S. dollar-denominated inter-affiliate loan. In July 2022, the Sur de Texas joint venture entered into an unsecured U.S. dollar-denominated term loan agreement with third parties and used the proceeds to fully repay the U.S. dollar-denominated inter-affiliate loan with TC Energy. Our share of related interest expense in Sur de Texas prior to this refinancing was fully offset by corresponding interest income recorded in Interest income and other in the Corporate segment.

Depreciation and amortization

Depreciation and amortization was US$10 million lower in 2022 compared to 2021 due to the change in accounting for Tamazunchale subsequent to the execution of the new TGNH TSA with the CFE in mid-2022. Under sales-type lease accounting, our in-service TGNH pipeline assets are reflected on our Consolidated balance sheet within net investment in leases with no depreciation expense being recognized. Depreciation and amortization in 2021 was consistent with 2020.

OUTLOOK

Comparable EBITDA

Mexico Natural Gas Pipelines comparable EBITDA reflects long-term, stable, principally U.S. dollar-denominated transportation contracts that are affected by the cost of providing service and includes our share of equity income from our 60 per cent interest in the Sur de Texas pipeline. Due to the long-term nature of the underlying transportation contracts, comparable EBITDA is generally consistent year-over-year except when new assets are placed in service. Comparable EBITDA for 2023 is expected to be higher than 2022 due to full-year revenues from VdR North and Tula East which were placed in service in third quarter 2022 under the new TGNH TSA with the CFE.

Capital spending

We spent a total of US$0.8 billion in 2022 primarily related to the construction of the Southeast Gateway, Villa de Reyes and Tula pipelines and the completion of specific Villa de Reyes and Tula segments. Capital spending in 2023 to advance construction of the Southeast Gateway, Villa de Reyes and Tula pipelines is expected to be US$2.1 billion.

NATURAL GAS PIPELINES – BUSINESS RISKS

The following are risks specific to our Natural Gas Pipelines business. Refer to page 99 for information about general risks related to TC Energy as a whole, including other operational, safety and financial risks as well as our approach to risk management.

Production levels within supply basins

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

Market access

We compete for market share with other natural gas pipelines. New supply basins are being developed closer to markets we have historically served and may reduce the throughput and/or distance of haul on our existing pipelines and impact revenues. New markets, including those created by LNG export facilities developed to access global natural gas demand, can lead to increased revenues through higher utilization of existing facilities and/or demand for new infrastructure. The long-term competitiveness of our pipeline systems and the avoidance of bypass pipelines will depend on our ability to adapt to changing flow patterns by offering competitive transportation services to the market. As part of our annual strategic planning process and scenario analysis, we monitor the pace and magnitude of energy transition through various signposts and watch for material shifts that pose threats or create opportunities. More detail on our management of climate-change related market risks and opportunities can be found in the TCFD section of our ESG Data Sheet.

Competition for greenfield pipeline expansion

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

Demand for pipeline capacity

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

Commodity prices

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

Regulatory risk

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

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

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

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

Governmental risk

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

Construction and operations

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

Liquids Pipelines

Our Liquids Pipelines infrastructure provides transportation of Canadian crude oil from Hardisty, Alberta to key refining and export markets in the U.S. Midwest and the U.S. Gulf Coast, as well as U.S. domestic service from Cushing, Oklahoma to the U.S. Gulf Coast. Our Liquids Pipelines assets in Alberta also transport oil from the Fort McMurray area to the Edmonton/Heartland areas.

Our Liquids Pipelines business includes:
- wholly-owned liquids pipelines – approximately 4,400 km (2,700 miles)
- wholly-owned operational and term storage – approximately 7 million barrels
- partially-owned liquids pipelines – over 460 km (287 miles).

Strategy

We remain focused on safely and reliably optimizing our Liquids Pipelines assets. We continue to expand our transportation service offerings to add incremental value to our business. We intend to leverage our existing competitive infrastructure to pursue in-corridor growth opportunities that enable increased optionality and market access for our customers.

ESG forms an important part of our strategy and we are committed to evolving our Liquids Pipelines business to support global energy transition goals. While low-carbon power generation is expected to grow significantly, our Liquids Pipelines assets could underpin early initiatives for our decarbonizing goals.

Recent highlights

- construction of the Port Neches Link Pipeline System is near completion and is expected to be placed in service in first quarter 2023
- commercialized an incremental 30,000 Bbl/d of the 2019 Open Season contracted volumes on the Keystone Pipeline System
- achieved record demand for throughput volumes on the Keystone Pipeline System.


TC Energy
Liquids Pipelines
As at December 31, 2022
Liquids Pipeline
Liquids Tank Terminal
Production Basin
Western Canadian Sedimentary Basin
4
Oil Sands
FORT MCMURRAY
3
EDMONTON
CANADA
HARDISTY
CALGARY
Williston
1
Powder River
Denver-Julesburg
UNITED STATES
WOOD RIVER
PATOKA
Anadarko
CUSHING
2
Permian
HOUSTON
PORT ARTHUR
Eagle Ford
MEXICO

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%

UNDERSTANDING OUR LIQUIDS PIPELINES BUSINESS

Our Liquids Pipelines segment consists of crude oil pipeline and terminal assets. The business safely transports crude oil from major supply sources to markets where crude oil can be refined into petroleum products. Ancillary services are also offered such as storage at terminal locations to provide our customers with delivery flexibility while optimizing the value of our pipeline assets. A non-regulated marketing entity also forms part of the Liquids Pipelines business.

We provide pipeline transportation capacity to customers predominantly supported by long-term contracts generating stable earnings over the contract term. These long-term contracts provide for the recovery of costs incurred to construct our assets, with operating and maintenance costs primarily recovered through a variable flow-through toll. Uncontracted pipeline capacity is offered to the market on a monthly spot basis and through periodic open seasons, per regulatory requirements, which provides opportunities to generate incremental earnings. Storage of liquids at terminals is offered to our customers in return for fixed fee payments.

Our pipeline systems and associated facilities are regulated by the CER and AER, as well as FERC, PHMSA and various state authorities. These entities regulate the construction, operation and abandonment of pipeline infrastructure. The CER and FERC regulate the transportation service of our pipeline systems and oversee the reasonableness of our tolls.

Keystone Pipeline System

The Keystone Pipeline System, our largest liquids pipeline asset, transports crude oil exported from western Canada to various delivery points in the U.S. Mid Continent and Gulf Coast. It also transports U.S. domestic crude receipts between Cushing, Oklahoma and the U.S. Gulf Coast market through the Marketlink lease. As the system operates in both Canadian and U.S. jurisdictions, it is subject to the common carrier obligations imposed by the CER and FERC, respectively.

TC Energy Liquids Marketing

Our liquids marketing business provides customers with a variety of crude oil marketing services including transportation, storage and logistics, 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.

Intra-Alberta Pipeline Systems

Our two intra-Alberta liquids pipelines, Grand Rapids and White Spruce, provide crude oil transportation for producers in northern Alberta to move volumes between the Fort McMurray area and the Edmonton/Heartland areas. These pipeline systems are regulated by the AER.

Business environment

Dynamic shifts in geopolitical events, government policy changes and various macroeconomic factors continue to impact global crude oil supply and demand balances. While the upstream sector remains focused on capital discipline, we expect crude oil demand to increase over the next 30 years, which is driven by world population growth and economic expansion. North America's crude oil supply, inclusive of the WCSB, is critical to supporting this future demand.

Supply outlook

Canada

Canada has the world's third largest crude oil reserves with over 160 billion barrels of economically and technically recoverable conventional and oil sands reserves, primarily in Alberta. WCSB crude oil production in 2022 was approximately 4.6 million Bbl/d and we expect it to increase to over 5 million Bbl/d by 2035. Oil sands heavy production comprises the majority of western Canadian crude oil supply at approximately 3.3 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 12 million Bbl/d in 2022. The majority of continental U.S. crude oil production is in the form of light tight oil from the Permian, Williston, Eagle Ford and Niobrara basins. With light oil processing capacity fully utilized in the U.S., exports to offshore markets are generally used as outlets for incremental light tight oil production. U.S. refineries have been optimized through significant capital investments to refine a mix of light and heavy crude oils to economically produce an optimized refined products slate. By 2035, we expect the U.S. to export over 5 million Bbl/d of light crude oil while importing approximately 4 million Bbl/d of heavy crude oil.

Demand

The U.S. is the primary source of crude oil demand in North America with refining capacity greater than 16 million Bbl/d. Canada's heavy crude oil production is 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 but have invested significant capital to process heavy crude oil. 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.

Demand for heavy crude oil in the U.S. has been resilient and is expected to remain strong for the foreseeable future. While Canada and Mexico are the top suppliers of heavy crude oil to the U.S., Mexico oil production is not expected to see significant growth moving forward. This presents a continued opportunity for Canada to remain the prominent supplier of heavy crude oil to the U.S. Gulf Coast.

Strategic priorities

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

Within our established risk preferences, we remain committed to:
- optimizing the value and competitiveness of our existing assets
- expanding and leveraging our existing infrastructure
- expanding the transportation services that we offer and extending into adjacent markets
- progressing our energy transition goals, including system operational improvements and decarbonizing our systems.

The long-term contract profile supporting our business model provides stable tolls for our customers and stable revenues for our business. The cyclical nature of commodity prices may influence the pace at which our customers expand their operations. This can impact the rate of project growth in our industry, the value of our services as contracts expire, and the timing for the demand of transportation services and/or new liquids infrastructure.

We believe that our Alberta assets are well-positioned to capture production growth from the stable and resilient WCSB, which is needed to meet the growing U.S. Gulf Coast demand for secure Canadian heavy crude oil, as traditional offshore imports decline.

With the continued growth of U.S. light tight oil production and a satisfied demand for light oil in North America, we will examine opportunities to expand our transportation services and extend our pipeline platform to include last-mile delivery connectivity to refineries and terminals with storage and marine export capabilities. We will also focus on leveraging our existing assets and development of projects to provide optionality for customers to reach new proximate supply sources.

We believe that Liquids Pipelines is well positioned to endure the impact of short-term commodity price fluctuations and supply/demand responses, while supporting North American energy security. Our assets are predominantly supported by long-term contracts generating stable earnings. We continually work with existing and potential customers to enhance their customer experience and provide pipeline transportation and terminal services to meet their needs. The combination of the scale and strategic location of our assets assists us in attracting additional volumes and in growing our business.

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

ESG considerations form an important part of our strategy. Our business will continue to factor sustainability into our projects, maintenance and operational activities, while keeping innovation at the forefront of our business, including modernizing and decarbonizing our existing liquids infrastructure.

SIGNIFICANT EVENTS

Milepost 14 Incident

In December 2022, a pipeline rupture occurred in Washington County, Kansas on the Cushing Extension section of the Keystone Pipeline System. Recovery and remediation efforts are underway and we are committed to fully remediating the site. To date, our oil recovery efforts continue to progress successfully with 90 per cent of the 12,937 barrel measured release volume recovered. The affected segment was restarted following approval of the repair and restart plan by PHMSA. Per the terms of a Corrective Action Order, the pipeline is required to operate under a pressure de-rate until the conditions are satisfied. The cause of the release remains the subject of an investigation.

At December 31, 2022, we accrued an environmental remediation liability of $650 million, before expected insurance recoveries and not including potential fines and penalties which are currently indeterminable. This amount represents our estimate of costs relating to emergency response, environmental remediation and cleanup activities required to fully remediate the site and has been recorded on an undiscounted basis. The accrual is based on certain assumptions such as the scope of remediation efforts that are subject to revision in future periods which could result in future modifications of this accrual. Therefore, it is reasonably possible that we will incur additional costs beyond the amounts accrued; however, we are currently unable to estimate the range of possible additional costs.

We have appropriate insurance policies in place and it is probable that the majority of estimated environmental remediation costs will be eligible for recovery under our existing insurance coverage. We have recorded an asset of $650 million, representing the expected recovery of the estimated environmental remediation costs. To the extent costs beyond the amounts accrued are incurred, they will be evaluated under our existing insurance policies. We expect remediation activities to be substantially completed within a year.

CER and FERC Proceedings

In 2019 and 2020, certain Keystone customers initiated complaints before FERC and the CER. The complaints indicated that Keystone had provided insufficient information to support its 2020 and 2021 estimated variable rates and challenged the just and reasonableness of Keystone's committed rates charged dating back to 2018 and 2020 at FERC and the CER, respectively.

CER proceedings concluded in September 2022 and in December 2022, the CER issued a decision which has resulted in a one-time adjustment related to previously charged tolls of $38 million. In January 2023, Keystone filed a Review and Variance application with the CER challenging the correctness of the original decision.

The FERC hearing commenced in June 2022 and concluded in August, with a judiciary recommendation expected to be issued in early 2023.

2019 Open Season

Approximately 20,000 Bbl/d of long-term contracts from the 2019 Open Season were commercialized in April 2022 with an additional 10,000 Bbl/d in September 2022.

Port Neches

Construction of the Port Neches Link Pipeline System, which connects the Keystone Pipeline System to Motiva's Port Neches Terminal, providing access to Motiva's 630,000 Bbl/d refinery as well as other downstream infrastructure, is nearly complete and expected to be placed in service in first quarter 2023.

Keystone XL

In September 2022, the International Centre for Settlement of Investment Disputes formally constituted a tribunal to hear our Request for Arbitration under NAFTA where we are seeking to recover more than US$15 billion in economic damages resulting from the revocation of the Presidential Permit for the Keystone XL pipeline project. This claim is in an early stage and the timing and outcome is unknown at present.

Keystone XL termination activities undertaken in 2022, including asset dispositions and preservation, will continue throughout 2023. We will continue to coordinate with regulators, stakeholders and Indigenous groups to meet our environmental and regulatory commitments.

FINANCIAL RESULTS

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

year ended December 31 (millions of $)	2022	2021	2020
Keystone Pipeline System[1]	**1,304**	1,448	1,614
Intra-Alberta pipelines[2]	**71**	87	92
Other[1]	**(9)**	(9)	(6)
Comparable EBITDA	**1,366**	1,526	1,700
Depreciation and amortization	**(329)**	(318)	(332)
Comparable EBIT	**1,037**	1,208	1,368
Specific items:			
Keystone XL asset impairment charge and other	**118**	(2,775)	—
Keystone CER decision	**(27)**	—	—
Keystone XL preservation and other	**(25)**	(43)	—
Gain on sale of Northern Courier	—	13	—
Risk management activities	**20**	(3)	(9)
Segmented earnings/(losses)	**1,123**	(1,600)	1,359
Comparable EBITDA denominated as follows:			
Canadian dollars	**383**	417	418
U.S. dollars	**754**	884	955
Foreign exchange impact	**229**	225	327
Comparable EBITDA	**1,366**	1,526	1,700

1 Liquids marketing results were previously disclosed separately, but almost fully relate to marketing activities with respect to the Keystone Pipeline System. For 2022 and comparative periods, liquids marketing results have been reclassified within Keystone Pipeline System.

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

Liquids Pipelines segmented earnings increased by $2.7 billion in 2022 compared to 2021 and decreased by $3.0 billion in 2021 compared to 2020 and included the following specified items which have been excluded from our calculation of comparable EBIT:

- a $2.8 billion pre-tax asset impairment charge was recognized in 2021 associated with the termination of the Keystone XL pipeline project and related projects following the January 2021 revocation of the Presidential Permit, net of expected contractual recoveries and other contractual and legal obligations
- a $118 million pre-tax adjustment in 2022 to the 2021 Keystone XL asset impairment charge and other resulting from the gain on sale of Keystone XL project assets and reduction to the estimate for contractual and legal obligations related to termination activities
- a $27 million pre-tax charge due to the CER decision issued in December 2022 in respect of a tolling-related complaint pertaining to amounts reflected in 2021 and 2020
- pre-tax preservation and other costs in 2022 of $25 million (2021 – $43 million) related to the preservation and storage of the Keystone XL pipeline project assets which could not be accrued as part of the Keystone XL asset impairment charge
- pre-tax gain of $13 million in 2021 related to the sale of the remaining 15 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 2022 had a positive impact on the Canadian dollar equivalent segmented earnings from our U.S. operations compared to 2021, while a weaker U.S. dollar in 2021 had a negative impact on the Canadian dollar equivalent segmented earnings from our U.S. operations compared to 2020.

Comparable EBITDA for Liquids Pipelines was $160 million lower in 2022 compared to 2021 primarily due to the net effect of:
- lower rates and volumes on the U.S. Gulf Coast section of the Keystone Pipeline System, partially offset by higher long-haul contracted volumes and approximately 20,000 Bbl/d of long-term contracts from the 2019 Open Season that were commercialized in April 2022 with an additional 10,000 Bbl/d in September 2022
- liquids marketing earnings for 2022 decreased relative to 2021 due to lower margins and volumes
- the CER decision on the tolling-related complaint in respect of amounts invoiced in 2022.

Comparable EBITDA for Liquids Pipelines was $174 million lower in 2021 compared to 2020 primarily due to the net effect of:
- lower volumes and compressed margins on the U.S. Gulf Coast section of the Keystone Pipeline System
- increased contributions from liquids marketing activities mainly attributable to higher margins and volumes.

Depreciation and amortization

Depreciation and amortization was $11 million higher in 2022 compared to 2021 primarily as a result of a stronger U.S. dollar. Depreciation and amortization was $14 million lower in 2021 compared to 2020 primarily as a result of a weaker U.S. dollar.

OUTLOOK

Comparable EBITDA

Comparable EBITDA in 2023 is expected to be modestly lower than 2022 for the Keystone Pipeline System including liquids marketing as a result of the de-rate associated with the Milepost 14 incident and continuing lower margins on the U.S. Gulf Coast section of the Keystone Pipeline System; however, we expect to continue to be able to fulfill our Keystone Pipeline System contract commitments.

Capital spending

We spent a total of $0.1 billion in 2022 primarily related to capital projects in the U.S. Gulf Coast and on our operating pipelines and expect to spend approximately $0.1 billion in 2023.

BUSINESS RISKS

The following are risks specific to our Liquids Pipelines business. Refer to page 99 for information about general risks related to TC Energy as a whole, including other operational, safety and financial risks as well as our approach to risk management.

Operations

Operating our liquids pipelines safely and reliably while optimizing available capacity are essential drivers of our business success. Interruptions in our pipeline operations may impact our throughput capacity and result in our inability to deliver on our contracted volume obligations and to capture spot volume opportunities. We manage these risks and possible impacts to local communities using environmental risk-based preventive maintenance programs, effective capital investments and a highly skilled workforce. We utilize in-line internal inspection equipment to monitor our pipelines regularly and perform repairs and preventative maintenance whenever necessary.

Regulatory and government

Decisions by Canadian and U.S. regulators can have a significant impact on the design, construction, operations and financial performance of our liquids pipelines. Shifts in government policy can impact the ability to grow our business. Public opinion about crude oil development and production, may also have an adverse impact on regulatory processes. In conjunction with this, there are individuals and special interest groups that express opposition to oil usage for energy by lobbying against the construction and operation of liquids pipelines. Changing environmental requirements or revisions to the current regulatory process may adversely impact the timing or ability to obtain approvals for our liquids pipelines. We manage these risks by continuously monitoring regulatory and government policy developments to determine their possible impact on our Liquids Pipelines business, building scenario analysis into our strategic outlook and 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 products could adversely impact the price that crude oil producers receive for their product. In the long term, lower crude oil prices could cause producers to curtail their investment in the further development of crude oil supplies. Depending on the severity, these factors could negatively impact opportunities to expand our liquids pipelines infrastructure and, in the longer term, to re-contract with customers as current agreements expire.

Competition

As we continue to further develop our competitive position in the North American liquids transportation market to connect growing crude oil supplies between key North American producing regions and demand markets, we face competition from other midstream companies which also seek to transport crude oil 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 logistics, primarily through the purchase and sale of physical crude oil. Changing market conditions could adversely impact the value of the underlying capacity contracts and margins realized. Availability of alternative pipeline systems that can deliver into the same areas can also impact contract value. The liquids marketing business complies with our risk management policies which are described in the Other Information – Enterprise risk management section.

Shifting political trends and ESG requirements

North American governments are changing their environmental standards and positioning climate goals as key priorities. Meanwhile, the business environment is also evolving quickly as investors demand greater ESG commitments. While there is downside risk to policies that shift support away from our traditional services, there are also opportunities to reduce GHG emissions and generate associated renewable energy and carbon credits for TC Energy. Numerous oil producers have set net GHG reduction targets, and there is significant work underway across North America to advance carbon capture, utilization and storage opportunities to help achieve these targets.

Power and Energy Solutions

The previously described Power and Storage segment has been renamed Power and Energy Solutions. This business consists of power generation, non-regulated natural gas storage assets as well as new technologies which reduce our emissions footprint, in addition to being a partner to our customers and other industries that are also looking for low-carbon solutions.

Our Power and Energy Solutions business includes approximately 4,300 MW of generation capacity located in Alberta, Ontario, Québec and New Brunswick, using natural gas and nuclear fuel sources and is generally supported by long-term contracts. Additionally, we have secured 600 MW in the U.S. and 416 MW in Canada of PPAs from wind and solar facilities. We continue to pursue generation assets and PPA opportunities in Canada and the U.S.

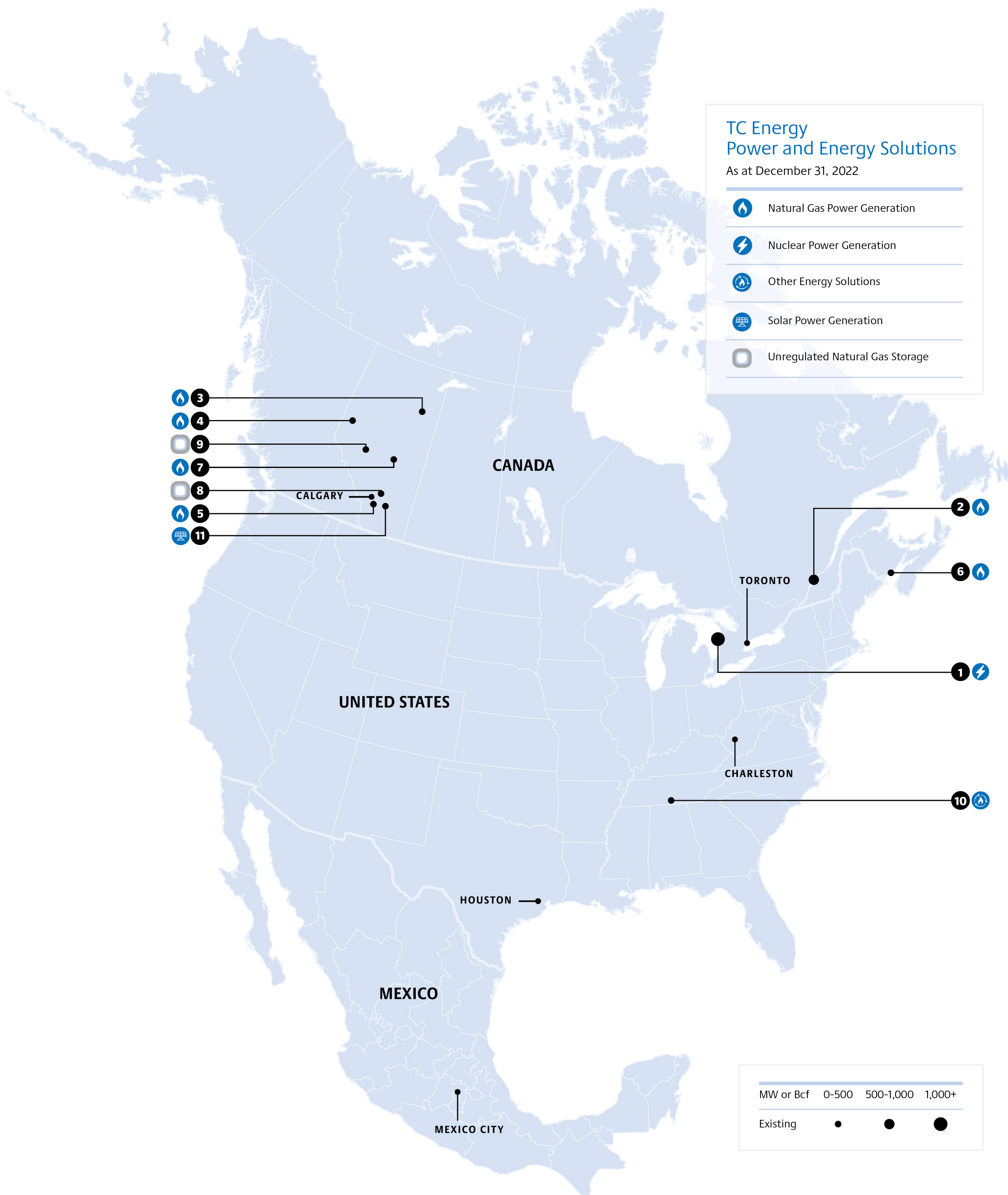
We also own and operate approximately 118 Bcf of non-regulated natural gas storage capacity in Alberta.

Strategy

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

Recent highlights

- further advanced the Bruce Power life extension program with the IESO verifying the Unit 3 MCR program's final cost and schedule duration estimate. As a result, the Unit 3 MCR program is scheduled to begin first quarter 2023 with expected completion in 2026. The Unit 6 MCR project is proceeding on budget and schedule with expected completion in fourth quarter 2023
- secured approximately 600 MW through PPAs from wind and solar facilities in the U.S.
- commenced construction of the Saddlebrook Solar project consisting of 81 MW of solar generation
- announced a plan to evaluate a hydrogen production hub in Crossfield, Alberta.


TC Energy
Power and Energy Solutions
As at December 31, 2022
Natural Gas Power Generation
Nuclear Power Generation
Other Energy Solutions
Solar 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
10
11
MW or Bcf
0-500
500-1,000
1,000+
Existing

Power and Energy Solutions assets currently have a combined power generation capacity, net to TC Energy, of 4,339 MW and we operate each facility except for Bruce Power.

		Generating capacity (MW)	Type of fuel	Description	Ownership
	Power assets				
1	Bruce Power[1]	3,170	nuclear	Eight operating reactors in Tiverton, Ontario. Bruce Power leases the nuclear facilities from OPG.	48.3%
2	Bécancour	550	natural gas	Cogeneration plant in Trois-Rivières, Québec. Power generation has been suspended since 2008 although we continue to receive PPA capacity payments while generation is suspended.	100%
3	Mackay River	207	natural gas	Cogeneration plant in Fort McMurray, Alberta.	100%
4	Bear Creek	100	natural gas	Cogeneration plant in Grande Prairie, Alberta.	100%
5	Carseland	95	natural gas	Cogeneration plant in Carseland, Alberta.	100%
6	Grandview	90	natural gas	Cogeneration plant in Saint John, New Brunswick.	100%
7	Redwater	46	natural gas	Cogeneration plant in Redwater, Alberta.	100%
	Canadian non-regulated natural gas storage				
8	Crossfield	68 Bcf		Underground facility connected to the NGTL System near Crossfield, Alberta.	100%
9	Edson	50 Bcf		Underground facility connected to the NGTL System near Edson, Alberta.	100%
	Under construction				
	Other energy solutions				
10	Lynchburg		RNG	RNG production facility in Lynchburg, Tennessee.	30%
11	Saddlebrook Solar	81	solar	Hybrid solar generation facility near Aldersyde, Alberta.	100%

1 Our share of power generation capacity.

UNDERSTANDING OUR POWER AND ENERGY SOLUTIONS BUSINESS

Canadian Power

Canadian Power Generation & Marketing

We own or have the rights to approximately 1,200 MW of power supply in Canada, excluding our investment in Bruce Power. In Alberta we own four natural gas-fired cogeneration facilities and are constructing a solar project. We exercise a disciplined operating strategy to maximize revenues. Our marketing group sells uncommitted power while also buying and selling power and natural gas to maximize earnings. To reduce commodity price exposure associated with uncontracted power, we sell a portion of this output in forward sales markets when acceptable contract terms are available while the remainder is retained to be sold in the spot market or under short-term forward arrangements. The objective of this strategy is to maintain adequate power supply to fulfill our sales obligations if we have unexpected plant outages and enable us to capture opportunities to increase earnings in periods of high spot prices. Our two eastern Canadian natural gas-fired cogeneration assets, Bécancour and Grandview, are fully contracted.

Bruce Power

Bruce Power is a nuclear power generation facility located near Tiverton, Ontario and is comprised of eight nuclear units with a combined capacity of approximately 6,550 MW. Bruce Power leases the facilities from OPG, has no spent fuel risk and will return the facilities to OPG for decommissioning at the end of the lease. We hold a 48.3 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.

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 years of operational life to each of the six units.

The Unit 6 MCR is the first of the six-unit MCR life extension program. This outage commenced in January 2020 and is moving to the last part of the installation phase and remains on time and on budget with an expected return to service in fourth quarter 2023. The second unit in the MCR program is Unit 3 and the final cost and schedule duration estimate was verified by the IESO in March 2022. The Unit 3 MCR is scheduled to commence in first quarter 2023 and has an expected completion in 2026. The third unit in the MCR program is Unit 4. The Unit 4 MCR definition phase was completed in June 2022 and is now in the preparation phase. A preliminary basis of estimate (including an initial cost and schedule duration estimate) for the Unit 4 MCR was submitted to the IESO in fourth quarter 2022, with the final submission following an FID, scheduled for fourth quarter 2023. Investments in the remaining three units' MCR programs are expected to continue through 2033. Future MCR investments will be subject to discrete decisions for each unit with specified off-ramps available for Bruce Power and the IESO.

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

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. Bruce Power's contract price increased on April 1, 2022, in accordance with contract terms, reflecting capital to be invested under the Unit 3 MCR program and the 2022 to 2027 Asset Management program plus normal annual inflation adjustments.

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. No operating cost efficiencies for the 2022 to 2024 period have been provided for at December 31, 2022, and no operating efficiencies were realized for the 2019 to 2021 period.

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

Power Purchase Agreements – Canada

We have secured 416 MW of wind and solar generation PPAs and associated environmental attributes in Alberta. These PPAs allow us to generate incremental earnings while also contributing to the reduction of our operational GHG intensity and allowing us to offer renewable power products to our customers.

U.S. Power

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

Power Purchase Agreements – U.S.

We have secured approximately 600 MW of wind and solar generation PPAs and associated environmental attributes in the U.S. These PPAs allow us to generate incremental earnings while also contributing to the reduction of our operational GHG intensity and allowing us to offer renewable power products to our customers.

Other Energy Solutions

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

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

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

Canadian Natural Gas Storage

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

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

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

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

Alberta Carbon Grid

The ACG is a world-leading carbon transportation and sequestration solution being designed to serve multiple customers, industries and sectors. A collaboration between Pembina and TC Energy, ACG is focused on providing CO2 transportation and sequestration solutions across Alberta by leveraging both companies' collective skills, experience and extensive network of pipeline infrastructure and right-of-ways.

ACG is exploring options to potentially develop several ACG hubs throughout the province that would be designed to independently, safely and cost-effectively collect and store CO2 from customers across multiple industries. The long-term vision is to annually transport and store up to 20 million tonnes of CO2 through several hubs across Alberta.

The ACG is part of Pembina’s and TC Energy’s commitment to energy diversification, industry collaboration and a lower carbon future that benefits the environment and the Alberta economy.

SIGNIFICANT EVENTS

Bruce Power Life Extension

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

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

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

Renewable Energy Contracts and/or Investment Opportunities

We are seeking potential contracts and/or investment opportunities in wind, solar and energy storage projects to meet the electricity needs of the U.S. portion of the Keystone Pipeline System and supply renewable energy products and services to industrial and oil and gas sectors proximate to our in-corridor demand. To date we have finalized contracts for approximately 600 MW from wind and solar projects.

Saddlebrook Solar Project

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

OTHER ENERGY SOLUTIONS

Hydrogen Hubs

As part of our JDA with Nikola, on April 26, 2022, we announced a plan to evaluate a hydrogen production hub on 140 acres in Crossfield, Alberta, where we currently operate our natural gas storage facility. Our significant pipeline, storage and power assets can potentially be leveraged to lower the cost and increase the speed of development of these hubs. This may include exploring the integration of pipeline assets to enable hydrogen distribution and storage via pipeline and/or to deliver carbon dioxide to permanent sequestration sites to decarbonize the hydrogen production process. We expect an FID in 2024, subject to customary regulatory approvals.

Alberta Carbon Grid

In June 2021, we announced a partnership with Pembina Pipeline Corporation to jointly develop a world-scale carbon transportation and sequestration system which, when fully constructed, is expected to be capable of transporting more than 20 million tonnes of carbon dioxide annually. On October 18, 2022, ACG announced that it has entered into a carbon sequestration evaluation agreement with the Government of Alberta to further evaluate one of the largest AOI for safely storing carbon from industrial emissions in Alberta. This agreement will allow ACG to continue evaluating the suitability of its AOI and move forward into the next stage of the province’s CCUS process to provide confidence to customers, Indigenous communities, stakeholders and the Government of Alberta in the project's carbon storage capabilities. ACG is exploring options to potentially leverage existing infrastructure and right-of-ways to connect the Alberta Industrial Heartland emissions region to a key sequestration location.

Lynchburg Renewable Fuels

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

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 $)	**2022**	**2021**	**2020**
Bruce Power[1]	**552**	397	430
Canadian Power[2]	**322**	253	213
Natural Gas Storage and other	**33**	19	25
Comparable EBITDA	**907**	669	668
Depreciation and amortization	**(72)**	(78)	(67)
Comparable EBIT	**835**	591	601
Specific items:			
Gain/(loss) on sale of Ontario natural gas-fired power plants	**—**	17	(414)
Bruce Power unrealized fair value adjustments	**(17)**	14	9
Risk management activities	**15**	6	(15)
Segmented earnings	**833**	628	181

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

Power and Energy Solutions segmented earnings increased by $205 million in 2022 compared to 2021 and increased by $447 million in 2021 compared to 2020 and included the following specific items which have been excluded from our calculation of comparable EBIT and comparable earnings:

- a $17 million pre-tax recovery of certain costs from the IESO in 2021 associated with the Ontario natural gas-fired power plants sold in April 2020 (pre-tax loss 2020 – $414 million)
- our proportionate share of Bruce Power's unrealized gains and losses on funds invested for post-retirement benefits and risk management activities
- unrealized gains and losses from changes in the fair value of derivatives used to reduce commodity exposures.

Comparable EBITDA for Power and Energy Solutions increased by $238 million in 2022 compared to 2021 primarily due to:

- positive contributions from Bruce Power primarily due to a higher contract price
- improved Canadian Power earnings primarily due to higher realized power prices
- increased Natural Gas Storage and other results from higher realized Alberta natural gas storage spreads in 2022.

Comparable EBITDA for Power and Energy Solutions increased by $1 million in 2021 compared to 2020 primarily due to the net effect of:

- increased Canadian Power earnings primarily due to higher realized margins in 2021, contributions from trading activities and a full of year of earnings from our MacKay River cogeneration facility following its return to service in May 2020, partially offset by the sale of our Ontario natural gas-fired power plants in April 2020
- decreased Bruce Power contributions as a result of increased operating expenses and lower volumes resulting from greater planned outage days, partially offset by higher realized prices. Additional financial and operating information on Bruce Power is provided below
- decreased Natural Gas Storage and other earnings as a result of increased business development costs across the segment, partially offset by higher realized Alberta natural gas storage spreads in 2021.

Depreciation and amortization

Depreciation and amortization decreased by $6 million in 2022 compared to 2021 as a result of certain adjustments in 2022. Depreciation increased by $11 million in 2021 compared to 2020 primarily due to incremental TC Turbines depreciation following the November 2020 acquisition of the remaining 50 per cent ownership interest as well as other adjustments in 2020.

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)	**2022**	**2021**	**2020**
Items included in comparable EBITDA and EBIT are comprised of:			
Revenues[1]	**1,848**	1,642	1,672
Operating expenses	**(924)**	(922)	(884)
Depreciation and other	**(372)**	(323)	(358)
Comparable EBITDA and EBIT[2]	**552**	397	430
Bruce Power – other information			
Plant availability[3,4]	**86%**	86%	88%
Planned outage days[4]	**302**	321	276
Unplanned outage days	**34**	22	36
Sales volumes (GWh)[5]	**20,610**	20,542	20,956
Realized power price per MWh[6]	**$89**	$80	$80

1 Net of amounts recorded to reflect operating cost efficiencies shared with the IESO.
2 Represents our 48.3 per cent ownership interest and internal costs supporting our investment in Bruce Power. Excludes unrealized gains and losses on funds invested for post-retirement benefits and risk management activities.
3 The percentage of time the plant was available to generate power, regardless of whether it was running.
4 Excludes Unit 6 MCR outage days.
5 Sales volumes include deemed generation.
6 Calculation based on actual and deemed generation. Realized power price per MWh includes realized gains and losses from contracting activities and cost flow-through items. Excludes unrealized gains and losses on contracting activities and non-electricity revenues.

The Unit 6 MCR outage, which began in January 2020, is now in the installation phase. Excluding Units 6 and 8, planned maintenance was completed on all units in 2022. In 2021, planned maintenance on Units 1 and 3 was completed and an outage on Unit 7 commenced in the fourth quarter. In 2020, planned maintenance was completed on Unit 3, 4, 5 and 8.

OUTLOOK

Comparable EBITDA

Power and Energy Solutions comparable EBITDA in 2023 is expected to be consistent with 2022 provided Alberta power prices experienced in 2022 continue into 2023. We expect that Bruce Power's equity income will be higher in 2023 than 2022 due to the full year impact of the Unit 3 MCR program contract price increase and fewer non-MCR planned outage days, partially offset by greater MCR outage days. The planned maintenance for 2023 is currently scheduled to begin on Unit 4 in the second quarter and on Unit 8 in the second half of 2023. The average 2023 plant availability percentage, excluding the Unit 3 and Unit 6 MCR programs, is expected to be in the low-90 per cent range.

Capital spending

We invested $0.9 billion in 2022 for our share of Bruce Power's life extension program, construction of the Saddlebrook Solar Project and other maintenance capital projects across the segment and expect to invest approximately $1.0 billion in 2023.

BUSINESS RISKS

The following are risks specific to our Power and Energy Solutions business. Refer to page 99 for information about general risks related to TC Energy as a whole, including other operational, safety and financial risks. The Power and Energy Solutions 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 power operations is currently exposed to commodity price volatility. These exposures are partially mitigated through long-term contracts and hedging activities including selling and purchasing power and natural gas in forward markets. As contracts expire, new contracts are entered into at prevailing market prices.

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

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

Plant availability

Operating our plants to ensure services are provided safely and reliably as well as optimizing and maintaining their availability are essential to the continued success of our Power and Energy Solutions business. Unexpected outages or extended planned outages at our power plants can increase maintenance costs as well as lower plant output, revenues 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 and the United States. These markets are subject to various federal, provincial and state regulations. As power markets evolve, there is the potential for regulatory bodies to implement new rules that could negatively affect us as a generator and marketer of electricity. These may be in the form of market rule or market design changes, changes in the interpretation and application of market rules by regulators, price caps, emission controls, emissions costs, cost allocations to generators and out-of-market actions taken by others to build excess generation, all of which may negatively affect the price of power. In addition, our development projects rely on an orderly permitting process and any disruption to that process can have negative effects on project schedules and costs. We are an active participant in formal and informal regulatory proceedings and take legal action where required.

Compliance

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

Weather

Significant changes in temperature and weather, including the potential impacts of climate change, have many effects on our business, ranging from the impact on demand, availability and commodity prices, to efficiency and output capability. Extreme temperature and weather can affect market demand for power and natural gas and can lead to significant price volatility, as well as 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 Canada and the U.S. as well as in the development of greenfield power plants. Traditional and non-traditional players are entering the growing low-carbon economy in North America and, as a result, we face competition in building low-carbon platforms with energy and financial options to provide customer-driven solutions for energy transition.

Execution and capital costs

We make substantial capital commitments developing power generation infrastructure based on the assumption that these assets will deliver an attractive return on investment. While we carefully consider the scope and expected costs of our capital projects, we are exposed to execution and capital cost overrun risk which may impact our return on these projects. We mitigate this risk by implementing comprehensive project governance and oversight processes and through the structuring of engineering, procurement and construction contracts with reputable counterparties.

Corporate

SIGNIFICANT EVENTS

Mexico Tax Audit

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

In 2022, we settled with the SAT on all of the above matters for the tax years 2013 through 2021 and recorded US$153 million of income tax expense (inclusive of withholding taxes, interest, penalties and other financial charges).

Dividend Reinvestment and Share Purchase Plan

To prudently fund our growth program that includes increased project costs on the NGTL System and following our July 2022 obligation to make an equity contribution of $1.9 billion to Coastal GasLink LP, we reinstated the issuance of common shares from treasury at a two per cent discount under our DRP commencing with the dividends declared on July 27, 2022. On dividends declared in 2022, the participation rate by common shareholders was approximately 33 per cent, resulting in $607 million reinvested in common equity under the program. The discounted DRP is expected to be in place through the dividend declarations for the quarter ending June 30, 2023.

Common Shares Issued Under Public Offering

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

Asset Divestiture Program

In late 2022, we announced our plan to proceed with a $5+ billion asset divestiture program that will include the sale of assets, and may include partial monetization of certain assets.

The objectives of this asset divestiture program are to accelerate our deleveraging, execute on our vast opportunity set and provide a self-funding source for high-value growth opportunities. We believe that executing these steps will strengthen our balance sheet to ensure we remain competitively positioned to capitalize on future opportunities. Refer to the Financial Condition section for further information.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and 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 $)	2022	2021	2020
Comparable EBITDA and EBIT	**(20)**	(24)	(16)
Specific items:			
Foreign exchange gain – inter-affiliate loans[1]	**28**	41	86
Voluntary Retirement Program	**—**	(63)	—
Segmented earnings/(losses)	**8**	(46)	70

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

Corporate segmented earnings of $8 million in 2022 increased by $54 million from segmented losses of $46 million in 2021. Corporate segmented losses of $46 million in 2021 increased by $116 million from segmented earnings of $70 million in 2020.

Corporate segmented earnings/(losses) included foreign exchange gains on our proportionate share of peso-denominated inter-affiliate loans to the Sur de Texas joint venture from its partners up to March 15, 2022 when the peso-denominated inter-affiliate loans were fully repaid upon maturity. These foreign exchange gains are recorded in Income from equity investments in the Corporate segment and have been excluded from our calculation of comparable EBITDA and EBIT as they are fully offset by corresponding foreign exchange losses on the inter-affiliate loan receivable included in Foreign exchange (loss)/gain, net. Refer to the Other Information – Related party transactions section for additional information on our peso-denominated inter-affiliate loans.

Corporate segmented losses in 2021 included pre-tax costs for the VRP offered in 2021 of $63 million.

Comparable EBITDA and EBIT for Corporate in 2022 was consistent with 2021 and decreased by $8 million in 2021 compared to 2020 primarily due to a U.S. capital tax adjustment recorded in 2020.

OTHER INCOME STATEMENT ITEMS

Interest expense

year ended December 31 (millions of $)	2022	2021	2020
Interest on long-term debt and junior subordinated notes			
Canadian dollar-denominated	**(776)**	(712)	(685)
U.S. dollar-denominated	**(1,267)**	(1,259)	(1,302)
Foreign exchange impact	**(383)**	(320)	(446)
	(2,426)	(2,291)	(2,433)
Other interest and amortization expense	**(189)**	(85)	(89)
Capitalized interest	**27**	22	294
Interest expense included in comparable earnings	**(2,588)**	(2,354)	(2,228)
Specific item:			
Keystone XL preservation and other	**—**	(6)	—
Interest expense	**(2,588)**	(2,360)	(2,228)

Interest expense increased by $228 million in 2022 compared to 2021 and increased by $132 million in 2021 compared to 2020. Interest expense in 2021 included $6 million related to the Keystone XL project-level credit facility for the period following the revocation of the Presidential Permit for the Keystone XL pipeline project. This has been removed from our calculation of interest expense included in comparable earnings.

Interest expense included in comparable earnings in 2022 increased by $234 million compared to 2021 primarily due to the net effect of:

- higher interest rates on increased levels of short-term borrowings
- long-term debt and junior subordinated note issuances, net of maturities. Refer to the Financial Condition section for additional information on long-term debt and junior subordinated notes
- the foreign exchange impact from a stronger U.S. dollar on translation of U.S. dollar-denominated interest expense.

Interest expense included in comparable earnings in 2021 increased by $126 million compared to 2020 mainly due to the net effect of:

- lower capitalized interest due to its cessation for the Keystone XL pipeline project following the revocation of the Presidential Permit in January 2021, the change to equity accounting for our Coastal GasLink investment upon the sale of a 65 per cent interest in Coastal GasLink LP in 2020 and the completion of the Napanee power plant in 2020
- the foreign exchange impact from a weaker U.S. dollar on translation of U.S. dollar-denominated interest expense
- lower interest rates on reduced levels of short-term borrowings
- long-term debt and junior subordinated note issuances, net of maturities.

Allowance for funds used during construction

year ended December 31 (millions of $)	**2022**	**2021**	**2020**
Allowance for funds used during construction			
Canadian dollar-denominated	**157**	140	106
U.S. dollar-denominated	**161**	101	182
Foreign exchange impact	**51**	26	61
Allowance for funds used during construction	**369**	267	349

AFUDC increased by $102 million in 2022 compared to 2021. The increase in Canadian dollar-denominated AFUDC is primarily related to increased capital expenditures on the NGTL System. The increase in U.S. dollar-denominated AFUDC is due to the reactivation of AFUDC on the TGNH assets under construction following the new TSA with the CFE as well as capital expenditures on the Southeast Gateway pipeline project, partially offset by the impact of decreased capital expenditures and projects placed in service on our U.S. natural gas pipeline projects. Refer to the Mexico Natural Gas Pipelines – Significant events section for additional information on the Southeast Gateway pipeline project.

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

Foreign exchange (loss)/gain, net

year ended December 31 (millions of $)	2022	2021	2020
Foreign exchange (loss)/gain, net included in comparable earnings	**(8)**	254	(12)
Specific items:			
Foreign exchange loss – inter-affiliate loan	**(28)**	(41)	(86)
Risk management activities	**(149)**	(203)	126
Foreign exchange (loss)/gain, net	**(185)**	10	28

Foreign exchange losses were $185 million in 2022 compared to foreign exchange gains of $10 million in 2021 and $28 million in 2020. The following specific items have been removed from our calculation of Foreign exchange (loss)/gain, net included in comparable earnings:

- foreign exchange losses on the peso-denominated inter-affiliate loan receivable from the Sur de Texas joint venture until March 15, 2022, when it was fully repaid upon maturity
- unrealized losses and gains from changes in the fair value of derivatives used to manage our foreign exchange risk. Refer to the Other Information – Financial risks and financial instruments sections for additional information.

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

Foreign exchange losses of $8 million were included in comparable earnings in 2022 compared to foreign exchange gains of $254 million in 2021, with the change primarily due to the net effect of:

- net realized losses in 2022 compared to net realized gains in 2021 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- foreign exchange losses in 2022 compared to gains in 2021 on the revaluation of peso-denominated net monetary liabilities
- higher realized gains in 2022 compared to 2021 on derivatives used to manage our exposure to net liabilities in Mexico that give rise to foreign exchange gains and losses.

Foreign exchange gains of $254 million were included in comparable earnings in 2021 compared to foreign exchange losses of $12 million in 2020. Realized gains in 2021 compared to realized losses in 2020 were related to derivatives used to manage our net exposure to foreign exchange rate fluctuation on U.S. dollar-denominated income.

Interest income and other

year ended December 31 (millions of $)	2022	2021	2020
Interest income and other	**146**	190	185

Interest income and other decreased by $44 million in 2022 compared to 2021 due to the March 15, 2022 refinancing of the inter-affiliate loan receivable from the Sur de Texas joint venture and subsequent repayment of the loan on July 29, 2022. Interest income and other included in comparable earnings in 2021 was relatively consistent compared to 2020.

Income tax expense

year ended December 31 (millions of $)	2022	2021	2020
Income tax expense included in comparable earnings	**(813)**	(830)	(651)
Specific items:			
Coastal GasLink LP impairment charge	**405**	—	—
Great Lakes goodwill impairment charge	**40**	—	—
Settlement of Mexico prior years' income tax assessments	**(196)**	—	—
Expected credit loss provision on net investment in leases and certain contract assets	**49**	—	—
Keystone CER decision	**7**	—	—
Keystone XL preservation and other	**6**	12	—
Bruce Power unrealized fair value adjustments	**4**	(3)	(3)
Keystone XL asset impairment charge and other	**(123)**	641	—
Voluntary Retirement Program	**—**	15	—
Sale of Northern Courier	**—**	6	—
Sale of Ontario natural gas-fired power plants	**—**	(10)	131
Partial sale of Coastal GasLink LP	**—**	—	38
Income tax valuation allowance releases	**—**	—	299
Sale of Columbia Midstream assets	**—**	—	18
Risk management activities	**32**	49	(26)
Income tax expense	**(589)**	(120)	(194)

Income tax expense in 2022 increased by $469 million compared to 2021 and decreased by $74 million in 2021 compared to 2020 and included the following specific items which have been removed from our calculation of Income tax expense included in comparable earnings, in addition to some of the income tax impacts on other specific items referenced elsewhere in this MD&A.

Specific items in 2022:
- a $405 million income tax recovery related to the impairment of our equity investment in Coastal GasLink LP, net of certain unrealized tax losses not recognized
- $196 million related to the settlement of prior years' income tax assessments related to our operations in Mexico. Refer to the Corporate – Significant events section for additional information
- a $123 million income tax expense as part of the Keystone XL asset impairment charge and other that includes a $96 million U.S. minimum tax related to the termination of the Keystone XL pipeline project.

Specific item in 2021:
- income tax impact of the Keystone XL pipeline project asset impairment charge and other.

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

Income tax expense included in comparable earnings in 2022 decreased by $17 million compared to 2021 primarily due to lower flow-through income taxes and higher foreign tax rate differentials, partially offset by higher earnings subject to tax and other various valuation allowances.

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

Net income attributable to non-controlling interests

year ended December 31 (millions of $)	2022	2021	2020
Net income attributable to non-controlling interests	**(37)**	(91)	(297)

Net income attributable to non-controlling interests decreased by $54 million in 2022 compared to 2021 and by $206 million in 2021 compared to 2020 primarily as a result of the March 2021 acquisition of all outstanding common units of TC PipeLines, LP not beneficially owned by TC Energy. Subsequent to the acquisition, TC PipeLines, LP became an indirect, wholly-owned subsidiary of TC Energy.

Preferred share dividends

year ended December 31 (millions of $)	2022	2021	2020
Preferred share dividends	**(107)**	(140)	(159)

Preferred share dividends decreased by $33 million in 2022 compared to 2021 and $19 million in 2021 compared to 2020 primarily due to the redemption of preferred shares in 2022 and 2021.

Financial condition

We strive to maintain financial strength and flexibility in all parts of the economic cycle. We rely on our operating cash flows to sustain our business, pay dividends and fund a portion of our growth. In addition, we access capital markets and engage in asset divestitures to meet our financing needs, manage our capital structure and to preserve our credit ratings. More information on how our credit ratings can impact our financing costs, liquidity and operations is available in our Annual Information Form available on SEDAR (www.sedar.com).

We believe we have the financial capacity to fund our existing capital program through predictable and growing cash flows from operations, access to capital markets, our asset divestiture program, 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.

Financial Plan

Our capital program is comprised of approximately $34 billion of secured projects, as well as our projects under development, which are subject to key corporate and regulatory approvals. As discussed throughout this Financial Condition section, our capital 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 divestitures
- 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
- discrete common equity issuance.

Balance sheet analysis

At December 31, 2022, our current assets totaled $7.3 billion and current liabilities amounted to $16.9 billion, leaving us with a working capital deficit of $9.6 billion compared to $5.6 billion at December 31, 2021. Our working capital deficiency is considered to be in the normal course of business and is managed through:

- our ability to generate predictable and growing cash flows from operations
- a total of $10.4 billion of committed revolving credit facilities of which $5.9 billion of short-term borrowing capacity remains available, net of $4.5 billion backstopping outstanding commercial paper balances. In addition, on November 22, 2022, TransCanada PipeLines Limited (TCPL) entered into a 364-day $1.5 billion senior unsecured term loan bearing interest at a floating rate. We also have arrangements in place for a further $2.4 billion of demand credit facilities of which $1.1 billion remains available as of December 31, 2022
- our access to capital markets, including through securities issuances, incremental credit facilities, our asset divestiture program and DRP, if deemed appropriate.

The working capital deficiency was reduced on January 17, 2023 as a result of a wholly-owned Mexican subsidiary entering into a US$1.8 billion senior unsecured term loan and a US$500 million senior unsecured credit facility further described below.

Our total assets at December 31, 2022 were $114.3 billion compared to $104.2 billion at December 31, 2021 with the increase primarily reflecting our 2022 capital spending program, and increased equity investments and net investment in leases, partially offset by depreciation. The increase was also due to a stronger U.S. dollar at December 31, 2022 compared to December 31, 2021 on translation of our U.S. dollar-denominated assets.

At December 31, 2022 our total liabilities were $80.2 billion, compared to $70.8 billion at December 31, 2021 due to the net effect of movements in debt, working capital and foreign exchange rates as discussed above.

Our equity at December 31, 2022 was $34.1 billion, consistent with $33.4 billion at December 31, 2021.

Consolidated capital structure

The following table summarizes the components of our capital structure.

at December 31 (millions of $, unless otherwise noted)	**2022**	**Per cent of total**	**2021**	**Per cent of total**
Notes payable	**6,262**	**7**	5,166	6
Long-term debt, including current portion	**41,543**	**45**	38,661	45
Cash and cash equivalents	**(620)**	**(1)**	(673)	(1)
	47,185	**51**	43,154	50
Junior subordinated notes	**10,495**	**11**	8,939	11
Preferred shares	**2,499**	**3**	3,487	4
Common shareholders' equity	**31,491**	**35**	29,784	35
Non-controlling interests	**126**	**—**	125	—
	91,796	**100**	85,489	100

Provisions of various trust indentures and credit arrangements with certain of our subsidiaries can restrict those subsidiaries' ability 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, 2022.

Cash flows

The following tables summarize our consolidated cash flows.

year ended December 31 (millions of $)	2022	2021	2020
Net cash provided by operations	**6,375**	6,890	7,058
Net cash used in investing activities	**(7,009)**	(7,712)	(6,052)
Net cash provided by/(used in) financing activities	**487**	(88)	(800)
	(147)	(910)	206
Effect of foreign exchange rate changes on cash and cash equivalents	**94**	53	(19)
(Decrease)/increase in cash and cash equivalents	**(53)**	(857)	187

Cash provided by operating activities

year ended December 31 (millions of $)	2022	2021	2020
Net cash provided by operations	**6,375**	6,890	7,058
Increase in operating working capital	**639**	287	327
Funds generated from operations	**7,014**	7,177	7,385
Specific items:			
Settlement of Mexico prior years' income tax assessments	**196**	—	—
Current income tax expense on Keystone XL asset impairment charge, preservation and other	**91**	131	—
Keystone CER decision	**27**	—	—
Keystone XL preservation and other	**25**	49	—
Voluntary Retirement Program	**—**	63	—
Current income tax recovery on Voluntary Retirement Program	**—**	(14)	—
Comparable funds generated from operations	**7,353**	7,406	7,385

Net cash provided by operations

Net cash provided by operations decreased by $515 million in 2022 compared to 2021 primarily due to the amount and timing of working capital changes and lower funds generated from operations.

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

Comparable funds generated from operations

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

Comparable funds generated from operations decreased by $53 million in 2022 compared to 2021 primarily due to higher interest expense and net realized foreign exchange losses on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income and peso-denominated transactions, partially offset by higher comparable EBITDA.

Comparable funds generated from operations increased by $21 million in 2021 compared to 2020 primarily due to higher comparable earnings, including realized gains in 2021 compared to realized losses in 2020 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income. This was partially offset by fees collected in 2020 associated with the construction of the Sur de Texas pipeline, as well as lower distributions from the operating activities of our equity investments in 2021.

Cash used in investing activities

year ended December 31 (millions of $)	**2022**	**2021**	**2020**
Capital spending			
Capital expenditures	**(6,678)**	(5,924)	(8,013)
Capital projects in development	**(49)**	—	(122)
Contributions to equity investments	**(2,234)**	(1,210)	(765)
	(8,961)	(7,134)	(8,900)
Keystone XL contractual recoveries	**571**	—	—
Proceeds from sales of assets, net of transaction costs	**—**	35	3,407
Loans to affiliate issued, net	**(11)**	(239)	—
Other distributions from equity investments	**1,433**	73	—
Deferred amounts and other	**(41)**	(447)	(559)
Net cash used in investing activities	**(7,009)**	(7,712)	(6,052)

Net cash used in investing activities decreased from $7.7 billion in 2021 to $7.0 billion in 2022 largely as a result of higher other distributions from our equity investments primarily related to our proportionate share of the Sur de Texas debt repayment, contractual recoveries received in 2022 with respect to the Keystone XL pipeline project termination in 2021, as well as a loan issued to one of our affiliates in 2021, partially offset by higher capital spending in 2022.

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

Capital spending[1]

The following table summarizes capital spending by segment.

year ended December 31 (millions of $)	2022	2021	2020
Canadian Natural Gas Pipelines	**4,719**	2,737	3,608
U.S. Natural Gas Pipelines	**2,137**	2,820	2,785
Mexico Natural Gas Pipelines	**1,027**	129	173
Liquids Pipelines	**143**	571	1,442
Power and Energy Solutions	**894**	842	834
Corporate	**41**	35	58
	8,961	7,134	8,900

1 Capital spending includes Capital expenditures, Capital projects in development and Contributions to equity investments. Refer to Note 4, Segmented information, of our 2022 Consolidated financial statements for the financial statement line items that comprise total capital spending.

Capital expenditures

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

Capital projects in development

Costs incurred during 2022 on Capital projects in development were predominantly attributable to spending on projects in the Power and Energy Solutions segment.

Contributions to equity investments

Contributions to equity investments increased in 2022 compared to 2021 mainly due to the partner equity contribution of approximately $1.3 billion made in 2022 to Coastal GasLink LP in accordance with revised agreements impacting Coastal GasLink LP. Refer to the Canadian Natural Gas Pipelines – Significant events section for additional information on the Coastal GasLink project. This was partially offset by contributions made to Iroquois in 2021.

As part of refinancing activities with the Sur de Texas joint venture, on March 15, 2022, our peso-denominated inter-affiliate loan was fully repaid upon maturity in the amount of $1.2 billion and was subsequently replaced with a new U.S. dollar-denominated inter-affiliate loan of an equivalent $1.2 billion. The Contributions to equity investments and Other distributions from equity investments with respect to these refinancing activities are presented above on a net basis, although they are reported on a gross basis in our Condensed consolidated statement of cash flows. Refer to the Financial risks and financial instruments – Related party transactions section for additional information.

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

Keystone XL contractual recoveries

In 2022, we received $571 million of contractual recoveries with respect to the Keystone XL pipeline project termination in 2021.

Proceeds from sales of assets

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

In 2020, we completed the following asset divestitures. 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.

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

Other distributions from equity investments
Other distributions from equity investments primarily relate to our proportionate share of the Sur de Texas debt repayments in 2022 and 2021 as well as the return of capital from our equity investment in Iroquois in 2022.

Subsequent to the refinancing activities with the Sur de Texas joint venture discussed above, on July 29, 2022, the joint venture entered into an unsecured term loan agreement with third parties, the proceeds of which were used to fully repay the U.S. dollar-denominated inter-affiliate loan with TC Energy.

Cash provided by/(used in) financing activities

year ended December 31			
(millions of $)	**2022**	**2021**	**2020**
Notes payable issued/(repaid), net	**766**	1,003	(220)
Long-term debt issued, net of issue costs	**2,508**	10,730	5,770
Long-term debt repaid	**(1,338)**	(7,758)	(3,977)
Junior subordinated notes issued, net of issue costs	**1,008**	495	—
Gain/(Loss) on settlement of financial instruments	**23**	(10)	(130)
Redeemable non-controlling interest repurchased	**—**	(633)	—
Contributions from redeemable non-controlling interest	**—**	—	1,033
Dividends and distributions paid	**(3,385)**	(3,548)	(3,367)
Common shares issued, net of issue costs	**1,905**	148	91
Preferred shares redeemed	**(1,000)**	(500)	—
Acquisition of TC PipeLines, LP transaction costs	**—**	(15)	—
Net cash provided by/(used in) financing activities	**487**	(88)	(800)

Net cash provided by financing activities increased by $575 million in 2022 compared to 2021 primarily due to higher proceeds from common shares and junior subordinated notes issued in 2022 as well as the 2021 subsequent repurchase of the redeemable non-controlling interest from contributions received in 2020 in support of Keystone XL construction, partially offset by lower net issuances of long-term debt and notes payable along with higher preferred shares redemption.

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

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 2022.

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

On January 17, 2023, a wholly-owned Mexican subsidiary entered into a US$1.8 billion senior unsecured term loan and a US$500 million senior unsecured credit facility. Both the term loan and the revolving commitment are due in January 2028 and bear interest at a floating rate.

Long-term debt retired

The following table outlines significant long-term debt retired in 2022.

(millions of Canadian $, unless otherwise noted) Company	Retirement date	Type	Amount	Interest rate
TRANSCANADA PIPELINES LIMITED				
	August 2022	Senior Unsecured Notes	US 1,000	2.50%

Junior subordinated notes issued

In March 2022, TransCanada Trust (the Trust) issued US$800 million of Trust Notes – Series 2022-A to investors with a fixed interest rate of 5.60 per cent per annum for the first 10 years and resetting on the tenth anniversary and every five years thereafter. All of the proceeds of the issuance by the Trust were loaned to TCPL for US$800 million of junior subordinated notes of TCPL at an initial fixed rate of 5.85 per cent per annum, including a 0.25 per cent administration charge. The rate on the junior subordinated notes of TCPL will reset every five years commencing March 2032 until March 2052 to the then Five-Year Treasury Rate, as defined in the document governing the subordinated notes, plus 4.236 per cent per annum; from March 2052 until March 2082, the interest rate will reset every five years to the then Five-Year Treasury Rate plus 4.986 per cent per annum. The junior subordinated notes are callable at TCPL's option at any time from December 7, 2031 to March 7, 2032 and on each interest payment and reset date thereafter at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption.

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

For more information about long-term debt and junior subordinated notes issued and long-term debt repaid in 2022, 2021 and 2020, refer to the notes to our 2022 Consolidated financial statements.

Redeemable non-controlling interest repurchased

On January 8, 2021, we exercised our call right in accordance with contractual terms and paid US$497 million ($633 million) to repurchase the Government of Alberta Class A Interests which were classified as Current liabilities on the Consolidated balance sheet at December 31, 2020. This transaction was funded by draws on the Keystone XL project-level credit facility.

Dividend reinvestment and share purchase plan

To prudently fund our growth program that includes increased project costs on the NGTL System and following our July 2022 obligation to make an equity contribution of $1.9 billion to Coastal GasLink LP, we reinstated the issuance of common shares from treasury at a two per cent discount under our DRP commencing with the dividends declared on July 27, 2022. On dividends declared in 2022, the participation rate by common shareholders was approximately 33 per cent, resulting in $607 million reinvested in common equity under the program. The discounted DRP is expected to be in place through the dividend declarations for the quarter ending June 30, 2023.

TC Energy Corporate ATM program

In December 2020, we established a new ATM program that allowed 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 was effective for a 25-month period, provided additional financial flexibility in support of our consolidated credit metrics and capital program. The ATM program was not activated and in January 2023, the ATM program expired with no common shares issued under this program thereunder.

Share information

as at February 8, 2023		
Common Shares	**issued and outstanding**	
	1.0 billion	
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
Options to buy common shares	**outstanding**	**exercisable**
	6 million	3 million

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

On May 31, 2022, we redeemed all of the 40 million issued and outstanding Series 15 preferred shares at a redemption price of $25.00 per share and paid the final quarterly dividend of $0.30625 per Series 15 preferred share for the period up to but excluding May 31, 2022, as previously declared on April 28, 2022.

For more information on preferred shares refer to the notes to our 2022 Consolidated financial statements.

Dividends

year ended December 31	2022	2021	2020
Dividends declared			
per common share	$3.60	$3.48	$3.24
per Series 1 preferred share	$0.86975	$0.86975	$0.86975
per Series 2 preferred share	$0.82611	$0.50997	$0.7099
per Series 3 preferred share	$0.4235	$0.4235	$0.48075
per Series 4 preferred share	$0.66655	$0.34997	$0.54989
per Series 5 preferred share	$0.48725	$0.48725	$0.56575
per Series 6 preferred share	$0.80668	$0.41622	$0.52537
per Series 7 preferred share	$0.97575	$0.97575	$0.97575
per Series 9 preferred share	$0.9405	$0.9405	$0.9405
per Series 11 preferred share	$0.83775	$0.83775	$0.92194
per Series 13 preferred share	—	$0.34375	$1.375
per Series 15 preferred share	$0.30625	$1.225	$1.225

On February 13, 2023, we increased the quarterly dividend on our outstanding common shares by 3.3 per cent to $0.93 per common share for the quarter ending March 31, 2023 which equates to an annual dividend of $3.72 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 8, 2023, we had a total of $12.8 billion of committed revolving and demand credit facilities, including:

(billions of Canadian $, unless otherwise noted) Borrower	Description	Matures	Total facilities	Unused capacity[1]
Committed, syndicated, revolving, extendible, senior unsecured credit facilities:				
TCPL	Supports TCPL's Canadian dollar commercial paper program and for general corporate purposes	December 2027	3.0	1.7
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 2023	US 3.0	US 1.7
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 2025	US 2.5	US 2.5
Demand senior unsecured revolving credit facilities:				
TCPL / TCPL USA	Supports the issuance of letters of credit and provides additional liquidity; TCPL USA facility guaranteed by TCPL	Demand	2.1 [2]	1.0 [2]
Mexico subsidiary	For Mexico general corporate purposes, guaranteed by TCPL	Demand	MXN 5.0 [2]	MXN 5.0 [2]

1 Unused capacity is net of commercial paper outstanding and facility draws.
2 Or the U.S. dollar equivalent.

Contractual obligations

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

Payments due (by period)

at December 31, 2022 (millions of $)	Total	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Notes payable	6,262	6,262	—	—	—
Long-term debt and junior subordinated notes[1]	52,299	1,898	5,609	5,391	39,401
Operating leases[2]	496	68	127	114	187
Purchase obligations and other	6,049	3,781	805	454	1,009
	65,106	12,009	6,541	5,959	40,597

1 Excludes issuance costs and fair value adjustments.
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 $6.3 billion at the end of 2022 compared to $5.2 billion at the end of 2021.

Long-term debt and junior subordinated notes

At December 31, 2022, we had $41.5 billion of long-term debt and $10.5 billion of junior subordinated notes outstanding compared to $38.7 billion of long-term debt and $8.9 billion of junior subordinated notes at December 31, 2021.

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

Interest payments

At December 31, 2022, scheduled interest payments related to our long-term debt and junior subordinated notes were as follows:

at December 31, 2022 (millions of $)	Total	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Long-term debt	23,966	1,964	3,630	3,129	15,243
Junior subordinated notes	49,109	612	1,239	1,477	45,781
	73,075	2,576	4,869	4,606	61,024

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.

We have entered into PPAs with solar and wind-power generating facilities ranging from one to 15 years, that require the purchase of generated energy and associated environmental attributes. At December 31, 2022, the total planned capacity secured under the PPAs is approximately 1,020 MWs with the generation subject to operating availability and capacity factors. Future payments and their timing cannot be reasonably estimated as they are dependent on when certain underlying facilities are placed in service and the amount of energy generated. Certain of these purchase commitments have offsetting sale PPAs for all or a portion of the related output from the facility.

Payments due (by period)

at December 31, 2022 (millions of $)	Total	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Canadian Natural Gas Pipelines					
Transportation by others[1]	1,671	185	320	300	866
Capital spending[2]	974	951	21	2	—
U.S. Natural Gas Pipelines					
Transportation by others[1]	640	154	247	98	141
Capital spending[2]	266	257	9	—	—
Mexico Natural Gas Pipelines					
Capital spending[2]	1,699	1,699	—	—	—
Liquids Pipelines					
Transportation by others[1]	68	26	38	4	—
Capital spending[2]	21	21	—	—	—
Other	7	3	4	—	—
Power and Energy Solutions					
Capital spending[2]	315	257	57	1	—
Other[3]	43	10	16	15	2
Corporate					
Other	319	192	93	34	—
Capital spending[2]	26	26	—	—	—
	6,049	3,781	805	454	1,009

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.

GUARANTEES

Sur de Texas

We and our partner on the Sur de Texas pipeline, IEnova, have jointly guaranteed the financial performance of the entity which owns the pipeline. Such agreements include a guarantee and a letter of credit which are primarily related to the delivery of natural gas. The guarantee has terms that can be renewed in June 2023, with the annual option to extend for one year periods ending in 2053.

At December 31, 2022, 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 that can be renewed in December 2023 and is extendable for any number of successive two-year periods, with a final renewal period of three years ending in 2065.

At December 31, 2022, 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, 2022 to be approximately $81 million with a carrying amount of $3 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 2022, we made funding contributions of $78 million to our defined benefit pension plans, $8 million for other post-retirement benefit plans and $64 million for the savings plan and defined contribution plans. No additional letters of credit were provided to the Canadian defined benefit plan for funding of solvency requirements.

Considering current market conditions and the reduction to the number of active plan members due to the VRP, we expect 2023 required funding levels to be lower than 2022 levels, although actuarial valuations for determining 2023 funding of our pension and other post-retirement benefit plans as at January 1, 2023 will be carried out in mid-2023. We currently expect 2023 funding contributions of approximately $32 million for the defined benefit pension plans, $6 million for other post-retirement benefit plans and approximately $69 million for the savings plans and defined contribution pension plans. We do not expect to issue additional letters of credit to the Canadian defined benefit plan for solvency funding requirements.

The net benefit cost for our defined benefit and other post-retirement plans decreased to $57 million in 2022 from $108 million in 2021 primarily due to the impact of increased interest 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) program that identifies enterprise risks, including ESG-related risks, that could materially impact the achievement of our strategic objectives.

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

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

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

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

Key segment-specific financial, health, safety and environment risks are covered in their respective sections of this MD&A. Further, our management of climate-related governance, strategy, risks, metrics and targets are outlined in the TCFD section of our ESG Data Sheet. The following is a summary of enterprise-wide risks with potential to affect all of our operations. These risks are being continuously monitored through our robust ERM program, which includes a network of emerging risk liaisons in key positions across the organization who are responsible for identifying potential enterprise-level risks that are reported quarterly to the Board of Directors.

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

Risk and description	Impact	Monitoring and mitigation
Reputation and relationships		
Our operations and growth prospects require us to have strong relationships with key stakeholders including customers, Indigenous communities, landowners, suppliers, investors, governments and government agencies and environmental non-governmental organizations.	Inadequately managing stakeholder expectations and concerns, including those related to ESG, can have a significant impact on our operations and projects, infrastructure development and overall reputation. It could also affect our ability to operate and grow.	Our core values – safety, responsibility, collaboration, integrity and innovation – guide us in building and maintaining our key relationships as well as our interactions with stakeholders. We are proud of the strong relationships we have built with stakeholders across our geographies, and we are continuously seeking ways to strengthen these relationships. Beyond our core values, we have specific stakeholder programs and policies that shape our interactions, clarify expectations, assess risks and facilitate mutually beneficial outcomes. Our most recent Report on Sustainability and ESG Data Sheet includes details on our specific commitments and performance metrics related to safety, partnerships with Indigenous communities, focus on landowner relationships and our workplace inclusion and diversity.
Regulatory uncertainty		
Our ability to construct and operate energy infrastructure requires regulatory approvals and is dependent on evolving policies and regulations by government authorities. This includes changes in regulation that may affect our projects and operations.	Adverse impacts on competitive geographic and business positions could result in the inability to meet our growth targets through missed or lost organic, greenfield and brownfield opportunities. Financial impacts of denied or delayed projects could include lost development costs, loss of investor confidence and potential legal costs from litigation. Regulations could also increase the cost of our operations resulting in the inability to earn a reasonable return on our invested capital.	We monitor regulatory and government developments and decisions to analyze their possible impact on our businesses. We build scenario analysis into our strategic outlook and work closely with our stakeholders in the development and operation of our assets. We identify emerging risks and signposts including customer, regulatory and government decisions as well as innovative technology development and report on our management of these risks quarterly through the ERM program to the Board. We also use this information to inform our capital allocation strategy and adapt to changing market conditions.
Access to capital at a competitive cost		
We require substantial amounts of capital in the form of debt and equity to finance our portfolio of growth projects and maturing debt obligations at costs that are sufficiently lower than the returns on our investments.	Significant deterioration in market conditions for an extended period of time and changes in investor and lender sentiment could affect our ability to access capital at a competitive cost, which could negatively impact our ability to deliver an attractive return on our investments or inhibit our growth.	We operate within our financial means and risk tolerances, maintain a diverse array of funding levers and also utilize asset divestitures as an important component of our financing program. In addition, we have candid and proactive engagement with the investment community, including credit rating agencies, with the objective of hearing their feedback and keeping them apprised of developments in our business and factually communicating our prospects, risks and challenges as well as ESG-related updates. We also conduct research around the evolving ESG preferences of our investors and financial partners which we consider in our decision making. In 2022, we launched our first sustainability linked loan as we continue to build sustainability and ESG performance metrics into our business strategy.

Risk and description	Impact	Monitoring and mitigation
Capital allocation strategy		
To be competitive, we must offer integral energy infrastructure services in supply and demand areas, and in forms of energy that are attractive to customers.	Should alternative lower-carbon forms of energy result in decreased demand for our services on an accelerated timeline versus our pace of depreciation, the value of our long-lived energy infrastructure assets could be negatively impacted.	We have a diverse portfolio of assets and use portfolio management to divest of non-strategic assets, effectively rotating capital while adhering to our risk preferences and focus on per share metrics. We conduct analyses to identify resilient supply sources as part of our energy fundamentals and strategic development reviews. We recover depreciation through our regulated pipeline rates which is an important lever to accelerate or decelerate the return of capital from a substantial portion of our assets. We also monitor signposts including customer, regulatory and government decisions as well as innovative technology development to inform our capital allocation strategy and adapt to changing market conditions.
Execution and capital costs		
Investing in large infrastructure projects involves substantial capital commitments and associated execution risks, including skilled labour shortages and weather-related delays which can impact project costs and schedules, based on the assumption that these assets will deliver an attractive return on investment in the future.	While we carefully determine the expected cost of our capital projects, under some commercial arrangements, we bear capital cost overrun and schedule risk which may decrease our return on these projects.	Our Project Governance program supports project execution and operational excellence. The program aligns with TOMS which provides the framework and standards to optimize project execution, supporting timely and on budget completion. We prefer to contractually structure our projects to recover development costs if a project does not proceed along with mechanisms to minimize the impact should cost overruns occur. However, under some commercial arrangements, we share or bear the cost of execution risk. Additionally, we can utilize project financing and/or involve partners in our projects to manage capital at risk.

Health, safety, sustainability and environment

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

Our management system, TOMS, is modeled after international standards, including the International Organization for Standardization (ISO) standard for environmental management systems, ISO 14001, and the Occupational Health and Safety Assessment Series for occupational health and safety. TOMS also conforms to applicable industry standards and complies with applicable regulatory requirements. Periodic audits of TOMS, as they apply to our Canadian assets, are conducted by the CER and lessons learned from these audits are shared and applied across our system where applicable. TOMS covers the lifecycle of our assets and follows a continuous improvement cycle organized into four key areas:

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

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

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

Focus on ESG and sustainability

Starting in 2022, we have embedded ESG goals into our corporate scorecard, with a weighting of 50 per cent of our overall corporate performance on progressing ESG priorities and advancing key strategic priorities including growth and energy transition. Key performance areas that we are tracking to measure success against these goals include achieving top personal safety, maintaining safe reliable operations and asset integrity while minimizing environmental impacts and developing solutions for a lower-carbon energy future. Our approach to sustainability is guided by our 10 commitments that align to the UN Sustainable Development Goals, with 30 tangible targets to measure and drive performance in areas including emissions reductions, biodiversity and safety. We are committed to ensuring balanced, transparent disclosure of our progress against these targets annually in our Report on Sustainability and ESG Data Sheet. Our targets relevant for environment, safety and sustainability include, but are not limited to the following:

- zero significant process safety incidents
- total Recordable Case Rate of no higher than 0.50 for employees and contractors combined
- reduce GHG emissions intensity from our operations by 30 per cent by 2030
- position to achieve zero emissions from our operations on a net basis by 2050
- restore or offset 100 per cent of disturbances to sensitive habitat resulting from construction and operation of our North American assets
- invest $1.2 million per year in community initiatives that restore biodiversity and reduce the impacts of climate change.

Another way in which we demonstrate our commitment to ESG and sustainability is through participation in international forums. In May 2022, we became an approved participant to the UNGC. The UNGC is a call for companies to align their strategies and operations with universal principles and take actions that advance societal goals. Our participation strengthens our commitment to the United Nations' global sustainability goals and involves submitting annual responses to a Communication on Progress questionnaire and submission of an annual statement expressing support for the UNGC. In July 2022, we were accepted to join the Task Force on Nature-based Financial Disclosures (TNFD) Forum. The mission of TNFD is to develop a risk management and disclosure framework for reporting, with the aim to shift global financial flows toward nature-positive outcomes. Participating in the TNFD Forum demonstrates alignment with TNFD's mission and provides early access to information on TNFD development and the opportunity to provide input to the framework. Working with TNFD aligns with our existing reporting alignment to the TCFD.

Health, safety and asset integrity

The safety of our employees, contractors and the public, the integrity of our pipelines and our power and energy solutions 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 2022, we are forecasting to spend $1.5 billion (2021 – $1.4 billion) for pipeline integrity on the natural gas and liquids pipelines we operate. 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 Energy Solutions assets we operate is used to minimize risk to employees, contractors, the public, equipment and the surrounding environment, and also prevent disruptions to serving the energy needs of our customers.

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

We are committed to protecting the health and safety of all individuals involved in our activities. Our Occupational Health and Hygiene Program provides comprehensive strategies for health promotion and protection. We are committed to delivering effective programs that:

- reduce the human and financial impact of illness and injury
- ensure fitness for work
- strengthen worker resiliency
- build organizational capacity by focusing on individual well-being, health education and improved working conditions to sustain a productive workforce
- increase mental well-being awareness, provide various mental health supports and training to employees and leaders, measure the success of programs and improve psychological health and safety.

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 in addition to complying 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. The program outlines environmental training requirements for applicable roles in the organization to raise awareness of environmental protection commitments and requirements plus sets environment performance goals that are monitored regularly.

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. We consider the information collected during environmental assessments, and where sensitive habitats or areas of high biodiversity value are identified, we apply the biodiversity protection hierarchy and avoid those areas, as practicable. Where those areas cannot be avoided, we minimize our disturbance, restore and reclaim the disturbed area and provide offset where required. To conserve and protect the environment during construction, information gathered for an environmental impact assessment is used to develop project-specific environmental protection plans. Whenever the potential exists for a proposed facility or pipeline to interact with water resources, we conduct evaluations to understand the full nature and extent of the interactions. When we temporarily use water to test the integrity of our pipelines, we adhere to strict regulatory requirements and ensure water meets applicable water quality standards before it is discharged or disposed of, and when our construction activities involve crossing waterbodies, we implement protection measures to avoid or minimize potential adverse effects. Project plans are communicated with stakeholders and Indigenous communities, as applicable, and engagement with these groups informs the environmental assessments and protection plans. Additionally, the Environment Program, which applies to all of our operations, includes practices and procedures to manage potential adverse environmental effects to these resources during the full lifecycle of our facilities.

Our primary sources of risk related to the environment include:

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

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

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

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

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

The timing and complete extent of future expenditures related to environmental matters is difficult to estimate accurately because:

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

At December 31, 2022, accruals related to these obligations, with the exception of the accrual related to the Milepost 14 incident, totaled $20 million (2021 – $30 million) representing the estimated amount we will need to manage our currently known environmental liabilities. Refer to the Liquids Pipelines – Significant events section for additional information regarding the Milepost 14 incident. 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 2022, we incurred $118 million (2021 – $59 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 are implemented. We support transparent climate change policies that promote sustainable and economically responsible natural resource development, and in October 2021, we published a GHG Emissions Reduction Plan that includes GHG reduction targets in support of global climate goals. Our assets in specific geographies are currently subject to GHG regulations and we expect that the number of our assets subject to GHG regulations will continue to increase over time across our footprint. Changes in regulations may result in higher operating costs, other expenses or capital expenditures to comply with new or changing regulations. We monitor the pace and magnitude of energy transition through various signposts and look for material shifts that pose threats or create opportunities. We evaluate climate-related scenarios to gain perspective on the implications for our footprint, growth opportunities and portfolio optimization; this plays a critical role in understanding how we can manage several of our key enterprise risks. The following existing jurisdictional policies and anticipated policies sections describe some of the more relevant existing and anticipated policies applicable to our business.

Existing jurisdictional policies

Canadian jurisdictions

- *Federal:* ECCC's methane reduction regulations that detail requirements to reduce methane emissions through operational and capital modifications came into effect in January 2020. ECCC's methane reduction regulation aims to reduce the oil and gas sector emissions by 40 to 45 per cent below 2012 levels by 2025. Alberta, British Columbia and Saskatchewan have drafted their own methane regulations that take the place of the federal regulation for provincially-regulated assets. For federally-regulated facilities in these jurisdictions, the federal methane regulation is applicable. Compliance with the regulations requires an increased level of leak detection and repair (LDAR) surveys, repairs to identified leaking equipment components following prescribed timelines and measurements to quantify emission reductions. Power facilities are not affected by this regulation at the current time
- *Federal:* 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 for 2022 in the provinces of Manitoba, Saskatchewan and New Brunswick as these jurisdictions did not have provincial carbon pricing plans in place which met the Government of Canada's equivalency criteria. As a result of the Federal program, our assets across Canada are all subject to some type of carbon pricing and the costs under these programs are recovered in tolls. These carbon prices are scheduled to increase by $15/tonne every year after 2022 to $170/tonne in 2030
- *Federal:* New requirements for federally regulated project applications under the Impact Assessment Agency were introduced through the Strategic Assessment of Climate Change, requiring a project proponent to provide a credible plan for a proposed project to achieve net-zero emissions by 2050. The CER published a revision to its Filing Manual to integrate the Strategic Assessment of Climate Change, which includes a requirement that projects regulated by the CER with a lifetime beyond 2050 must also include a credible plan to achieve net-zero emissions by 2050. Responses to this requirement are being developed and provided as part of the project applications on a case-by-case basis
- *British Columbia:* British Columbia implemented a tax on GHG emissions from fossil fuel combustion. While we are subject to this tax, the compliance costs are recovered through tolls. Additionally, British Columbia established the CleanBC program which provides incentive payments or tax rebates for industrial operations that meet an established emission intensity benchmark. The CleanBC Industry Fund 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
- *Alberta:* In Alberta, the Technology Innovation and Emissions Reduction (TIER) regulation has been in effect since January 2020. The TIER regulation requires established industrial facilities with GHG emissions above a certain threshold to reduce their emissions below an intensity baseline. The TIER system covers all of our natural gas pipelines and Power and Energy Solutions 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 Energy Solutions assets are recovered through market pricing and hedging activities
- *Québec:* 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 as are the Canadian Mainline and TQM natural gas pipeline facilities. The provincial 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. For TQM and the Canadian Mainline assets in Québec, compliance instruments have been or will be purchased in order to comply with the requirements of this initiative with these compliance costs being recovered through tolls
- *Ontario:* The Ontario and Federal governments reached an agreement whereby the Federal OBPS in Ontario was replaced on January 1, 2022 by the Ontario Emissions Performance Standards program. Federal OBPS and the Ontario Emissions Performance Standards apply to our Canadian Mainline operations in the province and costs under this program will be recovered in tolls. There was no material impact to the financial performance of our Ontario natural gas facilities as a result of the Ontario Emissions Performance Standards program
- *Saskatchewan:* In September 2022, the Saskatchewan and Federal governments reached an agreement whereby the Federal OBPS in Saskatchewan will be replaced on January 1, 2023 by the Saskatchewan Emissions Performance Standards program for pipeline transmission sector assets. Covered facilities are still required to meet the Federal OBPS regulations for the 2022 compliance period. Federal OBPS and the Saskatchewan Emissions Performance Standards apply to our Canadian Mainline and Foothills operations in the province and costs under this program will be recovered in tolls. At this time, we do not anticipate a material impact to the financial performance of our natural gas facilities as a result of the transition to the Saskatchewan Emissions Performance Standards program.

U.S. jurisdictions

- *Federal:* A joint Congressional resolution (CRA resolution) disapproving the 2020 policy amendment was signed into law in June 2021. The CRA resolution reinstated the 2016 New Source Performance Standards on the transmission and storage segments. The impact to us from the reinstatement was minimal as we previously made the decision to continue to comply even though the 2020 policy amendments removed the transmission and storage segment as an applicable source category
- *California:* Tuscarora facilities are subject to the California Air Resources Board's LDAR program requiring owners/operators of oil and gas facilities to monitor and repair methane leaks. Beginning in January 2020, thresholds for leak repair under this program were reduced. California also has a GHG cap-and-trade program linked with Québec's program through the WCI. All Tuscarora facilities fall below the threshold requiring participation in the GHG cap-and-trade program
- *Pennsylvania:* The Pennsylvania Department of Environmental Protection has an LDAR program for new source installations which require leak repair within 15 days of discovery
- *Pennsylvania:* Effective August 2022, the Pennsylvania Department of Environmental Protection (PDEP) finalized Reasonable Available Control Technologies (RACT) requirements and limitations for major stationary sources of nitrogen oxides (NOx) and volatile organic compounds (VOCs) statewide. TC Energy has four facilities impacted by this rule. If case by case evaluations to be submitted to PDEP by December 31, 2022 demonstrate that controls are needed to comply with the updated emission limitations, then the facilities would potentially have until December 2025 to install these controls
- *Ohio:* Effective March 2022, the Ohio Environmental Protection Agency (OEPA) finalized RACT requirements and limitations for emissions of NOx from stationary sources in the Cleveland non-attainment area. TC Energy has four facilities impacted by this rule, but only one potentially requires modifications to meet the updated emissions limitations. If a facility specific evaluation, which is due to OEPA by March 2023, demonstrates that additional controls are needed, then the facility would potentially have until March 2026 to install these controls
- *Oregon:* 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 on January 1, 2022. The state Department of Environmental Quality recommended a final draft of the rule to the state Environmental Quality Commission (EQC) and the EQC approved the program which still exempts our facilities and their emissions
- *Maryland:* Effective November 2020, the Maryland Department of the Environment (MDE) finalized a methane regulation program for new and existing natural gas facilities that includes an LDAR program, emission control and reporting requirements, plus a requirement to notify not only the MDE, but also the public of any events above a specific threshold. We have one electric-powered compressor station and associated pipeline segments impacted by this regulation
- *Washington:* The Washington Commercial Building Code passed a ban to limit the use of natural gas-powered furnaces and water heaters in all new commercial and residential properties with four stories or more, starting in July 2023.

Mexico jurisdictions

- the General Climate Change Law (LGCC) establishes various public policy instruments, including the National Emissions Registry and its regulations, which allow for the compilation of information on the emission of compounds and GHGs of the different productive sectors of the country. The LGCC defines the National Inventory of Emissions as the document that contains the estimate of anthropogenic emissions by sources and absorption by sinks in Mexico. This law requires an annual submission of our emissions
- the Government of Mexico published a regulation that established guidelines for the prevention and control of methane emissions from the hydrocarbon sector. Companies are required to prepare a Program for the Comprehensive Prevention and Control of Methane Emissions (PPCIEM) which includes identification of sources of methane, quantification of baseline emissions and an estimate of the expected emission reductions from prevention and control activities. This regulation requires the PPCIEM, through which operational and technological practices are adopted, to determine a reduction goal that must be met within a period not exceeding six calendar years from the delivery of the PPCIEM. TC Energy developed and applied the PPCIEM to all of its facilities in Mexico in 2020
- 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 functions as a three-year pilot from 2020 to 2022 allowing 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

- *Federal:* The Government of Canada is developing the Clean Fuel Standard (CFS) to achieve reductions in GHG emissions and in December 2020 the Canadian Federal Government unveiled its plan aimed to exceed their previous 2030 GHG emissions reduction target of 30 per cent below 2005 levels to a new target of 32 to 40 per cent below 2005 levels with the ultimate goal of achieving net-zero emissions by 2050. As part of this plan, the Canadian Federal Government narrowed the CFS scope to include only liquid fuels, which will not directly impact TC Energy. This plan also increased carbon pricing levels and released a complementary hydrogen strategy. Carbon prices are scheduled to increase by $15/tonne every year after 2022 to $170/tonne in 2030. While the scope of the CFS is limited to liquid fuels, there will be opportunities to generate credits for the gaseous fuel stream to incentivize emission reduction opportunities. We will continue to engage with Canadian policy makers and monitor and assess the extent of the impacts as more information is made available
- *Federal:* ECCC committed to expand on the current methane reduction regulations and develop a plan to reduce oil and gas sector methane emissions by at least 75 per cent below 2012 levels by 2030. We will continue to assess the potential implications of any policy and regulatory updates associated with this announcement as more information is made available
- *Federal:* In July 2022, ECCC released a discussion paper on the options to cap and cut oil and gas sector GHG emissions to achieve 2030 goals and net-zero by 2050. The discussion paper proposed excluding natural gas pipeline transmission from this proposed cap; however, coverage and details are yet to be worked out by ECCC and the provinces. We have provided feedback and supported the exclusion of natural gas transmission emission from this cap. We will continue monitoring and providing feedback to ECCC as this file evolves in 2023.

U.S. jurisdictions

- *Federal:* The U.S. Senate passed the PHMSA reauthorization bill, the PIPES Act, which included methane regulations requiring, for example, pipeline owners/operators to implement methane LDAR programs, deploy advanced leak detection technology and incorporate LDAR surveys in inspection and maintenance plans. If the U.S. House of Representatives also supports the inclusion of these methane provisions, PHMSA will join the United States Environmental Protection Agency (USEPA) as another federal regulator of GHG emissions, indicating the nation's increasing desire to combat climate change. The expected impact to our assets is still being evaluated
- *Federal:* On November 11, 2022, the USEPA released a supplemental proposal to expand and strengthen the November 2021 proposal to reduce methane and VOC emissions from the oil and natural gas industry. The associated public comment period ends on February 13, 2023. The supplemental proposal impacts any new projects (new, modified, or reconstructed on or after November 15, 2021) and also affects existing facilities when fully implemented. The supplemental proposal is expected to be finalized in 2023
- *Federal*: On June 21, 2022, USEPA proposed updates to the GHG Reporting program that would go into effect on January 1, 2023 and be included in 2023 GHG reporting due to the USEPA by April 1, 2024. TC Energy reports to the USEPA as required by the GHG Reporting rule (40 CFR 98). The proposal includes reporting of additional emission sources (such as reciprocating engine exhaust methane and centrifugal compressor dry seal venting), revisions to current emission factors for fugitive equipment leaks and pneumatic devices, and options to use facility specific measurements in place of emission factors for certain emission sources
- *Federal:* The Inflation Reduction Act (IRA) was passed and signed into law on August 16, 2022. The IRA instructs USEPA to implement a waste methane fee program by 2024 based on GHG emissions reported to USEPA as required by 40 CFR 98 Subpart W. TC Energy reports to Subpart W for the natural gas transmission compression, underground natural gas storage and onshore natural gas transmission pipeline industry segments. For these industry segments, the IRA imposes and collects a fee on methane emissions that exceeds 0.11 per cent of the natural gas sent for sale from the facility. The proposed fee is $900/tonne for 2024, $1,200/tonne for 2025 and $1,500/tonne for 2026 reporting and forward. In an initial assessment, there would have been no fee impact to TC Energy based on 2021 emissions. The IRA also instructs USEPA to revise Subpart W by August 2024 to ensure GHG reporting is based on empirical data

- *Washington:* On September 29, 2022, the Washington Department of Ecology (WDE) adopted Chapter 173-446 WAC Climate Commitment Act Program (AO# 21-06). Key proposed requirements affect facilities included in the GHG reporting program. WDE will participate in emission trading via the WCI program established in 2011. The applicability threshold is marginally higher for the trading program (25,000 tonnes annually) than the reporting program threshold (10,000 tonnes annually). WDE formally notified affected facilities in November 2022 that they are subject; those entities are required to provide WDE with corporate information and designate account representatives in December 2022. WDE will host four auctions a year, the first being in the first quarter of 2023. The program is designed to achieve Climate Commitment Act milestones of 40 per cent reduction by 2030 and net zero emissions by 2050
- *California:* Our assets may be affected by the Governor of California's executive order, issued in September 2020, requiring all new cars and light trucks sold in California to be emission-free by 2035 and heavy and medium trucks to be emission-free by 2045. The significance of the impact on our assets is still being evaluated
- *California:* California Air Resource Board is planning potential changes to their California Oil and Gas Methane Regulation that include requirements for monitoring plans, repairing leaks after being identified by satellites and changes that would align with USEPA’s proposed emissions guidelines for existing sources
- *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 February 2, 2022, the New York Department of Environmental Conservation (NY DEC) adopted 6 NYCRR Part 203, “Oil and Natural Gas Sector” with an effective date of March 3, 2022. Part 203 will regulate VOCs and methane emissions from the oil and gas sector. Compliance with the regulation is effective starting January 1, 2023. Compliance obligations include leak detection and repair at all storage wells, compressor stations and city gate meter and regulator sites, blowdown notifications, reporting of pigging activities and a baseline inventory for all assets in New York.

Changes to environmental remediation regulations – U.S. Jurisdictions

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

Financial risks

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

Market risk

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

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

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

Commodity price risk

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

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

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

Climate change also presents a potential financial impact to commodity prices and volumes. Our exposure to climate change-related 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/or long-term contracts. In addition, scenario planning against several demand outlooks and monitoring of key signposts is also considered as part of our long-term corporate strategic planning process.

Interest rate risk

We utilize both short- and long-term debt to finance our operations which exposes us to interest rate risk. We typically pay fixed rates of interest on our long-term debt and floating rates on short-term debt including our commercial paper programs and amounts drawn on our credit facilities. A small portion of our long-term debt bears interest at floating rates. In addition, we are exposed to interest rate risk on financial instruments and contractual obligations containing variable interest rate components. We actively manage our interest rate risk using interest rate derivatives. For eligible hedging relationships affected by the expected cessation of certain reference interest rates, we have applied the optional expedient permissible under U.S. GAAP allowing an entity to assume that the hedged forecasted transaction in a cash flow hedge is probable of occurring and, therefore, we expect no material impact on our consolidated financial statements.

Foreign exchange risk

Certain of our businesses generate all or most of their earnings in U.S. dollars and, since we report our financial results in Canadian dollars, changes in the value of the U.S. dollar against the Canadian dollar can affect our comparable EBITDA and comparable earnings.

A 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, therefore changes in the value of the Mexican peso against the U.S. dollar can affect our net income. In addition, foreign exchange gains or losses calculated for Mexico income tax purposes on the revaluation of U.S. dollar-denominated monetary assets and liabilities result in a peso-denominated income tax exposure for these entities, leading to fluctuations in Income from equity investments and Income tax expense.

We actively manage our foreign exchange risk using foreign exchange derivatives. Refer to the 2022 Financial highlights – Foreign exchange section for additional information on our foreign currency exposures.

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

Counterparty credit risk

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

- cash and cash equivalents
- accounts receivable and certain contractual recoveries
- available-for-sale assets
- fair value of derivative assets
- loans receivable
- net investment in leases and certain contract assets.

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 reasonable and supportable forecasts to determine any impairment, which is recognized in Plant operating costs and other. At December 31, 2022 and 2021, we had no significant credit risk concentrations and no significant amounts past due or impaired. We recorded a $163 million expected credit loss provision before tax recognized on the TGNH net investment in leases and certain contract assets in 2022, as required by U.S. GAAP. Other than the expected credit loss provision noted above, we had no significant credit losses at December 31, 2022 and 2021. Refer to Note 28, Risk management and financial instruments, of our 2022 Consolidated financial statements for additional information on expected credit loss provisions.

We have significant credit and performance exposure to financial institutions that hold cash deposits and provide committed credit lines and letters of credit that help manage our exposure to counterparties and provide liquidity in commodity, foreign exchange and interest rate derivative markets.

Liquidity risk

Liquidity risk is the risk that we will not be able to meet our financial obligations as they come due. We manage our liquidity risk by continuously forecasting our cash flows and ensuring we have adequate cash balances, cash flows from operations, committed and demand credit facilities and access to capital markets to meet our operating, financing and capital expenditure obligations under both normal and stressed economic conditions. 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, 2022, 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, 2022, 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, 2022, the internal control over financial reporting was effective.

Our internal control over financial reporting as of December 31, 2022 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their attestation report which is included in our 2022 Consolidated financial statements.

CEO and CFO certifications

Our President and CEO and our CFO have attested to the quality of the public disclosure in our fiscal 2022 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

In preparing our Consolidated financial statements, we are 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. We use the most current information available and exercise 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. Refer to Note 2, Accounting policies, of our 2022 Consolidated financial statements for additional information.

Equity Investment in Coastal GasLink LP

July 2022 Coastal GasLink Amended Agreements

On July 28, 2022, amended agreements were executed between Coastal GasLink LP, LNG Canada and TC Energy and its Coastal GasLink LP partners (collectively, the July 2022 agreements). These amendments revised the commercial terms between LNG Canada and Coastal GasLink LP, as well as funding provisions between the partners of Coastal GasLink LP and required TC Energy to make a contractual equity contribution to Coastal GasLink LP in the amount of $1.9 billion, which did not result in a change in our 35 per cent ownership. Refer to Note 32, Variable interest entities, of our 2022 Consolidated financial statements for additional information.

The $1.9 billion contractual equity contribution was accrued and initially recognized in Equity investments on the Consolidated balance sheet at the time of signing the July 2022 agreements and is being paid in installments over the period August 2022 to February 2023. At December 31, 2022, $0.5 billion of this equity contribution remained in Accounts payable and other on the Consolidated balance sheet.

Under the terms of the July 2022 agreements, any additional equity financing required by Coastal GasLink LP to fund construction of the pipeline beyond the $1.9 billion equity contribution will initially be financed through a subordinated loan agreement between TC Energy and Coastal GasLink LP. Any amounts outstanding on this loan will be repaid by Coastal GasLink LP to TC Energy once final costs are known, which will be determined after the pipeline is placed in service. Coastal GasLink LP partners, including TC Energy, will contribute equity to Coastal GasLink LP to ultimately fund Coastal GasLink LP's repayment of this subordinated loan to TC Energy. We expect that these additional equity contributions will be predominantly funded by TC Energy but will not result in a change to our 35 per cent ownership.

Capital Cost Update, Impairment and Maximum Exposure to Loss

In the fourth quarter of 2022, we announced that we expected a material increase in project costs and to our corresponding funding requirements. On February 1, 2023, TC Energy announced that the revised capital cost of the Coastal GasLink pipeline project was expected to be approximately $14.5 billion. While this estimate includes contingencies for certain factors that may be outside the control of Coastal GasLink LP, such as challenging conditions in the Western Canadian labour market, shortages of skilled labour, the impacts of contractor underperformance, as well as drought conditions and erosion and sediment control challenges, as with any complex construction project, the final capital cost is subject to certain risks and uncertainties. The increase in project costs and our corresponding funding requirements were indicators that a decrease in the value of our equity investment had occurred.

As a result, we completed a valuation assessment and concluded that the fair value of TC Energy's investment was below its carrying value at December 31, 2022. We determined that this was an other-than-temporary impairment of our equity investment in Coastal GasLink LP and a pre-tax impairment charge of $3,048 million ($2,643 million after tax) was recognized in fourth quarter 2022 in Impairment of equity investment in the Consolidated statement of income in the Canadian Natural Gas Pipelines segment. The pre-impairment carrying value of the investment in Coastal GasLink LP at December 31, 2022 consisted of amounts in Equity investments ($2.8 billion) and Loans receivable from affiliates ($250 million), which were reduced to a nil balance.

TC Energy expects to fund an additional $3.3 billion related to the revised estimated capital cost to complete the Coastal GasLink pipeline, and a significant portion of our future investment in Coastal GasLink LP is expected to be impaired. We will continue to assess for other-than-temporary declines in the fair value of this investment, and the extent of any future impairment charges will depend on the outcome of the valuation assessment performed at the respective reporting date.

The fair value of TC Energy's investment in Coastal GasLink LP at December 31, 2022 was estimated using a 40-year discounted, cash flow model. Cash inflows in the model were estimated using contractually agreed upon terms and extension provisions in the TSAs between Coastal GasLink LP and the LNG Canada participants.

For cash outflows in the model, the increase in estimated capital cost and our corresponding funding requirements have the most significant impact on the determination of the fair value of TC Energy's investment in Coastal GasLink LP. The cash flow analysis included a capital cost estimate for the Coastal GasLink pipeline of $14.5 billion. Any change from this capital cost estimate will have an approximate dollar-for-dollar impact on our future funding requirements, subject to any final cost sharing between the Coastal GasLink LP partners, and will impact the estimated fair value of, and our recovery of, our equity investment in Coastal GasLink LP in future periods.

Other assumptions included in the discounted cash flow model include discount rate, long-term project financing plans and estimated completion date. Changes to these other assumptions would not reasonably expect to change the impairment recorded in the fourth quarter of 2022.

The maximum exposure to loss as a result of our involvement with Coastal GasLink LP, a variable interest entity (VIE), as at December 31, 2022 was $3.3 billion. Our maximum exposure to loss is the maximum loss that could potentially be recorded through net income in future periods as a result of our variable interest in a VIE. Under the terms of the July 2022 agreements, TC Energy is contractually obligated to fund the capital costs to complete the Coastal GasLink pipeline, which is estimated to be $3.3 billion, through additional equity contributions in Coastal GasLink LP (future funding requirements), subject to any final cost sharing between the Coastal GasLink LP partners. The determination of our maximum exposure to loss involves an estimate of capital costs to complete.

Impairment of 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.

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.

Qualitative goodwill impairment indicators

As part of the annual goodwill impairment assessment, we evaluated qualitative factors impacting the fair value of the reporting units, other than the ANR reporting unit for which we elected to proceed directly to a quantitative impairment test. Qualitative factors such as macroeconomic conditions, industry and market considerations, valuation multiples and discount rates, cost factors and historical and forecasted financial results and events specific to the various reporting units were considered. It was determined that it was more likely than not that the fair value of all reporting units exceeded their carrying amounts, including goodwill, and therefore, goodwill was not impaired.

Valuation of goodwill for the ANR reporting unit
Following the passage of time from the previous test at December 31, 2016, and subsequent to the ANR settlement-in-principle, we performed a quantitative annual goodwill impairment test for ANR as at December 31, 2022.

The estimated fair value measurements used in our goodwill impairment analysis is classified as Level III. In the determination of the fair value utilized in the quantitative goodwill impairment test for the ANR reporting unit, we used a discounted cash flow model incorporating projections of our future revenue and capital expenditures as well as a valuation multiple and applied a risk-adjusted discount rate which involved significant estimates and judgments. It was determined that the fair value of ANR exceeded its carrying value, including goodwill, at December 31, 2022.

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

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

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

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

FINANCIAL INSTRUMENTS

With the exception of Long-term debt and Junior subordinated notes, our derivative and non-derivative financial instruments are recorded on the balance sheet at fair value unless they were entered into and continue to be held for the purpose of receipt or delivery in accordance with our normal purchase and sales exemptions and are documented as such. In addition, fair value accounting is not required for other financial instruments that qualify for certain accounting exemptions.

Derivative instruments

We use derivative instruments to reduce volatility associated with fluctuations in commodity prices, interest rates and foreign exchange rates. Derivative instruments, including those that qualify and are designated for hedge accounting treatment, are recorded at fair value.

The majority of derivative instruments that are not designated or do not qualify for hedge accounting treatment have been entered into as economic hedges to manage our exposure to market risk and are classified as held-for-trading. Changes in the fair value of held-for-trading derivative instruments are recorded in net income in the period of change. This may expose us to increased variability in reported operating results since the fair value of the held-for-trading derivative instruments can fluctuate significantly from period to period.

The recognition of gains and losses on derivatives for Canadian natural gas regulated pipeline exposures is determined through the regulatory process. Gains and losses arising from changes in the fair value of derivatives accounted for as part of RRA, including those that qualify for hedge accounting treatment, are expected to be refunded or recovered 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 $)	2022	2021
Other current assets	**614**	169
Other long-term assets	**91**	48
Accounts payable and other	**(871)**	(221)
Other long-term liabilities	**(151)**	(47)
	(317)	(51)

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, 2022 (millions of $)	Total fair value	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Derivative instruments held-for-trading					
Assets	685	608	73	4	—
Liabilities	(837)	(742)	(82)	(13)	—
Derivative instruments in hedging relationships					
Assets	20	6	1	5	8
Liabilities	(185)	(129)	(34)	(9)	(13)
	(317)	(257)	(42)	(13)	(5)

Unrealized and realized gains and losses on derivative instruments

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

year ended December 31 (millions of $)	2022	2021	2020
Derivative instruments held-for-trading[1]			
Amount of unrealized gains/(losses) in the year			
Commodities	**14**	9	(23)
Foreign exchange	**(149)**	(203)	126
Amount of realized gains/(losses) in the year			
Commodities	**759**	287	183
Foreign exchange	**(2)**	240	(33)
Derivative instruments in hedging relationships[2]			
Amount of realized (losses)/gains in the year			
Commodities	**(73)**	(44)	6
Interest rate	**(3)**	(32)	(16)

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 Foreign exchange (loss)/gain, net.

2 In 2022, 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 (2021 – realized loss of $10 million, 2020 – nil).

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 28, Risk management and financial instruments, of our 2022 Consolidated financial statements.

RELATED PARTY TRANSACTIONS

Loans receivable from affiliates

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

Sur de Texas

We hold a 60 per cent equity interest in a joint venture with IEnova to own the Sur de Texas pipeline, for which we are the operator. In 2017, we entered into a MXN$21.3 billion unsecured revolving credit facility with the joint venture, which bore interest at a floating rate and was fully repaid upon maturity on March 15, 2022 in the amount of $1.2 billion.

Our Consolidated statement of income reflects the related interest income and foreign exchange impact on this loan receivable until its repayment on March 15, 2022, which were fully offset upon consolidation with corresponding amounts included in our proportionate share of Sur de Texas equity earnings as follows:

year ended December 31 (millions of $)	2022	2021	2020	Affected line item in the Consolidated statement of income
Interest income[1]	**19**	87	110	Interest income and other
Interest expense[2]	**(19)**	(87)	(110)	Income from equity investments
Foreign exchange losses[1]	**(28)**	(41)	(86)	Foreign exchange loss/(gain), net
Foreign exchange gains[1]	**28**	41	86	Income from equity investments

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

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

Coastal GasLink LP

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

TC Energy Equity Contributions and Subordinated Loan Agreement

As part of the amendments in the July 2022 agreements between the Coastal GasLink LP partners, we are required to make an equity contribution to Coastal GasLink LP of $1.9 billion, payable in monthly installments from August 2022 to February 2023, with no resulting change to our 35 per cent ownership. The $1.9 billion equity contribution was recognized in Equity investments on the Consolidated balance sheet at December 31, 2022, and the remaining $0.5 billion of installments outstanding was recorded in Accounts payable and other on the Consolidated balance sheet.

In 2021, TC Energy entered into a subordinated loan agreement with Coastal GasLink LP. This loan agreement was amended as part of the July 2022 agreements, and subsequent draws on this loan by Coastal GasLink LP will be provided through an interest-bearing loan, subject to a floating, market-based interest rate to fund the incremental $3.3 billion related to the revised estimated capital cost to complete the Coastal GasLink pipeline. As at December 31, 2022, the total capacity committed by TC Energy under this subordinated loan agreement was $1.3 billion. The committed capacity is expected to increase in the future as required to support additional financing requirements under this loan. Any amounts outstanding on this loan will be repaid by Coastal GasLink LP to TC Energy, once final costs are known, which will be determined after the pipeline is placed in service. Coastal GasLink LP partners, including TC Energy, will contribute equity to Coastal GasLink LP to ultimately fund Coastal GasLink LP's repayment of this subordinated loan to TC Energy. We expect that, in accordance with the July 2022 agreements, these additional equity contributions will be predominantly funded by TC Energy but will not result in a change to our 35 per cent ownership. Refer to Note 7, Coastal GasLink, of our 2022 Consolidated financial statements for additional information.

The balance outstanding on this loan at December 31, 2022 was $250 million which was reduced to nil as part of the impairment charge recognized in fourth quarter 2022.

Subordinated Demand Revolving Credit Facility

We have a subordinated demand revolving credit facility with Coastal GasLink LP to provide additional short-term liquidity and funding flexibility to the project. The facility bears interest at a floating market-based rate and had a capacity of $100 million with an outstanding balance of nil at December 31, 2022 (December 31, 2021 – $1 million) reflected in Loans receivable from affiliates under Current assets on our Consolidated balance sheet. This revolver was not impacted by the impairment charge recognized in fourth quarter 2022.

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 2022 Consolidated financial statements.

QUARTERLY RESULTS

Selected quarterly consolidated financial data

2022 (millions of $, except per share amounts)	Fourth	Third	Second	First
Revenues	**4,041**	**3,799**	**3,637**	**3,500**
Net (loss)/income attributable to common shares	**(1,447)**	**841**	**889**	**358**
Comparable earnings	**1,129**	**1,068**	**979**	**1,103**
Share statistics:				
Net (loss)/income per common share – basic	**($1.42)**	**$0.84**	**$0.90**	**$0.36**
Comparable earnings per common share	**$1.11**	**$1.07**	**$1.00**	**$1.12**
Dividends declared per common share	**$0.90**	**$0.90**	**$0.90**	**$0.90**

2021 (millions of $, except per share amounts)	Fourth	Third	Second	First
Revenues	3,584	3,240	3,182	3,381
Net income/(loss) attributable to common shares	1,118	779	975	(1,057)
Comparable earnings	1,028	970	1,038	1,106
Share statistics:				
Net income/(loss) per common share – basic	$1.14	$0.80	$1.00	($1.11)
Comparable earnings per common share	$1.05	$0.99	$1.06	$1.16
Dividends declared per common share	$0.87	$0.87	$0.87	$0.87

Factors affecting quarterly financial information by business segment

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

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

- regulatory decisions
- negotiated settlements with customers
- newly constructed assets being placed in service
- acquisitions and divestitures
- natural gas marketing activities and commodity prices
- developments outside of the normal course of operations
- certain fair value adjustments and provisions for expected credit losses on net investment in leases and certain contract assets in Mexico.

In Liquids Pipelines, annual revenues and segmented earnings are based on contracted and uncontracted spot transportation, as well as liquids marketing activities. Quarter-over-quarter revenues and segmented earnings are affected by:

- regulatory decisions
- newly constructed assets being placed in service
- acquisitions and divestitures
- demand for uncontracted transportation services
- liquids marketing activities and commodity prices
- developments outside of the normal course of operations
- certain fair value adjustments.

In Power and Energy Solutions, quarter-over-quarter revenues and segmented earnings are affected by:
- weather
- customer demand
- newly constructed assets being placed in service
- acquisitions and divestitures
- market prices for natural gas and power
- capacity prices and payments
- power marketing and trading activities
- 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 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.

We exclude from comparable measures the unrealized gains and losses from changes in the fair value of derivatives related to financial and commodity price risk management activities. These derivatives generally provide effective economic hedges but do not meet the criteria for hedge accounting. Beginning in first quarter 2022, with consistent presentation of prior periods, we excluded from comparable measures our proportionate share of the unrealized gains and losses from changes in the fair value of Bruce Power's funds invested for post-retirement benefits and derivatives related to its risk management activities. These changes in fair value are recorded in net income. As these amounts do not accurately reflect the gains and losses that will be realized at settlement, we do not consider them reflective of our underlying operations.

In third quarter 2022, TGNH and the CFE executed agreements which consolidate a number of operating and in-development natural gas pipelines in central and southeast Mexico under one TSA. As this TSA contains a lease, we have recognized amounts in net investment in leases on our Condensed consolidated balance sheet. In accordance with the requirements of U.S. GAAP, we have recognized an expected credit loss provision related to net investment in leases. The amount of this provision will fluctuate from period to period based on changing economic assumptions and forward-looking information. The provision is an estimate of losses that may occur over the duration of the TSA through 2055. As this provision, as well as a provision related to certain contract assets in Mexico, do not reflect losses or cash outflows that were incurred under this lease arrangement in the current period or from our underlying operations, we have excluded any unrealized changes from comparable measures.

We also excluded from comparable measures the unrealized foreign exchange gains and losses on the peso-denominated loan receivable from an affiliate as well as the corresponding proportionate share of Sur de Texas foreign exchange gains and losses, as the amounts do not accurately reflect the gains and losses that will be realized at settlement. These amounts offset within each reporting period, resulting in no impact on net income. This peso-denominated loan was fully repaid in first quarter 2022.

In fourth quarter 2022, comparable earnings also excluded:
- an after-tax impairment charge of $2.6 billion related to our equity investment in Coastal GasLink LP. Refer to Note 7, Coastal GasLink, of our 2022 Consolidated financial statements for additional information
- a $64 million after-tax expected credit loss provision related to the TGNH net investment in leases and certain contract assets in Mexico
- $20 million after-tax charge due to the CER decision on Keystone issued in December 2022 in respect of a tolling-related complaint pertaining to amounts reflected in 2021 and 2020
- preservation and other costs for Keystone XL pipeline project assets of $8 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge
- a $5 million after-tax net expense related to the 2021 Keystone XL asset impairment charge and other due to a U.S. minimum tax, partially offset by the gain on the sale of Keystone XL project assets and reduction to the estimate for contractual and legal obligations related to termination activities
- a $1 million income tax expense for the settlement related to prior years' income tax assessments in Mexico.

In third quarter 2022, comparable earnings also excluded:
- preservation and other costs for Keystone XL pipeline project assets of $3 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge.

In second quarter 2022, comparable earnings also excluded:
- preservation and other costs for Keystone XL pipeline project assets of $3 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge
- a $2 million income tax expense for the settlement related to prior years' income tax assessments in Mexico.

In first quarter 2022, comparable earnings also excluded:
- an after-tax goodwill impairment charge of $531 million related to Great Lakes
- a $193 million income tax expense for the settlement-in-principle of matters related to prior years' income tax assessments in Mexico
- preservation and other costs for Keystone XL pipeline project assets of $5 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge.

In fourth quarter 2021, comparable earnings also excluded:
- an incremental $60 million after-tax reduction to the Keystone XL asset impairment charge, net of expected contractual recoveries and other contractual and legal obligations, related to the termination of the Keystone XL pipeline project
- an after-tax gain of $19 million related to the sale of the remaining interest in Northern Courier
- preservation and other costs for Keystone XL pipeline project assets of $10 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge
- a $7 million after-tax gain related to pension adjustments as part of the VRP
- an incremental $6 million income tax expense related to the sale of our Ontario natural gas-fired power plants sold in April 2020.

In third quarter 2021, comparable earnings also excluded:
- a $55 million after-tax expense with respect to transition payments incurred as part of the VRP
- preservation and other costs of $11 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge.

In second quarter 2021, comparable earnings also excluded:
- preservation and other costs of $16 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge and interest expense on the Keystone XL project-level credit facility prior to its termination
- a $13 million after-tax recovery of certain costs from the IESO associated with the Ontario natural gas-fired power plants sold in 2020
- an incremental $2 million after-tax asset impairment charge, net of expected contractual recoveries and other contractual and legal obligations, related to the termination of the Keystone XL pipeline project.

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

FOURTH QUARTER 2022 HIGHLIGHTS

Consolidated results

three months ended December 31 (millions of $, except per share amounts)	2022	2021
Canadian Natural Gas Pipelines	**(2,592)**	389
U.S. Natural Gas Pipelines	**882**	818
Mexico Natural Gas Pipelines	**96**	123
Liquids Pipelines	**322**	373
Power and Energy Solutions	**298**	191
Corporate	**(4)**	(6)
Total segmented (losses)/earnings	**(998)**	1,888
Interest expense	**(722)**	(611)
Allowance for funds used during construction	**115**	72
Foreign exchange (loss)/gain, net	**132**	28
Interest income and other	**53**	59
(Loss)/income before income taxes	**(1,420)**	1,436
Income tax recovery/(expense)	**4**	(278)
Net (loss)/income	**(1,416)**	1,158
Net income attributable to non-controlling interests	**(9)**	(8)
Net (loss)/income attributable to controlling interests	**(1,425)**	1,150
Preferred share dividends	**(22)**	(32)
Net (loss)/income attributable to common shares	**(1,447)**	1,118
Net (loss)/income per common share – basic	**($1.42)**	$1.14

Net (loss)/income attributable to common shares decreased by $2,565 million or $2.56 per common share for the three months ended December 31, 2022 compared to the same period in 2021. The significant decrease for the three months ended December 31, 2022 is primarily due to the net effect of specific items mentioned below. Net (loss)/income per common share also reflects the impact of common shares issued for the acquisition of TC PipeLines, LP in first quarter 2021 and common shares issued in 2022.

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

Fourth quarter 2022 results included:

- an after-tax impairment charge of $2.6 billion related to our equity investment in Coastal GasLink LP. Refer to Note 7, Coastal GasLink, of our 2022 Consolidated financial statements for additional information
- a $64 million after-tax expected credit loss provision related to the TGNH net investment in leases and certain contract assets in Mexico
- $20 million after-tax charge due to the CER decision on Keystone issued in December 2022 in respect of a tolling-related complaint pertaining to amounts reflected in 2021 and 2020
- preservation and other costs for Keystone XL pipeline project assets of $8 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge
- a $5 million after-tax net expense related to the 2021 Keystone XL asset impairment charge and other due to a U.S. minimum tax, partially offset by the gain on the sale of Keystone XL project assets and reduction to the estimate for contractual and legal obligations related to termination activities
- a $1 million income tax expense for the settlement related to prior years' income tax assessments in Mexico.

Fourth quarter 2021 results included:

- an incremental $60 million after-tax reduction to the Keystone XL asset impairment charge, net of expected contractual recoveries and other contractual and legal obligations, related to the termination of the Keystone XL pipeline project following the January 20, 2021 revocation of the Presidential Permit
- an after-tax gain of $19 million related to the sale of the remaining 15 per cent interest in Northern Courier
- preservation and other costs for Keystone XL pipeline project assets of $10 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge
- a $7 million after-tax gain primarily related to pension adjustments incurred as part of the VRP
- an incremental $6 million income tax expense related to the sale of our Ontario natural gas-fired power plants sold in April 2020.

Net (loss)/income in both periods included unrealized gains and losses on our proportionate share of Bruce Power's fair value adjustment on funds invested for post-retirement benefits and derivatives related to its risk management activities, as well as unrealized gains and losses from changes in our risk management activities, all of which we exclude along with the above noted items, to arrive at comparable earnings. A reconciliation of Net (loss)/income attributable to common shares to comparable earnings is shown in the following table.

Reconciliation of net (loss)/income attributable to common shares to comparable earnings

three months ended December 31 (millions of $, except per share amounts)	2022	2021
Net (loss)/income attributable to common shares	**(1,447)**	1,118
Specific items (net of tax):		
Coastal GasLink LP impairment charge	**2,643**	—
Expected credit loss provision on net investment in leases and certain contract assets	**64**	—
Keystone CER decision	**20**	—
Keystone XL preservation and other	**8**	10
Keystone XL asset impairment charge and other	**5**	(60)
Settlement of Mexico prior years' income tax assessments	**1**	—
Bruce Power unrealized fair value adjustments	**(9)**	(7)
Loss on sale of Ontario natural gas-fired power plants	**—**	6
Voluntary Retirement Program	**—**	(7)
Gain on sale of Northern Courier	**—**	(19)
Risk management activities[1]	**(156)**	(13)
Comparable earnings	**1,129**	1,028
Net (loss)/income per common share	**($1.42)**	$1.14
Specific items (net of tax):		
Coastal GasLink LP impairment charge	**2.60**	—
Expected credit loss provision on net investment in leases and certain contract assets	**0.06**	—
Keystone CER decision	**0.02**	—
Keystone XL preservation and other	**0.01**	0.01
Keystone XL asset impairment charge and other	**—**	(0.06)
Settlement of Mexico prior years' income tax assessments	**—**	—
Bruce Power unrealized fair value adjustments	**(0.01)**	(0.01)
Loss on sale of Ontario natural gas-fired power plants	**—**	0.01
Voluntary Retirement Program	**—**	(0.01)
Gain on sale of Northern Courier	**—**	(0.02)
Risk management activities	**(0.15)**	(0.01)
Comparable earnings per common share	**$1.11**	$1.05

1

three months ended December 31 (millions of $)	2022	2021
U.S. Natural Gas Pipelines	(28)	7
Liquids Pipelines	(38)	(5)
Canadian Power	30	4
U.S. Power	5	—
Natural Gas Storage	67	30
Foreign exchange	172	(20)
Income tax attributable to risk management activities	(52)	(3)
Total unrealized gains from risk management activities	156	13

Comparable EBITDA to comparable earnings

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

three months ended December 31 (millions of $, except per share amounts)	2022	2021
Comparable EBITDA		
Canadian Natural Gas Pipelines	**768**	674
U.S. Natural Gas Pipelines	**1,141**	1,032
Mexico Natural Gas Pipelines	**211**	151
Liquids Pipelines	**364**	380
Power and Energy Solutions	**203**	168
Corporate	**(4)**	(10)
Comparable EBITDA	**2,683**	2,395
Depreciation and amortization	**(670)**	(634)
Interest expense	**(722)**	(611)
Allowance for funds used during construction	**115**	72
Foreign exchange (loss)/gain, net included in comparable earnings	**(40)**	44
Interest income and other	**53**	59
Income tax expense included in comparable earnings	**(259)**	(257)
Net income attributable to non-controlling interests	**(9)**	(8)
Preferred share dividends	**(22)**	(32)
Comparable earnings	**1,129**	1,028
Comparable earnings per common share	**$1.11**	$1.05

Comparable EBITDA – 2022 versus 2021

Comparable EBITDA increased by $288 million for the three months ended December 31, 2022 compared to the same period in 2021 primarily due to the net effect of the following:

- higher EBITDA in U.S. Natural Gas Pipelines mainly due to increased earnings from our U.S. natural gas marketing business relative to 2021 as a result of increased trading activity and higher margins, incremental earnings from growth projects placed in service and increased earnings from our mineral rights business, partially offset by a decrease due to certain discrete items recognized in 2021
- increased EBITDA from Canadian Natural Gas Pipelines largely attributable to the impact of higher flow-through costs and increased rate-base earnings on the NGTL System and higher Canadian Mainline incentive earnings and flow-through costs
- higher EBITDA from Mexico Natural Gas Pipelines primarily related to earnings from VdR North and Tula East that were placed in commercial service in third quarter 2022
- increased Power and Energy Solutions EBITDA primarily as a result of higher contributions from Bruce Power due to a higher contract price, partially offset by realized losses on funds invested for post-retirement benefits and lower plant output
- lower EBITDA from Liquids Pipelines due to lower results on the U.S. Gulf Coast section of the Keystone Pipeline System and the CER decision in respect of a tolling-related complaint pertaining to amounts reflected in 2022, partially offset by increased contributions from liquids marketing activities attributable to higher margins
- the positive foreign exchange impact of a stronger U.S. dollar on the Canadian dollar equivalent comparable EBITDA in our U.S. dollar-denominated operations. U.S. dollar-denominated comparable EBITDA increased by US$27 million compared to 2021; this was translated to Canadian dollars at an average rate of 1.36 in 2022 versus 1.26 in 2021. Refer to the Foreign exchange discussion below for additional information.

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

Comparable earnings – 2022 versus 2021

Comparable earnings increased by $101 million or $0.06 per common share for the three months ended December 31, 2022 compared to the same period in 2021 and was primarily the net effect of:

- changes in comparable EBITDA described above
- higher AFUDC primarily due to the reactivation of AFUDC on the TGNH assets under construction following the new TSA with the CFE in third quarter 2022 and capital expenditures on the Southeast Gateway pipeline project, partially offset by the impact of decreased capital expenditures on our U.S. natural gas pipeline projects
- increased Interest expense primarily due to higher interest rates on increased levels of short-term borrowings, long-term debt and junior subordinated note issuances, net of maturities and the foreign exchange impact of a stronger U.S. dollar in 2022
- net foreign exchange losses in the fourth quarter compared to net foreign exchange gains for the same period in 2021 on derivatives used to manage our net exposure to foreign exchange rate fluctuation on U.S. dollar-denominated income, partially offset by higher realized gains for the same period in 2022 compared to 2021 on derivatives used to manage our exposure to net liabilities in Mexico that give rise to foreign exchange gains and losses
- higher Depreciation and amortization on the NGTL System from expansion facilities that were placed in service.

Foreign exchange

Certain of our businesses generate all or most of their earnings in U.S. dollars and, since we report our financial results in Canadian dollars, changes in the value of the U.S. dollar against the Canadian dollar directly affect our comparable EBITDA and may also impact comparable earnings. As our U.S. dollar-denominated operations continue to grow, this exposure increases. A portion of the U.S. dollar-denominated comparable EBITDA exposure is naturally offset by U.S. dollar-denominated amounts below comparable EBITDA within Depreciation and amortization, Interest expense and other income statement line items. The balance of the exposure is actively managed on a rolling forward basis up to three years using foreign exchange derivatives; however, the natural exposure beyond that period remains. The net impact of the U.S. dollar movements on comparable earnings during the three months ended December 31, 2022 after considering natural offsets and economic hedges was not significant.

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

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

three months ended December 31 (millions of US$)	2022	2021
Comparable EBITDA		
U.S. Natural Gas Pipelines	**842**	819
Mexico Natural Gas Pipelines[1]	**156**	140
Liquids Pipelines	**204**	216
	1,202	1,175
Depreciation and amortization	**(237)**	(245)
Interest on long-term debt and junior subordinated notes	**(323)**	(314)
Allowance for funds used during construction	**55**	28
Non-controlling interests and other	**(44)**	(9)
	653	635
Average exchange rate - U.S. to Canadian dollars	**1.36**	1.26

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

A 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 comparable earnings. In addition, foreign exchange gains or losses calculated for Mexico income tax purposes on the revaluation of the U.S. dollar-denominated monetary assets and liabilities result in a peso-denominated income tax exposure for these entities, leading to fluctuations in Income from equity investments and Income tax expense. As our U.S. dollar-denominated monetary assets and liabilities continue to grow, this exposure increases. These exposures are partially managed using foreign exchange derivatives, with the gains and losses on the derivatives recorded in Foreign exchange loss/(gain), net in our Consolidated statement of income.

Highlights by business segment

Canadian Natural Gas Pipelines

Canadian Natural Gas Pipelines segmented (losses)/earnings decreased by $2,981 million for the three months ended December 31, 2022 compared to the same period in 2021 and included the following specific item which has been excluded from our calculation of comparable EBIT and comparable earnings:

- a pre-tax impairment charge of $3.0 billion in 2022 related to our equity investment in Coastal GasLink LP. Refer to Note 7, Coastal GasLink, of our 2022 Consolidated financial statements for additional information.

Net income for the NGTL System increased by $21 million for the three months ended December 31, 2022 compared to the same period in 2021 mainly due to a higher average investment base resulting from continued system expansions. The NGTL System is operating under the 2020-2024 Revenue Requirement Settlement which includes an approved ROE of 10.1 per cent on 40 per cent deemed common equity. This settlement provides the NGTL System the opportunity to increase depreciation rates if tolls fall below specified levels and an incentive mechanism for certain operating costs where variances from projected amounts are shared with our customers.

Net income for the Canadian Mainline for the three months ended December 31, 2022 increased by $4 million compared to the same period in 2021 mainly due to higher incentive earnings. The Canadian Mainline is operating under the 2021-2026 Mainline Settlement which includes an approved ROE of 10.1 per cent on 40 per cent deemed common equity and an incentive to decrease costs and increase revenues on the pipeline under a beneficial sharing mechanism with our customers.

Comparable EBITDA for Canadian Natural Gas Pipelines increased by $94 million for the three months ended December 31, 2022 compared to the same period in 2021 due to the net effect of:

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

Depreciation and amortization increased by $27 million for the three months ended December 31, 2022 compared to the same period in 2021 due to NGTL System expansion facilities that were placed in service.

U.S. Natural Gas Pipelines

U.S. Natural Gas Pipelines segmented earnings increased by $64 million for the three months ended December 31, 2022 compared to the same period in 2021 and included the following specific item which has been excluded from our calculation of comparable EBITDA and comparable EBIT:

- unrealized gains and losses from changes in the fair value of derivatives related to our U.S. natural gas marketing business.

A stronger U.S. dollar for the three months ended December 31, 2022 had a positive impact on the Canadian dollar equivalent segmented earnings from our U.S. operations compared to the same period in 2021.

Comparable EBITDA for U.S. Natural Gas Pipelines increased by US$23 million for the three months ended December 31, 2022 compared to the same period in 2021 and was primarily due to the net effect of:

- higher realized earnings related to our U.S. natural gas marketing business relative to 2021 due to increased trading activity and higher margins
- incremental earnings from growth projects placed in service
- increased earnings from our mineral rights business due to higher commodity prices
- decreased earnings in 2022 primarily due to certain discrete items recognized in 2021
- a decrease in earnings as a result of certain fourth quarter 2022 adjustments related to regulatory deferrals, partially offset by an increase in earnings due to higher transportation rates effective August 1, 2022, both pursuant to the ANR uncontested rate settlement. Refer to the U.S. Natural Gas Pipelines – Significant events section for additional information.

Depreciation and amortization decreased by US$4 million for the three months ended December 31, 2022 compared to the same period in 2021 mainly due to the timing of certain depreciation adjustments related to the Columbia Gas rate case settlement in 2021, partially offset by new projects placed in service.

Mexico Natural Gas Pipelines
Mexico Natural Gas Pipelines segmented earnings decreased by $27 million for the three months ended December 31, 2022 compared to the same period in 2021. This decrease is due to the impact of an expected credit loss provision of $92 million, relating to the TGNH net investment in leases and certain contract assets. In accordance with the requirements of U.S. GAAP, an expected credit loss provision must be recognized on the TGNH net investment in leases. The provision is an estimate of losses that may occur over the duration of the TSA through 2055. As this provision, as well as a provision related to certain contract assets in Mexico, do not reflect actual losses or cash outflows that were incurred under the lease arrangement in the current period or from our underlying operations, we have excluded these unrealized changes from our calculation of comparable EBITDA and comparable EBIT. Refer to Note 28, Risk management and financial instruments, of our 2022 Consolidated financial statements for additional information on expected credit loss provisions.

A stronger U.S. dollar for the three months ended December 31, 2022 had a positive impact on the Canadian dollar equivalent segmented earnings compared to the same period in 2021.

Comparable EBITDA for Mexico Natural Gas Pipelines increased by US$34 million for the three months ended December 31, 2022 compared to the same period in 2021, primarily due to higher revenues related to the commercial in-service of VdR North and Tula East in third quarter 2022.

The decrease in Depreciation and amortization of US$4 million for the three months ended December 31, 2022 compared to the same period in 2021 is due to the change in accounting for Tamazunchale subsequent to execution of the new TGNH TSA with the CFE in third quarter 2022. Under sales-type lease accounting, our in-service TGNH pipeline assets are reflected on our Consolidated balance sheet within net investment in leases with no depreciation expense being recognized.

Liquids Pipelines
Liquids Pipelines segmented earnings decreased by $51 million for the three months ended December 31, 2022 compared to the same period in 2021 and included the following specific items which have been excluded from our calculation of comparable EBIT:

- a $118 million pre-tax adjustment in 2022 to the 2021 Keystone XL asset impairment charge and other resulting from the gain on sale of Keystone XL project assets and reduction to the estimate for contractual and legal obligations related to termination activities
- a $79 million pre-tax asset impairment charge reduction recognized for the three months ended December 31, 2021, associated with the termination of the Keystone XL pipeline project and related projects following the January 2021 revocation of the Presidential Permit
- a $27 million pre-tax charge due to the CER decision issued in December 2022 in respect of a tolling-related complaint pertaining to amounts reflected in 2021 and 2020
- pre-tax gain of $13 million in 2021 related to the sale of the remaining 15 per cent interest in Northern Courier
- pre-tax preservation and other costs for Keystone XL pipeline project assets of $10 million for the three months ended December 31, 2022 ($14 million for the three months ended December 31, 2021), which could not be accrued as part of the Keystone XL asset impairment charge
- unrealized gains and losses from changes in the fair value of derivatives related to our liquids marketing business.

A stronger U.S. dollar in 2022 relative to 2021 had a positive impact on the Canadian dollar equivalent segmented earnings from our U.S. operations.

Comparable EBITDA for Liquids Pipelines decreased by $16 million for the three months ended December 31, 2022 compared to the same period in 2021 primarily due to the net effect of:

- lower rates and volumes on the U.S. Gulf Coast section of the Keystone Pipeline System, partially offset by higher long-haul contracted volumes and approximately 20,000 Bbl/d of long-term contracts from the 2019 Open Season that were commercialized in April 2022 with an additional 10,000 Bbl/d in September 2022
- the CER decision issued in December 2022 in respect of a tolling-related complaint pertaining to amounts invoiced in 2022
- increased contributions from liquids marketing activities due to higher margins.

Depreciation and amortization increased by $5 million for the three months ended December 31, 2022 compared to the same period in 2021 primarily as a result of a stronger U.S. dollar.

Power and Energy Solutions

Power and Energy Solutions segmented earnings increased by $107 million for the three months ended December 31, 2022 compared to the same period in 2021 and included the following specific items which have been excluded from our calculations of comparable EBITDA and comparable EBIT:

- our proportionate share of Bruce Power's unrealized gains and losses on funds invested for post-retirement benefits and risk management activities
- unrealized gains and losses from changes in the fair value of derivatives used to reduce commodity exposures.

Comparable EBITDA for Power and Energy Solutions increased by $35 million for the three months ended December 31, 2022 compared to the same periods in 2021 primarily due to the net effect of:

- higher contributions from Bruce Power primarily due to a higher contract price, partially offset by realized losses on funds invested for post-retirement benefits and risk management activities and lower plant output resulting from greater outage days
- increased Natural Gas Storage and other results mainly due to decreased business development costs across the segment in the fourth quarter of 2022
- lower results from Canadian Power were primarily due to reduced contributions from trading activities, partially offset by higher realized power prices.

Depreciation and amortization for the three months ended December 31, 2022 was consistent with the same period in 2021.

Corporate

Corporate segmented losses for the three months ended December 31, 2022 were consistent compared to the same period in 2021. Corporate segmented (losses)/earnings included accrued pre-tax costs for the VRP offered in 2021 and foreign exchange losses and gains on our proportionate share of peso-denominated inter-affiliate loans to the Sur de Texas joint venture from its partners up to March 15, 2022 when the peso-denominated inter-affiliate loans were fully repaid upon maturity. These foreign exchange losses and gains were recorded in Income from equity investments in the Corporate segment and were excluded from our calculation of comparable EBITDA and comparable EBIT as they were fully offset by corresponding foreign exchange gains and losses on the inter-affiliate loan receivable included in Foreign exchange (loss)/gain, net. Corporate segmented (losses)/earnings for the three months ended December 31, 2021 included an $8 million gain primarily due to a pension settlement and curtailment following the VRP offered in 2021.

Comparable EBITDA and EBIT for Corporate for the three months ended December 31, 2022 was consistent with the same period in 2021.

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
HCAs	High-consequence areas
HSSE	Health, safety, sustainability and environment
investment base	Includes rate base as well as assets under construction
LDC	Local distribution company
LNG	Liquefied natural gas
MOU	Memorandum of understanding
OM&A	Operating, maintenance and administration
PPA	Power purchase arrangement
rate base	Average assets in service, working capital and deferred amounts used in setting of regulated rates
RNG	Renewable natural gas
TSA	Transportation Service Agreement
TOMS	TC Energy's Operational Management System
UNGC	United Nations Global Compact
WCSB	Western Canadian Sedimentary basin

Accounting terms

AFUDC	Allowance for funds used during construction
U.S.GAAP / 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

AER	Alberta Energy Regulator
CER	Canada Energy Regulator
CFE	Comisión Federal de Electricidad (Mexico)
CRE	Comisión Reguladora de Energia, or Energy Regulatory Commission (Mexico)
ECCC	Environment and Climate Change Canada
FERC	Federal Energy Regulatory Commission (U.S.)
IESO	Independent Electricity System Operator (Ontario)
NYSE	New York Stock Exchange
OBPS	Output Based Pricing System
OPEC+	Organization of the Petroleum Exporting Countries plus certain other oil-exporting nations
OPG	Ontario Power Generation
PHMSA	Pipeline and Hazardous Materials Safety Administration
SEC	U.S. Securities and Exchange Commission
TCFD	Task Force on Climate-Related Financial Disclosures
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 2022 to that in 2021, and highlights significant changes between 2021 and 2020. 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, 2022, 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 consolidated 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 four 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.

François L. Poirier
President and
Chief Executive Officer

Joel E. Hunter
Executive Vice-President and
Chief Financial Officer

February 13, 2023

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors
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, 2022 and 2021, 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, 2022, 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, 2022 and 2021, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2022, 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, 2022, 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 13, 2023 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 Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the Audit Committee and that: (1) relate to accounts or disclosures that are material to the consolidated financial statements; and (2) involved our especially challenging, subjective or complex judgments. The communication of critical audit matters 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 matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Assessment of control of Coastal GasLink Limited Partnership under the variable interest model

As discussed in Notes 2, 7, 11, 12 and 32 to the consolidated financial statements, in July 2022, the Company entered into revised project agreements (collectively, the July 2022 agreements) relating to its investment in Coastal GasLink Limited Partnership (Coastal GasLink LP) and committed to make additional equity contributions. These revisions and additional equity contributions were determined to be a variable interest entity (VIE) reconsideration event for the Company's investment in Coastal GasLink LP. The Company performed a re-assessment of control and determined that Coastal GasLink LP continued to meet the definition of a VIE in which the Company held a variable interest. The re-assessment further determined that the Company was not the primary beneficiary of Coastal GasLink LP as the Company does not have the power, either explicit or implicit through voting rights or otherwise, to direct the activities that most significantly impact the economic performance of Coastal GasLink LP. Accordingly, the Company continued to account for its investment using the equity method of accounting. The carrying value of the Company's equity investment in Coastal GasLink LP was nil and its maximum exposure to loss as it relates to its investment in Coastal GasLink LP was $3.3 billion as of December 31, 2022.

We identified the determination of the primary beneficiary under the VIE model for the Company's interest in Coastal GasLink LP following the reconsideration event as a critical audit matter. Evaluating whether the July 2022 agreements, which included changes to the governing documents and contractual arrangements relating to Coastal GasLink LP, would provide the Company with the substantive power to direct the activities of Costal GasLink LP that most significantly impacted its economic performance, required an increased extent of audit effort due to the complexity of the July 2022 agreements.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of internal control related to the re-assessment of control as a result of the reconsideration event, including the determination of the primary beneficiary. In addition, we performed the following:

- inquired of management and inspected relevant internal materials and the July 2022 agreements to obtain an understanding and evaluate the business purpose of the reconsideration event and its impact on the risks Coastal GasLink LP was designed to create and pass along to its variable interest holders and on the overall governance at Coastal GasLink LP
- evaluated management's determination of:
  - the activities that most significantly impact the economic performance of Coastal GasLink LP
  - how decisions about the most significant activities are made and the party or parties that make them, including whether the Company's economic interest in Coastal GasLink LP provides actual or effective power beyond its stated power
  - whether the Company had substantive power to direct the activities of Coastal GasLink LP that most significantly impact its economic performance

by comparing to relevant internal materials and the July 2022 agreements, as well as other publicly disclosed information.

Evaluation of the Company's maximum exposure to loss resulting from its involvement with Coastal GasLink LP
As discussed in Notes 7 and 32 to the consolidated financial statements, the maximum exposure to loss as a result of the Company's involvement with Coastal GasLink LP, a VIE, as of December 31, 2022 was $3.3 billion. As discussed in Note 2, the Company's maximum exposure to loss is the maximum loss that could potentially be recorded through net income in future periods as a result of the Company's variable interest in a VIE. Under the terms of the July 2022 agreements, the Company is contractually obligated to fund the capital costs to complete the Coastal GasLink pipeline which is estimated to be $3.3 billion (capital costs to complete) through additional equity contributions in Coastal GasLink LP (future funding requirements), which are subject to any final cost sharing between the Coastal GasLink LP partners. The determination of the Company's maximum exposure to loss involves an estimate of capital costs to complete.

We identified the evaluation of the Company's maximum exposure to loss resulting from its involvement with Coastal GasLink LP as a critical audit matter. The estimate of capital costs to complete involved significant audit effort, subjectivity, and judgment. 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 determination of the estimate of capital costs to complete and resulting maximum exposure to loss. In addition, we performed the following:

- evaluated the estimate of capital costs to complete used in the Company's determination of its maximum exposure to loss by:
  - inspecting the July 2022 agreements and documents with contractors
  - gaining an understanding of the status of pipeline construction project activities and the related risks by comparing to status reports provided to the partners of Coastal GasLink LP, governance committee minutes, and interviewing project personnel
- tested the Company's maximum exposure to loss resulting from its involvement with Coastal GasLink LP using the estimate of capital costs to complete and future funding requirements in accordance with the July 2022 agreements.

Qualitative goodwill impairment indicators for the Columbia reporting unit

As discussed in Notes 2 and 14 to the consolidated financial statements, the goodwill balance as of December 31, 2022 for the Columbia Pipeline Group, Inc. (Columbia) reporting unit was $9,948 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, including goodwill, might be impaired. The Company performed qualitative assessments to determine whether events or changes in circumstances indicate that the Columbia reporting unit goodwill might be impaired. This qualitative assessment was performed as of December 31, 2022.

We identified the evaluation of qualitative goodwill impairment indicators, or qualitative factors, for the Columbia reporting unit as a critical audit matter. The assessment of the potential impact that these qualitative factors have on the Columbia reporting unit's fair value required the application of subjective auditor judgment. Qualitative factors include macroeconomic conditions, industry and market considerations, valuation multiples and discount rates, cost factors, historical and forecasted financial results and events specific to the Columbia reporting unit, 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. In addition, the audit effort associated with this evaluation required specialized skills and knowledge.

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 with respect to the Columbia reporting unit against our knowledge of event-specific changes obtained through other audit procedures. We evaluated information relevant to the Columbia reporting unit 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 the current valuation multiple and discount rate, cost factors, historical and forecasted financial results of the Columbia reporting unit, including the impact of newly approved growth projects to assumptions used in the quantitative goodwill impairment test performed in a previous period. In addition, we involved a valuation professional with specialized skills and knowledge, who assisted in:

- evaluating the Company's determination of the valuation multiple by comparing it to independently observed, recent market transactions of comparable assets and using publicly available market data for comparable entities
- evaluating the discount rate used by management in the assessment, by comparing it against a discount rate range that was independently developed using publicly available market data for comparable entities.

Valuation of goodwill for the ANR reporting unit

As discussed in Notes 2 and 14 to the consolidated financial statements, the goodwill balance as of December 31, 2022 for the American Natural Resources (ANR) reporting unit was $2,634 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, including goodwill, might be impaired. The Company has the option to first assess qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment assessment. In respect of the ANR reporting unit, the Company elected to proceed directly to the quantitative goodwill impairment test as of December 31, 2022 following the passage of time from the previous test as of December 31, 2016, and following the ANR settlement-in-principle in 2022. The quantitative goodwill impairment assessment involves determining the fair value of a reporting unit and comparing that value to the carrying value of the reporting unit, including goodwill. Fair value is estimated using a discounted cash flow model which requires the use of assumptions related to revenue and capital expenditure projections, the valuation multiple and the discount rate (key assumptions). It was determined that the fair value of the ANR reporting unit exceeded its carrying value, including goodwill, as of December 31, 2022.

We identified the valuation of goodwill for the ANR reporting unit as a critical audit matter. A high degree of auditor judgment was required to evaluate the key assumptions. Minor changes to the key assumptions could have had a significant effect on the Company's determination of the fair value of the ANR reporting unit. In addition, the audit effort associated with this estimate required specialized skills and knowledge.

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 critical audit matter. This included controls related to the Company's determination of the fair value of the ANR reporting unit and key assumptions. We compared the Company's historical revenue and capital expenditure projections to actual results to assess the Company's ability to accurately forecast. We evaluated the Company's revenue and capital expenditure projections by comparing them to the actual results and the outcomes of the ANR settlement-in-principle in 2022. We also compared the Company's revenue and capital expenditure projections to assumptions used in industry publications related to North American and global energy consumption and natural gas production forecasts. In addition, we involved a valuation professional with specialized skills and knowledge, who assisted in:

- evaluating the Company's determination of a valuation multiple by comparing it to independently observed recent market transactions of comparable assets and publicly available market data for comparable entities
- evaluating the discount rate used by management in the valuation, by comparing it against a discount rate range that was independently developed using publicly available market data for comparable entities
- evaluating the Company's estimate of the fair value of the ANR reporting unit by comparing the result of the Company's estimate to publicly available market data and valuation metrics for comparable entities.

Valuation of goodwill for the Great Lakes reporting unit

As discussed in Notes 2 and 14 to the consolidated financial statements, the Company performed a quantitative goodwill impairment test for the Great Lakes reporting unit during first quarter 2022. 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, including goodwill, might be impaired. In respect of the Great Lakes reporting unit, the Company performed the quantitative goodwill impairment test following an unopposed rate case settlement. The quantitative goodwill impairment assessment involves determining the fair value of a reporting unit and comparing that value to the carrying value of the reporting unit, including goodwill. Fair value is estimated using a discounted cash flow model which requires the use of assumptions related to revenue and capital expenditure projections, the valuation multiple and the discount rate (key assumptions). It was determined that the estimated fair value of the Great Lakes reporting unit no longer exceeded its carrying value and a pre-tax goodwill impairment charge of $571 million was recorded during the period.

We identified the valuation of goodwill for the Great Lakes reporting unit as a critical audit matter. A high degree of auditor judgment was required to evaluate the key assumptions. Minor changes to the key assumptions used to estimate fair value could have had a significant effect on the Company’s determination of the fair value of the Great Lakes reporting unit. In addition, the audit effort associated with this estimate required specialized skills and knowledge.

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 critical audit matter. This included controls related to the Company’s determination of the fair value of the Great Lakes reporting unit and key assumptions. We compared the Company’s historical revenue and capital expenditure projections to actual results to assess the Company’s ability to accurately forecast. We evaluated the Company’s revenue and capital expenditure projections by comparing them to the actual results and the outcomes of the unopposed rate case settlement with shippers during first quarter of 2022. We also compared the Company’s revenue projections to assumptions used in industry publications related to North American and global energy consumption and natural gas production forecasts. In addition, we involved a valuation professional with specialized skills and knowledge, who assisted in:

- evaluating the Company’s determination of a valuation multiple by comparing it to independently observed recent market transactions of comparable assets and publicly available market data for comparable entities
- evaluating the discount rate used by management in the valuation, by comparing it against a discount rate range that was independently developed using publicly available market data for comparable entities
- evaluating the Company’s estimate of the fair value of the Great Lakes reporting unit by comparing the result of the Company’s estimate to publicly available market data and valuation metrics for comparable entities.

KPMG LLP

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

Calgary, Canada
February 13, 2023

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors
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, 2022, 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, 2022, 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, 2022 and 2021, 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, 2022, and the related notes (collectively, the consolidated financial statements), and our report dated February 13, 2023 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 included in the Company's Management's Discussion and Analysis. 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 13, 2023

Consolidated statement of income

year ended December 31 (millions of Canadian $, except per share amounts)	2022	2021	2020
Revenues (Note 5)			
Canadian Natural Gas Pipelines	**4,764**	4,519	4,469
U.S. Natural Gas Pipelines	**5,933**	5,233	5,031
Mexico Natural Gas Pipelines	**688**	605	716
Liquids Pipelines	**2,668**	2,306	2,371
Power and Energy Solutions	**924**	724	412
	14,977	13,387	12,999
Income from Equity Investments (Note 11)	**1,054**	898	1,019
Impairment of Equity Investment (Notes 7 and 11)	**(3,048)**	—	—
Operating and Other Expenses			
Plant operating costs and other	**4,932**	4,098	3,878
Commodity purchases resold	**534**	87	—
Property taxes	**848**	774	727
Depreciation and amortization	**2,584**	2,522	2,590
Goodwill and asset impairment charges and other (Notes 6 and 14)	**453**	2,775	—
	9,351	10,256	7,195
Net Gain/(Loss) on Sale of Assets (Note 30)	**—**	30	(50)
Financial Charges			
Interest expense (Note 20)	**2,588**	2,360	2,228
Allowance for funds used during construction	**(369)**	(267)	(349)
Foreign exchange loss/(gain), net (Note 22)	**185**	(10)	(28)
Interest income and other	**(146)**	(190)	(185)
	2,258	1,893	1,666
Income before Income Taxes	**1,374**	2,166	5,107
Income Tax Expense (Note 19)			
Current	**415**	305	252
Deferred	**174**	(185)	(58)
	589	120	194
Net Income	**785**	2,046	4,913
Net income attributable to non-controlling interests (Note 23)	**37**	91	297
Net Income Attributable to Controlling Interests	**748**	1,955	4,616
Preferred share dividends	**107**	140	159
Net Income Attributable to Common Shares	**641**	1,815	4,457
Net Income per Common Share (Note 24)			
Basic	**$0.64**	$1.87	$4.74
Diluted	**$0.64**	$1.86	$4.74
Dividends Declared per Common Share	**$3.60**	$3.48	$3.24
Weighted Average Number of Common Shares (millions) (Note 24)			
Basic	**995**	973	940
Diluted	**996**	974	940

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 $)	2022	2021	2020
Net Income	**785**	2,046	4,913
Other Comprehensive Income/(Loss), Net of Income Taxes			
Foreign currency translation gains and losses on net investment in foreign operations	**1,494**	(108)	(609)
Change in fair value of net investment hedges	**(36)**	(2)	36
Change in fair value of cash flow hedges	**(39)**	(10)	(583)
Reclassification to net income of gains and losses on cash flow hedges	**42**	55	489
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	**63**	158	12
Reclassification to net income of actuarial gains and losses on pension and other post-retirement benefit plans	**6**	14	17
Other comprehensive income/(loss) on equity investments	**867**	535	(280)
Other comprehensive income/(loss) (Note 26)	**2,397**	642	(918)
Comprehensive Income	**3,182**	2,688	3,995
Comprehensive income attributable to non-controlling interests	**45**	81	259
Comprehensive Income Attributable to Controlling Interests	**3,137**	2,607	3,736
Preferred share dividends	**107**	140	159
Comprehensive Income Attributable to Common Shares	**3,030**	2,467	3,577

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 $)	2022	2021	2020
Cash Generated from Operations			
Net income	**785**	2,046	4,913
Depreciation and amortization	**2,584**	2,522	2,590
Goodwill and asset impairment charges and other (Notes 6 and 14)	**453**	2,775	—
Deferred income taxes (Note 19)	**174**	(185)	(58)
Income from equity investments (Note 11)	**(1,054)**	(898)	(1,019)
Impairment of equity investment (Notes 7 and 11)	**3,048**	—	—
Distributions received from operating activities of equity investments (Note 11)	**1,025**	975	1,123
Employee post-retirement benefits funding, net of expense (Note 27)	**(29)**	(5)	(19)
Net (gain)/loss on sale of assets (Note 30)	**—**	(30)	50
Equity allowance for funds used during construction	**(248)**	(191)	(235)
Unrealized losses/(gains) on financial instruments	**135**	194	(103)
Expected credit loss provision	**163**	—	—
Foreign exchange losses on loan receivable from affiliate (Note 12)	**28**	41	86
Other	**(50)**	(67)	57
Increase in operating working capital (Note 29)	**(639)**	(287)	(327)
Net cash provided by operations	**6,375**	6,890	7,058
Investing Activities			
Capital expenditures (Note 4)	**(6,678)**	(5,924)	(8,013)
Capital projects in development (Note 4)	**(49)**	—	(122)
Contributions to equity investments (Notes 4, 7 and 11)	**(3,433)**	(1,210)	(765)
Keystone XL contractual recoveries (Note 6)	**571**	—	—
Proceeds from sales of assets, net of transaction costs	**—**	35	3,407
Loans to affiliate issued, net (Notes 7 and 12)	**(11)**	(239)	—
Other distributions from equity investments (Note 11)	**2,632**	73	—
Deferred amounts and other	**(41)**	(447)	(559)
Net cash used in investing activities	**(7,009)**	(7,712)	(6,052)
Financing Activities			
Notes payable issued/(repaid), net	**766**	1,003	(220)
Long-term debt issued, net of issue costs	**2,508**	10,730	5,770
Long-term debt repaid	**(1,338)**	(7,758)	(3,977)
Junior subordinated notes issued, net of issue costs	**1,008**	495	—
Gain/(loss) on settlement of financial instruments	**23**	(10)	(130)
Redeemable non-controlling interest repurchased (Note 6)	**—**	(633)	—
Contributions from redeemable non-controlling interest (Note 6)	**—**	—	1,033
Dividends on common shares	**(3,192)**	(3,317)	(2,987)
Dividends on preferred shares	**(106)**	(141)	(159)
Distributions to non-controlling interests	**(44)**	(74)	(221)
Distributions on Class C Interests (Note 6)	**(43)**	(16)	—
Common shares issued, net of issue costs	**1,905**	148	91
Preferred shares redeemed (Note 25)	**(1,000)**	(500)	—
Acquisition of TC PipeLines, LP transaction costs (Note 23)	**—**	(15)	—
Net cash provided by/(used in) financing activities	**487**	(88)	(800)
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**94**	53	(19)
(Decrease)/Increase in Cash and Cash Equivalents	**(53)**	(857)	187
Cash and Cash Equivalents			
Beginning of year	**673**	1,530	1,343
Cash and Cash Equivalents			
End of year	**620**	673	1,530

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

Consolidated balance sheet

at December 31 (millions of Canadian $)		2022	2021
ASSETS			
Current Assets			
Cash and cash equivalents		**620**	673
Accounts receivable		**3,624**	3,092
Loans receivable from affiliates (Note 12)		**—**	1,217
Inventories		**936**	724
Other current assets (Note 8)		**2,152**	1,717
		7,332	7,423
Plant, Property and Equipment (Note 9)		**75,940**	70,182
Net Investment in Leases (Note 10)		**1,895**	—
Equity Investments (Note 11)		**9,535**	8,441
Long-Term Loans Receivable from Affiliate (Notes 7 and 12)		**—**	238
Restricted Investments		**2,108**	2,182
Regulatory Assets (Note 13)		**1,910**	1,767
Goodwill (Note 14)		**12,843**	12,582
Other Long-Term Assets (Note 15)		**2,785**	1,403
		114,348	104,218
LIABILITIES			
Current Liabilities			
Notes payable (Note 16)		**6,262**	5,166
Accounts payable and other (Note 17)		**7,149**	5,099
Dividends payable		**930**	879
Accrued interest		**668**	577
Current portion of long-term debt (Note 20)		**1,898**	1,320
		16,907	13,041
Regulatory Liabilities (Note 13)		**4,520**	4,300
Other Long-Term Liabilities (Note 18)		**1,017**	1,059
Deferred Income Tax Liabilities (Note 19)		**7,648**	6,142
Long-Term Debt (Note 20)		**39,645**	37,341
Junior Subordinated Notes (Note 21)		**10,495**	8,939
		80,232	70,822
EQUITY			
Common shares, no par value (Note 24)		**28,995**	26,716
Issued and outstanding:	December 31, 2022 – 1,018 million shares		
	December 31, 2021 – 981 million shares		
Preferred shares (Note 25)		**2,499**	3,487
Additional paid-in capital		**722**	729
Retained earnings		**819**	3,773
Accumulated other comprehensive income/(loss) (Note 26)		**955**	(1,434)
Controlling Interests		**33,990**	33,271
Non-controlling interests (Note 23)		**126**	125
		34,116	33,396
		114,348	104,218

Commitments, Contingencies and Guarantees (Note 31)
Variable Interest Entities (Note 32)
Subsequent Event (Note 33)

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

On behalf of the Board:

François L. Poirier, Director

Una M. Power, Director

Consolidated statement of equity

year ended December 31 (millions of Canadian $)	2022	2021	2020
Common Shares (Note 24)			
Balance at beginning of year	**26,716**	24,488	24,387
Shares issued:			
Under public offering, net of issue costs	**1,754**	—	—
Dividend reinvestment and share purchase plan	**342**	—	—
Exercise of stock options	**183**	165	101
Acquisition of TC PipeLines, LP, net of transaction costs (Note 23)	**—**	2,063	—
Balance at end of year	**28,995**	26,716	24,488
Preferred Shares (Note 25)			
Balance at beginning of year	**3,487**	3,980	3,980
Redemption of shares	**(988)**	(493)	—
Balance at end of year	**2,499**	3,487	3,980
Additional Paid-In Capital			
Balance at beginning of year	**729**	2	—
Issuance of stock options, net of exercises	**(7)**	(6)	2
Keystone XL project-level credit facility retirement and issuance of Class C Interests (Note 6)	**—**	737	—
Acquisition of TC PipeLines, LP (Note 23)	**—**	(398)	—
Repurchase of redeemable non-controlling interest (Note 6)	**—**	394	—
Balance at end of year	**722**	729	2
Retained Earnings			
Balance at beginning of year	**3,773**	5,367	3,955
Net income attributable to controlling interests	**748**	1,955	4,616
Common share dividends	**(3,595)**	(3,409)	(3,045)
Preferred share dividends	**(95)**	(133)	(159)
Redemption of preferred shares	**(12)**	(7)	—
Balance at end of year	**819**	3,773	5,367
Accumulated Other Comprehensive Income/(Loss) (Note 26)			
Balance at beginning of year	**(1,434)**	(2,439)	(1,559)
Other comprehensive income/(loss) attributable to controlling interests	**2,389**	652	(880)
Acquisition of TC PipeLines, LP (Note 23)	**—**	353	—
Balance at end of year	**955**	(1,434)	(2,439)
Equity Attributable to Controlling Interests	**33,990**	33,271	31,398
Equity Attributable to Non-Controlling Interests			
Balance at beginning of year	**125**	1,682	1,634
Net income attributable to non-controlling interests	**37**	90	307
Other comprehensive income/(loss) attributable to non-controlling interests	**8**	(10)	(38)
Distributions declared to non-controlling interests	**(44)**	(74)	(221)
Acquisition of TC PipeLines, LP (Note 23)	**—**	(1,563)	—
Balance at end of year	**126**	125	1,682
Total Equity	**34,116**	33,396	33,080

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 Energy Solutions. 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 40,792 km (25,347 miles) of regulated natural gas pipelines currently in operation.

U.S. Natural Gas Pipelines

The U.S. Natural Gas Pipelines segment primarily consists of the Company's investments in 50,164 km (31,170 miles) of regulated natural gas pipelines, 532 Bcf of regulated natural gas storage facilities and other assets currently in operation.

Mexico Natural Gas Pipelines

The Mexico Natural Gas Pipelines segment primarily consists of the Company's investments in 2,775 km (1,723 miles) of regulated natural gas pipelines currently in operation.

Liquids Pipelines

The Liquids Pipelines segment primarily consists of the Company's investments in 4,856 km (3,019 miles) of crude oil pipeline systems currently in operation which connect Alberta and U.S. crude oil supplies to U.S. refining markets in Illinois, Oklahoma and Texas.

Power and Energy Solutions

For the period ended December 31, 2022, the Power and Storage segment has been renamed the Power and Energy Solutions segment, which primarily consists of the Company's investments in approximately 4,300 MW of power generation facilities and 118 Bcf of non-regulated natural gas storage facilities. These assets are located in Alberta, Ontario, Québec and New Brunswick. In addition, TC Energy has physical and virtual power purchase agreements (PPAs) in Canada and the U.S. to buy and/or sell power from wind and solar facilities. These PPAs have the potential to be leases, derivatives or revenue arrangements depending on the contractual terms of the agreement.

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. 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.

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:

- assessment of goodwill impairment indicators and fair value of reporting units that contain goodwill (Note 14)
- capital cost estimates to complete the Coastal GasLink pipeline used to measure TC Energy’s maximum exposure to loss resulting from its involvement with Coastal GasLink Limited Partnership (Coastal GasLink LP) and in measuring the fair value of TC Energy’s equity investment in Coastal GasLink LP (Notes 7 and 32).

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:

- valuation of Keystone XL assets (Note 6)
- recoverability and depreciation rates of plant, property and equipment (Note 9)
- allocation of consideration to lease and non-lease components in a contract that contains a lease (Note 10)
- assumptions used to measure the carrying amount of (Note 10) and expected credit losses (Note 28) on net investment in leases and certain contract assets
- fair value of equity investments not otherwise noted above (Note 11)
- carrying value of regulatory assets and liabilities (Note 13)
- assumptions used to measure the environmental remediation liability from the Keystone pipeline rupture (Note 17)
- recognition of asset retirement obligations (Note 18)
- provisions for income taxes, including valuation allowances and releases (Note 19)
- assumptions used to measure retirement and other post-retirement benefit obligations (Note 27)
- fair value of financial instruments (Note 28)
- fair value of assets and liabilities acquired in a business combination (Note 30)
- provisions for commitments, contingencies and guarantees (Note 31).

TC Energy continues to assess the impact of climate change on the consolidated financial statements. The Company has announced internal greenhouse gas reduction targets and closely monitors regulatory initiatives that may impact its existing businesses. There were also recent developments in the ESG frameworks and regulatory initiatives that could further impact accounting estimates and judgments including, but not limited to, assessment of asset useful lives, goodwill valuation, impairment of plant, property and equipment and accrued environmental costs. The impact of these changes is continuously assessed to ensure any changes in assumptions that would impact estimates listed above are adjusted on a timely basis.

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), the Alberta Energy Regulator or the B.C. Oil and Gas Commission. In the U.S., regulated interstate natural gas pipelines and liquids pipelines as well as 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
- 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 natural gas pipelines in Canada, U.S. and Mexico 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.

Revenues from non-lease components associated with a lease arrangement are recognized systematically over the term of the contract.

The majority of income earned from marketing activities, as it relates to the purchase and sale of crude oil, natural gas and electricity, is recorded on a net basis in the month of delivery.

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 regard 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.

Mexico Natural Gas Pipelines

Capacity Arrangements and Transportation

Revenues from certain of 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.

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.

Power and Energy Solutions

Power

Revenues from the Company's Power and Energy Solutions 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 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, proprietary natural gas inventory in storage and emissions allowances and credits not held for compliance. The Company purchases certain emissions allowances and credits as part of bundled arrangements that also include the purchase of electricity for a fixed price. The cost allocated to emissions allowances and credits under such arrangements is based on observable market prices. 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 0.75 per cent to 6.67 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.

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 Energy Solutions

Plant, property and equipment for Power and Energy Solutions 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 construction stage is probable or costs are otherwise likely to be recoverable. The Company 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

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

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

The Company considers non-lease components as distinct elements of a contract that are not related to the use of the leased asset. A good or service that is provided to a customer is distinct if: 1) the customer can benefit from the good or service either on its own or together with other resources that are readily available to the customer and 2) the entity's promise to transfer the good or service to the customer is separately identifiable from other promises in the contract. The Company applies the practical expedient to not separate lease and non-lease components for all lessee contracts and facilities and liquids tank terminals for which the Company is the lessor in an operating lease.

Lessee Accounting Policy
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 expedient to not recognize ROU assets or lease liabilities for leases that qualify for the short-term lease recognition exemption.

Lessor Accounting Policy
The Company provides transportation and other services on certain assets to customers according to long-term service agreements through sales-type and operating leases.

In a sales-type lease, the Company measures the total consideration within the contract at lease commencement. When a lease arrangement contains more than one lease and/or non-lease component, a portion of the contract consideration is allocated to each component based on the stand-alone selling price for each distinct service. The Company applies judgment to determine reasonable estimates of the expected future cost of satisfying the performance obligations of each service. The payments associated with lease components are apportioned between a reduction in the lease receivable and sales-type lease income.

At lease commencement, the Company recognizes a net investment in lease represented by the present value of both the future lease payments and the estimated residual value of the leased asset. The plant, property and equipment of the leased asset is derecognized, with related gains/losses, if any, recognized in the Consolidated statement of income. Sales-type lease income is determined using the rate implicit in the lease and is recorded in Revenues.

The Company is the lessor within certain other contracts, including PPAs, that are accounted for as operating leases. In an operating lease, the leased asset remains capitalized in Plant, property and equipment on the Consolidated balance sheet and is depreciated over its useful life, while lease payments are recognized as income over the term of the lease on a straight-line basis. Variable lease payments are recognized as income in the period in which they occur.

Impairment of Long-Lived Assets
The Company reviews long-lived assets such as plant, property and equipment 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.

Impairment of Equity Method Investments
The Company reviews equity method investments for impairment when an event or change in circumstances has a significant adverse effect on the investment's fair value. Where the Company concludes an investment's fair value is below its carrying value, the Company then determines whether the impairment is other-than-temporary, and if so, an impairment loss is recognized for the excess of the carrying value over the estimated fair value of the investment, not exceeding the carrying value of the investment.

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. The fair value of a reporting unit is determined by using a discounted cash flow analysis which requires the use of assumptions that may include, but are not limited to, revenue and capital expenditure projections, valuation multiples and discount rates. The Company has elected to allocate goodwill impairment charges first to goodwill that is non-deductible for income tax purposes, with any remaining charge allocated to tax-deductible goodwill.

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, inclusive of net investment in leases and certain contract 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. An expected credit loss (ECL) is calculated using a model and methodology based on assumptions and judgment considering historical data, current counterparty information as well as reasonable and supportable forecasts of future economic conditions.

The ECL is recognized in Plant operating costs and other on the Consolidated statement of income, and is presented on the Consolidated balance sheet as a reduction to the carrying value of the related financial asset.

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. The Company's exposure to uncertain tax positions is evaluated and a provision is made where it is more likely than not that this exposure will materialize.

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

Any interest and/or penalty incurred related to tax is reflected in income tax expense.

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
- 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 and Emission Allowances and Credits

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. TC Energy evaluates recoveries from insurers and other third parties separately from the liability and, when recovery is probable, it records an asset separately from the associated liability. These recoveries are presented, along with environmental remediation costs, on a net basis in Plant operating costs and other in the Consolidated statement of income. Variations in one or more of the categories described above could result in additional costs such as fines, penalties and/or expenditures associated with litigation and settlement of claims with respect to environmental liabilities.

Emission allowances or credits purchased for compliance are recorded on the Consolidated balance sheet at historical cost and derecognized 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 within the Power and Energy Solutions segment in the Consolidated statement of income. The Company records allowances and credits held for compliance in Other current assets and Other long-term assets on the Consolidated balance sheet. Allowances and credits not held for compliance are classified as Inventories on the Consolidated balance sheet.

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 income/(loss) (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.

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. The assessment of whether an entity is a VIE and, if so, whether the Company is the primary beneficiary, is completed at the inception of the entity or at a reconsideration event.

Consolidated VIEs

The Company's consolidated VIEs consist of legal entities where the Company has a variable interest and for which it is considered 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.

Non-Consolidated VIEs

The Company's non-consolidated VIEs consist of legal entities where the Company has a variable interest but is not the primary beneficiary as it does not have the power (either explicit or implicit), through voting or similar rights, 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. Non-consolidated VIEs are accounted for as equity investments.

The Company's maximum exposure to loss is the maximum loss that could potentially be recorded through net income in future periods as a result of the Company's variable interest in a VIE.

3. ACCOUNTING CHANGES

Changes in Accounting Policies for 2022

Reference Rate Reform

In March 2020, FASB issued optional guidance with respect to the expected cessation of certain reference interest rates. The guidance provides optional expedients for contracts and hedging relationships that are affected by reference rate reform if certain criteria are met. In December 2022, FASB issued an update to defer the sunset date of the guidance to December 31, 2024. For eligible hedging relationships, the Company has applied the optional expedient allowing an entity to assume that the hedged forecasted transaction in a cash flow hedge is probable of occurring. The Company expects to use practical expedients available in the guidance to treat contract modifications as events that do not require contract remeasurement or reassessment of previous accounting determinations. As such, these changes are not expected to have a material impact on the Company's consolidated financial statements.

Government Assistance

In November 2021, the FASB issued new guidance that expands annual disclosure requirements for entities that account for a transaction with a government by applying a grant or contribution accounting model by analogy to other accounting guidance. Entities are required to disclose the nature of the transactions, the related accounting policies used to account for the transactions, the effect of the transactions on an entity's financial statements and any significant terms and conditions of the transaction. This new guidance is effective for annual disclosure requirements at December 31, 2022 and can be applied either prospectively or retrospectively, with early application permitted. The Company adopted the guidance effective January 1, 2022 on a prospective basis and it did not have a material impact on the Company's consolidated financial statements.

Contract Assets and Liabilities from Contracts with Customers

In October 2021, the FASB issued new guidance that amends the accounting for contract assets and liabilities from contracts with customers acquired in a business combination. At the acquisition date, an acquirer should account for the contract assets and liabilities in accordance with guidance on revenue from contracts with customers. This new guidance is effective January 1, 2023 and is applied prospectively with early adoption permitted. Early adoption requires the application of the amendments retrospectively to all business combinations with an acquisition date in the year of early adoption. The Company elected to adopt the new guidance effective January 1, 2022 and it did not have any impact on the Company's consolidated financial statements.

4. SEGMENTED INFORMATION

year ended December 31, 2022 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Energy Solutions	Corporate[1]	Total
Revenues	**4,764**	**5,933**	**688**	**2,668**	**924**	**—**	**14,977**
Intersegment revenues	**—**	**132**	**—**	**—**	**12**	**(144)** [2]	**—**
	4,764	**6,065**	**688**	**2,668**	**936**	**(144)**	**14,977**
Income from equity investments	**18**	**292**	**122**	**55**	**539**	**28** [3]	**1,054**
Impairment of equity investment	**(3,048)**	**—**	**—**	**—**	**—**	**—**	**(3,048)**
Plant operating costs and other	**(1,679)**	**(1,856)**	**(221)**	**(756)**	**(544)**	**124** [2]	**(4,932)**
Commodity purchases resold	**—**	**—**	**—**	**(512)**	**(22)**	**—**	**(534)**
Property taxes	**(297)**	**(426)**	**—**	**(121)**	**(4)**	**—**	**(848)**
Depreciation and amortization	**(1,198)**	**(887)**	**(98)**	**(329)**	**(72)**	**—**	**(2,584)**
Goodwill and asset impairment charges and other	**—**	**(571)**	**—**	**118**	**—**	**—**	**(453)**
Segmented (Losses)/Earnings	**(1,440)**	**2,617**	**491**	**1,123**	**833**	**8**	**3,632**
Interest expense							**(2,588)**
Allowance for funds used during construction							**369**
Foreign exchange loss, net[3]							**(185)**
Interest income and other							**146**
Income before Income Taxes							**1,374**
Income tax expense							**(589)**
Net Income							**785**
Net income attributable to non-controlling interests							**(37)**
Net Income Attributable to Controlling Interests							**748**
Preferred share dividends							**(107)**
Net Income Attributable to Common Shares							**641**
Capital Spending							
Capital expenditures	**3,274**	**2,137**	**1,027**	**106**	**93**	**41**	**6,678**
Capital projects in development	**—**	**—**	**—**	**—**	**49**	**—**	**49**
Contributions to equity investments[4]	**1,445**	**—**	**—**	**37**	**752**	**—**	**2,234**
	4,719	**2,137**	**1,027**	**143**	**894**	**41**	**8,961**

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 Foreign exchange loss, net by the corresponding foreign exchange losses and gains on the affiliate receivable balance until March 15, 2022, when it was fully repaid upon maturity. Refer to Note 12, Loans receivable from affiliates, for additional information.

4 Contributions to equity investments in the Corporate segment of $1.2 billion are offset by the equivalent amount in Other distributions from equity investments, although they are reported on a gross basis in the Company's Consolidated statement of cash flows. Refer to Note 12, Loans receivable from affiliates, for additional information.

year ended December 31, 2021 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Energy Solutions	Corporate[1]	Total
Revenues	4,519	5,233	605	2,306	724	—	13,387
Intersegment revenues	—	145	—	—	14	(159) [2]	—
	4,519	5,378	605	2,306	738	(159)	13,387
Income from equity investments	12	244	119	71	411	41 [3]	898
Plant operating costs and other	(1,567)	(1,393)	(55)	(700)	(455)	72 [2]	(4,098)
Commodity purchases resold	—	—	(3)	(84)	—	—	(87)
Property taxes	(289)	(367)	—	(113)	(5)	—	(774)
Depreciation and amortization	(1,226)	(791)	(109)	(318)	(78)	—	(2,522)
Asset impairment charge and other	—	—	—	(2,775)	—	—	(2,775)
Gain on sale of assets	—	—	—	13	17	—	30
Segmented Earnings/(Losses)	1,449	3,071	557	(1,600)	628	(46)	4,059
Interest expense							(2,360)
Allowance for funds used during construction							267
Foreign exchange gain, net[3]							10
Interest income and other							190
Income before Income Taxes							2,166
Income tax expense							(120)
Net Income							2,046
Net income attributable to non-controlling interests							(91)
Net Income Attributable to Controlling Interests							1,955
Preferred share dividends							(140)
Net Income Attributable to Common Shares							1,815
Capital Spending							
Capital expenditures	2,629	2,611	129	488	32	35	5,924
Contributions to equity investments	108	209	—	83	810	—	1,210
	2,737	2,820	129	571	842	35	7,134

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 Foreign exchange gain, net by the corresponding foreign exchange losses and gains on the affiliate receivable balance. Refer to Note 12, Loans receivable from affiliates, for additional 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 Energy Solutions	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
Foreign exchange gain, net[3]							28
Interest income and other							185
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 Foreign exchange gain, net by the corresponding foreign exchange losses and gains on the affiliate receivable balance. Refer to Note 12, Loans receivable from affiliates, for additional information.

at December 31 (millions of Canadian $)	2022	2021
Total Assets by Segment		
Canadian Natural Gas Pipelines	**27,456**	25,452
U.S. Natural Gas Pipelines	**50,038**	45,502
Mexico Natural Gas Pipelines	**9,231**	7,547
Liquids Pipelines	**15,587**	14,951
Power and Energy Solutions	**8,272**	6,563
Corporate	**3,764**	4,203
	114,348	104,218

Geographic Information

year ended December 31 (millions of Canadian $)	2022	2021	2020
Revenues			
Canada – domestic	**4,942**	4,603	4,392
Canada – export	**1,322**	1,226	1,059
United States	**8,025**	6,953	6,832
Mexico	**688**	605	716
	14,977	13,387	12,999

at December 31 (millions of Canadian $)	2022	2021
Plant, Property and Equipment		
Canada	**27,232**	24,890
United States	**43,505**	39,335
Mexico	**5,203**	5,957
	75,940	70,182

5. REVENUES

Disaggregation of Revenues

year ended December 31, 2022 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Energy Solutions	Total
Revenues from contracts with customers						
Capacity arrangements and transportation	**4,696**	**4,621**	**507**	**1,983**	**—**	**11,807**
Power generation	**—**	**—**	**—**	**—**	**490**	**490**
Natural gas storage and other[1,2]	**68**	**1,298**	**54**	**4**	**391**	**1,815**
	4,764	**5,919**	**561**	**1,987**	**881**	**14,112**
Sales-type lease income[3]	**—**	**—**	**127**	**—**	**—**	**127**
Other revenues[4,5]	**—**	**14**	**—**	**681**	**43**	**738**
	4,764	**5,933**	**688**	**2,668**	**924**	**14,977**

1 Includes $68 million of fee revenues from an affiliate related to development and construction of the Coastal GasLink pipeline project which is 35 per cent owned by TC Energy as at December 31, 2022. Refer to Note 30, Acquisitions and dispositions, for additional information.

2 Includes $37 million of revenues generated from non-lease components for the provision of operating and maintenance services with respect to sales-type leases on the in-service TGNH pipelines. Refer to Note 10, Leases, for additional information.

3 Represents the sales-type lease income on the in-service TGNH pipelines. Refer to Note 10, Leases, for additional information.

4 Other revenues include income from the Company's operating lease arrangements, marketing activities and financial instruments. Refer to Note 10, Leases, and Note 28, Risk management and financial instruments, for additional information on income from operating lease arrangements and financial instruments, respectively.

5 Other revenues from U.S. Natural Gas Pipelines include the amortization of the net regulatory liabilities resulting from H.R.1, the Tax Cuts and Jobs Act (U.S. Tax Reform). Refer to Note 13, Rate-regulated businesses, for additional information.

year ended December 31, 2021 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Energy Solutions	Total
Revenues from contracts with customers						
Capacity arrangements and transportation	4,432	4,139	576	2,025	—	11,172
Power generation	—	—	—	—	324	324
Natural gas storage and other[1]	87	1,057	29	5	278	1,456
	4,519	5,196	605	2,030	602	12,952
Other revenues[2,3]	—	37	—	276	122	435
	4,519	5,233	605	2,306	724	13,387

1 Includes $87 million of fee revenues from an affiliate related to development and construction of the Coastal GasLink pipeline project which is 35 per cent owned by TC Energy as at December 31, 2021. Refer to Note 30, Acquisitions and dispositions, for additional information.

2 Other revenues include income from the Company's operating lease arrangements, marketing activities and financial instruments. Refer to Note 10, Leases, and Note 28, Risk management and financial instruments, for additional information on income from operating 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 13, Rate-regulated businesses, for additional 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 Energy Solutions	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 was related to the construction of the Sur de Texas pipeline which is 60 per cent owned by TC Energy and $61 million was 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 30, Acquisitions and dispositions, for additional information.

2 Other revenues include income from the Company's operating lease arrangements, marketing activities and financial instruments. Refer to Note 10, Leases, and Note 28, Risk management and financial instruments, for additional information on income from operating 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 13, Rate-regulated businesses, for additional information.

Contract Balances

at December 31 (millions of Canadian $)	2022	2021	Affected line item on the Consolidated balance sheet
Receivables from contracts with customers	**1,907**	1,627	Accounts receivable
Contract assets (Note 8)	**155**	202	Other current assets
Long-term contract assets (Note 15)	**355**	249	Other long-term assets
Contract liabilities[1] (Note 17)	**62**	90	Accounts payable and other
Long-term contract liabilities (Note 18)	**32**	184	Other long-term liabilities

1 During the year ended December 31, 2022, $51 million (2021 – $95 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 represent unearned revenue for contracted services. In the prior year, contract liabilities and long-term contract liabilities primarily related to force majeure fixed capacity payments received on long-term capacity arrangements in Mexico. During the year ended December 31, 2022, and under the terms of the consolidated Transportation Service Agreement (TSA), the contract liability relating to the in-service TGNH pipelines was netted against certain contract asset balances and settled against the initial recording of the net investment in leases on the Consolidated balance sheet.

Future Revenues from Remaining Performance Obligations

As at December 31, 2022, future revenues from long-term pipeline capacity arrangements and transportation as well as natural gas storage and other contracts extending through 2055 are approximately $23.3 billion, of which approximately $3.8 billion is expected to be recognized in 2023.

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. Future revenues exclude lease income from the Company's Mexico natural gas pipelines on projects that have not been placed into service.

6. KEYSTONE XL

Asset Impairment Charge and Other

Following the revocation of the Presidential Permit for the Keystone XL pipeline project on January 20, 2021, the Company terminated the Keystone XL pipeline project and evaluated the Keystone XL investment for impairment in 2021. As a result, the Company determined that the carrying amount of these assets within the Liquids Pipelines segment was no longer fully recoverable and recognized an asset impairment charge, net of expected contractual recoveries and other contractual and legal obligations related to termination activities, of $2,775 million ($2,134 million after tax) for the year ended December 31, 2021. The asset impairment charge was based on the excess of the carrying value of $3,301 million over the estimated fair value of $175 million.

year ended December 31, 2021 (millions of Canadian $)	Estimated Fair Value of Plant, Property and Equipment	Asset impairment charge and other	
		Pre tax	After tax
Asset impairment charge			
Plant and equipment	175	412	312
Related capital projects in development	—	230	175
Other capitalized costs	—	2,158	1,642
Capitalized interest	—	326	248
	175	3,126	2,377
Other			
Contractual recoveries	n/a	(693)	(525)
Contractual and legal obligations related to termination activities	n/a	342	282
	175	2,775	2,134

The estimated fair value of $175 million at December 31, 2021 related to plant and equipment was based on the price that was expected to be received from selling these assets in their current condition and is updated as required. The initial key assumptions used in the determination of selling price included an estimated two-year disposal period and current energy market demand. The valuation considered a variety of potential selling prices based on various markets that could be used to dispose of these assets and required the use of unobservable inputs. As a result, the fair value is classified in Level III of the fair value hierarchy.

In 2022, the Company received $571 million towards its contractual recoveries, resulting in a remaining balance of $130 million at December 31, 2022.

In 2022, the Company revised its estimate of contractual and legal obligations related to termination activities based on a review of costs and commitments incurred, which resulted in a $54 million reduction to the asset impairment charge. The Company paid $24 million in 2022 (2021 – $192 million) towards contractual and legal obligations related to termination activities. At December 31, 2022, the remaining balance accrued was $48 million.

For the year ended December 31, 2022, the Company sold plant and equipment with a carrying value of approximately $25 million (2021 – $16 million), resulting in a gain of $64 million (2021 – nil). The Company expects to dispose of the remaining assets in 2023.

In 2022, as part of the Keystone XL impairment charge and other, the Company recognized a $96 million U.S. minimum tax related to the termination of the Keystone XL pipeline project.

Redeemable Non-Controlling Interest and Long-Term Debt

In March 2020, the Company announced that it would proceed with construction of the Keystone XL pipeline. As part of the funding plan, the Government of Alberta invested $1,033 million in the form of Class A Interests in the year ended December 31, 2020.

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 was fully guaranteed by the Government of Alberta and non-recourse to the Company. On January 8, 2021, the Company exercised its call right with the Government of Alberta in accordance with contractual terms and paid $633 million (US$497 million) to repurchase the Government of Alberta Class A Interests in certain Keystone XL subsidiaries. This transaction was funded by draws on the project-level credit facility. For the year ended December 31, 2021, the Company made draws under the Keystone XL project-level credit facility totaling $1,028 million (US$849 million) and in accordance with the terms of the guarantee, the Government of Alberta repaid the full outstanding balance in June 2021 and it was subsequently terminated. As part of this arrangement, TC Energy issued $91 million of Class C Interests in the Keystone XL subsidiaries which entitled the Government of Alberta to future liquidation proceeds from specified Keystone XL project assets. The entire $91 million was recorded (net of distributions) in Accounts payable and other on the Consolidated balance sheet. Termination of the project-level credit facility, net of the issuance of Class C Interests, resulted in $937 million ($737 million after tax) recorded to Additional paid-in capital. In June 2021, the Company repurchased the remaining Government of Alberta Class A Interests for a nominal amount, which was accounted for as an equity transaction and resulted in $394 million recognized in Additional paid-in capital. For the year ended December 31, 2022, the Company made Class C distributions to the Government of Alberta of $43 million (2021 – $16 million).

The changes in Redeemable non-controlling interest classified in mezzanine equity were as follows:

(millions of Canadian $)	
Balance at January 1, 2021	393
Net income attributable to redeemable non-controlling interest	1
Class A Interests repurchased	(394)
Balance at December 31, 2021	—

7. COASTAL GASLINK

Impairment of Equity Investment in Coastal GasLink LP

July 2022 Amended Coastal GasLink Agreements

On July 28, 2022, amended agreements were executed between Coastal GasLink LP, LNG Canada, TC Energy and its Coastal GasLink LP partners (collectively, the July 2022 agreements). These amendments revised the commercial terms between LNG Canada and Coastal GasLink LP, as well as funding provisions between the partners of Coastal GasLink LP and required TC Energy to make a contractual equity contribution to Coastal GasLink LP in the amount of $1.9 billion, which did not result in a change in the Company's 35 per cent ownership. Refer to Note 32, Variable interest entities, for additional information.

The $1.9 billion contractual equity contribution was accrued and initially recognized in Equity investments on the Consolidated balance sheet at the time of signing the July 2022 agreements and is being paid in installments over the period August 2022 to February 2023. At December 31, 2022, $0.5 billion of this equity contribution remained in Accounts payable and other on the Consolidated balance sheet.

Under the terms of the July 2022 agreements, any additional equity financing required by Coastal GasLink LP to fund construction of the pipeline beyond the $1.9 billion equity contribution will initially be financed through a subordinated loan agreement between TC Energy and Coastal GasLink LP. Any amounts outstanding on this loan will be repaid by Coastal GasLink LP to TC Energy, once final costs are known, which will be determined after the pipeline is placed in service. Coastal GasLink LP partners, including TC Energy, will contribute equity to Coastal GasLink LP to ultimately fund Coastal GasLink LP's repayment of this subordinated loan to TC Energy. The Company expects that these additional equity contributions will be predominantly funded by TC Energy but will not result in a change to the Company's 35 per cent ownership.

Capital Cost Update and Impairment

In the fourth quarter of 2022, the Company announced that it expected a material increase in project costs and to the Company's corresponding funding requirements. On February 1, 2023, TC Energy announced that the revised capital cost of the Coastal GasLink pipeline project was expected to be approximately $14.5 billion. While this estimate includes contingencies for certain factors that may be outside the control of Coastal GasLink LP, such as challenging conditions in the Western Canadian labour market, shortages of skilled labour, the impacts of contractor underperformance, as well as drought conditions and erosion and sediment control challenges, as with any complex construction project, the final capital cost is subject to certain risks and uncertainties. The increase in project costs and the Company's corresponding funding requirements were indicators that a decrease in the value of the Company's equity investment had occurred.

As a result, the Company completed a valuation assessment and concluded that the fair value of TC Energy's investment was below its carrying value at December 31, 2022. The Company determined that this was an other-than-temporary impairment of its equity investment in Coastal GasLink LP and a pre-tax impairment charge of $3,048 million ($2,643 million after tax) was recognized in fourth quarter 2022 in Impairment of equity investment in the Consolidated statement of income in the Canadian Natural Gas Pipelines segment. The pre-impairment carrying value of the investment in Coastal GasLink LP at December 31, 2022 consisted of amounts in Equity investments ($2,798 million) and Loans receivable from affiliates ($250 million), which were reduced to a nil balance.

TC Energy expects to fund an additional $3.3 billion related to the revised estimated capital cost to complete the Coastal GasLink pipeline, and a significant portion of the Company's future investment in Coastal GasLink LP is expected to be impaired. The Company will continue to assess for other-than-temporary declines in the fair value of this investment, and the extent of any future impairment charges will depend on the outcome of the valuation assessment performed at the respective reporting date.

The fair value of TC Energy's investment in Coastal GasLink LP at December 31, 2022 was estimated using a 40-year discounted cash flow model. Cash inflows in the model were estimated using contractually agreed upon terms and extension provisions in the TSAs between Coastal GasLink LP and the LNG Canada participants.

For cash outflows in the model, the increase in estimated capital cost and the Company's corresponding funding requirements have the most significant impact on the determination of the fair value of TC Energy's investment in Coastal GasLink LP. The cash flow analysis included a capital cost estimate for the Coastal GasLink pipeline of $14.5 billion. Any change from this capital cost estimate will have an approximate dollar-for-dollar impact on the Company's future funding requirements, subject to any final cost sharing between the Coastal GasLink LP partners, and will impact the estimated fair value of, and the Company's recovery of, its equity investment in Coastal GasLink LP in future periods.

Other assumptions included in the discounted cash flow model include discount rate, long-term project financing plans and estimated completion date. Changes to these other assumptions would not reasonably expect to change the impairment recorded in the fourth quarter of 2022.

A deferred income tax recovery was recognized on the pre-tax impairment charge, net of certain unrealized tax losses not recognized. Refer to Note 19, Income taxes, for additional information.

Subordinated Loan Agreement

In 2021, TC Energy entered into a subordinated loan agreement with Coastal GasLink LP. This loan agreement was amended as part of the July 2022 agreements, and subsequent draws on this loan by Coastal GasLink LP will be provided through an interest-bearing loan, subject to a floating market-based interest rate to fund the capital cost to complete the Coastal GasLink pipeline, which is estimated to be $3.3 billion. As at December 31, 2022, the total capacity committed by TC Energy under this subordinated loan agreement was $1.3 billion. The committed capacity under this loan is expected to increase in the future as required to support additional financing requirements. Any amounts outstanding will be repaid by Coastal GasLink LP to TC Energy, once final costs are known, which will be determined after the pipeline is placed in service. Coastal GasLink LP partners, including TC Energy, will contribute equity to Coastal GasLink LP to ultimately fund Coastal GasLink LP's repayment of this subordinated loan to TC Energy. The Company expects that, in accordance with the July 2022 agreements, these additional equity contributions will be predominantly funded by TC Energy but will not result in a change to the Company's 35 per cent ownership.

As noted above, the $250 million balance outstanding on this loan at December 31, 2022 was reduced to nil as part of the impairment charge recognized in fourth quarter 2022.

The table below reflects the changes in this loan balance for the year ended December 31, 2022.

(millions of Canadian $)	
Outstanding balance as at December 31, 2021	238
Issuances[1]	**112**
Repayments[1]	**(100)**
Outstanding balance at December 31, 2022	**250**
Impairment	**(250)**
Carrying value at December 31, 2022	**—**

1 Presented on a net basis on the Company's Consolidated statement of cash flows.

8. OTHER CURRENT ASSETS

at December 31 (millions of Canadian $)	2022	2021
Fair value of derivative contracts (Note 28)	**614**	169
Current portion of Keystone environmental provision recovery (Note 17)	**410**	—
Current portion of net investment in leases (Note 10)	**291**	—
Contract assets (Note 5)	**155**	202
Keystone XL assets held for sale	**122**	138
Prepaid expenses	**118**	112
Cash provided as collateral	**106**	273
Keystone XL contractual recoveries (Note 6)	**86**	640
Regulatory assets (Note 13)	**67**	53
Other	**183**	130
	2,152	1,717

9. PLANT, PROPERTY AND EQUIPMENT

at December 31	2022			2021		
(millions of Canadian $)	Cost	Accumulated Depreciation	Net Book Value	Cost	Accumulated Depreciation	Net Book Value
Canadian Natural Gas Pipelines						
NGTL System						
Pipeline	**18,119**	**6,285**	**11,834**	14,892	5,751	9,141
Compression	**6,265**	**2,224**	**4,041**	6,191	2,065	4,126
Metering and other	**1,518**	**769**	**749**	1,458	705	753
	25,902	**9,278**	**16,624**	22,541	8,521	14,020
Under construction	**1,552**	**—**	**1,552**	2,285	—	2,285
	27,454	**9,278**	**18,176**	24,826	8,521	16,305
Canadian Mainline						
Pipeline	**10,472**	**7,852**	**2,620**	10,423	7,698	2,725
Compression	**4,328**	**3,247**	**1,081**	4,165	3,125	1,040
Metering and other	**692**	**285**	**407**	652	264	388
	15,492	**11,384**	**4,108**	15,240	11,087	4,153
Under construction	**269**	**—**	**269**	139	—	139
	15,761	**11,384**	**4,377**	15,379	11,087	4,292
Other Canadian Natural Gas Pipelines[1]						
Other	**1,984**	**1,624**	**360**	1,937	1,567	370
Under construction	**455**	**—**	**455**	58	—	58
	2,439	**1,624**	**815**	1,995	1,567	428
	45,654	**22,286**	**23,368**	42,200	21,175	21,025
U.S. Natural Gas Pipelines						
Columbia Gas						
Pipeline	**12,471**	**1,069**	**11,402**	11,205	799	10,406
Compression	**5,190**	**495**	**4,695**	4,522	381	4,141
Metering and other	**4,026**	**346**	**3,680**	3,657	257	3,400
	21,687	**1,910**	**19,777**	19,384	1,437	17,947
Under construction	**659**	**—**	**659**	433	—	433
	22,346	**1,910**	**20,436**	19,817	1,437	18,380
ANR						
Pipeline	**2,066**	**641**	**1,425**	1,820	557	1,263
Compression	**3,785**	**734**	**3,051**	2,559	565	1,994
Metering and other	**1,666**	**440**	**1,226**	1,391	422	969
	7,517	**1,815**	**5,702**	5,770	1,544	4,226
Under construction	**328**	**—**	**328**	833	—	833
	7,845	**1,815**	**6,030**	6,603	1,544	5,059

at December 31 (millions of Canadian $)	2022 Cost	2022 Accumulated Depreciation	2022 Net Book Value	2021 Cost	2021 Accumulated Depreciation	2021 Net Book Value
Other U.S. Natural Gas Pipelines						
Columbia Gulf	**3,511**	**224**	**3,287**	2,749	178	2,571
GTN	**2,964**	**1,239**	**1,725**	2,701	1,071	1,630
Great Lakes	**2,367**	**1,387**	**980**	2,162	1,255	907
Other[2]	**1,928**	**760**	**1,168**	1,755	657	1,098
	10,770	**3,610**	**7,160**	9,367	3,161	6,206
Under construction	**328**	**—**	**328**	533	—	533
	11,098	**3,610**	**7,488**	9,900	3,161	6,739
	41,289	**7,335**	**33,954**	36,320	6,142	30,178
Mexico Natural Gas Pipelines[3]						
Pipeline	**2,299**	**348**	**1,951**	2,957	476	2,481
Compression	**374**	**59**	**315**	480	80	400
Metering and other	**487**	**113**	**374**	626	155	471
	3,160	**520**	**2,640**	4,063	711	3,352
Under construction	**2,547**	**—**	**2,547**	2,590	—	2,590
	5,707	**520**	**5,187**	6,653	711	5,942
Liquids Pipelines						
Keystone Pipeline System						
Pipeline	**9,777**	**2,056**	**7,721**	9,209	1,758	7,451
Pumping equipment	**1,064**	**288**	**776**	1,020	252	768
Tanks and other	**3,723**	**859**	**2,864**	3,534	737	2,797
	14,564	**3,203**	**11,361**	13,763	2,747	11,016
Under construction	**96**	**—**	**96**	72	—	72
	14,660	**3,203**	**11,457**	13,835	2,747	11,088
Intra-Alberta Pipelines	**199**	**19**	**180**	199	14	185
	14,859	**3,222**	**11,637**	14,034	2,761	11,273
Power and Energy Solutions						
Natural Gas Power Generation	**1,260**	**642**	**618**	1,267	605	662
Natural Gas Storage and Other	**820**	**238**	**582**	797	216	581
	2,080	**880**	**1,200**	2,064	821	1,243
Under construction	**80**	**—**	**80**	5	—	5
	2,160	**880**	**1,280**	2,069	821	1,248
Corporate	**900**	**386**	**514**	836	320	516
	110,569	**34,629**	**75,940**	102,112	31,930	70,182

1 Includes Foothills, Ventures LP and Great Lakes Canada.
2 Includes Portland, North Baja, Tuscarora, Crossroads and mineral rights.
3 During the year ended December 31, 2022, the Company derecognized $2,319 million of Plant, property and equipment and recorded a corresponding asset for net investment in leases for the in-service TGNH pipelines. Refer to Note 10, Leases, for additional information.

10. 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 $)	2022	2021
Operating lease cost[1]	**106**	105
Sublease income	**(5)**	(8)
Net operating lease cost	**101**	97

1 Includes short-term leases and variable lease costs.

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

year ended December 31 (millions of Canadian $)	2022	2021
Cash paid for amounts included in the measurement of operating lease liabilities	**67**	69
ROU assets obtained in exchange for new operating lease liabilities	**49**	7

at December 31	2022	2021
Weighted average remaining lease term	**8 years**	9 years
Weighted average discount rate	**3.5%**	3.5%

Maturities of operating lease liabilities are as follows:

(millions of Canadian $)	2022	2021
Less than one year	**68**	63
One to two years	**65**	60
Two to three years	**62**	58
Three to four years	**60**	55
Four to five years	**54**	54
More than five years	**187**	213
Total operating lease payments	**496**	503
Imputed interest	**(63)**	(74)
Operating lease liabilities	**433**	429

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

at December 31 (millions of Canadian $)	**2022**	**2021**
Accounts payable and other	**54**	49
Other long-term liabilities (Note 18)	**379**	380
	433	429

As at December 31, 2022, the carrying value of the ROU assets recorded under operating leases was $415 million (2021 – $415 million) and is included in Plant, property and equipment on the Consolidated balance sheet.

As a Lessor

Operating Leases

The Grandview and Bécancour power plants in the Power and Energy Solutions segment are accounted for as operating leases. The Company has long-term PPAs for the sale of power from these assets which expire between 2024 and 2026.

Some operating 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, 2022 was $118 million (2021 – $126 million; 2020 – $130 million).

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

(millions of Canadian $)	**2022**	**2021**
Less than one year	**113**	113
One to two years	**111**	111
Two to three years	**94**	110
Three to four years	**70**	94
Four to five years	**—**	70
	388	498

The cost and accumulated depreciation for facilities accounted for as operating leases was $802 million and $360 million, respectively, at December 31, 2022 (2021 – $812 million and $340 million, respectively).

Sales-Type Leases

On August 4, 2022, TC Energy announced a strategic alliance with Mexico's state-owned electric utility, the Comisión Federal de Electricidad (CFE), for the development of new natural gas infrastructure in central and southeast Mexico. This alliance consolidates previous TSAs executed between TC Energy's Mexico-based subsidiary TGNH and the CFE in connection with the Company's natural gas pipeline assets in central Mexico (including the Tamazunchale, Villa de Reyes and Tula pipelines) under a single, U.S. dollar-denominated take-or-pay TSA that extends through 2055.

The consolidated TSA contains a lease with multiple lease and non-lease components. The lease components represent the capacity available to the CFE provided by the in-service pipelines which, at December 31, 2022, included the Tamazunchale pipeline, the north section of the Villa de Reyes pipeline and the east section of the Tula pipeline. The non-lease components represent the Company's services with respect to operation and maintenance of the TGNH pipelines in service.

The consolidated TSA provides the CFE with substantially all of the economic benefits from the use of each identified in-service asset, therefore, the lease arrangements in the consolidated TSA are classified as sales-type leases.

The Company allocated a portion of the contract consideration to non-lease components for the provision of operating and maintenance services based on the stand-alone selling price using an expected cost plus margin approach. The remaining consideration was allocated to the lease components using the residual approach due to uncertainty surrounding the stand-alone selling price.

At lease commencement, the Company recognized an aggregate net investment in sales-type leases. The TGNH pipelines are rate-regulated and the tolls are designed to recover the cost of providing service. On this basis, the Company applied judgment to determine that, at the inception of the lease arrangement, the fair value of the underlying assets approximated the carrying value and the residual value approximated the remaining carrying value at the end of the lease term.

The following table lists the components of the aggregate Net investment in leases reflected on the Company's Consolidated balance sheet:

(millions of Canadian $)	December 31, 2022
Net Investment in Leases	
Minimum lease payments	**9,457**
Unearned lease income	**(7,132)**
Lease receivable	**2,325**
Expected credit loss provision[1]	**(150)**
Present value of unguaranteed residual value	**11**
	2,186
Current portion included in Other current assets (Note 8)	**(291)**
	1,895

1 Includes $1 million of foreign currency translation losses.

Future lease payments to be received under the existing sales-type leases are as follows:

(millions of Canadian $)	December 31, 2022
Less than one year	**291**
One to two years	**291**
Two to three years	**291**
Three to four years	**291**
Four to five years	**291**
More than five years	**8,002**
	9,457

Future lease payments will increase as assets associated with sales-type leases come into service.

For the year ended December 31, 2022, the Company recorded $127 million of sales-type lease income in Mexico Natural Gas Pipelines revenues.

For the year ended December 31, 2022, the Company recorded a $149 million (2021 and 2020 – nil) ECL provision in Plant operating costs and other relating to net investment in leases. Refer to Note 28, Risk management and financial instruments, for additional information.

11. EQUITY INVESTMENTS

(millions of Canadian $)	Ownership Interest at December 31, 2022	Income from Equity Investments year ended December 31			Equity Investments at December 31	
		2022	**2021**	**2020**	**2022**	**2021**
Canadian Natural Gas Pipelines						
TQM[1]	50.0%	**17**	12	12	**165**	118
Coastal GasLink[1]	35.0%	**1**	—	—	**—**	386
U.S. Natural Gas Pipelines						
Northern Border	50.0%	**92**	80	100	**516**	505
Millennium	47.5%	**103**	91	96	**500**	474
Iroquois	50.0%	**77**	55	52	**237**	392
Other	Various	**20**	18	16	**122**	137
Mexico Natural Gas Pipelines						
Sur de Texas	60.0%	**150**	160	213	**1,050**	835
Liquids Pipelines						
Grand Rapids[1]	50.0%	**54**	54	53	**964**	980
Port Neches Link LLC[2]	95.0%	**—**	—	—	**149**	103
HoustonLink Pipeline[1]	50.0%	**1**	1	—	**19**	18
Northern Courier[1,3]	nil	**—**	16	22	**—**	—
Power and Energy Solutions						
Bruce Power[1]	48.3%	**537**	411	439	**5,783**	4,493
Other	Various	**2**	—	16	**30**	—
		1,054	898	1,019	**9,535**	8,441

1 Classified as a non-consolidated VIE. Refer to Note 32, Variable interest entities, for additional information.
2 Classified as a non-consolidated VIE in 2021. Refer to Note 32, Variable interest entities, for additional information.
3 In November 2021, TC Energy sold its remaining 15 per cent equity interest in Northern Courier. Refer to Note 30, Acquisitions and dispositions, for additional information.

Impairment of Equity Investment

On February 1, 2023, Coastal GasLink LP announced that the revised capital cost of the Coastal GasLink pipeline project is expected to be approximately $14.5 billion. The increase in the expected capital cost of the project caused TC Energy to re-evaluate its investment in Coastal GasLink LP, resulting in a pre-tax impairment charge of $3,048 million ($2,643 million after tax) recorded in fourth quarter 2022. Refer to Note 7, Coastal GasLink, for additional information.

Distributions and Contributions

Distributions received from equity investments and contributions made to equity investments for the years ended December 31, 2022, 2021 and 2020 were as follows:

year ended December 31 (millions of Canadian $)	2022	2021	2020
Distributions			
Sur de Texas debt repayments[1,2]	**2,404**	73	—
Distributions received from operating activities of equity investments	**1,025**	975	1,123
Other[1]	**228**	—	—
	3,657	1,048	1,123
Contributions			
Contributions to Coastal GasLink[1]	**1,414**	92	101
Sur de Texas debt financing[1,2]	**1,199**	—	—
Contributions made to other equity investments[1]	**820**	1,118	664
	3,433	1,210	765

1 Included in Investing activities in the Consolidated statement of cash flows.
2 Represents TC Energy's proportionate share of the Sur de Texas debt financing requirements and subsequent repayments. Refer to Note 12, Loans receivable from affiliates, for further information on 2022 refinancing activities with the Sur de Texas joint venture.

Summarized Financial Information of Equity Investments

year ended December 31 (millions of Canadian $)	2022	2021	2020
Income			
Revenues	**5,891**	5,447	5,838
Operating and other expenses	**(3,390)**	(3,293)	(3,341)
Net income	**2,147**	1,859	2,047
Net income attributable to TC Energy	**1,054**	898	1,019

at December 31 (millions of Canadian $)	2022	2021
Balance Sheet		
Current assets	**3,414**	3,498
Non-current assets	**37,713**	30,165
Current liabilities	**(2,856)**	(2,540)
Non-current liabilities	**(17,690)**	(16,400)

At December 31, 2022, the cumulative carrying value of the Company's equity investments was $299 million lower than the cumulative underlying equity in the net assets primarily due to the 2022 impairment of the equity investment in Coastal GasLink LP, partially offset by fair value adjustments at the time of acquisition or partial monetization as well as interest capitalized during construction. Refer to Note 7, Coastal GasLink, for additional information. At December 31, 2021, the cumulative carrying value of the Company's equity investments was $1,109 million higher than the cumulative underlying equity in the net assets primarily due to fair value adjustments at the time of acquisition or partial monetization as well as interest capitalized during construction.

12. LOANS RECEIVABLE FROM AFFILIATES

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

Sur de Texas

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 bore interest at a floating rate and was fully repaid upon maturity on March 15, 2022 in the amount of $1.2 billion.

The Company's Consolidated statement of income reflects the related interest income and foreign exchange impact on this loan receivable until its repayment on March 15, 2022, 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 $)	**2022**	**2021**	**2020**	**Affected line item in the Consolidated statement of income**
Interest income[1]	**19**	87	110	Interest income and other
Interest expense[2]	**(19)**	(87)	(110)	Income from equity investments
Foreign exchange losses[1]	**(28)**	(41)	(86)	Foreign exchange loss/(gain), net
Foreign exchange gains[1]	**28**	41	86	Income from equity investments

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

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

Coastal GasLink Pipeline Limited Partnership

TC Energy holds a 35 per cent equity interest in Coastal GasLink LP and has been contracted to develop and operate the Coastal GasLink pipeline.

Subordinated Demand Revolving Credit Facility

The Company has a subordinated demand revolving credit facility with Coastal GasLink LP to provide additional short-term liquidity and funding flexibility to the project. The facility bears interest at a floating market-based rate and had a capacity of $100 million with an outstanding balance of nil at December 31, 2022 (2021 – $1 million) reflected in Loans receivable from affiliates under Current assets on the Company's Consolidated balance sheet.

Subordinated Loan Agreement

In 2021, TC Energy entered into a subordinated loan agreement with Coastal GasLink LP. This loan agreement was amended on July 28, 2022. Refer to Note 7, Coastal GasLink, for additional information.

13. 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). The Impact Assessment Agency continues to assess designated projects 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 on capital as approved by the CER. 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 which includes an ROE of 10.1 per cent on 40 per cent deemed common equity. This settlement provides the NGTL System the opportunity to increase depreciation rates if tolls fall below specified levels and an incentive mechanism for certain operating costs where variances from projected amounts are shared between the NGTL System and its customers.

Canadian Mainline

The Canadian Mainline currently operates under the terms of the 2015-2030 Tolls Application approved in 2014 (the 2014 Decision). The terms in the 2015-2020 six-year settlement of the 2014 Decision, which ended December 31, 2020, included an ROE of 10.1 per cent on 40 per cent deemed common equity, 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 2014 Decision. The 2014 Decision also directed TC Energy to file an application to review tolls for the 2018-2020 period. In December 2018, a decision was received on the 2018-2020 Tolls Review 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.

In April 2020, the CER approved the six-year unanimous negotiated settlement (2021-2026 Mainline Settlement) effective January 1, 2021. Similar to the previous settlement, 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. 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 and the Company will commence amortization over the remaining settlement term when predetermined thresholds per the settlement agreement are met.

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, acquisition 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.

Columbia Gas

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

Additionally, Columbia Gas maintains a FERC-approved modernization program allowing for the cost recovery and return on additional investment up to US$1.2 billion over a four-year period through 2024 to modernize the Columbia Gas system, thereby improving system integrity and enhancing service reliability and flexibility.

ANR Pipeline

ANR Pipeline operated under rates established through a 2016 FERC-approved rate settlement until July 31, 2022. To meet terms of the 2016 settlement, on January 28, 2022, ANR Pipeline filed a Section 4 Rate Case with FERC requesting an increase to maximum transportation rates. On December 14, 2022 ANR Pipeline filed a Stipulation and Agreement of Settlement (ANR Settlement) with FERC. The ANR Settlement reflects the agreement of ANR Pipeline and its shippers and FERC staff to resolve all outstanding issues pertaining to the original rate case filing on January 28, 2022. The ANR Settlement was uncontested and is currently awaiting final FERC approval which is expected in early 2023.

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 which took effect on August 1, 2020. This settlement established a rate case and tariff filing moratorium, which expired on 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.

Great Lakes

Great Lakes operates under a settlement approved by FERC in February 2018 which does not include a moratorium; however, Great Lakes was required to file for new rates no later than March 31, 2022.

On March 18, 2022, Great Lakes filed a rate settlement (2022 Great Lakes Settlement) with FERC that satisfies the obligations from the 2017 settlement that Great Lakes file for rates to become effective no later than October 1, 2022. The 2022 Great Lakes Settlement, approved by FERC on April 26, 2022, maintains Great Lakes' existing maximum transportation rates through October 31, 2025. The 2022 Great Lakes Settlement contains a moratorium until October 31, 2025. Great Lakes will be required to file for new rates no later than April 30, 2025, with such new rates effective no later than November 1, 2025.

Tuscarora

Tuscarora operates under rates established as part of the FERC-approved rate settlement effective August 1, 2019. Under the terms of this settlement, Tuscarora is required to file for new rates to be effective no later than February 1, 2023. Tuscarora filed a general NGA Section 4 Rate Case with FERC on July 29, 2022, requesting an increase to its maximum rates effective February 1, 2023, subject to refund.

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 are in compliance with CRE economic regulations that provide for cost recovery, including a return of and on invested capital.

Regulatory Assets and Liabilities

at December 31 (millions of Canadian $)	2022	2021	Remaining Recovery/ Settlement Period (years)
Regulatory Assets			
Deferred income taxes[1]	**1,817**	1,509	n/a
Pensions and other post-retirement benefits[1,2]	**28**	203	n/a
Foreign exchange on long-term debt[1,3]	**19**	3	1-7
Operating and debt-service regulatory assets[4]	**2**	1	1
Other	**111**	104	n/a
	1,977	1,820	
Less: Current portion included in Other current assets (Note 8)	**67**	53	
	1,910	1,767	
Regulatory Liabilities			
Pipeline abandonment trust balances[5]	**2,014**	2,086	n/a
Deferred income taxes – U.S. Tax Reform[6]	**1,197**	1,141	n/a
Canadian Mainline bridging amortization account[7]	**429**	483	8
Cost of removal[8]	**337**	254	n/a
Canadian Mainline short-term adjustment and toll-stabilization accounts[7,9]	**284**	60	n/a
Canadian Mainline long-term adjustment account[7,10]	**149**	186	4
Deferred income taxes[1]	**181**	139	n/a
Operating and debt-service regulatory liabilities[4]	**50**	32	1
ANR post-employment and retirement benefits other than pension[11]	**43**	40	n/a
Pensions and other post-retirement benefits[2]	**10**	13	n/a
Other	**99**	66	n/a
	4,793	4,500	
Less: Current portion included in Accounts payable and other (Note 17)	**273**	200	
	4,520	4,300	

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 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.

3 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.

4 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.

5 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.

6 The U.S. corporate income tax rate was reduced from 35 per cent to 21 per cent in 2017 as a result of H.R.1, the Tax Cuts and Jobs Act (U.S. Tax Reform). This U.S. regulated operations balance, where applicable, represents established regulatory liabilities driven by 2018 FERC prescribed changes related to U.S. Tax Reform being amortized over varying terms that approximate the expected reversal of the underlying deferred tax liabilities that gave rise to the regulatory liabilities.

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

8 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.

9 Under the terms of the 2021-2026 Mainline Settlement, the STAA account will commence amortization when predetermined thresholds are met, over the term outlined per the settlement agreement.

10 Under the terms of the 2021-2026 Mainline Settlement, $223 million is amortized over the six-year settlement term.

11 This balance represents the amount ANR estimates it 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 $43 million (US$32 million) balance at December 31, 2022 is subject to resolution through future regulatory proceedings and, accordingly, a settlement period cannot be determined at this time.

14. GOODWILL

The Company's Goodwill balance on the Consolidated balance sheet is comprised of the following amounts:

at December 31	2022		2021	
(millions)	Canadian dollars	US dollars	Canadian dollars	US dollars
Columbia Pipeline Group, Inc.	**9,948**	**7,351**	9,303	7,351
ANR	**2,634**	**1,946**	2,464	1,946
Great Lakes	**165**	**122**	725	573
North Baja	**65**	**48**	61	48
Tuscarora	**31**	**23**	29	23
	12,843	**9,490**	12,582	9,941

Changes in Goodwill were as follows:

(millions of Canadian $)	U.S. Natural Gas Pipelines
Balance at January 1, 2021	12,679
Foreign exchange rate changes	(97)
Balance at December 31, 2021[1]	12,582
Great Lakes impairment charge	**(571)**
Foreign exchange rate changes	**832**
Balance at December 31, 2022[1]	**12,843**

1 Represents gross amount of goodwill as at December 31, 2022 of $14,578 million (2021 – $13,746 million), net of accumulated impairment of $1,735 million (2021 – $1,164 million).

As part of the annual goodwill impairment assessment at December 31, 2022, the Company evaluated qualitative factors impacting the fair value of the underlying reporting units for all reporting units other than the ANR reporting unit. It was determined that it was more likely than not that the fair value of these reporting units exceeded their carrying amounts, including goodwill.

ANR

The Company elected to proceed directly to a quantitative annual impairment test at December 31, 2022 for the $2,634 million (US$1,946 million) of goodwill related to the ANR reporting unit following the passage of time from the previous test at December 31, 2016, and subsequent to the ANR settlement-in-principle in 2022. It was determined that the fair value of ANR exceeded its carrying value, including goodwill at December 31, 2022.

Great Lakes

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

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

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

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

The estimated fair value measurements used in the Company's goodwill impairment analysis is classified as Level III. In the determination of the fair value utilized in the quantitative goodwill impairment test for each reporting unit, the Company used its projections of future cash flows and applied a risk-adjusted discount rate which involved significant estimates and judgments.

Asset Divestiture Program

TC Energy has announced an asset divestiture program that may involve the divestiture of reporting units, or portions thereof. To the extent that a sale transaction indicates a value lower than previously estimated, goodwill could be impaired. These divestitures could include assets that have associated goodwill. In the event of a partial sale of such assets, the anticipated proceeds will be considered in management’s assessment of fair value of the retained interest and any associated goodwill.

15. OTHER LONG-TERM ASSETS

at December 31 (millions of Canadian $)	**2022**	**2021**
Deferred income tax assets (Note 19)	**1,070**	509
Employee post-retirement benefits (Note 27)	**563**	312
Long-term contract assets (Note 5)	**355**	249
Keystone environmental provision recovery (Note 17)	**240**	—
Capital projects in development	**99**	42
Fair value of derivative contracts (Note 28)	**91**	48
Keystone XL contractual recoveries (Note 6)	**44**	50
Other	**323**	193
	2,785	1,403

16. NOTES PAYABLE

(millions of Canadian $, unless otherwise noted)	2022 Outstanding at December 31	2022 Weighted Average Interest Rate per Annum at December 31	2021 Outstanding at December 31	2021 Weighted Average Interest Rate per Annum at December 31
Canada[1]	**5,971**	**4.9%**	4,953	0.4%
U.S. (2022 – nil; 2021 – US$54)	**—**	**—**	68	0.3%
Mexico (2022 – US$215; 2021 – US$115)[2]	**291**	**6.0%**	145	1.7%
	6,262		5,166	

1 At December 31, 2022, Notes payable consisted of Canadian dollar-denominated notes of $2,810 million (2021 – $1,989 million) and U.S. dollar-denominated notes of US$2,336 million (2021 – US$2,341 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.

On November 22, 2022, TransCanada PipeLines Limited (TCPL) entered into a 364-day $1.5 billion senior unsecured term loan bearing interest at a floating rate. At December 31, 2022 and 2021, Notes payable reflects short-term borrowings in Canada by TCPL, in the U.S. by TransCanada PipeLine USA Ltd. (TCPL USA) and in Mexico by a wholly-owned Mexican subsidiary.

At December 31, 2022, total committed revolving and demand credit facilities were $12.9 billion (2021 – $12.4 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) Borrowers	Description	Matures	2022 Total Facilities	2022 Unused Capacity[1]	2021 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 2027	**3.0**	**1.7**	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 2023	**US 3.0**	**US 0.6**	US 4.5
TCPL / TCPL USA / Columbia / TransCanada American Investments Ltd.	Supports TCPL's and TCPL USA's U.S. dollar commercial paper programs and for general and corporate purposes of the borrowers, guaranteed by TCPL	December 2025	**US 2.5**	**US 2.5**	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]	**1.0**	2.1 [3]
Mexico subsidiary	For Mexico general corporate purposes, guaranteed by TCPL	Demand	**MXN 5.0** [3]	**MXN 0.8**	MXN 5.0 [3]

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

2 Provisions of various trust indentures and 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 trust indentures and credit arrangements also require the Company to comply with various affirmative and negative covenants and maintain certain financial ratios. At December 31, 2022, the Company was in compliance with all financial covenants.

3 Or the U.S. dollar equivalent.

For the year ended December 31, 2022, the cost to maintain the above facilities was $14 million (2021 – $17 million; 2020 – $21 million).

17. ACCOUNTS PAYABLE AND OTHER

at December 31 (millions of Canadian $)	2022	2021
Trade payables	**4,330**	4,183
Fair value of derivative contracts (Note 28)	**871**	221
Keystone environmental provision	**650**	—
Coastal GasLink contractual contribution (Notes 7, 11 and 32)	**537**	—
Regulatory liabilities (Note 13)	**273**	200
Contract liabilities (Note 5)	**62**	90
Class C Interests (Note 6)	**37**	75
Other	**389**	330
	7,149	5,099

Keystone Environmental Provision

In December 2022, a pipeline rupture occurred in Washington County, Kansas on the Cushing Extension section of the Keystone Pipeline System. At December 31, 2022, the Company accrued an environmental remediation liability of $650 million, before expected insurance recoveries, and not including potential fines and penalties which are currently indeterminable. This amount represents the Company's estimate of costs relating to emergency response, environmental remediation and cleanup activities required to fully remediate the site and has been recorded on an undiscounted basis. The accrual is based on certain assumptions such as the scope of remediation efforts that are subject to revision in future periods which could result in future modifications of this accrual. Therefore, it is reasonably possible that the Company will incur additional costs beyond the amounts accrued. TC Energy has accrued the minimum estimated cost of environmental remediation; however, the Company is currently unable to estimate a maximum range of possible costs.

TC Energy has appropriate insurance policies in place and it is probable that the majority of estimated environmental remediation costs will be eligible for recovery under the Company's existing insurance coverage. The Company has recorded an asset of $410 million in Other current assets and $240 million in Other long-term assets, representing the expected recovery of the estimated environmental remediation costs. Estimated insured amounts expected to be recovered from insurers are presented in the same income statement line as the environmental remediation costs. To the extent costs beyond the amounts accrued are incurred, they will be evaluated under the Company's existing insurance policies. The Company expects remediation activities to be substantially completed within a year.

18. OTHER LONG-TERM LIABILITIES

at December 31 (millions of Canadian $)	2022	2021
Operating lease obligations (Note 10)	**379**	380
Fair value of derivative contracts (Note 28)	**151**	47
Employee post-retirement benefits (Note 27)	**111**	174
Asset retirement obligations	**79**	61
Long-term contract liabilities (Note 5)	**32**	184
Other	**265**	213
	1,017	1,059

19. INCOME TAXES

Geographic Components of Income before Income Taxes

year ended December 31 (millions of Canadian $)	2022	2021	2020
Canada	**(2,154)**	(292)	691
Foreign	**3,528**	2,458	4,416
Income before Income Taxes	**1,374**	2,166	5,107

Provision for Income Taxes

year ended December 31 (millions of Canadian $)	2022	2021	2020
Current			
Canada	**43**	29	(54)
Foreign	**372**	276	306
	415	305	252
Deferred			
Canada	**(467)**	(327)	(224)
Foreign	**641**	142	166
	174	(185)	(58)
Income Tax Expense	**589**	120	194

Reconciliation of Income Tax Expense

year ended December 31 (millions of Canadian $)	2022	2021	2020
Income before income taxes	**1,374**	2,166	5,107
Federal and provincial statutory tax rate	**23.0%**	23.0%	24.0%
Expected income tax expense	**316**	498	1,226
Foreign income tax rate differentials	**(271)**	(230)	(258)
Income tax differential related to regulated operations	**(174)**	(139)	(228)
Income from non-controlling interests and equity investments	**(54)**	(70)	(141)
Valuation allowance/(releases)	**199**	(8)	(400)
Non-taxable capital (gains) and losses	**173**	—	(62)
Settlement of Mexico prior years' income tax assessments	**196**	—	—
U.S. minimum tax	**96**	—	—
Non-deductible goodwill impairment	**91**	—	—
Impact of Mexico inflationary adjustments	**24**	32	7
Other	**(7)**	37	50
Income Tax Expense	**589**	120	194

Deferred Income Tax Assets and Liabilities

at December 31 (millions of Canadian $)	2022	2021
Deferred Income Tax Assets		
Tax loss and credit carryforwards	**1,519**	1,163
Regulatory and other deferred amounts	**571**	537
Unrealized foreign exchange losses on long-term debt	**333**	130
Other	**193**	46
	2,616	1,876
Less: Valuation allowance	**640**	229
	1,976	1,647
Deferred Income Tax Liabilities		
Difference in accounting and tax bases of plant, property and equipment	**6,686**	5,616
Equity investments	**1,152**	1,219
Taxes on future revenue requirement	**397**	333
Financial instruments	**126**	—
Other	**193**	112
	8,554	7,280
Net Deferred Income Tax Liabilities	**6,578**	5,633

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

at December 31 (millions of Canadian $)	2022	2021
Deferred Income Tax Assets		
Other long-term assets (Note 15)	**1,070**	509
Deferred Income Tax Liabilities		
Deferred income tax liabilities	**7,648**	6,142
Net Deferred Income Tax Liabilities	**6,578**	5,633

At December 31, 2022, the Company has recognized the benefit of non-capital loss carryforwards of $5,429 million (2021 – $4,067 million) for federal and provincial purposes in Canada, which expire from 2030 to 2042. The Company has not yet recognized the benefit of capital loss carryforwards of $251 million (2021 – $21 million) for federal and provincial purposes in Canada which have no expiry date. The Company also has Ontario corporate minimum tax (CMT) credits of $126 million (2021 – $113 million), which expire from 2026 to 2042. As of December 31, 2022, the Company has not recognized the benefit of CMT credits of $22 million (2021 – nil).

At December 31, 2022, the Company has fully utilized the benefit of net operating loss carryforwards (2021 – US$446 million) for federal purposes in the U.S.

At December 31, 2022, the Company has recognized the benefit of net operating loss carryforwards of US$69 million (2021 – US$10 million) in Mexico, which expire from 2024 to 2032.

TC Energy recorded an income tax valuation allowance of $640 million and $229 million against the deferred income tax asset balances at December 31, 2022 and 2021, respectively. The increase in the valuation allowance is primarily a result of the foreign exchange movement on unrecognized capital losses and the unrealized capital losses on the Coastal GasLink equity investment. At December 31, 2022, the Company recorded $173 million in valuation allowance as a result of the Coastal GasLink equity investment impairment that resulted in a portion of the impairment having unrealized non-taxable capital losses. These losses have not been recognized as of December 31, 2022. 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, 2022, 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.

At December 31, 2020, the Company recorded $400 million in valuation allowance releases 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 30, Acquisitions and dispositions, for additional information on the sale of the Ontario natural gas-fired power plants and Coastal GasLink LP equity sale.

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, 2022 by approximately $1,216 million (2021 – $896 million) if there had been a provision for these taxes.

Income Tax Payments

Income tax payments of $394 million, net of refunds, were made in 2022 (2021 – payments, net of refunds, of $371 million; 2020 – payments, net of refunds, of $252 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 $)	**2022**	**2021**	**2020**
Unrecognized tax benefit at beginning of year	**80**	52	29
Gross increases – tax positions in prior years	**6**	5	26
Gross decreases – tax positions in prior years	**—**	(1)	(2)
Gross increases – tax positions in current year	**7**	26	1
Lapse of statutes of limitations	**(2)**	(2)	(2)
Unrecognized Tax Benefit at End of Year	**91**	80	52

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, 2022 reflects $6 million interest expense (2021 – $1 million; 2020 – $4 million). At December 31, 2022, the Company had accrued $18 million in interest expense (2021 – $12 million; 2020 – $11 million). The Company incurred no penalties associated with income tax uncertainties related to Income tax expense for the years ended December 31, 2022, 2021 and 2020 and no penalties were accrued as at December 31, 2022, 2021 and 2020.

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 2014. Substantially all material U.S. federal, state and local income tax matters have been concluded for years through 2015. Substantially all material Mexico income tax matters have been concluded for years through 2014, except as further described below.

Mexico Tax Audit

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

During 2022, TC Energy settled with the SAT on all of the above matters for the tax years 2013 through 2021 and recorded $196 million (US$153 million) of income tax expense, inclusive of withholding taxes, interest, penalties and other financial charges for the year ended December 31, 2022.

20. LONG-TERM DEBT

Outstanding amounts		2022		2021	
(millions of Canadian $, unless otherwise noted)	Maturity Dates	Outstanding at December 31	Interest Rate[1]	Outstanding at December 31	Interest Rate[1]
TRANSCANADA PIPELINES LIMITED					
Medium Term Notes					
Canadian	2023 to 2052	**13,966**	**4.5%**	12,491	4.2%
Senior Unsecured Notes					
U.S. (2022 – US$15,542; 2021 – US$16,542)	2023 to 2049	**21,032**	**4.9%**	20,936	4.8%
		34,998		33,427	
NOVA GAS TRANSMISSION LTD.					
Debentures and Notes					
Canadian	2024	**100**	**9.9%**	100	9.9%
U.S. (2022 and 2021 – US$200)	2023	**271**	**7.9%**	254	7.9%
Medium Term Notes					
Canadian	2025 to 2030	**504**	**7.4%**	504	7.4%
U.S. (2022 and 2021 – US$33)	2026	**44**	**7.5%**	41	7.5%
		919		899	
COLUMBIA PIPELINE GROUP, INC.					
Senior Unsecured Notes[2]					
U.S. (2022 and 2021 – US$1,500)	2025 to 2045	**2,030**	**4.9%**	1,898	4.9%
ANR PIPELINE COMPANY					
Senior Unsecured Notes					
U.S. (2022 – US$1,172; 2021 – US$372)	2024 to 2037	**1,587**	**4.1%**	472	5.3%
TC PIPELINES, LP					
Senior Unsecured Notes					
U.S. (2022 and 2021 – US$850)	2025 to 2027	**1,150**	**4.2%**	1,076	4.2%
GAS TRANSMISSION NORTHWEST LLC					
Senior Unsecured Notes					
U.S. (2022 and 2021 – US$325)	2030 to 2035	**440**	**4.3%**	411	4.3%

Outstanding amounts (millions of Canadian $, unless otherwise noted)	Maturity Dates	2022 Outstanding at December 31	2022 Interest Rate[1]	2021 Outstanding at December 31	2021 Interest Rate[1]
PORTLAND NATURAL GAS TRANSMISSION SYSTEM					
Senior Unsecured Notes					
U.S. (2022 and 2021 – US$250)	2030 to 2031	**338**	**2.8%**	316	2.8%
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP					
Senior Unsecured Notes					
U.S. (2022 – US$146; 2021 – US$167)	2028 to 2030	**198**	**7.6%**	211	7.6%
TUSCARORA GAS TRANSMISSION COMPANY					
Unsecured Term Loan					
U.S. (2022 – US$34; 2021 – US$36)	2024	**46**	**6.5%**	46	1.3%
		41,706		38,756	
Current portion of long-term debt		**(1,898)**		(1,320)	
Unamortized debt discount and issue costs		**(239)**		(243)	
Fair value adjustments[3]		**76**		148	
		39,645		37,341	

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 $140 million (2021 – $148 million) related to the acquisition of Columbia Pipeline Group, Inc. These adjustments also include a decrease of $64 million (2021 – nil) related to hedged interest rate risk. Refer to Note 28, Risk management and financial instruments for additional information.

Principal Repayments

At December 31, 2022, principal repayments for the next five years on the Company's long-term debt are approximately as follows:

(millions of Canadian $)	2023	2024	2025	2026	2027
Principal repayments on long-term debt	1,898	2,782	2,827	2,278	3,113

Long-Term Debt Issued

The Company issued long-term debt over the three years ended December 31, 2022 as follows:

(millions of Canadian $, unless otherwise noted)					
Company	Issue Date	Type	Maturity Date	Amount	Interest Rate
TRANSCANADA PIPELINES LIMITED					
	May 2022	Medium Term Notes	May 2032	800	5.33%
	May 2022	Medium Term Notes	May 2026	400	4.35%
	May 2022	Medium Term Notes	May 2052	300	5.92%
	October 2021	Senior Unsecured Notes	October 2024	US 1,250	1.00%
	October 2021	Senior Unsecured Notes	October 2031	US 1,000	2.50%
	June 2021	Medium Term Notes	June 2024	750	Floating
	June 2021	Medium Term Notes	June 2031	500	2.97%
	June 2021	Medium Term Notes	September 2047	250	4.33% [1]
	April 2020	Senior Unsecured Notes	April 2030	US 1,250	4.10%
	April 2020	Medium Term Notes	April 2027	2,000	3.80%
ANR PIPELINE COMPANY					
	May 2022	Senior Unsecured Notes	May 2032	US 300	3.43%
	May 2022	Senior Unsecured Notes	May 2034	US 200	3.58%
	May 2022	Senior Unsecured Notes	May 2037	US 200	3.73%
	May 2022	Senior Unsecured Notes	May 2029	US 100	3.26%
PORTLAND NATURAL GAS TRANSMISSION SYSTEM					
	October 2021	Senior Unsecured Notes	October 2031	US 125	2.68%
	October 2020	Senior Unsecured Notes	October 2030	US 125	2.84%
TUSCARORA GAS TRANSMISSION COMPANY					
	August 2021	Unsecured Term Loan	August 2024	US 13	Floating
KEYSTONE XL SUBSIDIARIES [2]					
	Various	Project-Level Credit Facility	June 2021	US 849	Floating
COLUMBIA PIPELINE GROUP, INC. [3]					
	January 2021	Unsecured Term Loan	June 2022	US 4,040	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

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 4.186 per cent.

2 In January 2021, the Company established a US$4.1 billion project-level credit facility to support the construction of the Keystone XL pipeline, which was fully guaranteed by the Government of Alberta and non-recourse to TC Energy. The availability of this credit facility was subsequently reduced to US$1.6 billion and all amounts outstanding were fully repaid by the Government of Alberta in June 2021. Refer to Note 6, Keystone XL, for additional information.

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

4 In April 2020, Coastal GasLink LP entered into secured long-term project financing credit facilities. In May 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 30, 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, 2022 as follows:

(millions of Canadian $, unless otherwise noted) Company	Retirement/ Repayment Date	Type	Amount	Interest Rate
TRANSCANADA PIPELINES LIMITED				
	December 2022	Medium Term Notes	25	9.95%
	August 2022	Senior Unsecured Notes	US 1,000	2.50%
	November 2021	Medium Term Notes	500	3.65%
	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[1]	Senior Unsecured Notes	US 750	4.60%
COLUMBIA PIPELINE GROUP, INC.				
	December 2021	Unsecured Term Loan[2]	US 4,040	Floating
	June 2020	Senior Unsecured Notes	US 750	3.30%
NORTH BAJA PIPELINE, LLC				
	December 2021	Unsecured Term Loan	US 50	Floating
TC PIPELINES, LP				
	November 2021	Unsecured Term Loan	US 450	Floating
	March 2021	Senior Unsecured Notes	US 350	4.65%
ANR PIPELINE COMPANY				
	November 2021	Senior Unsecured Notes	US 300	9.625%
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP				
	November 2021	Senior Unsecured Notes	US 10	9.09%
PORTLAND NATURAL GAS TRANSMISSION SYSTEM				
	October 2021	Unsecured Loan Facility	US 93	Floating
	October 2020	Unsecured Loan Facility	US 99	Floating
KEYSTONE XL SUBSIDIARIES[3]				
	June 2021	Project-Level Credit Facility	US 849	Floating
GAS TRANSMISSION NORTHWEST LLC				
	June 2020	Senior Unsecured Notes	US 100	5.29%

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.

2 In December 2020, Columbia entered into a US$4.2 billion Unsecured Term Loan agreement. In January 2021, US$4.0 billion was drawn on the Unsecured Term Loan and the total availability under the loan agreement was reduced accordingly. The loan was fully repaid and retired in December 2021. Related unamortized debt issue costs of $5 million were included in Interest expense in the Consolidated statement of income for the year ended December 31, 2021.

3 In June 2021, in accordance with the terms of the guarantee, the Government of Alberta repaid the US$849 million outstanding balance under the Keystone XL project-level credit facility bearing interest at a floating rate, subsequent to which it was terminated, resulting in no cash impact to TC Energy. Refer to Note 6, Keystone XL, for additional information.

In March 2021, the Company's subsidiary, TC PipeLines, LP, terminated its US$500 million Unsecured Loan Facility bearing interest at a floating rate on which no amount was outstanding.

Interest Expense

year ended December 31 (millions of Canadian $)	2022	2021	2020
Interest on long-term debt	**1,883**	1,841	1,963
Interest on junior subordinated notes	**543**	453	470
Interest on short-term debt	**153**	10	46
Capitalized interest	**(27)**	(22)	(294)
Amortization and other financial charges[1]	**36**	78	43
	2,588	2,360	2,228

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 $2,478 million in 2022 (2021 – $2,299 million; 2020 – $2,203 million) on long-term debt, junior subordinated notes and short-term debt, net of interest capitalized.

21. JUNIOR SUBORDINATED NOTES

Outstanding loan amount (millions of Canadian $, unless otherwise noted)	Maturity Date	2022 Outstanding at December 31	2022 Effective Interest Rate[1]	2021 Outstanding at December 31	2021 Effective Interest Rate[1]
TRANSCANADA PIPELINES LIMITED					
US$1,000 notes issued 2007 at 6.35%[2]	2067	**1,353**	**6.2%**	1,265	4.0%
US$750 notes issued 2015 at 5.875%[3,4]	2075	**1,015**	**7.4%**	949	5.0%
US$1,200 notes issued 2016 at 6.125%[3,4]	2076	**1,624**	**8.0%**	1,519	5.8%
US$1,500 notes issued 2017 at 5.55%[3,4]	2077	**2,030**	**7.1%**	1,899	4.7%
$1,500 notes issued 2017 at 4.90%[3,4]	2077	**1,500**	**6.8%**	1,500	4.5%
US$1,100 notes issued 2019 at 5.75%[3,4]	2079	**1,488**	**7.6%**	1,392	5.4%
$500 notes issued 2021 at 4.45%[3,5]	2081	**500**	**5.7%**	500	4.0%
US$800 notes issued 2022 at 5.85%[3,5]	2082	**1,083**	**7.2%**	—	—
		10,593		9,024	
Unamortized debt discount and issue costs		**(98)**		(85)	
		10,495		8,939	

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 (the Trust), a financing trust subsidiary wholly-owned by TCPL. While the obligations of the 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.
5 The coupon rate is initially a fixed interest rate for the first 10 years and resets every five years thereafter.

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

In March 2022, TransCanada Trust (the Trust) issued US$800 million of Trust Notes – Series 2022-A to investors with a fixed interest rate of 5.60 per cent per annum for the first 10 years and resetting on the 10th anniversary and every five years thereafter. All of the proceeds of the issuance by the Trust were loaned to TCPL for US$800 million of junior subordinated notes of TCPL at an initial fixed rate of 5.85 per cent per annum, including a 0.25 per cent administration charge. The rate on the junior subordinated notes of TCPL will reset every five years commencing March 2032 until March 2052 to the then Five-Year Treasury Rate, as defined in the document governing the subordinated notes, plus 4.236 per cent per annum; from March 2052 until March 2082, the interest rate will reset every five years to the then Five-Year Treasury Rate plus 4.986 per cent per annum. The junior subordinated notes are callable at TCPL's option at any time from December 7, 2031 to March 7, 2032 and on each interest payment and reset date thereafter at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption.

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

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

22. FOREIGN EXCHANGE LOSS/(GAIN), NET

year ended December 31 (millions of Canadian $)	2022	2021	2020
Derivative instruments held for trading (Note 28)	**151**	(37)	(93)
Other	**34**	27	65
	185	(10)	(28)

23. NON-CONTROLLING INTERESTS

TC PipeLines, LP

Acquisition

In December 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. Upon close of the transaction on March 3, 2021, TC PipeLines, LP common unitholders received 0.70 TC Energy common shares for each issued and outstanding publicly-held TC PipeLines, LP common unit representing, in aggregate, 37,955,093 TC Energy common shares. As a result, TC PipeLines, LP became an indirect, wholly-owned subsidiary of TC Energy.

As the Company controlled TC PipeLines, LP, this acquisition was accounted for as an equity transaction with the following impact reflected on the Consolidated balance sheet:

(millions of Canadian $)	March 3, 2021
Common shares	**2,063**
Additional paid-in-capital	**(398)**
Accumulated other comprehensive loss	**353**
Non-controlling interests	**(1,563)**
Deferred income tax liabilities	**(443)**
Other	**(12)**

Non-controlling interests

Prior to the March 3, 2021 acquisition described above, the non-controlling interests in TC PipeLines, LP were 74.5 per cent (2020 – 74.5 per cent). Subsequent to this acquisition, the remaining non-controlling interest on the Consolidated balance sheet is related to the Company's 61.7 per cent investment in Portland Natural Gas Transmission System (PNGTS), which is held by TC PipeLines, LP.

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

year ended December 31 (millions of Canadian $)	2022	2021	2020
Non-controlling interest in TC PipeLines, LP	**—**	60	284
Non-controlling interest in PNGTS	**37**	30	23
Redeemable non-controlling interest (Note 6)	**—**	1	(10)
	37	91	297

24. COMMON SHARES

	Number of Shares (thousands)	Amount (millions of Canadian $)
Outstanding at January 1, 2020	938,400	24,387
Exercise of options	1,664	101
Outstanding at December 31, 2020	940,064	24,488
Acquisition of TC PipeLines, LP, net of transaction costs (Note 23)	37,955	2,063
Exercise of options	2,797	165
Outstanding at December 31, 2021	980,816	26,716
Issued under public offering[1]	**28,400**	**1,754**
Dividend reinvestment and share purchase plan	**5,916**	**342**
Exercise of options	**2,830**	**183**
Outstanding at December 31, 2022	**1,017,962**	**28,995**

1 Net of underwriting commissions and deferred income taxes.

Common Shares Issued and Outstanding

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

Common Shares Issued Under Public Offering

On August 10, 2022, TC Energy issued 28,400,000 common shares at a price of $63.50 each for total gross proceeds of approximately $1.8 billion.

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. Commencing with the dividends declared on July 27, 2022, the Company reinstated the issuance of common shares from treasury at a two per cent discount. For dividends declared between January 1, 2020 and July 27, 2022, common shares purchased with reinvested cash dividends under the DRP were acquired on the open market at 100 per cent of the weighted average purchase price.

Acquisition of TC PipeLines, LP

On March 3, 2021, TC Energy issued 37,955,093 common shares to acquire all the outstanding publicly-held common units of TC PipeLines, LP. Refer to Note 23, Non-controlling interests, for additional information.

TC Energy Corporation At-the-Market Equity Issuance Program

In December 2020, the Company established an At-the-Market (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. The ATM program was effective for a 25-month period to assist in managing the Company's capital structure. Under this program, the Company had the ability to issue up to $1.0 billion in common shares or the U.S. dollar equivalent. In January 2023, the ATM program expired with no common shares issued thereunder.

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, subsequent to July 27, 2022, common shares issuable from treasury under the DRP.

Weighted Average Common Shares Outstanding (millions)	**2022**	**2021**	**2020**
Basic	**995**	973	940
Diluted	**996**	974	940

Stock Options

	Number of Options (thousands)	**Weighted Average Exercise Prices**	**Weighted Average Remaining Contractual Life** (years)
Options outstanding at January 1, 2022	**7,769**	**$61.29**	
Options granted	**1,396**	**$66.49**	
Options exercised	**(2,830)**	**$58.09**	
Options forfeited/expired	**(226)**	**$63.96**	
Options Outstanding at December 31, 2022	**6,109**	**$63.86**	**4.4**
Options Exercisable at December 31, 2022	**3,175**	**$63.13**	**3.4**

At December 31, 2022, an additional 3,656,518 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 and applied the following weighted average assumptions:

year ended December 31	**2022**	**2021**	**2020**
Weighted average fair value	**$8.24**	$7.39	$7.73
Expected life (years)[1]	**5.4**	5.4	5.7
Interest rate	**1.6%**	0.5%	1.5%
Volatility[2]	**22%**	25%	17%
Dividend yield	**5.5%**	6.0%	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 $10 million in 2022 (2021 – $12 million; 2020 – $12 million). At December 31, 2022, unrecognized compensation costs related to non-vested stock options were $12 million. The cost is expected to be fully recognized over a weighted average period of 1.9 years.

The following table summarizes additional stock option information:

year ended December 31 (millions of Canadian $, unless otherwise noted)	**2022**	**2021**	**2020**
Total intrinsic value of options exercised	**33**	28	31
Total fair value of options that have vested	**89**	110	101
Total options vested	**1.6 million**	1.9 million	2.0 million

As at December 31, 2022, the aggregate intrinsic values of the total options exercisable and the total options outstanding were each less than $1 million.

Shareholder Rights Plan

TC Energy's Shareholder Rights Plan is designed to provide the Board of Directors (Board) 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.

25. PREFERRED SHARES

at December 31, 2022	**Number of Shares Outstanding** (thousands)	**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] **2022** (millions of Canadian $)	**2021**	**2020**
Cumulative First Preferred Shares									
Series 1	14,577	3.479%	$0.86975	$25.00	December 31, 2024	Series 2	**360**	360	360
Series 2	7,423	Floating [4]	Floating	$25.00	December 31, 2024	Series 1	**179**	179	179
Series 3	9,997	1.694%	$0.4235	$25.00	June 30, 2025	Series 4	**246**	246	246
Series 4	4,003	Floating [4]	Floating	$25.00	June 30, 2025	Series 3	**97**	97	97
Series 5	12,071	1.949% [5]	$0.48725	$25.00	January 30, 2026	Series 6	**294**	294	310
Series 6	1,929	Floating [4]	Floating	$25.00	January 30, 2026	Series 5	**48**	48	32
Series 7	24,000	3.903%	$0.97575	$25.00	April 30, 2024	Series 8	**589**	589	589
Series 9	18,000	3.762%	$0.9405	$25.00	October 30, 2024	Series 10	**442**	442	442
Series 11	10,000	3.351%	$0.83775	$25.00	November 28, 2025	Series 12	**244**	244	244
Series 13	—	—	—	—	—	—	**—**	—	493
Series 15	—	—	—	—	—	—	**—**	988	988
							2,499	3,487	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), or 2.96 per cent (Series 12). 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), or 2.96 per cent (Series 11).

3 Net of underwriting commissions and deferred income taxes.

4 The floating quarterly dividend rate for the Series 2 preferred shares is 6.053 per cent for the period starting December 30, 2022 to, but excluding, March 31, 2023. The floating quarterly dividend rate for the Series 4 preferred shares is 5.413 per cent for the period starting December 30, 2022 to, but excluding, March 31, 2023. The floating quarterly dividend rate for the Series 6 preferred shares is 5.192 per cent for the period starting October 30, 2022 to, but excluding, January 30, 2023. These rates will reset each quarter going forward.

5 The fixed rate dividend for Series 5 preferred shares decreased from 2.263 per cent to 1.949 per cent on January 30, 2021 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 May 31, 2022, TC Energy redeemed all 40,000,000 issued and outstanding Series 15 preferred shares at a redemption price of $25.00 per share and paid the final quarterly dividend of $0.30625 per Series 15 preferred share, for the period up to but excluding May 31, 2022. The Company used the proceeds from the March 2022 issuance of US$800 million of Junior Subordinated Notes through the Trust to finance this preferred share redemption.

In May 2021, TC Energy redeemed all 20,000,000 issued and outstanding Series 13 preferred shares at a redemption price of $25.00 per share and paid the final quarterly dividend of $0.34375 per Series 13 preferred share for the period up to but excluding May 31, 2021. The Company used the proceeds from the March 2021 issuance of $500 million of Junior Subordinated Notes through the Trust to finance this preferred share redemption.

In February 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.

In June 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.

26. OTHER COMPREHENSIVE INCOME/(LOSS) AND ACCUMULATED OTHER COMPREHENSIVE INCOME/(LOSS)

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

year ended December 31, 2022 (millions of Canadian $)	Before Tax Amount	Income Tax Recovery/ (Expense)	Net of Tax Amount
Foreign currency translation gains and losses on net investment in foreign operations	**1,410**	**84**	**1,494**
Change in fair value of net investment hedges	**(48)**	**12**	**(36)**
Change in fair value of cash flow hedges	**(58)**	**19**	**(39)**
Reclassification to net income of gains and losses on cash flow hedges	**63**	**(21)**	**42**
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	**81**	**(18)**	**63**
Reclassification to net income of actuarial gains and losses on pension and other post-retirement benefit plans	**9**	**(3)**	**6**
Other comprehensive income on equity investments	**1,156**	**(289)**	**867**
Other Comprehensive Income	**2,613**	**(216)**	**2,397**

year ended December 31, 2021 (millions of Canadian $)	Before Tax Amount	Income Tax Recovery/ (Expense)	Net of Tax Amount
Foreign currency translation gains and losses on net investment in foreign operations	(100)	(8)	(108)
Change in fair value of net investment hedges	(3)	1	(2)
Change in fair value of cash flow hedges	(13)	3	(10)
Reclassification to net income of gains and losses on cash flow hedges	68	(13)	55
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	208	(50)	158
Reclassification to net income of actuarial gains and losses on pension and other post-retirement benefit plans	20	(6)	14
Other comprehensive income on equity investments	714	(179)	535
Other Comprehensive Income	894	(252)	642

year ended December 31, 2020 (millions of Canadian $)	Before Tax Amount	Income Tax Recovery/ (Expense)	Net of Tax Amount
Foreign currency translation gains and 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)

The changes in AOCI by component were as follows:

(millions of Canadian $)	Currency Translation Adjustments	Cash Flow Hedges	Pension and Other Post-Retirement Benefit Plan Adjustments	Equity Investments	Total[1]
AOCI balance at January 1, 2020	(730)	(58)	(314)	(457)	(1,559)
Other comprehensive (loss)/income before reclassifications[2]	(543)	(567)	12	(292)	(1,390)
Amounts reclassified from AOCI	—	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)
Other comprehensive (loss)/income before reclassifications[2]	(98)	(11)	158	506	555
Amounts reclassified from AOCI	—	55	14	28	97
Net current period other comprehensive (loss)/income	(98)	44	172	534	652
Acquisition of TC PipeLines, LP[3]	362	(13)	—	4	353
AOCI balance at December 31, 2021	(1,009)	(112)	(113)	(200)	(1,434)
Other comprehensive income/(loss) before reclassifications[2]	**1,450**	**(39)**	**63**	**870**	**2,344**
Amounts reclassified from AOCI[4]	**—**	**42**	**6**	**(3)**	**45**
Net current period other comprehensive income	**1,450**	**3**	**69**	**867**	**2,389**
AOCI balance at December 31, 2022	**441**	**(109)**	**(44)**	**667**	**955**

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

2 Other comprehensive income/(loss) before reclassifications on currency translation adjustments, cash flow hedges and equity investments are net of non-controlling interest gains of $8 million (2021 – losses of $12 million; 2020 – losses of $30 million), nil (2021 – gains of $1 million; 2020 – losses of $16 million), and nil (2021 – gains of $1 million; 2020 – gains of $1 million), respectively.

3 Represents the AOCI attributable to non-controlling interests of TC PipeLines, LP which was reclassified to AOCI on the Consolidated balance sheet upon completion of the acquisition of all the outstanding publicly-held common units of TC PipeLines, LP on March 3, 2021. Refer to Note 23, Non-controlling interests, for additional information.

4 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 $84 million ($64 million, net of tax) at December 31, 2022. 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	Amounts Reclassified From AOCI			
(millions of Canadian $)	**2022**	2021	2020	**Affected Line Item in the Consolidated Statement of Income[1]**
Cash flow hedges				
Commodities	**(47)**	(22)	(1)	Revenues (Power and Energy Solutions)
Interest rate	**(16)**	(46)	(28)	Interest expense
Interest rate	**—**	—	(613)	Net gain/(loss) on sale of assets[2]
	(63)	(68)	(642)	Total before tax
	21	13	160	Income tax expense
	(42)	(55)	(482)	Net of tax[3]
Pension and other post-retirement benefit plan adjustments				
Amortization of actuarial losses	**(11)**	(22)	(23)	Plant operating costs and other[4]
Settlement gain	**2**	2	—	Plant operating costs and other[4]
	(9)	(20)	(23)	Total before tax
	3	6	6	Income tax expense
	(6)	(14)	(17)	Net of tax
Equity investments				
Equity income	**4**	(37)	(15)	Income from equity investments
	(1)	9	4	Income tax expense
	3	(28)	(11)	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 30, Acquisitions and dispositions, for additional information.

3 Amounts reclassified from AOCI on cash flow hedges are net of non-controlling interest of nil (2021 – nil; 2020 – losses of $7 million).

4 These AOCI components are included in the computation of net benefit cost. Refer to Note 27, Employee post-retirement benefits, for additional information.

27. EMPLOYEE POST-RETIREMENT BENEFITS

The Company sponsors DB Plans for certain 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 for employees hired prior to January 1, 2019. 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 was approximately nine years at December 31, 2022 (2021 – 10 years; 2020 – 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 12 years at December 31, 2022 (2021 and 2020 – 11 years). In 2022, the Company expensed $64 million (2021 and 2020 – $58 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 $)	**2022**	**2021**	**2020**
DB Plans	**78**	105	124
Other post-retirement benefit plans	**8**	8	9
Savings and DC Plans	**64**	58	58
	150	171	191

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. After the cash contributions noted above, no additional letters of credit were provided to the Canadian DB Plan in 2022 (2021 – $20 million; 2020 – $13 million). Total letters of credit provided to the Canadian DB plan at December 31, 2022 was $322 million.

The most recent actuarial valuation of the pension plans for funding purposes was as at January 1, 2022 and the next required valuation is at January 1, 2023.

In 2022, a settlement occurred for the U.S. DB Plan as a result of lump sum payments made during the year. The impact of the settlement was determined using actuarial assumptions consistent with those employed at December 31, 2022. The settlement gain decreased the U.S. DB Plan's unrealized actuarial gain by $2 million which was included in OCI, and was recorded in net benefit cost in 2022.

In mid-2021, the Company offered a one-time Voluntary Retirement Program (VRP) to eligible employees. Participants in the program retired by December 31, 2021 and received a transition payment along with existing retirement benefits. In 2021, the Company expensed $81 million mainly related to VRP transition payments which were included in Plant operating costs and other. In addition, $18 million was recorded in Revenues related to costs that are recoverable through regulatory and tolling structures on a flow-through basis.

As a result of employee participation in the VRP in 2021, a settlement and curtailment occurred for the U.S. DB Plan and a curtailment occurred in the U.S. other post-retirement benefits plan (OPEB). The impact of these amounts were determined using actuarial assumptions consistent with those employed at December 31, 2021. The settlement gain decreased the U.S. DB Plan's unrealized actuarial gain by $2 million which was included in OCI, while the curtailment gain decreased the U.S. DB Plan's benefit obligation by $5 million, both of which were recorded in net benefit cost in 2021. The curtailment loss decreased the OPEB's unrealized actuarial gain by $3 million which was included in OCI and increased the OPEB obligation by $3 million, resulting in no adjustment to net benefit cost in 2021.

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 $)	**2022**	2021	**2022**	2021
Change in Benefit Obligation[1]				
Benefit obligation – beginning of year	**4,027**	4,326	**419**	457
Service cost	**145**	171	**5**	6
Interest cost	**125**	119	**13**	12
Employee contributions	**6**	6	**2**	1
Benefits paid	**(324)**	(372)	**(24)**	(21)
Actuarial gain	**(949)**	(208)	**(120)**	(35)
Curtailment	**—**	(5)	**—**	3
Foreign exchange rate changes	**51**	(10)	**15**	(4)
Benefit obligation – end of year	**3,081**	4,027	**310**	419
Change in Plan Assets				
Plan assets at fair value – beginning of year	**4,145**	4,038	**431**	441
Actual return on plan assets	**(483)**	376	**(89)**	5
Employer contributions[2]	**78**	105	**8**	8
Employee contributions	**6**	6	**2**	1
Benefits paid	**(324)**	(372)	**(24)**	(21)
Foreign exchange rate changes	**59**	(8)	**26**	(3)
Plan assets at fair value – end of year	**3,481**	4,145	**354**	431
Funded Status – Plan Surplus	**400**	118	**44**	12

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 nil (2021 – $20 million) letter of credit provided to the Canadian DB Plan for funding purposes.

The actuarial gain realized on the defined benefit plan obligation is primarily attributable to an increase in the weighted average discount rate from 3.05 per cent in 2021 to 5.15 per cent in 2022.

The actuarial gain realized on the other post-retirement benefit plan obligation is primarily due to the increase in the weighted average discount rate from 3.10 per cent in 2021 to 5.45 per cent in 2022.

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 $)	**2022**	2021	**2022**	2021
Other long-term assets (Note 15)	**400**	119	**163**	193
Accounts payable and other	**—**	—	**(8)**	(8)
Other long-term liabilities (Note 18)	**—**	(1)	**(111)**	(173)
	400	118	**44**	12

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	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
(millions of Canadian $)	**2022**	2021	**2022**	2021
Projected benefit obligation[1]	**—**	(2,687)	**(119)**	(183)
Plan assets at fair value	**—**	2,686	**—**	—
Funded Status – Plan Deficit	**—**	(1)	**(119)**	(183)

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 $)	**2022**	2021
Accumulated benefit obligation	**(2,880)**	(3,714)
Plan assets at fair value	**3,481**	4,145
Funded Status – Plan Surplus	**601**	431

The Company's DB Plans with respect to accumulated benefit obligations and the fair value of plan assets were fully funded as at December 31, 2022 and December 31, 2021.

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

at December 31	Percentage of Plan Assets		Target Allocations
	2022	2021	**2022**
Fixed income securities	**38%**	34%	**25% to 50%**
Equity securities	**44%**	53%	**30% to 55%**
Other investments	**18%**	13%	**10% to 25%**
	100%	100%	

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

at December 31			Percentage of Plan Assets	
(millions of Canadian $)	**2022**	2021	**2022**	2021
Fixed income securities	**7**	7	**0.2%**	0.2%
Equity securities	**3**	5	**0.1%**	0.1%

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 may be used to hedge certain liabilities.

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 28, 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 $)	**2022**	2021	**2022**	2021	**2022**	2021	**2022**	2021	**2022**	2021
Asset Category										
Cash and Cash Equivalents	**55**	68	**1**	2	**—**	—	**56**	70	**1**	2
Equity Securities:										
Canadian	**117**	269	**—**	148	**—**	—	**117**	417	**3**	9
U.S.	**897**	649	**—**	164	**—**	—	**897**	813	**24**	18
International	**172**	126	**172**	354	**—**	—	**344**	480	**9**	10
Global	**—**	111	**75**	313	**—**	—	**75**	424	**2**	9
Emerging	**50**	25	**127**	120	**—**	—	**177**	145	**5**	3
Fixed Income Securities:										
Canadian Bonds:										
Federal	**—**	—	**221**	226	**—**	—	**221**	226	**6**	5
Provincial	**—**	—	**249**	331	**—**	—	**249**	331	**6**	7
Municipal	**—**	—	**12**	16	**—**	—	**12**	16	**—**	—
Corporate	**—**	—	**108**	147	**—**	—	**108**	147	**3**	4
U.S. Bonds:										
Federal	**177**	433	**158**	15	**—**	—	**335**	448	**9**	10
Municipal	**—**	—	**1**	1	**—**	—	**1**	1	**—**	—
Corporate	**345**	67	**94**	143	**—**	—	**439**	210	**11**	5
International:										
Government	**5**	6	**6**	7	**—**	—	**11**	13	**—**	—
Corporate	**—**	—	**58**	73	**—**	—	**58**	73	**1**	2
Mortgage backed	**36**	42	**1**	5	**—**	—	**37**	47	**1**	1
Net forward contracts	**—**	—	**(78)**	—	**—**	—	**(78)**	—	**(2)**	—
Other Investments:										
Real estate	**—**	—	**—**	—	**336**	283	**336**	283	**9**	6
Infrastructure	**—**	—	**—**	—	**296**	281	**296**	281	**8**	6
Private equity funds	**—**	—	**—**	—	**—**	1	**—**	1	**—**	—
Funds held on deposit	**144**	150	**—**	—	**—**	—	**144**	150	**4**	3
	1,998	1,946	**1,205**	2,065	**632**	565	**3,835**	4,576	**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, 2020	417
Purchases and sales	100
Realized and unrealized gains	48
Balance at December 31, 2021	565
Purchases and sales	**52**
Realized and unrealized gains	**15**
Balance at December 31, 2022	**632**

The Company's expected funding contributions in 2023 are approximately $32 million for the DB Plans, $6 million for the other post-retirement benefit plans and approximately $69 million for the savings plans and DC Plans. The Company does not expect to issue additional letters 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**
2023	210	25
2024	214	24
2025	217	24
2026	221	23
2027	224	23
2028 to 2032	1,160	111

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, 2022. 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:

at December 31	**Pension Benefit Plans**		**Other Post-Retirement Benefit Plans**	
	2022	**2021**	**2022**	**2021**
Discount rate	**5.15%**	3.05%	**5.45%**	3.10%
Rate of compensation increase	**3.30%**	2.95%	**—**	—

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

year ended December 31	**Pension Benefit Plans**			**Other Post-Retirement Benefit Plans**		
	2022	**2021**	**2020**	**2022**	**2021**	**2020**
Discount rate	**3.05%**	2.70%	3.20%	**3.10%**	2.80%	3.35%
Expected long-term rate of return on plan assets	**6.10%**	6.15%	6.40%	**3.25%**	3.00%	3.50%
Rate of compensation increase	**3.00%**	2.60%	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 6.10 per cent weighted-average annual rate of increase in the per capita cost of covered health care benefits was assumed for 2023 measurement purposes. The rate was assumed to decrease gradually to 4.80 per cent by 2030 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:

year ended December 31	Pension Benefit Plans			Other Post-Retirement Benefit Plans		
(millions of Canadian $)	**2022**	**2021**	**2020**	**2022**	**2021**	**2020**
Service cost[1]	**145**	171	155	**5**	6	6
Other components of net benefit cost[1]						
Interest cost	**125**	119	133	**13**	12	14
Expected return on plan assets	**(239)**	(234)	(230)	**(14)**	(13)	(14)
Amortization of actuarial loss	**10**	23	21	**1**	2	2
Amortization of regulatory asset	**12**	27	25	**1**	2	2
Curtailment gain	**—**	(5)	—	**—**	—	—
Settlement gain – AOCI	**(2)**	(2)	—	**—**	—	—
	(94)	(72)	(51)	**1**	3	4
Net Benefit Cost Recognized	**51**	99	104	**6**	9	10

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:

year ended December 31	2022		2021		2020	
(millions of Canadian $)	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits
Net loss	**38**	**24**	147	5	358	22

Pre-tax amounts recognized in OCI were as follows:

year ended December 31	2022		2021		2020	
(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	**(10)**	**(1)**	(23)	(2)	(21)	(2)
Curtailment	**—**	**—**	—	3	—	—
Settlement	**2**	**—**	2	—	—	—
Funded status adjustment	**(101)**	**20**	(190)	(18)	(18)	3
	(109)	**19**	(211)	(17)	(39)	1

28. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

Risk Management Overview

TC Energy has exposure to various financial risks and has strategies, policies and limits in place to manage the impact of these risks on its 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. TC Energy's risks are managed within limits that are established by the Company's Board, implemented by senior management and monitored by the Company's risk management, internal audit and business segment groups. The Board's Audit Committee oversees how management monitors compliance with 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- 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, cash flows 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 the Company's exposure to market risk resulting from commodity price risk management activities 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 businesses, TC Energy manages the exposure to fluctuating commodity prices through long-term contracts and hedging activities including selling and purchasing electricity 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.

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 demand for these commodities could negatively impact opportunities to expand the Company's asset base and/or re-contract with TC Energy's shippers and customers as contractual agreements expire.

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

Interest rate risk

TC Energy utilizes short- 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 short-term debt including 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. For eligible hedging relationships affected by the expected cessation of certain reference interest rates, the Company has applied the optional expedient allowing an entity to assume that the hedged forecasted transaction in a cash flow hedge is probable of occurring and, therefore, these changes are not expected to have a material impact on the consolidated financial statements. Refer to Note 3, Accounting changes, for additional information on Reference Rate Reform.

Foreign exchange risk

Certain of TC Energy's businesses generate all or most of their earnings in U.S. dollars and, 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 basis up to three years in advance using foreign exchange derivatives; however, the natural exposure beyond that period remains.

A portion of the Company's Mexico Natural Gas Pipelines monetary assets and liabilities are peso-denominated, while the functional currency for TC Energy's 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. In addition, foreign exchange gains or losses calculated for Mexico income tax purposes on the revaluation of U.S. dollar-denominated monetary assets and liabilities result in peso-denominated income tax exposure for these entities, leading to fluctuations in Income from equity investments and Income tax expense. As the Company's U.S. dollar-denominated monetary assets and liabilities in our Mexico operations continue to grow, this exposure increases. These exposures are managed using foreign exchange derivatives.

Net investment in foreign operations

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 interest rate swaps and foreign exchange options as appropriate.

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

at December 31	2022		2021	
(millions of Canadian $, unless otherwise noted)	Fair Value[1,2]	Notional Amount	Fair Value[1,2]	Notional Amount
U.S. dollar foreign exchange options (maturing 2023 to 2024)	**(22)**	**US 3,600**	(4)	US 3,800
U.S. dollar cross-currency interest rate swaps (maturing 2023 to 2025)[3]	**(5)**	**US 300**	23	US 400
	(27)	**US 3,900**	19	US 4,200

1 Fair value equals carrying value.
2 No amounts have been excluded from the assessment of hedge effectiveness.
3 In 2022, Net income includes net realized gains of $1 million (2021 – gains of $1 million) 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)	2022	2021
Notional amount	**32,500 (US 24,000)**	30,700 (US 24,200)
Fair value	**30,800 (US 22,700)**	35,500 (US 28,100)

Counterparty Credit Risk

TC Energy's exposure to counterparty credit risk includes its cash and cash equivalents, accounts receivable and certain contractual recoveries, available-for-sale assets, the fair value of derivative assets, loans receivable, net investment in leases and contract assets.

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
- the competitive position of the Company's assets and the demand for the Company's services
- 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 reasonable and supportable forecasts to determine any impairment, which is recognized in Plant operating costs and other.

The Company’s net investment in leases and certain contract assets are financial assets subject to ECL. TC Energy’s methodology for assessing the ECL regarding these financial assets includes consideration of the probability of default (the probability that the customer will default on its obligation), the loss given default (the economic loss as a proportion of the financial asset balance in the event of a default) and the exposure at default (the financial asset balance at the time of a hypothetical default) with one-year forward-looking information that includes assumptions for future macroeconomic conditions under three probability-weighted future scenarios.

The macroeconomic factors considered most relevant to the Company's net investment in leases and contract assets include Mexico's GDP, Mexico's government debt to GDP and Mexico's inflation. The ECL amount is updated at each reporting date to reflect changes in assumptions and forecasts for future economic conditions.

For the year ended December 31, 2022, the Company recorded a $149 million (2021 and 2020 – nil) ECL provision with respect to the net investment in leases associated with the in-service TGNH pipelines and a $14 million (2021 and 2020 – nil) ECL provision for contract assets related to certain other Mexico Natural Gas pipelines.

Other than the ECL provision noted above, the Company had no significant credit losses at December 31, 2022 and 2021. At December 31, 2022 and 2021, there were no significant credit risk concentrations and no significant amounts past due or impaired.

TC Energy has significant credit and performance exposure to financial institutions that 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.

Non-Derivative Financial Instruments

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, Loans receivable from affiliates, Other current assets, Long-term loans receivable from affiliate, Restricted investments, Net investment in leases, Other long-term assets, Notes payable, Accounts payable and other, 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 $)	2022 Carrying Amount	2022 Fair Value	2021 Carrying Amount	2021 Fair Value
Long-term debt, including current portion (Note 20)[1,2]	**(41,543)**	**(39,505)**	(38,661)	(45,615)
Junior subordinated notes (Note 21)	**(10,495)**	**(9,415)**	(8,939)	(9,236)
	(52,038)	**(48,920)**	(47,600)	(54,851)

1 Long-term debt is recorded at amortized cost, except for US$1.6 billion (2021 – nil) that is attributed to hedged risk and recorded at fair value.

2 Net income for 2022 included unrealized gains of $64 million (2021 – nil) for fair value adjustments attributable to the hedged interest rate risk associated with interest rate swap fair value hedging relationships on US$1.6 billion of long-term debt at December 31, 2022 (2021 – nil). 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 $)	2022 LMCI Restricted Investments	2022 Other Restricted Investments[1]	2021 LMCI Restricted Investments	2021 Other Restricted Investments[1]
Fair value of fixed income securities[2,3]				
Maturing within 1 year	**—**	**54**	—	26
Maturing within 1-5 years	**—**	**106**	8	107
Maturing within 5-10 years	**1,153**	**—**	1,150	—
Maturing after 10 years	**77**	**—**	84	—
Fair value of equity securities[2,4]	**749**	**—**	817	—
	1,979	**160**	2,059	133

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 $)	2022 LMCI Restricted Investments[1]	2022 Other Restricted Investments[2]	2021 LMCI Restricted Investments[1]	2021 Other Restricted Investments[2]	2020 LMCI Restricted Investments[1]	2020 Other Restricted Investments[2]
Net unrealized (losses)/gains	**(244)**	**(7)**	45	(2)	130	1
Net realized (losses)/gains[3]	**(32)**	**—**	3	—	20	1

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 regulatory 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.

Derivative Instruments

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 refunded or recovered 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 rate payers in subsequent years when the derivative settles.

Balance sheet presentation of derivative instruments

The balance sheet classification of the fair value of derivative instruments was as follows:

at December 31, 2022 (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 8)					
Commodities[2]	—	—	—	597	597
Foreign exchange	—	—	6	11	17
	—	—	6	608	614
Other long-term assets (Note 15)					
Commodities[2]	—	—	—	62	62
Foreign exchange	—	—	2	15	17
Interest rate	—	12	—	—	12
	—	12	2	77	91
Total Derivative Assets	—	12	8	685	705
Accounts payable and other (Note 17)					
Commodities[2]	(72)	—	—	(584)	(656)
Foreign exchange	—	—	(31)	(158)	(189)
Interest rate	—	(26)	—	—	(26)
	(72)	(26)	(31)	(742)	(871)
Other long-term liabilities (Note 18)					
Commodities[2]	(2)	—	—	(75)	(77)
Foreign exchange	—	—	(4)	(20)	(24)
Interest rate	—	(50)	—	—	(50)
	(2)	(50)	(4)	(95)	(151)
Total Derivative Liabilities	(74)	(76)	(35)	(837)	(1,022)
Total Derivatives	(74)	(64)	(27)	(152)	(317)

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

The balance sheet classification of the fair value of derivative instruments was as follows:

at December 31, 2021 (millions of Canadian $)	Cash Flow Hedges	Net Investment Hedges	Held for Trading	Total Fair Value of Derivative Instruments[1]
Other current assets (Note 8)				
Commodities[2]	—	—	122	122
Foreign exchange	—	10	37	47
	—	10	159	169
Other long-term assets (Note 15)				
Commodities[2]	—	—	8	8
Foreign exchange	—	32	6	38
Interest rate	2	—	—	2
	2	32	14	48
Total Derivative Assets	2	42	173	217
Accounts payable and other (Note 17)				
Commodities[2]	(23)	—	(138)	(161)
Foreign exchange	—	(4)	(46)	(50)
Interest rate	(10)	—	—	(10)
	(33)	(4)	(184)	(221)
Other long-term liabilities (Note 18)				
Commodities[2]	(4)	—	(6)	(10)
Foreign exchange	—	(19)	(10)	(29)
Interest rate	(8)	—	—	(8)
	(12)	(19)	(16)	(47)
Total Derivative Liabilities	(45)	(23)	(200)	(268)
Total Derivatives	(43)	19	(27)	(51)

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 $)	2022	2021	2022	2021
Long-term debt	**(2,101)**	—	**64**	—

1 At December 31, 2022 and 2021, 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, 2022	Power	Natural Gas	Liquids	Foreign Exchange	Interest Rate
Net sales/(purchases)[1]	**673**	**(96)**	**11**	**—**	**—**
Millions of U.S. dollars	**—**	**—**	**—**	**5,997**	**1,600**
Millions of Mexican pesos	**—**	**—**	**—**	**9,747**	**—**
Maturity dates	**2023-2026**	**2023-2027**	**2023-2024**	**2023-2026**	**2030-2032**

1 Volumes for power, natural gas and liquids derivatives are in GWh, Bcf and MMBbls, respectively. In 2022, TC Energy updated this presentation to a net basis as it better reflects the Company's trading positions and how it manages its business.

at December 31, 2021	Power	Natural Gas	Liquids	Foreign Exchange	Interest Rate
Net sales/(purchases)[1]	490	(52)	4	—	—
Millions of U.S. dollars	—	—	—	6,636	650
Millions of Mexican pesos	—	—	—	5,500	—
Maturity dates	2022-2026	2022-2027	2022	2022-2026	2024-2026

1 Volumes for power, natural gas and liquids derivatives are in GWh, Bcf and MMBbls, respectively. In 2022, TC Energy updated this presentation to a net basis as it better reflects the Company's trading positions and how it manages its business.

Unrealized and Realized Gains and Losses on Derivative Instruments

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

year ended December 31 (millions of Canadian $)	2022	2021	2020
Derivative Instruments Held For Trading[1]			
Amount of unrealized gains/(losses) in the year			
Commodities	**14**	9	(23)
Foreign exchange (Note 22)	**(149)**	(203)	126
Amount of realized gains/(losses) in the year			
Commodities	**759**	287	183
Foreign exchange (Note 22)	**(2)**	240	(33)
Derivative Instruments in Hedging Relationships[2]			
Amount of realized (losses)/gains in the year			
Commodities	**(73)**	(44)	6
Interest rate	**(3)**	(32)	(16)

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 Foreign exchange (loss)/gain, net.

2 In 2022, 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 (2021 – realized loss of $10 million, 2020 – nil).

Derivatives in cash flow hedging relationships

The components of OCI (Note 26) 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)	2022	2021	2020
Change in fair value of derivative instruments recognized in OCI[1]			
Commodities	**(94)**	(35)	(5)
Interest rate	**36**	22	(766)
	(58)	(13)	(771)

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 $)	2022	2021	2020
Fair Value Hedges			
Interest rate contracts[1]			
Hedged items	**(30)**	—	(3)
Derivatives designated as hedging instruments	**(1)**	—	1
Cash Flow Hedges			
Reclassification of losses on derivative instruments from AOCI to Net income[2,3]			
Commodity contracts[4]	**(47)**	(22)	(1)
Interest rate contracts[1]	**(16)**	(46)	(648)

1 Presented within Interest expense in the Consolidated statement of income, except for a loss of $613 million recorded in May 2020 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 was included in Net gain/(loss) on sale of assets. Refer to Note 30, Acquisitions and dispositions, for additional information.

2 Refer to Note 26, Other comprehensive income/(loss) and accumulated other comprehensive income/(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 Energy Solutions) 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, 2022 (millions of Canadian $)	Gross Derivative Instruments	Amounts Available for Offset[1]	Net Amounts
Derivative Instrument Assets			
Commodities	**659**	**(591)**	**68**
Foreign exchange	**34**	**(33)**	**1**
Interest rate	**12**	**(4)**	**8**
	705	**(628)**	**77**
Derivative Instrument Liabilities			
Commodities	**(733)**	**591**	**(142)**
Foreign exchange	**(213)**	**33**	**(180)**
Interest rate	**(76)**	**4**	**(72)**
	(1,022)	**628**	**(394)**

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

at December 31, 2021 (millions of Canadian $)	Gross Derivative Instruments	Amounts Available for Offset[1]	Net Amounts
Derivative Instrument Assets			
Commodities	130	(91)	39
Foreign exchange	85	(54)	31
Interest rate	2	(1)	1
	217	(146)	71
Derivative Instrument Liabilities			
Commodities	(171)	91	(80)
Foreign exchange	(79)	54	(25)
Interest rate	(18)	1	(17)
	(268)	146	(122)

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 $138 million and letters of credit of $68 million at December 31, 2022 (2021 – $144 million and $130 million, respectively) to its counterparties. At December 31, 2022, the Company held less than $1 million in cash collateral and $10 million in letters of credit (2021 – nil and $6 million, 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, 2022, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $19 million (2021 – $5 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, 2022, 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 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, 2022 (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	**515**	**142**	**2**	**659**
Foreign exchange	**—**	**34**	**—**	**34**
Interest rate	**—**	**12**	**—**	**12**
Derivative Instrument Liabilities				
Commodities	**(478)**	**(242)**	**(13)**	**(733)**
Foreign exchange	**—**	**(213)**	**—**	**(213)**
Interest rate	**—**	**(76)**	**—**	**(76)**
	37	**(343)**	**(11)**	**(317)**

1 There were no transfers from Level II to Level III for the year ended December 31, 2022.

at December 31, 2021 (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	39	91	—	130
Foreign exchange	—	85	—	85
Interest rate	—	2	—	2
Derivative Instrument Liabilities				
Commodities	(49)	(116)	(6)	(171)
Foreign exchange	—	(79)	—	(79)
Interest rate	—	(18)	—	(18)
	(10)	(35)	(6)	(51)

1 There were no transfers from Level II to Level III for the year ended December 31, 2021.

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)	2022	2021
Balance at beginning of year	**(6)**	(4)
Net losses included in Net income	**(10)**	(3)
Net losses included in OCI	**(3)**	—
Transfers out of Level III	**7**	—
Settlements	**1**	1
Balance at End of Year[1]	**(11)**	(6)

1 Revenues include unrealized losses of $10 million attributed to derivatives in the Level III category that were still held at December 31, 2022 (2021 – unrealized losses of $3 million).

29. CHANGES IN OPERATING WORKING CAPITAL

year ended December 31 (millions of Canadian $)	2022	2021	2020
(Increase)/decrease in Accounts receivable	**(575)**	(925)	129
Increase in Inventories	**(190)**	(93)	(55)
Decrease/(increase) in Other current assets	**118**	(141)	(221)
(Decrease)/increase in Accounts payable and other	**(83)**	890	(162)
Increase/(decrease) in Accrued interest	**91**	(18)	(18)
Increase in Operating Working Capital	**(639)**	(287)	(327)

30. ACQUISITIONS AND DISPOSITIONS

Canadian Natural Gas Pipelines

Coastal GasLink LP

In May 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 included $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 incorporated 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 reflected the utilization of previously unrecognized tax loss benefits. The pre-tax gain was included in Net gain/(loss) on sale of assets in the Consolidated statement of income. As part of this transaction, TC Energy was 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.

Immediately preceding the equity sale, Coastal GasLink LP drew down $1.6 billion on the secured long-term project financing credit facilities, of which approximately $1.5 billion was paid to TC Energy.

Liquids Pipelines

Northern Courier

In November 2021, TC Energy completed the sale of its remaining 15 per cent equity interest in Northern Courier to a third party for gross proceeds of approximately $35 million resulting in a pre-tax gain of $13 million ($19 million after tax). The pre-tax gain was included in Net gain/(loss) on sale of assets in the Consolidated statement of income.

Power and Energy Solutions

TransCanada Turbines Ltd.

In November 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

In April 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. The total pre-tax loss of $676 million ($470 million after tax) on this transaction included losses accrued during 2019 while classified as an asset held for sale and a 2021 post-close adjustment and also reflected utilization of previously unrecognized tax loss benefits. The pre-tax loss was included in Net gain/(loss)on sale of assets in the Consolidated statement of income. This loss may be amended in the future upon the settlement of existing insurance claims.

31. 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 2022 were $362 million (2021 – $239 million; 2020 – $224 million).

The Company has entered into PPAs with solar and wind-power generating facilities ranging from one to 15 years that require the purchase of generated energy and associated environmental attributes. At December 31, 2022, the total planned capacity secured under the PPAs is approximately 1,020 MW with the generation subject to operating availability and capacity factors. Future payments and their timing cannot be reasonably estimated as they are dependent on when certain underlying facilities are placed into service and the amount of energy generated. Certain of these purchase commitments have offsetting sale PPAs for all or a portion of the related output from the facility.

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, 2022, TC Energy had the following capital expenditure commitments:

- approximately $1.0 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 Gas pipeline projects
- approximately $1.7 billion for its Mexico natural gas pipelines, primarily related to construction of the Southeast Gateway pipeline
- approximately $0.3 billion for its Power and Energy Solutions business, primarily related to the Company's proportionate share of commitments for Bruce Power's life extension program.

Contingencies

TC Energy is subject to laws and regulations governing environmental quality and pollution control. At December 31, 2022, the Company had accrued approximately $20 million (2021 – $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.

Keystone XL

In September 2022, the International Centre for Settlement of Investment Disputes (ICSID) formally constituted a tribunal to hear TC Energy's request for arbitration under NAFTA where the Company is seeking to recover more than US$15 billion in economic damages resulting from the revocation of the Presidential Permit for the Keystone XL pipeline project. This claim is in an early stage and the timing and outcome is unknown at present. Termination activities undertaken in 2022, including asset dispositions and preservation, will continue throughout 2023. The Company will continue to coordinate with regulators, stakeholders and Indigenous groups to meet its environmental and regulatory commitments.

Guarantees

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 Other long-term liabilities on the Consolidated balance sheet. Information regarding the Company's guarantees were as follows:

at December 31		**2022**		**2021**	
(millions of Canadian $)	**Term**	**Potential Exposure**[1]	**Carrying Value**	**Potential Exposure**[1]	**Carrying Value**
Sur de Texas	Renewable to 2053	**100**	**—**	93	—
Bruce Power	Renewable to 2065	**88**	**—**	88	—
Other jointly-owned entities	to 2043	**81**	**3**	80	4
		269	**3**	261	4

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

32. VARIABLE INTEREST ENTITIES

Consolidated VIEs

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 $)	2022	2021
ASSETS		
Current Assets		
Cash and cash equivalents	**60**	72
Accounts receivable	**98**	70
Inventories	**32**	28
Other current assets	**14**	13
	204	183
Plant, Property and Equipment	**3,997**	3,672
Equity Investments	**748**	890
Goodwill	**449**	421
	5,398	5,166
LIABILITIES		
Current Liabilities		
Accounts payable and other	**234**	232
Accrued interest	**18**	17
Current portion of long-term debt	**31**	29
	283	278
Regulatory Liabilities	**78**	66
Other Long-Term Liabilities	**1**	1
Deferred Income Tax Liabilities	**16**	13
Long-Term Debt	**2,136**	2,025
	2,514	2,383

Non-Consolidated VIEs

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 $)	2022	2021
Balance sheet		
Loans receivable from affiliates (Notes 7 and 12)[1]	—	1
Equity investments		
Bruce Power	**5,783**	4,493
Coastal GasLink (Note 7)[1]	—	386
Pipeline equity investments and other	**1,148**	1,219
Long-term loans receivable from affiliate (Note 7)	—	238
Off-balance sheet[2]		
Bruce Power[3]	**2,025**	974
Coastal GasLink[4]	**3,300**	3,037
Pipeline equity investments	**58**	171
Maximum exposure to loss	**12,314**	10,519

1 The pre-impairment balances in Equity investments ($2,798 million) and Loans receivable from affiliates ($250 million) at December 31, 2022 related to TC Energy's investment in Coastal GasLink LP were reduced to a nil balance and an impairment charge was recognized in fourth quarter 2022 in Impairment of equity investment in the Consolidated statement of income.

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

3 On March 7, 2022, the IESO verified Bruce Power's Unit 3 MCR program final cost and schedule duration estimate submitted in December 2021. As at December 31, 2022, the maximum exposure includes TC Energy's portion of capital to be invested under the Unit 3 MCR program as well as the expected increase in the capital to be invested under the Asset Management program through 2027.

4 TC Energy is contractually obligated to fund the capital costs to complete the Coastal GasLink pipeline by funding the remaining equity requirements of Coastal GasLink LP through incremental capacity on the subordinated loan agreement with Coastal GasLink LP until final costs are determined. The committed capacity under the subordinated loan agreement was $1,262 million as at December 31, 2022 and will increase in the future as required to support the estimated $3.3 billion of additional equity financing requirements through completion of construction of the Coastal GasLink pipeline. The determination of the Company's maximum exposure to loss involves an estimate of the capital costs to complete the Coastal GasLink pipeline.

In July 2022, the Company entered into revised project agreements relating to its investment in Coastal GasLink LP and committed to make additional equity contributions, which did not result in a change in the Company's 35 per cent ownership. These revisions and additional equity contributions were determined to be a VIE reconsideration event for TC Energy's investment in Coastal GasLink LP. The Company performed a re-assessment of control and determined that Coastal GasLink LP continued to meet the definition of a VIE in which the Company held a variable interest. The re-assessment further determined that TC Energy was not the primary beneficiary of Coastal GasLink LP as the Company does not have the power, either explicit or implicit through voting rights or otherwise, to direct the activities that most significantly impact the economic performance of Coastal GasLink LP. Accordingly, the Company continued to account for its investment using the equity method of accounting. Refer to Note 7, Coastal GasLink, for additional information.

33. SUBSEQUENT EVENT

Mexico Debt Issuance

On January 17, 2023, a wholly-owned Mexican subsidiary entered into a US$1.8 billion senior unsecured term loan and a US$500 million senior unsecured credit facility. Both the term loan and the revolving commitment are due in January 2028 and bear interest at a floating rate.

SHAREHOLDER INFORMATION

TC Energy welcomes questions from shareholders and investors.
Please contact:

Gavin Wylie
Vice-President, Investor Relations
Phone: **1-403-920-7911**
Toll free: **1-800-361-6522**
Email: **investor_relations@tcenergy.com**
Website: **TCEnergy.com/Investors**

LISTING INFORMATION

Common shares (TSX, NYSE): TRP

Preferred shares (TSX):

Series 1: TRP.PR.A

Series 2: TRP.PR.F

Series 3: TRP.PR.B

Series 4: TRP.PR.H

Series 5: TRP.PR.C

Series 6: TRP.PR.I

Series 7: TRP.PR.D

Series 9: TRP.PR.E

Series 11: TRP.PR.G

JOIN OUR ONLINE CONVERSATION

Facebook:
@TCEnergyCorporation

Instagram:
@TCEnergy

LinkedIn:
@TC Energy

Twitter:
@TCEnergy

TRANSFER AGENT

Computershare Investor Services, Inc.
100 University Avenue, 8th Floor, Toronto, ON
Canada, M5J 2Y1

Phone: **1-514-982-7959**
Toll free: **1-800-340-5024**
Fax: **1-888-453-0330**
Email: **tcenergy@computershare.com**

CORPORATE HEAD OFFICE

TC Energy Corporation
450 – 1st Street S.W. Calgary, AB
Canada, T2P 5H1

Visit our website for more information:
TCEnergy.com

Find our annual report online:
TCEnergy.com/AnnualReport

Printed in Canada
February 2023

TC Energy