Management's discussion and analysis

February 15, 2024

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, 2023.

This MD&A should also be read in conjunction with our December 31, 2023 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 15, 2024 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
- expectations about the new Liquids Pipelines Company, South Bow Corporation, following the anticipated completion of the proposed spinoff transaction of our Liquids Pipelines business into a separate publicly listed company, including the management and credit ratings thereof
- expectations regarding the size, structure, timing, conditions and outcome of ongoing and future transactions, including the proposed spinoff transaction and our asset divestiture program
- expected dividend growth
- 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
- expected impact of future tax and accounting changes
- commitments and targets contained in our 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, the proposed spinoff transaction 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, divestitures, the proposed spinoff transaction and energy transition
- terms, timing and completion of the proposed spinoff transaction, including the timely receipt of all necessary approvals and tax rulings
- that market or other conditions are no longer favourable to completing the proposed spinoff transaction
- business disruption during the period prior to or directly following the proposed spinoff transaction
- our ability to successfully implement our strategic priorities, including the Focus Project, and whether they will yield the expected benefits
- our ability to implement a capital allocation strategy aligned with maximizing shareholder value
- operating performance of our pipelines, power generation and storage assets
- amount of capacity sold and rates achieved in our pipeline businesses
- 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, availability of, and inflationary pressures on, labour, equipment and materials
- 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
- cybersecurity and technological developments
- sustainability-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.sedarplus.ca).

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
- net capital expenditures.

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 (loss) 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
- expected credit loss provisions on net investment in leases and certain contract assets in Mexico
- legal, contractual, bankruptcy and other settlements
- impairment of goodwill, plant, property and equipment, equity investments and other assets
- acquisition, integration and restructuring costs
- unrealized fair value adjustments related to risk management activities of Bruce Power's funds invested for post-retirement benefits
- unrealized gains and losses from changes in the fair value of derivatives related to financial and commodity price risk management activities.

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. The changes in fair value, including our proportionate share of changes in fair value related to Bruce Power 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 2023, we announced plans to separate into two independent, investment-grade, publicly listed companies through the proposed spinoff of our Liquids Pipelines business (the spinoff Transaction). A separation management office was established to guide the successful coordination and governance between the two entities, including the development of a separation agreement and transition service agreement. Liquids Pipelines business separation costs related to the spinoff Transaction include internal costs related to separation activities, legal, tax, audit and other consulting fees, which are recognized in the results of our Liquids Pipelines and Corporate segments. These items have been excluded from comparable measures as we do not consider them reflective of our ongoing underlying operations.

In second quarter 2023, we accrued an additional amount for environmental remediation costs related to the Milepost 14 incident. We have appropriate insurance policies in place and we believe that it remains probable that the majority of the environmental remediation costs will be eligible for recovery under our existing insurance coverage. We expect to receive a portion of these insurance proceeds from our wholly-owned captive insurance subsidiary, which resulted in an impact to net income in the consolidated financial results of TC Energy in second quarter 2023. This amount has been excluded from comparable measures as it is not reflective of our ongoing underlying operations.

In first quarter 2023, TransCanada PipeLines Limited (TCPL) entered into an unsecured revolving credit facility with Transportadora de Gas Natural de la Huasteca (TGNH). The loan receivable and loan payable are eliminated upon consolidation; however, due to differences in the currency that each entity reports its financial results, there is an impact to net income reflecting the translation of the loan receivable and payable to TC Energy's reporting currency. As the amounts do not accurately reflect what will be realized at settlement, beginning in second quarter 2023, we excluded from comparable measures the unrealized foreign exchange gains and losses on the loan receivable, as well as the corresponding unrealized foreign exchange gains and losses on the loan payable.

In 2022, we launched the Focus Project to identify opportunities to improve safety, productivity and cost-effectiveness and to date have identified a broad set of opportunities expected to improve safety and financial performance over the long term. Certain initiatives have been implemented and we expect to continue designing and implementing additional initiatives beyond 2023, with benefits in the form of enhanced safety, productivity and cost-effectiveness expected to be realized in the future. Beginning in 2023, we recognized expenses in Plant operating costs and other, primarily related to Focus Project costs for external consulting and severance, some of which are not recoverable through regulatory and commercial tolling structures. These amounts have been excluded from comparable measures as they are not reflective of our ongoing underlying operations.

Prior to full repayment in first quarter 2022, we 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 did not accurately reflect the gains and losses that would be realized at settlement. These amounts offset within each reporting period, resulting in no impact on net income.

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

Comparable measure	GAAP measure
comparable EBITDA	segmented earnings (losses)
comparable EBIT	segmented earnings (losses)
comparable earnings	net income (loss) attributable to common shares
comparable earnings per common share	net income (loss) per common share
funds generated from operations	net cash provided by operations
comparable funds generated from operations	net cash provided by operations
net capital expenditures	capital expenditures

Comparable EBITDA and comparable EBIT

Comparable EBITDA represents segmented earnings (losses) adjusted for certain specific items, excluding 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 (losses) 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 (losses).

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 (losses), Interest expense, AFUDC, Foreign exchange gains (losses), net, Interest income and other, Income tax (expense) recovery, Net (income) loss attributable to non-controlling interests and Preferred share dividends, adjusted for specific items. Refer to the Financial highlights section for reconciliations to Net income (loss) attributable to common shares and Net income (loss) per common share.

Funds generated from operations and comparable funds generated from operations

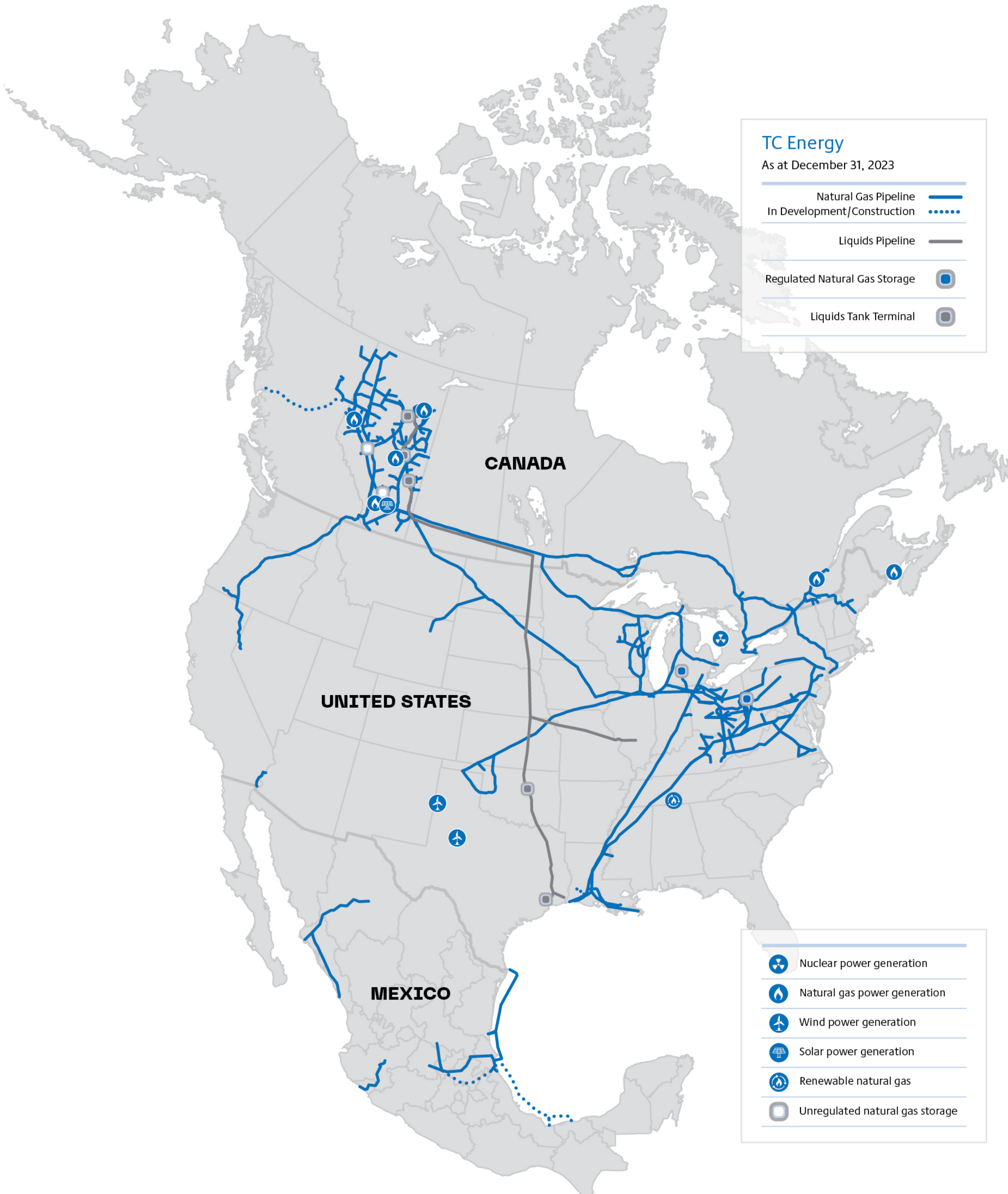
Funds generated from operations reflects net cash provided by operations before changes in operating working capital. The components of changes in working capital are disclosed in Note 30, Changes in operating working capital, of our 2023 Consolidated financial statements. We believe funds generated 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.

Net capital expenditures

Net capital expenditures represents capital expenditures, including growth projects, maintenance capital expenditures, contributions to equity investments, and projects under development, adjusted for the portion attributed to non-controlling interests in the entities we control. We use net capital expenditures as we believe it is a useful measure of our cash flow used for capital reinvestment.

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 $)	2023	2022
Total assets by segment		
Canadian Natural Gas Pipelines	**29,782**	27,456
U.S. Natural Gas Pipelines	**50,499**	50,038
Mexico Natural Gas Pipelines	**12,003**	9,231
Liquids Pipelines	**15,490**	15,587
Power and Energy Solutions	**9,525**	8,272
Corporate	**7,735**	3,764
	125,034	114,348

year ended December 31 (millions of $)	2023	2022
Total revenues by segment		
Canadian Natural Gas Pipelines	**5,173**	4,764
U.S. Natural Gas Pipelines	**6,229**	5,933
Mexico Natural Gas Pipelines	**846**	688
Liquids Pipelines	**2,667**	2,668
Power and Energy Solutions	**1,019**	924
	15,934	14,977

year ended December 31 (millions of $)	2023	2022
Comparable EBITDA by segment[1]		
Canadian Natural Gas Pipelines	**3,335**	2,806
U.S. Natural Gas Pipelines	**4,385**	4,089
Mexico Natural Gas Pipelines	**805**	753
Liquids Pipelines	**1,457**	1,366
Power and Energy Solutions	**1,020**	907
Corporate	**(14)**	(20)
	10,988	9,901

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 safely operate a portfolio of infrastructure assets that enable us to prosper irrespective of the pace and direction of energy transition and at all points in the economic cycle. We are a team of energy problem solvers working to deliver this energy in a safe, reliable, secure and affordable manner through lower carbon energy solutions including natural gas, nuclear energy and pumped hydro.

Our business consists of natural gas and crude oil transportation, storage and delivery systems, as well as power generation assets that produce electricity. These long-life infrastructure assets cover all strategic North American corridors, are anchored by our conservative risk preferences 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 and support global GHG emissions reduction
- crude oil will remain an important part of the fuel mix
- the need for reliable, on-demand energy sources to support electric grid stability will grow significantly
- existing infrastructure assets will become more valuable given the challenges in developing new greenfield, linear-energy infrastructure; in particular, pipelines.

On July 27, 2023, we announced plans to separate into two independent, investment-grade, publicly listed companies through the spinoff Transaction and on November 8, 2023, we communicated that the name of the new Liquids Pipelines business will be South Bow Corporation. In addition to shareholder and court approvals, the spinoff Transaction is subject to receipt of favourable tax rulings from Canadian and U.S. tax authorities, receipt of necessary regulatory approvals, and satisfaction of other customary closing conditions. We expect that the spinoff Transaction will be completed in the second half of 2024.

Allocation of comparable EBITDA[1]

year ended December 31	2023	2022
Comparable EBITDA by segment		
Canadian Natural Gas Pipelines	**31%**	28%
U.S. Natural Gas Pipelines	**40%**	41%
Mexico Natural Gas Pipelines	**7%**	8%
Liquids Pipelines	**13%**	14%
Power and Energy Solutions	**9%**	9%
	100%	100%

1 Refer to Note 5, Segmented information, of our 2023 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. We anticipate the following shifts in capital allocation as the world progresses towards a low-carbon future while balancing energy security and affordability needs:

- Natural Gas Pipelines will continue to attract capital driven by coal to gas conversion and LNG exports
- Power and Energy Solutions weighting in our portfolio is expected to gradually grow over time, heavily weighted to nuclear and pumped hydro. Measured investment in emerging technologies will develop capabilities that are complementary to our core businesses, without taking significant commodity price, volumetric or technology risk
- The separation of the Liquids Pipelines business will allow it to pursue growth opportunities to capture incremental value.

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 $31 billion in secured projects, largely underpinned by long-term contracts or commercial rate regulation. We expect that these investments will contribute to incremental earnings and cash flows as they are placed in service
- Our extensive asset footprint offers significant in-corridor growth opportunities that support our current incumbent positions in natural gas, liquids and nuclear energy. This also includes possible future opportunities to deploy lower GHG emission infrastructure technologies such as pumped hydro, hydrogen and carbon capture, which will help reduce our GHG emissions footprint and that of our customers, while supporting longevity of our existing assets
- We strive 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 policy, 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 sustainability 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, protects and grows our franchise businesses, enhances future resilience under a changing energy mix, and diversifies access to attractive supply and market regions within our risk preferences. Refer to the Risk oversight and enterprise risk management section for an overview of our enterprise risks
- We focus on commercially rate-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 lower carbon growth initiatives in emerging sub-sectors where we are likely to build a strong competitive position in the future, to full development and construction when market conditions are appropriate, technology is proven, and project risks and returns are known and acceptable
- We monitor trends specific to energy supply and demand fundamentals, in addition to analyzing how our portfolio performs under different energy mix scenarios. 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 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 while protecting and growing our incumbencies. 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 any energy transition scenario and across all economic cycles
- 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 safe, reliable, secure and affordable 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:** the strategic advantage supporting our vision is our extensive asset footprint and franchises with high barriers to entry. Our low-risk portfolio of assets offers the scale to provide essential and highly competitive infrastructure services, enabling us to maximize the full-life value of our investments throughout all points of the business cycle. We have five incumbent franchise businesses – transporting natural gas from the WCSB; transporting natural gas from the Appalachian basin; importing natural gas into Mexico; exporting crude oil to the U.S. Midwest and Gulf Coast markets; and our nuclear business in Ontario through Bruce Power. These platforms not only provide a diversified portfolio but also position TC Energy as a leader in the energy infrastructure sector. Our synergistic footprint supports both molecules and electrons, providing us flexibility to allocate capital towards natural gas, electrification or other emerging low-carbon technologies that are complementary to our core businesses
- **disciplined operations:** our 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 while preserving financial flexibility, including asset divestitures, to fund our operations in all market conditions. We deliver a balance of dividend income and growth. 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 Valhalla North and Berland River (VNBR) and WR projects in Canada and the U.S., respectively, and currently assessing development of grid-scale, flexible and clean energy storage through the proposed Ontario Pumped Storage Project
- **commitment to sustainability:** 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. We publish our GHG emissions intensity on a corporate-wide basis in our annual Report on Sustainability, and in 2023, we issued reports on the Reliability of Methane Emissions Disclosure and Climate-related Lobbying to provide more transparency and insight into our climate-related goals and efforts. We continue to assess our emission reduction targets and major components of our longer-term reduction plan against various criteria, including policy, regulatory, commercial and economic developments, the outcomes of our capital rotation program and the proposed spin-off of our Liquids Pipelines business. Aligned with our Commitment Statement and integrated throughout our 2023 Report on Sustainability, our refreshed sustainability commitments reflect the material topics most relevant to our business and our stakeholders. We continue to focus on our nine sustainability commitments, and associated metrics and targets, including positioning to achieve net zero emissions from our operations by 2050, that help ensure our business is well positioned for long-term success
- **open communication:** we carefully manage relationships with our customers, suppliers, regulators and other 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, partnership agreements, human capital and capabilities constraints.

Business underpinned by strong fundamentals and policy support

- Invest in assets that are investment-grade on a stand-alone basis with stable cash flows supported by strong underlying macroeconomic fundamentals, conducive policy and regulations 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.

2023 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 88, as well as the Financial results section in each business segment for reconciliations to the most directly comparable GAAP measures.

year ended December 31 (millions of $, except per share amounts)	2023	2022	2021
Income			
Revenues	**15,934**	14,977	13,387
Net income (loss) attributable to common shares	**2,829**	641	1,815
per common share – basic	**$2.75**	$0.64	$1.87
Comparable EBITDA[1]	**10,988**	9,901	9,368
Comparable earnings	**4,652**	4,279	4,142
per common share	**$4.52**	$4.30	$4.26
Cash flows			
Net cash provided by operations	**7,268**	6,375	6,890
Comparable funds generated from operations	**7,980**	7,353	7,406
Capital spending[2]	**12,298**	8,961	7,134
Acquisitions, net of cash acquired	**(307)**	—	—
Proceeds from sales of assets, net of transaction costs	**33**	—	35
Disposition of equity interest, net of transaction costs[3]	**5,328**	—	—
Balance sheet[4]			
Total assets	**125,034**	114,348	104,218
Long-term debt, including current portion	**52,914**	41,543	38,661
Junior subordinated notes	**10,287**	10,495	8,939
Preferred shares	**2,499**	2,499	3,487
Non-controlling interests	**9,455**	126	125
Common shareholders' equity	**27,054**	31,491	29,784
Dividends declared			
per common share	**$3.72**	$3.60	$3.48
Basic common shares (millions)			
– weighted average for the year	**1,030**	995	973
– issued and outstanding at end of year	**1,037**	1,018	981

1 Additional information on Segmented earnings (losses), the most directly comparable GAAP measure, can be found on page 11.
2 Capital spending reflects cash flows associated with our Capital expenditures, Capital projects in development and Contributions to equity investments. Refer to Note 5, Segmented information, of our 2023 Consolidated financial statements for the financial statement line items that comprise total capital spending.
3 Included in the Financing activities section of the Consolidated statement of cash flows.
4 At December 31.

Consolidated results

year ended December 31 (millions of $, except per share amounts)	2023	2022	2021
Canadian Natural Gas Pipelines	**(90)**	(1,440)	1,449
U.S. Natural Gas Pipelines	**3,531**	2,617	3,071
Mexico Natural Gas Pipelines	**796**	491	557
Liquids Pipelines	**1,011**	1,123	(1,600)
Power and Energy Solutions	**1,004**	833	628
Corporate	**(116)**	8	(46)
Total segmented earnings (losses)	**6,136**	3,632	4,059
Interest expense	**(3,263)**	(2,588)	(2,360)
Allowance for funds used during construction	**575**	369	267
Foreign exchange gains (losses), net	**320**	(185)	10
Interest income and other	**242**	146	190
Income (loss) before income taxes	**4,010**	1,374	2,166
Income tax (expense) recovery	**(942)**	(589)	(120)
Net income (loss)	**3,068**	785	2,046
Net (income) loss attributable to non-controlling interests	**(146)**	(37)	(91)
Net income (loss) attributable to controlling interests	**2,922**	748	1,955
Preferred share dividends	**(93)**	(107)	(140)
Net income (loss) attributable to common shares	**2,829**	641	1,815
Net income (loss) per common share – basic	**$2.75**	$0.64	$1.87

Net income attributable to common shares in 2023 was $2.8 billion or $2.75 per share (2022 – $0.6 billion or $0.64 per share; 2021 – $1.8 billion or $1.87 per share), an increase of $2.2 billion or $2.11 per share compared to 2022. The significant increase for the year ended December 31, 2023 compared to 2022, as well as the significant decrease in Net income attributable to common shares of $1.2 billion or $1.23 per share in 2022 compared to 2021 are primarily due to the net effect of specific items mentioned below. Net income per common share in all years also reflects the impact of common shares issued, including common shares issued for the acquisition of TC PipeLines, LP in first quarter 2021.

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

2023

- an after-tax impairment charge of $1.9 billion related to our equity investment in Coastal GasLink Pipeline Limited Partnership (Coastal GasLink LP). Refer to Note 8, Coastal GasLink, of our 2023 Consolidated financial statements for additional information
- a $52 million after-tax charge as a result of the FERC Administrative Law Judge initial decision on Keystone issued in February 2023 in respect of a tolling-related complaint pertaining to amounts recognized from 2018 to 2022, which consists of a one-time pre-tax charge of $57 million and included accrued pre-tax carrying charges of $10 million
- a $48 million after-tax expense related to Focus Project costs. Refer to the Corporate – Significant events section for additional information
- an after-tax unrealized foreign exchange loss of $44 million on the peso-denominated intercompany loan between TCPL and TGNH
- a $36 million after-tax accrued insurance expense related to the Milepost 14 incident. Refer to the Liquids Pipelines – Significant events section for additional information
- an after-tax charge of $34 million due to Liquids Pipelines business separation costs related to the spinoff Transaction. Refer to the Liquids Pipelines – Significant events section for additional information

- preservation and other costs for Keystone XL pipeline project assets of $14 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge
- a $55 million after-tax recovery on the expected credit loss provision related to the TGNH net investment in leases and certain contract assets in Mexico
- an $18 million after-tax recovery related to the net impact of a U.S. minimum tax recovery on the 2021 Keystone XL asset impairment charge and other and a gain on the sale of Keystone XL project assets, offset partially by adjustments to the estimate for contractual and legal obligations related to termination activities.

2022

- an after-tax impairment charge of $2.6 billion related to our equity investment in Coastal GasLink LP
- an after-tax goodwill impairment charge of $531 million related to Great Lakes
- 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 expense related to the net impact of a U.S. minimum tax on the 2021 Keystone XL asset impairment charge and other, partially offset by a gain on the sale of Keystone XL project assets and adjustments 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.

Refer to the Financial results section in each business segment and the Financial condition section of this MD&A for additional information.

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 (loss) attributable to common shares to comparable earnings is shown in the following table.

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

year ended December 31 (millions of $, except per share amounts)	2023	2022	2021
Net income (loss) attributable to common shares	**2,829**	641	1,815
Specific items (net of tax):			
Coastal GasLink impairment charge	**1,943**	2,643	—
Keystone regulatory decisions	**52**	20	—
Focus Project costs	**48**	—	—
Foreign exchange (gains) losses, net – intercompany loan	**44**	—	—
Milepost 14 insurance expense	**36**	—	—
Liquids Pipelines business separation costs	**34**	—	—
Keystone XL preservation and other	**14**	19	37
Expected credit loss provision on net investment in leases and certain contract assets in Mexico	**(55)**	114	—
Keystone XL asset impairment charge and other	**(18)**	5	2,134
Great Lakes goodwill impairment charge	**—**	531	—
Settlement of Mexico prior years' income tax assessments	**—**	196	—
Voluntary Retirement Program	**—**	—	48
Gain on sale of Northern Courier	**—**	—	(19)
Gain on sale of Ontario natural gas-fired power plants	**—**	—	(7)
Bruce Power unrealized fair value adjustments	**(5)**	13	(11)
Risk management activities[1]	**(270)**	97	145
Comparable earnings	**4,652**	4,279	4,142
Net income (loss) per common share	**$2.75**	$0.64	$1.87
Coastal GasLink impairment charge	**1.89**	2.66	—
Keystone regulatory decisions	**0.05**	0.02	—
Focus Project costs	**0.05**	—	—
Foreign exchange (gains) losses, net – intercompany loan	**0.04**	—	—
Milepost 14 insurance expense	**0.03**	—	—
Liquids Pipelines business separation costs	**0.03**	—	—
Keystone XL preservation and other	**0.01**	0.02	0.04
Expected credit loss provision on net investment in leases and certain contract assets in Mexico	**(0.05)**	0.11	—
Keystone XL asset impairment charge and other	**(0.02)**	0.01	2.19
Great Lakes goodwill impairment charge	**—**	0.53	—
Settlement of Mexico prior years' income tax assessments	**—**	0.20	—
Voluntary Retirement Program	**—**	—	0.05
Gain on sale of Northern Courier	**—**	—	(0.02)
Gain on sale of Ontario natural gas-fired power plants	**—**	—	(0.01)
Bruce Power unrealized fair value adjustments	**—**	0.01	(0.01)
Risk management activities	**(0.26)**	0.10	0.15
Comparable earnings per common share	**$4.52**	$4.30	$4.26

1 year ended December 31			
(millions of $)	**2023**	**2022**	**2021**
U.S. Natural Gas Pipelines	**80**	(15)	6
Liquids Pipelines	**(34)**	20	(3)
Canadian Power	**(31)**	4	12
U.S. Power	**9**	—	—
Natural Gas Storage	**91**	11	(6)
Foreign exchange	**246**	(149)	(203)
Income tax attributable to risk management activities	**(91)**	32	49
Total unrealized gains (losses) from risk management activities	**270**	(97)	(145)

Comparable EBITDA to comparable earnings

Comparable EBITDA represents segmented earnings (losses) adjusted for the specific items described above and excludes 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)	**2023**	**2022**	**2021**
Comparable EBITDA			
Canadian Natural Gas Pipelines	**3,335**	2,806	2,675
U.S. Natural Gas Pipelines	**4,385**	4,089	3,856
Mexico Natural Gas Pipelines	**805**	753	666
Liquids Pipelines	**1,457**	1,366	1,526
Power and Energy Solutions	**1,020**	907	669
Corporate	**(14)**	(20)	(24)
Comparable EBITDA	**10,988**	9,901	9,368
Depreciation and amortization	**(2,778)**	(2,584)	(2,522)
Interest expense included in comparable earnings	**(3,253)**	(2,588)	(2,354)
Allowance for funds used during construction	**575**	369	267
Foreign exchange gains (losses), net included in comparable earnings	**118**	(8)	254
Interest income and other included in comparable earnings	**278**	146	190
Income tax (expense) recovery included in comparable earnings	**(1,037)**	(813)	(830)
Net (income) loss attributable to non-controlling interests	**(146)**	(37)	(91)
Preferred share dividends	**(93)**	(107)	(140)
Comparable earnings	**4,652**	4,279	4,142
Comparable earnings per common share	**$4.52**	$4.30	$4.26

Comparable EBITDA – 2023 versus 2022

Comparable EBITDA in 2023 increased by $1,087 million compared to 2022 primarily due to the net result of the following:

- increased EBITDA from Canadian Natural Gas Pipelines primarily due to higher flow-through costs and increased rate-base earnings on the NGTL System and higher earnings from Coastal GasLink related to the recognition of a $200 million incentive payment upon meeting certain milestones
- increased Power and Energy Solutions EBITDA primarily attributable to higher contributions from Bruce Power as a result of a higher contract price, fewer planned outage days and lower depreciation expense, partially offset by increased business development activities across the segment
- higher U.S. dollar-denominated EBITDA from U.S. Natural Gas Pipelines due to incremental earnings from growth projects placed in service, a net increase in earnings from ANR resulting from an increase in transportation rates effective August 2022, higher realized margins related to our U.S. natural gas marketing business, partially offset by higher operational costs reflective of increased system utilization and lower commodity prices related to our mineral rights business
- increased EBITDA from Liquids Pipelines due to higher volumes on the Keystone Pipeline System and the foreign exchange impact of a stronger U.S. dollar on the translation of our U.S. dollar-denominated operations
- higher U.S. dollar-denominated EBITDA from Mexico Natural Gas Pipelines primarily related to certain sections of the Villa de Reyes and Tula pipelines that were placed in commercial service in third quarter 2022 and 2023, partially offset by lower equity earnings from Sur de Texas primarily due to peso-denominated financial exposure and higher interest expense
- 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 84, U.S. dollar-denominated comparable EBITDA increased by US$142 million compared to 2022, which was translated to Canadian dollars at an average rate of 1.35 in 2023 versus 1.30 in 2022. Refer to the Foreign exchange section for additional information.

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 realized power prices and increased contributions from Natural Gas Storage and Other as a result of higher realized spreads in 2022
- higher U.S. dollar-denominated EBITDA from U.S. Natural Gas Pipelines largely due to incremental earnings from growth projects placed in service, higher commodity prices from our mineral rights business, as well as increased net earnings from Columbia Gas primarily due to an increase in transportation rates effective February 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 lower flow-through costs, partially offset by higher incentive earnings on Canadian Mainline
- higher EBITDA from Mexico Natural Gas Pipelines primarily related to certain sections of the Villa de Reyes and Tula pipelines that were placed in commercial service in third quarter 2022
- decreased EBITDA from Liquids Pipelines as a result of lower rates and contracted volumes on the U.S. Gulf Coast section of the Keystone Pipeline System, as well as reduced contributions from liquids marketing activities and the foreign exchange impact of a stronger U.S. dollar on the translation of our U.S. dollar-denominated operations
- 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 84, 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 section 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 – 2023 versus 2022

Comparable earnings in 2023 were $373 million or $0.22 per common share higher than in 2022, and were primarily the net result of:

- changes in comparable EBITDA described above
- higher interest expense primarily due to long-term debt issuances, net of maturities, the foreign exchange impact of a stronger U.S. dollar in 2023 compared to 2022 and higher interest rates on our long-term debt
- increased income tax expense due to the impact of higher comparable earnings subject to income tax, Mexico foreign exchange exposure, lower foreign tax rate differentials, partially offset by lower flow-through income taxes and lower Mexico inflation adjustments
- higher depreciation and amortization reflecting expansion facilities and new projects placed in service and the acquisitions of the Fluvanna Wind Farm and Blue Cloud Wind Farm (Texas Wind Farms), partially offset by the discontinuance of depreciation expense on TGNH assets in Mexico accounted for as leases
- higher net income attributable to non-controlling interests primarily due to the net effect of the sale of a 40 per cent non-controlling equity interest in Columbia Gas Transmission, LLC (Columbia Gas) and Columbia Gulf Transmission, LLC (Columbia Gulf) and the acquisition of the Texas Wind Farms
- higher AFUDC predominantly due to the Southeast Gateway pipeline project, as well as the reactivation of AFUDC on the TGNH assets under construction, partially offset by projects placed in service
- higher interest income and other due to higher interest earned on short-term investments
- the impact of activities to manage our foreign exchange exposure to net liabilities in Mexico, partially offset by derivatives used to manage our net exposure to foreign exchange rate fluctuation on U.S. dollar-denominated income and the revaluation of our peso-denominated net monetary liabilities to U.S. dollars.

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
- the impact of derivatives used to manage our net exposure to foreign exchange rate fluctuation on U.S. dollar-denominated income and the revaluation of our peso-denominated net monetary liabilities to U.S. dollars, partially offset by activities to manage our foreign exchange exposure to net liabilities in Mexico
- 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, partially offset by the impact of decreased capital expenditures and projects placed in service
- higher depreciation and amortization 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 per common share reflect the dilutive effect of common shares issued in 2023 and 2022 and the impact of common shares issued for the acquisition of the remaining ownership interests in TC PipeLines, LP in March 2021. Refer to the Financial Condition section for additional information.

Cash flows

Net cash provided by operations of $7.3 billion in 2023 was 14 per cent higher than 2022 primarily due to the amount and timing of working capital changes and higher funds generated from operations. Comparable funds generated from operations of $8.0 billion in 2023 were nine per cent higher than 2022 primarily due to higher comparable earnings and increased distributions from operating activities of our equity investments.

Funds used in investing activities

Capital spending[1]

year ended December 31 (millions of $)	2023	2022	2021
Canadian Natural Gas Pipelines	**6,184**	4,719	2,737
U.S. Natural Gas Pipelines	**2,660**	2,137	2,820
Mexico Natural Gas Pipelines	**2,292**	1,027	129
Liquids Pipelines	**49**	143	571
Power and Energy Solutions	**1,080**	894	842
Corporate	**33**	41	35
	12,298	8,961	7,134

1 Capital spending reflects cash flows associated with our Capital expenditures, Capital projects in development and Contributions to equity investments. Refer to Note 5, Segmented information, of our 2023 Consolidated financial statements for the financial statement line items that comprise total capital spending.

In 2023 and 2022, we invested $12.3 billion and $9.0 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 2023 and 2022 included contributions of $4.1 billion and $2.2 billion, respectively, to our equity investments, predominantly related to Coastal GasLink LP and Bruce Power.

Acquisitions

In 2023, we acquired 100 per cent of the Class B Membership Interests in Texas Wind Farms for US$224 million, before post-closing adjustments.

Proceeds from sales of assets

In 2023, we completed the sale of a 20.1 per cent equity interest in Port Neches Link LLC to its joint venture partner, Motiva Enterprises, for gross proceeds of US$25 million.

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

Balance sheet

We continue to maintain a solid financial position while growing our total assets by $10.7 billion in 2023. At December 31, 2023, common shareholders' equity and non-controlling interests, represented 37 per cent (2022 – 35 per cent) of our capital structure, while other subordinated capital, in the form of junior subordinated notes and preferred shares, represented an additional 13 per cent (2022 – 14 per cent). Refer to the Financial Condition section for additional information.

Dividends

We increased the quarterly dividend on our outstanding common shares by 3.2 per cent to $0.96 per common share for the quarter ending March 31, 2024, which equates to an annual dividend of $3.84 per common share. This was the twenty-fourth 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. From August 31, 2022 to July 31, 2023, common shares were issued from treasury at a discount of two per cent to market prices over a specified period. The participation rate by common shareholders in the DRP in 2023 was approximately 39 per cent (2022 – 33 per cent), resulting in $737 million (2022 – $607 million) reinvested in common equity under the program.

Commencing with the dividends declared on July 27, 2023, common shares purchased under TC Energy's DRP are acquired on the open market at 100 per cent of the weighted average purchase price.

Cash dividends paid

year ended December 31 (millions of $)	2023	2022	2021
Common shares	**2,787**	3,192	3,317
Preferred shares	**92**	106	141

OUTLOOK

Comparable EBITDA and comparable earnings

Our 2024 comparable EBITDA and comparable earnings per common share outlooks do not take into consideration the impact of the spinoff Transaction as it is subject to TC Energy shareholder approval, court approval, favourable tax rulings, other regulatory approvals and satisfaction of other customary closing conditions.

We expect our 2024 comparable EBITDA to be higher than 2023 primarily due to the following:
- growth in the NGTL System from advancement of expansion programs
- full-year impact of Bruce Power Unit 6 return to service in September 2023
- new projects anticipated to be placed in service in 2024, along with the full-year impact of projects placed in service in 2023.

Our 2024 comparable earnings per common share is expected to be lower than 2023 due to the net impact of the following:
- higher net income attributable to non-controlling interests as a result of the sale of a 40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf in 2023
- increase in comparable EBITDA described above
- 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 outlooks.

Consolidated capital expenditures

In 2023, we incurred approximately $12.4 billion in capital expenditures on our secured capital program and projects under development. Prior to adjustments for non-controlling interests, we expect to incur gross capital expenditures, including capitalized interest, of approximately $8.5 to $9.0 billion in 2024 on growth projects, maintenance capital expenditures, contributions to equity investments and projects under development. We anticipate our net capital expenditures in 2024 to be approximately $8.0 to $8.5 billion after considering capital expenditures attributable to the non-controlling interests of entities we control.

The majority of our 2024 capital program is expected to be focused on the advancement of secured projects including the Southeast Gateway pipeline, U.S. Natural Gas Pipelines projects, the Coastal GasLink pipeline project, Bruce Power Major Component Replacement (MCR) programs and normal course maintenance capital expenditures.

Refer to the Outlook section in each business segment for additional details on expected earnings and capital expenditures for 2024.

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 $31 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 2023, we placed approximately $5.3 billion of projects in service, which included natural gas pipeline capacity capital projects along our extensive North American asset footprint, as well as the Bruce Power Unit 6 MCR, which was declared commercially operational on September 14, 2023. In addition, approximately $2.2 billion of maintenance and modernization 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 projects within entities that we own or partially own and fully consolidate, as well as our share of equity contributions to fund projects within our equity investments, primarily Coastal GasLink and Bruce Power.

(billions of $)	Expected in-service date	Estimated project cost	Project costs incurred at December 31, 2023
Canadian Natural Gas Pipelines			
NGTL System	2024	0.7	0.5
	2026+	0.7	0.1
Coastal GasLink[1]	2024	5.5	4.6
Regulated maintenance capital expenditures	2024-2026	2.3	—
U.S. Natural Gas Pipelines			
Modernization and other[2]	2024-2026	US 1.7	US 0.9
Delivery market projects	2025	US 1.5	US 0.2
Heartland project	2027	US 0.9	—
Other capital	2024-2028	US 1.5	US 0.5
Regulated maintenance capital expenditures	2024-2026	US 2.2	—
Mexico Natural Gas Pipelines			
Villa de Reyes – south section[3]	2024	US 0.3	US 0.3
Tula[4]	—	US 0.4	US 0.3
Southeast Gateway	2025	US 4.5	US 2.4
Liquids Pipelines			
Recoverable maintenance capital expenditures	2024-2026	0.3	—
Power and Energy Solutions			
Bruce Power – Unit 3 MCR	2026	1.1	0.6
Bruce Power – Unit 4 MCR	2028	0.9	0.1
Bruce Power – life extension[5]	2024-2027	1.8	0.7
Other			
Non-recoverable maintenance capital expenditures[6]	2024-2026	0.4	—
		26.7	11.2
Foreign exchange impact on secured projects[7]		4.2	1.5
Total secured projects (Cdn$)		30.9	12.7

1 The estimated project cost noted above represents our share of anticipated partner equity contributions to the project. Mechanical completion was achieved in November 2023. Commercial in-service of the Coastal GasLink pipeline will occur after completion of plant commissioning activities at the LNG Canada facility and upon receiving notice from LNG Canada. Refer to the Canadian Natural Gas Pipelines – Significant events section for additional information.

2 Includes 100 per cent of the capital expenditures related to our modernization program on Columbia Gas, as well as certain large-scope maintenance projects across our U.S. natural gas pipelines footprint due to their discrete nature and timing for regulatory recovery. Refer to the U.S. Natural Gas Pipelines – Significant events section for additional information.

3 We are working with the CFE on completing the remaining section of the Villa de Reyes pipeline, with an anticipated commercial in-service date in the second half of 2024. Refer to the Mexico Natural Gas Pipelines – Significant events section for additional information.

4 Estimated project cost as per contracts signed in 2022 as part of the TGNH strategic alliance between TC Energy and the CFE. We continue to evaluate the development and completion of the Tula pipeline, with the CFE, subject to a future FID and updated cost estimate. Refer to the Mexico Natural Gas Pipelines – Significant events section for additional information.

5 Reflects amounts to be invested under the Asset Management program, other life extension projects 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 assets.

7 Reflects U.S./Canada foreign exchange rate of 1.32 at December 31, 2023.

Projects under development

In addition to our secured projects, we are pursuing a portfolio of quality projects in various stages of development across each of our business units. 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. While each business segment also has additional areas of focus for further ongoing business development activities and growth opportunities, new opportunities will be assessed within our capital allocation framework in order to fit within our annual capital expenditure parameters. 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, connections to growing shale gas supplies and other opportunities supporting our reduction in GHG emissions intensity.

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 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 a focus on cleaner energy.

We are actively developing RNG transportation hubs within our U.S. Natural Gas Pipelines footprint. 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 the development of these hubs is an important step towards the acceleration of methane capture projects and the concurrent reduction of GHG emissions.

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.

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.

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 MCR program costs on Units 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 5, 7 and 8 MCRs is underway and 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 $4.0 billion for our proportionate share of the Bruce Power MCR program costs for Units 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.

Ontario Pumped Storage

Along with the Saugeen Ojibway Nation, our prospective partner, we continue to advance 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. Next steps to advance the OPSP include:

- working with the Ministry of Energy (Ministry) and Ontario Energy Board on the establishment of a potential long-term revenue framework by July 2024
- providing a breakdown of estimated development costs and schedule to the Ministry after which the Ministry will provide a recommendation to proceed with pre-development work within 45 days
- negotiation of cost recovery agreement with the IESO to recover eligible, prudently incurred expenses associated with pre-development work. A follow up report from the IESO to the Ministry to be provided within 60 days of estimates submission
- provide further information to assist with the Ontario government's assessment of OPSP societal and economic benefits.

A final decision to fund development costs of OPSP is subject to Cabinet approvals and Ministerial directive to the IESO to execute agreements with us.

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.

The OPSP remains subject to approval by our Board of Directors and the Saugeen Ojibway Nation. Construction would begin in the latter part of this decade with in-service in the early 2030s, subject to receipt of regulatory and corporate approvals.

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).

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 CO_2 annually. As an open-access system, the Alberta Carbon Grid (ACG) is intended to serve as the backbone for Alberta's emerging carbon capture utilization and storage industry. In October 2022, ACG 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. ACG continues to progress an appraisal program needed to evaluate the suitability of our AOI, including the advancement and completion of well drilling and testing activities to support the development of a detailed Measurement, Monitoring and Verification plan required to apply for a sequestration permit.

Other Carbon Capture

We are collaborating with Minnkota Power Cooperative (Minnkota), Mitsubishi Heavy Industries and Kiewit on Project Tundra, a next-generation technology carbon capture and storage project. Project Tundra would be our first carbon capture and sequestration project in the U.S., capturing up to approximately four million tons of CO_2 per annum from Minnkota's Milton R. Young Generating Station. When constructed, Project Tundra is expected to be the largest post-combustion carbon capture project in North America and would support the continuation of baseload, reliable, power generation in the region. In December 2023, the U.S. Department of Energy and Office for Clean Energy Demonstrations announced up to US$350 million in funding for Project Tundra.

Hydrogen Hubs

We are advancing multiple hydrogen production opportunities to potentially serve long-haul transportation, power generation, large industrials and heating customers across the U.S. and Canada. We believe that measured investment in emerging technologies like hydrogen will help us expand our capabilities through energy transition, focusing on opportunities that complement our core business and where we can obtain favourable and strategically-consistent commercial arrangements such as rate regulation and/or long-term contracts.

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 – 64,207 km (39,896 miles)
- partially-owned natural gas pipelines – 29,372 km (18,251 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 in North America and developing new projects to provide connectivity to LNG export terminals, both operating and proposed
- connections to growing Canadian and U.S. shale gas and other supplies
- decarbonizing our energy consumption, thereby reducing overall GHG emissions 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 emissions intensity reduction target, 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 model 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 $2.8 billion of capital projects placed in service in 2023 primarily related to the NGTL System and NGTL System/ Foothills West Path expansions, as well as spending on maintenance capital
- mechanical completion of the Coastal GasLink pipeline project in fourth quarter 2023
- CER approved the VNBR project in fourth quarter 2023
- achieved record throughput volumes on the NGTL System and Canadian Mainline.

U.S. Natural Gas Pipelines

- placed approximately US$1.6 billion of capital projects in service in 2023, including the North Baja XPress project, as well as spending on modernization and maintenance capital
- sanctioned an additional US$1.6 billion of capital projects including the Heartland project on ANR and the Bison XPress project on Northern Border
- sale of a 40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf for proceeds of $5.3 billion (US$3.9 billion), which closed on October 4, 2023
- ANR, Columbia Gulf and Tuscarora rate case settlements approved by FERC
- achieved record throughput volumes on a number of our pipelines.

Mexico Natural Gas Pipelines

- the Southeast Gateway pipeline project is progressing according to planned milestones and began construction on all facilities and installations in Veracruz and Tabasco, as well as offshore pipe laying at the end of 2023
- the lateral section of the Villa de Reyes pipeline was placed in commercial service in third quarter 2023
- in December 2023, TGNH and the CFE obtained from Mexico's Federal Economic Competition Commission (COFECE) a favourable merger ruling and a determination that the proposed minority CFE equity participation in TGNH did not require a favourable cross participation opinion given that the CFE would not have a controlling interest in TGNH. TGNH and the CFE subsequently requested the CRE to confirm that a cross participation permit is not required given that the CFE would not have a controlling interest in TGNH
- 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 39 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 and Foothills System: These are 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 to the U.S. markets including Great Lakes, Midwest, Gulf Coast and U.S. 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. We own a 60 per cent equity interest and are the operator of this pipeline.

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. We own a 60 per cent equity interest and are the operator of this pipeline.

Other U.S. Natural Gas Pipelines: We have ownership interests in ten wholly-owned or partially-owned natural gas pipelines serving major markets in the U.S.

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 2023 supplied approximately 17 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, 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 the 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 135 Bcf/d by 2027, reflecting an increase of approximately 28 Bcf/d from 2022 levels.

As the world shifts toward lower GHG emission-intensive 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 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 their existing footprint. Modernizing our existing systems and assets, and decarbonizing energy consumption along our natural gas pipeline systems is expected to provide ongoing additional capital investment opportunities that will meet our risk preferences while supporting our GHG emissions intensity reduction goal.

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 believe that natural gas is a key energy transition fuel for Mexico.

Overall, we are forecasting significant gas demand growth in the future to support economic expansion and industrial load growth, conversion to lower GHG emission-intensive 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.

Commodity prices

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

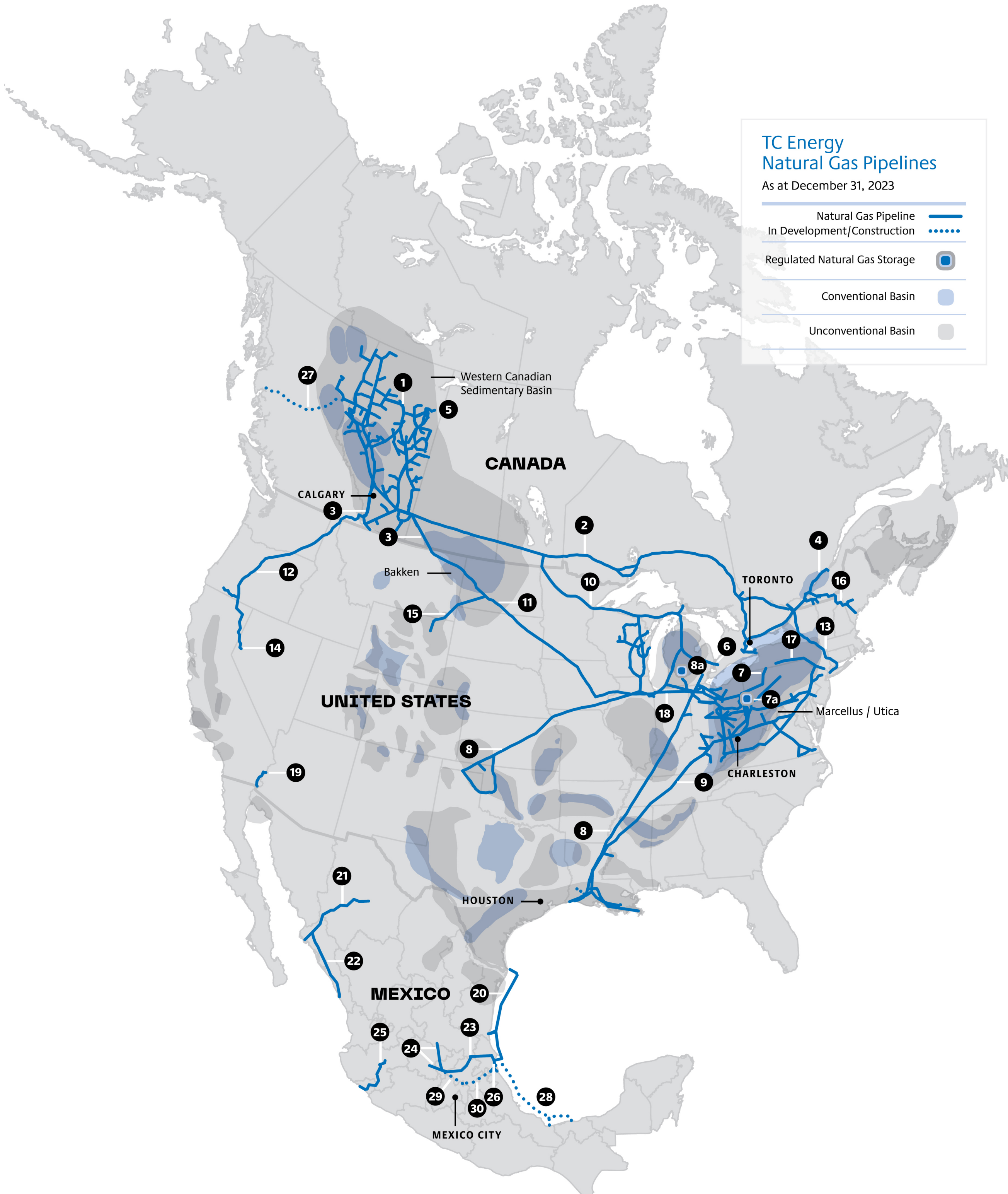
Changes in supply and demand levels and locations have resulted in increased competition to provide transportation services throughout North America. Our well-distributed footprint of natural gas pipelines, particularly in the liquids-rich and low-cost WCSB and the Appalachian basin, both of which are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

In 2024, we will continue to focus on the execution of our existing capital program that includes progressing construction on our Southeast Gateway pipeline in Mexico, investment in the NGTL System, as well as the completion and initiation of new pipeline projects in the United States. We will remain focused on capital discipline as we 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, 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, 2023
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
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MEXICO CITY
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We are the operator of all of the following natural gas pipelines and regulated natural gas storage assets except for Iroquois.

		Length	Description	Ownership
	Canadian pipelines			
1	NGTL System	24,386 km (15,153 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 Canadian and U.S. markets.	100%
3	Foothills	1,284 km (798 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)	651 km (405 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%
6	Great Lakes Canada	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			
7	Columbia Gas	18,692 km (11,615 miles)	Transports natural gas primarily from the Appalachian basin to markets and pipeline interconnects throughout the U.S. Northeast, Midwest and Atlantic regions.	60%
7a	Columbia Storage	285 Bcf	Provides regulated underground natural gas storage service from several facilities (not all shown) to customers in key eastern markets. We own a 60 per cent interest in the 273 Bcf Columbia Storage facility and a 50 per cent interest in the 12 Bcf Hardy Storage facility.	Various
8	ANR[3]	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%
8a	ANR Storage	247 Bcf	Provides regulated underground natural gas storage service from several facilities (not all shown) to customers in key mid-western markets.	
9	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.	60%
10	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%
11	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%
12	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%
13	Iroquois	669 km (416 miles)	Connects with the Canadian Mainline and serves markets in New York.	50%
14	Tuscarora	491 km (305 miles)	Transports natural gas from GTN at Malin, Oregon to markets in northeastern California and northwestern Nevada.	100%
15	Bison	488 km (303 miles)	Transports natural gas from the Powder River basin in Wyoming to Northern Border in North Dakota.	100%
16	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
17	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%
18	Crossroads	325 km (202 miles)	Interstate natural gas pipeline operating in Indiana and Ohio with multiple interconnects to other pipelines.	100%
19	North Baja[3]	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			
20	Sur de Texas	770 km (478 miles)	Offshore pipeline that transports natural gas from the U.S./Mexican border near Brownsville, Texas, to Mexican power plants in Altamira, Tamaulipas and Tuxpan, Veracruz, where it interconnects with the Tamazunchale and Tula pipelines and other third-party facilities.	60%
21	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%
22	Mazatlán	430 km (267 miles)	Transports natural gas from El Oro to Mazatlán, Sinaloa and connects to the Topolobampo pipeline at El Oro.	100%
23	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%
24	Villa de Reyes – north and lateral section	326 km (203 miles)	The north and lateral sections of the Villa de Reyes pipeline are interconnected to our Tamazunchale pipeline and third-party systems, supporting gas deliveries to power plants in Villa de Reyes, San Luis Potosí and Salamanca, Guanajuato.	100%
25	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%
26	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%
	Under construction			
	Canadian pipelines			
27	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 near Kitimat, British Columbia. Coastal GasLink pipeline was mechanically complete in November 2023 and is ready to deliver gas to the LNG Canada facility. Commercial in-service of the Coastal GasLink pipeline will occur after completion of plant commissioning activities at the LNG Canada facility and upon receiving notice from LNG Canada.	35%
	NGTL System 2024 Facilities[1]	n/a	Compressor station components of the 2023 NGTL System Intra-Basin Expansion expected to be placed in service in 2024.	100%
	U.S. pipelines			
	East Lateral XPress[1,3]	n/a	An expansion project on Columbia Gulf through compressor station modifications and additions expected to be placed in service in 2025.	60%
	Gillis Access Project[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. The project is expected to be placed in service in 2024.	100%

	Under construction (continued)	Length	Description	Ownership
	GTN XPress[3]	n/a	An expansion project of GTN through compressor station modifications and additions with the remaining sections expected to be placed in service in 2024.	100%
	Mexico pipelines			
28	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%
29	Villa de Reyes – south section	110 km (68 miles)	This pipeline section will connect to the operational north and lateral sections of the Villa de Reyes pipeline and to the Tula pipeline.	100%
30	Tula[2]	n/a	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. TC Energy and CFE are assessing options to complete the remaining sections of the pipeline, which are subject to an FID.	100%
	Permitting and pre-construction phase			
	Canadian pipelines			
	NGTL System 2025+ Facilities[1,2]	50 km (31 miles)	The VNBR project, along with other facilities expected to be placed in service in 2026.	100%
	U.S. pipelines			
	Bison XPress Project[3]	n/a	A project with Northern Border, a 50 per cent owned subsidiary, and Bison, a wholly-owned subsidiary, that will replace and upgrade certain facilities while improving reliability, which is expected to be placed in service in 2026	Various
	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, which is expected to be placed in service in 2025.	60%
	WR Project[3]	n/a	A delivery market project on ANR that will replace and upgrade certain facilities while improving reliability and reducing emissions, which is expected to be placed in service in 2025.	100%
	Ventura XPress Project[3]	n/a	A project on ANR that will replace and upgrade certain facilities improving base system reliability, which is expected to be placed in service in 2025.	100%
	Heartland Project[3]	n/a	Expansion project on ANR that will increase capacity and improve system reliability with upgrades to compression facilities, expected to be placed in service in 2027.	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 Includes compressor station modifications, additions and/or expansion projects 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 reached mechanical completion in fourth quarter 2023 and is regulated by the BC Energy Regulator (formerly the BC Oil & Gas Commission).

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 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.

Subject to approval by the CER, we and our customers can also establish settlement arrangements 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 successfully achieved mechanical completion, completed required commissioning activities and was ready to deliver gas to the LNG Canada facility in fourth quarter 2023. These milestones entitle Coastal GasLink LP to receive a $200 million incentive payment from LNG Canada. In accordance with the contractual terms between the Coastal GasLink LP partners, this amount accrues in full to TC Energy as the project developer and was settled through a cash distribution on February 12, 2024. We recognized the incentive payment as Income (loss) from equity investments in the Consolidated statement of income for the year ended December 31, 2023 and recorded a corresponding amount in Accounts receivable on the Consolidated balance sheet.

Through 2024, Coastal GasLink LP will continue post-construction reclamation activities. Coastal GasLink LP also continues to pursue cost recovery, including certain arbitration proceedings which involve claims by, and the defense of certain claims against, Coastal GasLink LP. These claims have not yet been conclusively determined, but our expectation is that these proceedings are likely to result in cost recoveries. For more information on these proceedings, refer to Note 32, Commitments, contingencies and guarantees, of our 2023 Consolidated financial statements for additional information. The project remains on track with its cost estimate of approximately $14.5 billion.

Commercial in-service of the Coastal GasLink pipeline will occur after completion of plant commissioning activities at the LNG Canada facility and upon receiving notice from LNG Canada. Once in service, the pipeline will transport natural gas from a receipt point in the Dawson Creek area of British Columbia to LNG Canada's natural gas liquefaction facility near Kitimat, British Columbia. 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.

In 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. Project costs are funded by existing project-level credit facilities and equity contributions from the Coastal GasLink LP partners, including us. Beginning in 2023, the equity financing required to fund construction of the pipeline to completion is initially provided through a subordinated loan agreement between TC Energy and Coastal GasLink LP. 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 will be predominantly funded by us, except under certain conditions, but will not result in a change to our 35 per cent ownership. At December 31, 2023, committed capacity under this subordinated loan agreement was $3,375 million, on which $2,520 million was drawn.

The expectation that additional equity contributions will predominantly be funded by us was an indicator during the first three quarters of 2023 that a decrease in the value of our equity investment had occurred. As a result, we completed valuation assessments and concluded that there was an other-than-temporary impairment of our investment, resulting in a pre-tax impairment charge on our investment in Coastal GasLink LP of $2,100 million ($1,943 million after tax) for the year ended December 31, 2023. The impairment charge reflected the net impact of changes in the subordinated loan for the nine months ended September 30, 2023, along with TC Energy's proportionate share of unrealized gains and losses on interest rate derivatives in Coastal GasLink LP and other changes to the equity investment. The impairment of the subordinated loan resulted in unrealized non-taxable capital losses that are not recognized. The cumulative pre-tax impairment charge recognized to date at December 31, 2023 is $5,148 million ($4,586 million after tax). Refer to Note 8, Coastal GasLink, of our 2023 Consolidated financial statements for additional information.

At December 31, 2023, the carrying value of our equity investment was $294 million. There was no indicator that there was an other-than-temporary impairment of this investment, and no impairment charge was recognized in fourth quarter 2023.

NGTL System and Foothills

In the year ended December 31, 2023, the NGTL System and Foothills placed approximately $2.0 billion and $0.8 billion, respectively, of capacity projects in service. The details of the significant capacity programs are listed below.

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 $3.6 billion. As of December 31, 2023, $3.4 billion of the program's facilities have been placed in service, including all facilities required to declare contracts.

2022 NGTL System Expansion Program

The 2022 NGTL System Expansion Program was completed in 2023 and consists of approximately 166 km (103 miles) of new pipeline, one compressor unit and associated facilities and provides incremental capacity of approximately 773 TJ/d (722 MMcf/d) to meet firm-receipt and intra-basin delivery requirements with eight-year minimum terms. The capital cost of the program was $1.4 billion with all assets placed in service.

NGTL System/Foothills West Path Delivery Program

The NGTL System/Foothills West Path Delivery Program was 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. The capital cost of the program was $1.6 billion with all remaining assets placed in service in 2023.

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 $0.5 billion. Construction activities commenced in 2022 with the pipeline placed in service in late 2023 and construction of the compressor stations is underway with anticipated in-service by second quarter 2024.

Valhalla North and Berland River Project

The VNBR project will serve aggregate system requirements and connect migrating supply to key demand markets, providing incremental capacity on the NGTL System of approximately 428 TJ/d (400 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. On December 21, 2023, we received approval from the CER to construct, own and operate the VNBR project with an anticipated in-service date in second quarter 2026.

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 $)	2023	2022	2021
NGTL System	**2,201**	1,853	1,649
Canadian Mainline	**789**	770	838
Other Canadian pipelines[1]	**345**	183	188
Comparable EBITDA	**3,335**	2,806	2,675
Depreciation and amortization	**(1,325)**	(1,198)	(1,226)
Comparable EBIT	**2,010**	1,608	1,449
Specific item:			
Coastal GasLink impairment charge	**(2,100)**	(3,048)	—
Segmented earnings (losses)	**(90)**	(1,440)	1,449

1 Includes results from Foothills, Ventures LP, Great Lakes Canada and our proportionate share of income related to investments in TQM and Coastal GasLink, as well as general and administrative and business development costs related to our Canadian Natural Gas Pipelines.

Canadian Natural Gas Pipelines segmented losses in 2023 decreased by $1.4 billion compared to 2022. Canadian Natural Gas Pipelines segmented losses were $1.4 billion in 2022 compared to segmented earnings of $1.4 billion in 2021. A pre-tax impairment charge in 2023 of $2.1 billion (2022 – $3.0 billion) related to our equity investment in Coastal GasLink LP was recognized, which has been excluded from our calculation of comparable EBITDA and comparable EBIT. Refer to Note 8, Coastal GasLink, of our 2023 Consolidated financial statements for additional information.

Net income and comparable EBITDA for our rate-regulated Canadian natural gas pipelines are primarily affected by our approved ROE, 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 $)	2023	2022	2021
Net income			
NGTL System	**770**	708	631
Canadian Mainline	**230**	223	213
Average investment base			
NGTL System	**19,008**	17,493	15,560
Canadian Mainline	**3,709**	3,735	3,724

Net income for the NGTL System increased by $62 million in 2023 compared to 2022 and by $77 million in 2022 compared to 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 increased by $7 million in 2023 compared to 2022 and by $10 million in 2022 compared to 2021 mainly as a result of 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

Comparable EBITDA for Canadian Natural Gas Pipelines was $529 million higher in 2023 compared to 2022 primarily due to the net effect of:

- higher flow-through financial charges, depreciation and income taxes, as well as higher rate-base earnings on the NGTL System
- earnings from Coastal GasLink related to the recognition of a $200 million incentive payment upon meeting certain milestones, partially offset by lower development fee revenue resulting from timing of revenue recognition. Refer to the Canadian Natural Gas Pipelines – Significant events section for additional information
- higher flow-through depreciation, financial charges and higher incentive earnings, partially offset by lower flow-through income taxes on the Canadian Mainline.

Comparable EBITDA for Canadian Natural Gas Pipelines in 2022 was $131 million higher than 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.

Depreciation and amortization

Depreciation and amortization was $127 million higher in 2023 compared to 2022 due to higher depreciation on the NGTL System from expansion facilities that were placed in service and on the Canadian Mainline due to assets placed in service on a section with higher depreciation rates per the terms of the 2021-2026 Mainline Settlement. Depreciation and amortization was $28 million lower in 2022 compared to 2021 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 in 2024 is expected to be consistent with 2023 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; offset by the Coastal GasLink incentive payment recognized in 2023 for achieving certain milestones. 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. We expect our comparable earnings in 2024 for the NGTL System and the Canadian Mainline to be consistent with 2023.

Capital expenditures

We incurred $2.6 billion in 2023 in our Canadian Natural Gas Pipelines business on growth projects and maintenance capital expenditures. We expect to incur approximately $1.2 billion in 2024, 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 $3.0 billion to our investment in Coastal GasLink LP in 2023 and expect to contribute $0.9 billion in 2024. Refer to the Canadian Natural Gas Pipelines – Significant events section for additional information.

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 recently, and will continue to, produce new rules affecting numerous aspects of operation and maintenance of our pipeline system. PHMSA’s priorities are generally dictated by legislation which is influenced by numerous stakeholders and informed by learnings from recent industry incidents and stakeholder priorities. When PHMSA implements new rules TC Energy seeks recovery of additional expenditures driven by such rules in future rate cases and modernization settlements.

SIGNIFICANT EVENTS

Columbia Gas and Columbia Gulf Monetization

On October 4, 2023, we successfully completed the sale of a 40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf to Global Infrastructure Partners (GIP) for proceeds of $5.3 billion (US$3.9 billion). Columbia Gas and Columbia Gulf are held by a newly formed entity with GIP. Preceding the close of the equity sale, on August 8, 2023, Columbia Pipelines Operating Company LLC and Columbia Pipelines Holding Company LLC issued US$4.6 billion and US$1.0 billion of long-term, senior unsecured debt, respectively. The net proceeds from the offerings were used to repay existing intercompany indebtedness with TC Energy entities and directed towards reducing leverage. Refer to the Financial Condition section for additional information.

We continue to have a controlling interest in Columbia Gas and Columbia Gulf and we remain the operator of these pipelines. TC Energy and GIP will each fund their proportionate share of annual maintenance, modernization and sanctioned growth capital expenditures through internally generated cash flows, debt financing within the Columbia entities, or from proportionate contributions from TC Energy and GIP.

ANR Section 4 Rate Case

ANR reached a settlement with its customers effective August 2022 and received FERC approval in April 2023. As part of the settlement, there is a moratorium on any further rate changes until November 1, 2025. ANR must file for new rates with an effective date no later than August 1, 2028. The settlement also included an additional rate step up effective August 2024 related to certain modernization projects. In second quarter 2023, previously accrued rate refund liabilities, including interest, were refunded to customers.

Columbia Gulf Rate Settlement

On July 7, 2023, Columbia Gulf filed an uncontested rate settlement which would set new recourse rates for Columbia Gulf effective March 1, 2024 and institute a rate moratorium through February 28, 2027. The revised rates are not expected to have a significant impact on our U.S. Natural Gas Pipelines segment comparable earnings. Columbia Gulf must file for new rates no later than March 1, 2029.

Line VB Strasburg
On July 25, 2023, a natural gas pipeline rupture on Columbia Gas occurred alongside Interstate 81 in Strasburg, Virginia. Emergency response procedures were enacted and the segment of impacted pipeline was isolated shortly thereafter. There were no reported injuries involved with this incident and no significant damage to surrounding structures. The pipeline has been operating at reduced pressure in accordance with PHMSA's Corrective Action Order (CAO) since July 28, 2023 and we are working with PHMSA under the CAO to return the system to normal operations as soon as possible. The Root Cause Failure Analysis (RCFA) findings indicated that similar pipeline segment locations within the Columbia Gas pipeline system require further testing; however, we do not expect the Line VB Strasburg event or the additional testing to have a material impact on our financial results.

North Baja XPress
In June 2023, the North Baja XPress project, an expansion project designed to expand capacity and meet increased customer demand on our North Baja pipeline, was placed in service. The capital cost of this project was approximately US$0.1 billion.

Bison XPress Project
In third quarter 2023, we approved the Bison XPress project, an expansion project on our Northern Border and Bison systems that will replace and upgrade certain facilities and provide much needed production egress from the Bakken basin to a delivery point at the Cheyenne Hub. The project has an anticipated in-service date in 2026. Total estimated project costs are US$0.4 billion, of which our share is US$0.2 billion, representing our 50 per cent equity investment in Northern Border and 100 per cent ownership in Bison.

GTN XPress Project
In October 2023, FERC provided a certificate order approving our GTN XPress project. The GTN XPress project is an expansion of the GTN system that will provide for the transport of incremental contracted export capacity facilitated by the NGTL System/Foothills West Path Delivery Program. The anticipated in-service date is in 2024 with an estimated project cost of US$0.1 billion.

VR and WR Projects
In November and December 2023, the FERC provided a certificate order approving our VR and WR projects, respectively. The VR project will provide incremental capacity from Greensville County, Virginia to delivery points in Norfolk, Virginia. The anticipated in-service date is late 2025 with an estimated project cost of US$0.7 billion. The WR project will provide mainline capacity to multiple points of delivery on our ANR System in Wisconsin. The anticipated in-service date is late 2025 with an estimated project cost of US$0.8 billion.

Virginia Electrification Project
In February 2024, the Virginia Electrification project, an expansion project that replaced and upgraded certain facilities through conversion to electric compression, reducing GHG emissions intensity along portions of our Columbia Gas system, was placed in service with a capital cost of approximately US$0.1 billion.

Heartland Project
In February 2024, we approved the Heartland project, an expansion project on our ANR system that is expected to increase capacity and improve system reliability. The Heartland project involves pipeline looping, compressor facility additions, as well as upgrades, and upon in-service, will increase ANR's overall market share in the Midwest region. The anticipated in-service date is late 2027 with an estimated project cost of US$0.9 billion.

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.

The table below reflects 100 per cent of comparable EBITDA on assets we own or partially own and fully consolidate, as well as equity income for assets we own an equity interest in and do not consolidate.

year ended December 31 (millions of US$, unless otherwise noted)	2023	2022	2021
Columbia Gas[1]	**1,530**	1,511	1,529
ANR	**650**	582	592
Columbia Gulf[1]	**208**	207	220
GTN[2]	**202**	184	170
Great Lakes[2]	**183**	178	176
Portland[1]	**104**	101	78
Other U.S. pipelines[3]	**371**	379	310
Comparable EBITDA	**3,248**	3,142	3,075
Depreciation and amortization	**(692)**	(681)	(630)
Comparable EBIT	**2,556**	2,461	2,445
Foreign exchange impact	**895**	742	620
Comparable EBIT (Cdn$)	**3,451**	3,203	3,065
Specific items:			
Great Lakes goodwill impairment charge	**—**	(571)	—
Risk management activities	**80**	(15)	6
Segmented earnings (losses) (Cdn$)	**3,531**	2,617	3,071

1 Includes non-controlling interest. Refer to the Corporate - Financial results section for additional information.
2 Reflects 100 per cent of comparable EBITDA in GTN and Great Lakes, subsequent to the TC PipeLines, LP acquisition in March 2021.
3 Reflects comparable EBITDA from our ownership in our mineral rights business (CEVCO), North Baja, Tuscarora, Bison, Crossroads and our share of equity income from Northern Border, Iroquois, 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.

U.S. Natural Gas Pipelines segmented earnings in 2023 increased by $914 million compared to 2022 and decreased by $454 million in 2022 compared to 2021 and included the following specific items, which have been excluded from our calculation of comparable EBITDA and comparable EBIT:

- a pre-tax goodwill impairment charge of $571 million related to Great Lakes in first quarter 2022
- 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 2023 and 2022 had a positive impact on the Canadian dollar equivalent segmented earnings from our U.S. operations compared to 2022 and 2021, respectively. Refer to the Foreign Exchange section for additional information.

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 Gas 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$106 million higher in 2023 than 2022 primarily due to the net effect of:

- incremental earnings from growth and modernization projects placed in service and additional contract sales on Columbia Gas, ANR and Great Lakes
- a net increase in earnings from ANR following the FERC-approved settlement for higher transportation rates effective August 2022, partially offset by decreased earnings due to the sale of natural gas from certain gas storage facilities in 2022
- higher realized earnings related to our U.S. natural gas marketing business primarily due to higher margins
- increased equity earnings from Iroquois and Northern Border
- decreased earnings due to higher operational costs, reflective of increased system utilization across our footprint, as well as higher property taxes related to projects in service
- reduced earnings from our mineral rights business due to lower commodity prices.

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 from ANR as a result of certain fourth quarter 2022 adjustments related to regulatory deferrals, partially offset by higher transportation rates effective August 1, 2022, both pursuant to the ANR uncontested rate settlement.

Depreciation and amortization

Depreciation and amortization was US$11 million higher in 2023 compared to 2022 and US$51 million higher in 2022 compared to 2021. The increase in depreciation in both years is primarily due to the net effect of new projects placed in service, while 2023 is partially offset by certain adjustments made in third quarter 2023.

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 2024 is expected to be higher than 2023. This is primarily due to the completion of expansion projects in 2023 and anticipated completion of expansion projects in 2024 on the Columbia Gas and GTN systems, as well as the in-service of the Gillis Access project and higher revenues on Columbia Gas due to return on and recovery of modernization capital costs. Our pipeline systems continue to see historically strong demand for service and we anticipate that during 2024, our assets will maintain the high utilization levels experienced in 2023. These positive results are expected to be partially offset by higher operational costs, reflective of continued increases to system utilization across our footprint and an anticipated increase in property taxes from capital projects placed in service.

Capital expenditures

We incurred a total of US$2.1 billion in 2023 on our U.S. natural gas pipelines and expect to incur approximately US$1.9 billion in 2024 primarily on our Gillis Access, Columbia Gulf, ANR and Columbia Gas expansion projects and 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. We expect net capital expenditures in 2024 to be approximately US$1.4 billion after considering capital expenditures attributable to the non-controlling interests of entities we control.

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

TGNH Strategic Alliance with the CFE

In August 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. 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.

We placed the lateral section of the Villa de Reyes pipeline into service in third quarter 2023. Construction of the south section of the Villa de Reyes pipeline is targeted for mechanical completion in the second half of 2024, subject to successful resolution of stakeholder issues. Additionally, we continue to evaluate the development and completion of the Tula pipeline with the CFE, which is subject to a future FID. Due to the delay of an FID, effective November 1, 2023, we have suspended recording AFUDC on the assets under construction for the Tula pipeline project.

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, subject to regulatory approvals from COFECE and the CRE. Upon in-service of the Southeast Gateway pipeline and the completion of certain other contractual obligations, the CFE’s equity interest in TGNH will equal approximately 15 per cent, and will increase to approximately 35 per cent upon expiry of the contract in 2055. In December 2023, TGNH and the CFE obtained from COFECE, a favourable merger ruling and a determination that the proposed minority CFE equity participation in TGNH did not require a favourable cross participation opinion given that the CFE would not have a controlling interest in TGNH. TGNH and the CFE subsequently requested the CRE to confirm that a cross participation permit is not required given that the CFE would not have a controlling interest in TGNH. TGNH anticipates receiving CRE’s approval in early 2024.

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 US$, unless otherwise noted)	2023	2022	2021
TGNH[1]	**232**	164	118
Topolobampo	**157**	161	161
Sur de Texas[2]	**75**	112	113
Guadalajara	**61**	73	71
Mazatlán	**71**	67	70
Comparable EBITDA	**596**	577	533
Depreciation and amortization	**(66)**	(76)	(86)
Comparable EBIT	**530**	501	447
Foreign exchange impact	**186**	153	110
Comparable EBIT (Cdn$)	**716**	654	557
Specific item:			
Expected credit loss provision on net investment in leases and certain contract assets in Mexico	**80**	(163)	—
Segmented earnings (losses) (Cdn$)	**796**	491	557

1 Includes the operating sections of the Tamazunchale, Villa de Reyes and Tula pipelines.
2 Includes our share of 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 2023 increased by $305 million compared to 2022 and decreased by $66 million in 2022 compared to 2021 and included the impact of an $80 million recovery in 2023 (2022 – $163 million loss) on the expected credit loss provision related to the TGNH net investment in leases and certain contract assets in Mexico, which we have excluded from our calculation of comparable EBITDA and comparable EBIT. Refer to Note 29, Risk management and financial instruments, of our 2023 Consolidated financial statements for additional information.

A stronger U.S. dollar in 2023 and 2022 had a positive impact on the Canadian dollar equivalent segmented earnings from our U.S. dollar-denominated operations in Mexico compared to 2022 and 2021, respectively. Refer to the Foreign Exchange section for additional information.

Comparable EBITDA for Mexico Natural Gas Pipelines increased by US$19 million in 2023 compared to 2022 mainly due to:

- higher earnings in TGNH primarily related to the commercial in-service of the north section of the Villa de Reyes pipeline (VdR North) and the east section of the Tula pipeline (Tula East) in third quarter 2022, as well as the commercial in-service of the lateral section of the Villa de Reyes pipeline (VdR Lateral) in third quarter 2023
- lower earnings from Guadalajara primarily due to lower fixed revenue in accordance with the current transportation contract and higher operating costs associated with a disruption of service due to a weather event
- lower equity earnings in Sur de Texas primarily due to foreign exchange impacts upon the revaluation of peso-denominated liabilities as a result of a stronger Mexican peso and increased interest expense due to higher interest rates. We use foreign exchange derivatives to manage this exposure, the impact of which is recognized in Foreign exchange (gains) losses, net in the Consolidated statement of income. Refer to the Foreign exchange section for additional information.

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.

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 2023 compared to 2022 and in 2022 compared to 2021 due to the change to lease accounting for Tamazunchale subsequent to the execution of the 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.

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 2024 is expected to be higher than 2023 due to full-year, incremental revenue from VdR Lateral that was placed in commercial service in third quarter 2023.

Capital expenditures

We incurred a total of US$1.8 billion in 2023 primarily related to the construction of the Southeast Gateway, Villa de Reyes and Tula pipelines. We expect to incur approximately US$1.6 billion in 2024 to advance construction of the Southeast Gateway and Villa de Reyes pipelines.

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, we evaluate the resilience of our asset portfolio over a range of potential energy supply and demand outcomes.

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 business provides safe and reliable crude oil transportation through infrastructure extending from the WCSB in Canada to the U.S. Midwest and Gulf Coast. We offer long haul transportation from the WCSB to key refining and export markets in the U.S., as well as domestic transportation within Alberta and from Cushing, Oklahoma to the U.S. Gulf Coast.

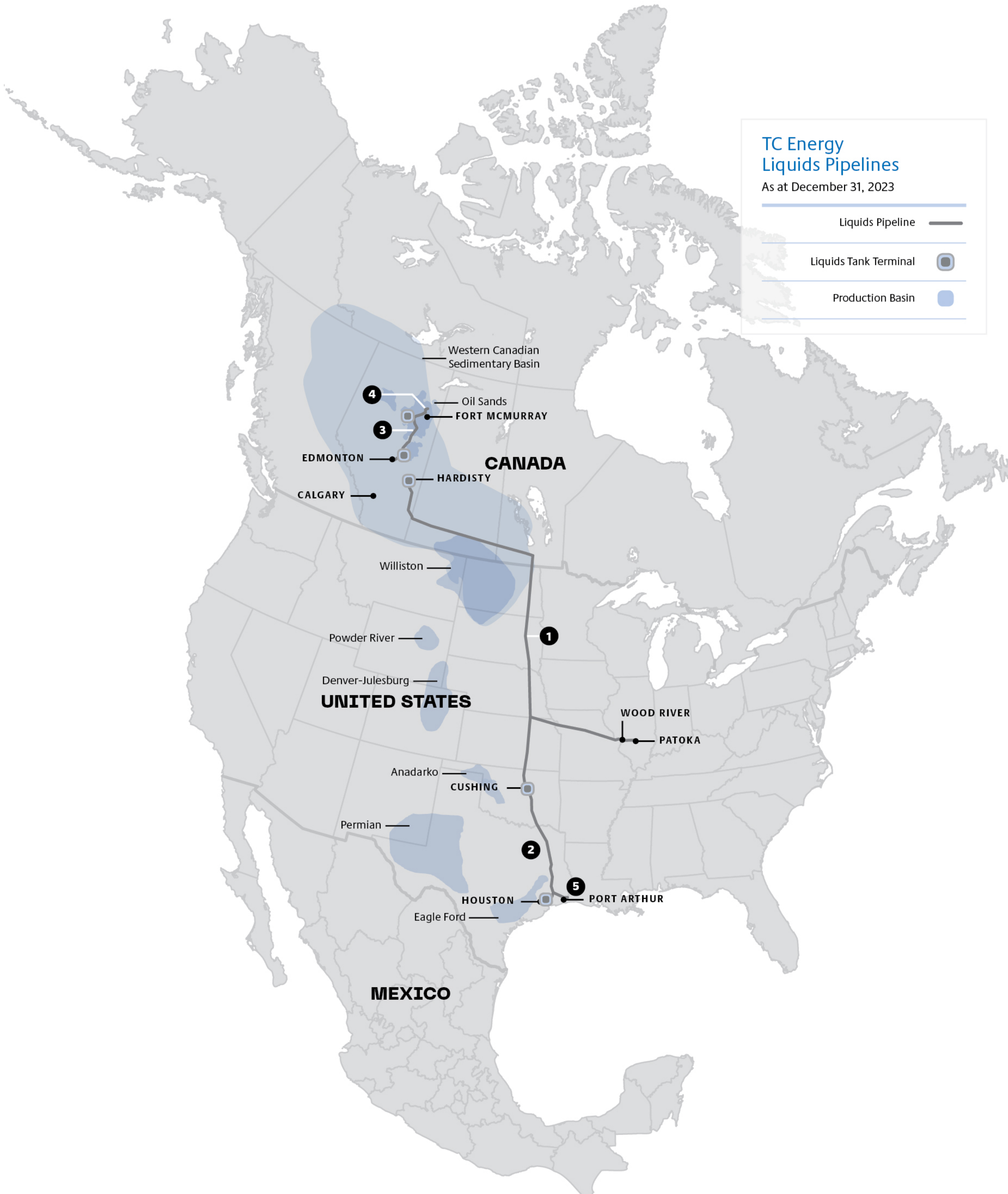
Our Liquids Pipelines business includes:
- wholly-owned liquids pipelines – approximately 4,400 km (2,700 miles)
- wholly-owned operational and term storage – approximately 7 million barrels
- partially-owned liquids pipelines – approximately 460 km (290 miles).

Strategy

We remain focused on the safe, secure and reliable operations of our Liquids Pipelines assets, while maximizing operational performance. We continue to expand our transportation service offerings and leverage existing infrastructure to pursue in-corridor growth opportunities, enabling increased optionality and market access for our customers and adding value to our business.

Recent highlights

- announced the proposed spinoff of our Liquids Pipelines business into a separate, investment-grade, publicly listed company named South Bow Corporation, which is expected to be completed in the second half of 2024, subject to receipt of required shareholder, court and regulatory approvals, favourable tax rulings and satisfaction of other customary closing conditions
- placed the Port Neches Link Pipeline System in service in first quarter 2023
- completed the recovery of all released volumes related to the Milepost 14 incident and returned Mill Creek to its natural flowing state. We will maintain our commitment to long-term reclamation and environmental monitoring activities.


TC Energy
Liquids Pipelines
As at December 31, 2023
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
Permian
2
5
HOUSTON
PORT ARTHUR
Eagle Ford
MEXICO

We are the operator and developer of the following:

		Length	Description	Ownership
	Liquids pipelines			
1	Keystone Pipeline System	4,327 km (2,689 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 (286 miles)	Transports crude oil from the producing area northwest of Fort McMurray, Alberta to the Edmonton/Heartland, Alberta market region.	50%
4	White Spruce	72 km (45 miles)	Transports crude oil from Canadian Natural Resources Limited's Horizon facility in northeast Alberta to the Grand Rapids pipeline.	100%
5	Port Neches	6 km (4 miles)	Transports crude oil from the Keystone Pipeline System and other liquids terminals in the Port Arthur, Texas area to the Motiva Terminal in Port Neches, Texas.	74.9%

UNDERSTANDING OUR LIQUIDS PIPELINES BUSINESS

Our Liquids Pipelines segment consists of crude oil pipeline and terminal assets. The business safely, securely and reliably transports crude oil from major supply sources to key refining and trading markets, where crude oil can be refined into petroleum products or marketed into other domestic or international markets. We also offer ancillary services, including storage at terminals, to provide our customers with increased delivery flexibility and increase the competitive position of our assets. In addition to our crude oil pipeline and terminal assets, we conduct marketing activities through a non-regulated marketing entity.

We provide pipeline transportation services to customers, primarily supported by long-term contracts providing certainty and 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 an uncommitted spot basis and through periodic open seasons, in accordance with regulatory requirements. Crude oil storage at terminals is offered to customers in exchange for fixed fee, term contracts.

In Canada, our pipeline systems and associated facilities are regulated by either the CER or AER, and in the U.S., by PHMSA and FERC or various state authorities. Combined, these entities regulate the construction, operation and abandonment of our pipeline infrastructure, as well as oversee the reasonableness of our tolls.

Keystone Pipeline System

Keystone Pipeline

The Keystone Pipeline System, our largest liquids pipeline asset, transports crude oil exported from Western Canada to various delivery points in the U.S. Midwest, and U.S. Gulf Coast. It also serves as the physical infrastructure for our Marketlink system, which leases capacity for the transportation of U.S. domestic crude receipts between Cushing, Oklahoma and the U.S. Gulf Coast. The Keystone Pipeline System operates in both Canada and the U.S. and is therefore subject to the common carrier obligations set by the CER and FERC in those jurisdictions, respectively.

Port Neches Link Pipeline

Our Port Neches Link Pipeline System provides crude oil transportation between our Keystone Pipeline System, as well as additional liquids terminals in the Port Arthur area, including the Phillips 66 Beaumont Terminal, to the Motiva Terminal in Port Neches, Texas. Port Neches Link Pipeline System is regulated by the Railroad Commission of Texas.

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 oil sands region 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 balancing capital discipline and growth, we expect crude oil demand to continue to increase this decade. Over a longer time horizon, we expect global demand to grow, before slowly declining in later decades; however, crude oil is expected to remain a vital source in helping the world meet its energy needs for decades to come. North America's crude oil supply, inclusive of the WCSB, will remain critical in supporting long-term demand.

Supply outlook

Canada has the world's third largest crude oil reserves with over 160 billion barrels of proven and economically recoverable oil. Production from the WCSB, which is the main supply source for our liquids assets, was approximately 5.0 million Bbl/d in 2023 and is expected to grow by over 500,000 Bbl/d to 5.5 million Bbl/d by 2030. The oil sands, which are located within the WCSB and directly connected to our intra-Alberta assets, make up the majority of Canadian crude oil supply. The oil sands are considered a world class supply source given its decades-long reserve life, low base production decline and rapidly improving cost and environmental performance.

The U.S. is one of the largest crude oil producing countries in the world, with production exceeding 12 million Bbl/d in 2023. 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. U.S. refineries have been optimized through significant capital investments to refine a mix of light and heavy crude oils to produce an optimized refined products slate. With our Keystone Pipeline System's connection to key refining and export markets, we believe we are well positioned to attract barrels from major U.S. tight oil basins, which themselves are expected to grow through the end of the decade.

Demand

The U.S. is the primary source of crude oil demand in North America with refining capacity exceeding 18 million Bbl/d. Our Liquids Pipelines assets serve the U.S. Midwest and U.S. Gulf Coast refining markets, PADD 2 and PADD 3, respectively. PADD 2 represents 23 per cent and PADD 3 represents 56 per cent of U.S. refining throughput or in aggregate, 79 per cent. Many PADD 2 and PADD 3 refineries are large-scale, complex facilities, with deep conversion capacity for heavy crude oil. These markets are expected to remain globally competitive for decades to come due to their access to low-cost Canadian heavy and U.S. light crude oil, as well as their proximity to abundant low-cost natural gas supply, positioning them to be among the most profitable refineries in the world.

While domestic consumption makes up the predominance of current North American crude oil demand, exports are expected to grow, increasing their proportion of North American crude oil demand out past the end of the decade, driven by growth in emerging markets. Crude oil export from the U.S. Gulf Coast, a market served by our pipelines, is expected to grow from 3.2 million Bbl/d to 4.6 million Bbl/d by the early 2030s.

Strategic priorities

Our Liquids Pipelines assets strategically position our liquids business to provide competitive transportation solutions for growing supplies of Alberta and U.S. crude oil to the U.S. Midwest and the U.S. Gulf Coast.

Within our established risk preferences, we remain committed to:

- optimizing the operational performance and commercial value of our existing assets
- expanding and leveraging our existing infrastructure for growth expansions
- progressing our energy transition goals, including system operational improvements and reducing our GHG emissions.

The long-term contract profile supporting our business model provides stable tolls for our customers and stable revenues for our business. As we continually augment our connectivity to resilient supply and premium markets, our business is well positioned for further growth.

We believe that our Liquids Pipelines 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 continually work with existing and potential customers to enhance their customer experience and provide competitive, reliable and efficient pipeline transportation and terminal services to meet their needs. The combination of the scale and strategic location of our assets assists in attracting additional volumes and 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.

SIGNIFICANT EVENTS

Spinoff of Liquids Pipelines Business

On July 27, 2023, we announced plans to separate into two independent, investment-grade, publicly listed companies through the proposed spinoff of our Liquids Pipelines business into its own entity named South Bow Corporation. In addition to TC Energy shareholder and court approvals, the spinoff Transaction is subject to receipt of favourable tax rulings from Canadian and U.S. tax authorities, receipt of necessary regulatory approvals, and satisfaction of other customary closing conditions. We expect that the spinoff Transaction will be completed in the second half of 2024.

Under the spinoff Transaction, TC Energy shareholders will retain their current ownership in TC Energy's common shares and receive a pro-rata allocation of common shares in South Bow Corporation. The determination of the number of common shares in South Bow Corporation to be distributed to TC Energy shareholders will be determined prior to the closing of the spinoff Transaction, which is expected to be tax free to TC Energy's Canadian and U.S. shareholders.

For the year ended December 31, 2023, we incurred pre-tax Liquids Pipelines business separation costs related to the spinoff Transaction of $40 million ($34 million after tax), of which $3 million and $37 million pre tax were included in the results of our Liquids Pipelines and Corporate segments, respectively, and have been excluded from comparable measures.

Milepost 14 Incident

In December 2022, a pipeline incident occurred in Washington County, Kansas on the Keystone Pipeline System, releasing 12,937 barrels of crude oil. In June 2023, we completed the recovery of all released volumes and in October 2023, we returned Mill Creek to its natural flowing state. We will maintain our commitment to long-term reclamation and environmental monitoring activities.

A CAO was issued by PHMSA in December 2022, and later amended in March 2023. The pipeline is operating subject to the Amended CAO (ACAO), which includes certain operating pressure restrictions. Under the ACAO, we expect to continue to fulfill our Keystone contract commitments.

A RCFA was conducted by an independent third party and was released on April 21, 2023. The RCFA revealed that a unique set of circumstances occurred at the rupture location, which likely originated during construction, with the primary cause of the rupture being a fatigue crack. A comprehensive remedial work plan is being implemented, including the RCFA's recommendations, to enhance pipeline integrity and safety performance of the system.

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 was revised at June 30, 2023 to $794 million based on a review of costs and commitments incurred. At December 31, 2023, the remediation cost estimate remains unchanged. Appropriate insurance policies are in place and we believe that it remains probable that the majority of environmental remediation costs will be eligible for recovery under our existing insurance coverage. As of December 31, 2023, we have received $575 million (2022 – nil) from insurance proceeds related to the environmental remediation. The additional environmental remediation costs recognized in second quarter 2023 included $36 million that we estimate to be recoverable from our wholly-owned captive insurance subsidiary, which was recorded in Interest income and other in the Consolidated statement of income. This amount has been excluded from comparable measures.

CER and FERC Proceedings

In 2019 and 2020, three Keystone customers initiated complaints before FERC and the CER regarding certain costs within the variable toll calculation. In December 2022, the CER issued a decision in respect of the complaint that resulted in an adjustment to previously charged tolls of $38 million. The CER has established a proceeding to consider Keystone's compliance filing required by the decision regarding the allocation of costs for drag reducing agent in the variable toll.

In February 2023, FERC released its initial decision in respect of the complaint. As a result, we have recorded a one-time pre-tax charge of $57 million reflective of previously charged tolls between 2018 and 2022. This amount has been excluded from comparable measures. A final order from FERC is expected in 2024.

Port Neches

In March 2023, the Port Neches Link Pipeline System was placed in service, connecting the Keystone Pipeline System to Motiva's Port Neches Terminal, enabling last-mile connectivity to Motiva's 630,000 Bbl/d refinery.

In December 2023, Motiva, our partner in Port Neches LLC, exercised their option to increase their equity interest in the company. As a result, and in exchange for approximately US$25 million in proceeds, subject to the agreed upon post-closing adjustments, our ownership interest has decreased from 95 per cent to 74.9 per cent.

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. In April 2023, the tribunal suspended the proceeding, granting a request from the U.S. Department of State to decide the jurisdictional grounds of the case as a preliminary matter. A hearing on the jurisdictional matter is set to occur in second quarter 2024. In April 2023, The Government of Alberta filed its own request for arbitration, which will proceed separately from our claim.

Keystone XL termination activities will continue in 2024 and include asset dispositions and preservation. 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 $)	2023	2022	2021
Keystone Pipeline System[1]	**1,389**	1,304	1,448
Intra-Alberta pipelines[2]	**70**	71	87
Other[1]	**(2)**	(9)	(9)
Comparable EBITDA	**1,457**	1,366	1,526
Depreciation and amortization	**(338)**	(329)	(318)
Comparable EBIT	**1,119**	1,037	1,208
Specific items:			
Keystone regulatory decisions	**(57)**	(27)	—
Keystone XL preservation and other	**(18)**	(25)	(43)
Liquids Pipelines business separation costs	**(3)**	—	—
Keystone XL asset impairment charge and other	**4**	118	(2,775)
Gain on sale of Northern Courier	—	—	13
Risk management activities	**(34)**	20	(3)
Segmented earnings (losses)	**1,011**	1,123	(1,600)
Comparable EBITDA denominated as follows:			
Canadian dollars	**382**	383	417
U.S. dollars	**796**	754	884
Foreign exchange impact	**279**	229	225
Comparable EBITDA	**1,457**	1,366	1,526

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 decreased by $112 million in 2023 compared to 2022 and increased by $2,723 million in 2022 compared to 2021 and included the following specified items, which have been excluded from our calculation of comparable EBITDA and comparable EBIT:

- a $57 million pre-tax charge in 2023 as a result of the FERC Administrative Law Judge initial decision issued in February 2023 in respect of a tolling-related complaint pertaining to amounts recognized from 2018 to 2022 and 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 2022. Refer to the Liquids Pipelines – Significant events section for additional information
- pre-tax preservation and other costs in 2023 of $18 million (2022 – $25 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
- a pre-tax charge of $3 million incurred in 2023 due to Liquids Pipelines business separation costs related to the spinoff Transaction. Refer to the Liquids Pipelines – Significant events section for additional information
- a $4 million pre-tax adjustment in 2023 (2022 – $118 million) to the 2021 Keystone XL asset impairment charge and other resulting from the net effect of the gain on sale of Keystone XL project assets and adjustments to the estimate for contractual and legal obligations related to termination activities
- 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
- 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 2023 and 2022 had a positive impact on the Canadian dollar equivalent segmented earnings from our U.S. operations compared to 2022 and 2021, respectively. Refer to the Foreign Exchange section for additional information.

Comparable EBITDA for Liquids Pipelines was $91 million higher in 2023 compared to 2022 primarily due to the net effect of:
- higher contracted and uncontracted volumes across the Keystone Pipeline System
- higher contributions from the Port Neches Link Pipeline System which began operations in March 2023
- a stronger U.S. dollar as described above.

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
- a stronger U.S. dollar as described above.

Depreciation and amortization

Depreciation and amortization was $9 million higher in 2023 compared to 2022 and $11 million higher in 2022 compared to 2021 primarily as a result of a stronger U.S. dollar.

OUTLOOK

Comparable EBITDA

Comparable EBITDA in 2024 is expected to be consistent with 2023. Comparable EBITDA in 2024 does not take into consideration the impact of the spinoff Transaction as it is subject to TC Energy shareholder approval, court approval, favourable tax rulings, other regulatory approvals and satisfaction of other customary closing conditions.

Capital expenditures

We incurred a total of $44 million in 2023 primarily related to capital projects in the U.S. Gulf Coast and on our operating pipelines and expect to incur approximately $0.2 billion in 2024.

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 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 and by working closely with our stakeholders in the development and operation of our assets.

Crude oil supply and demand for pipeline capacity

A decrease in demand for refined 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 may face competition from other companies which also seek to transport crude oil to the same markets. Our success will be 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 – Risk oversight and enterprise risk management section.

Market Volatility

The cyclical nature of commodity prices may influence the pace at which our customers expand their operations. This can impact the rate of output growth in our industry, the value of our services as contracts expire, and timing for the demand of transportation services and/or new liquids infrastructure. We seek to mitigate this risk through term contracting and offering a market competitive transportation service.

Power and Energy Solutions

The Power and Energy Solutions business consists of power generation, non-regulated natural gas storage assets, as well as emerging technologies that can provide low-carbon solutions for our customers and industry.

Our Power and Energy Solutions business includes approximately 4,600 MW of generation powered by nuclear, natural gas, wind and solar. These generation assets are generally supported by long-term contracts. Our Canadian power infrastructure assets are located in Alberta, Ontario, Québec and New Brunswick while our U.S. power infrastructure assets are located in Texas. Additionally, we have approximately 400 MW of PPAs in both the U.S. and Canada from wind and solar facilities. We continue to pursue generation assets and PPA opportunities in Canada and the U.S.

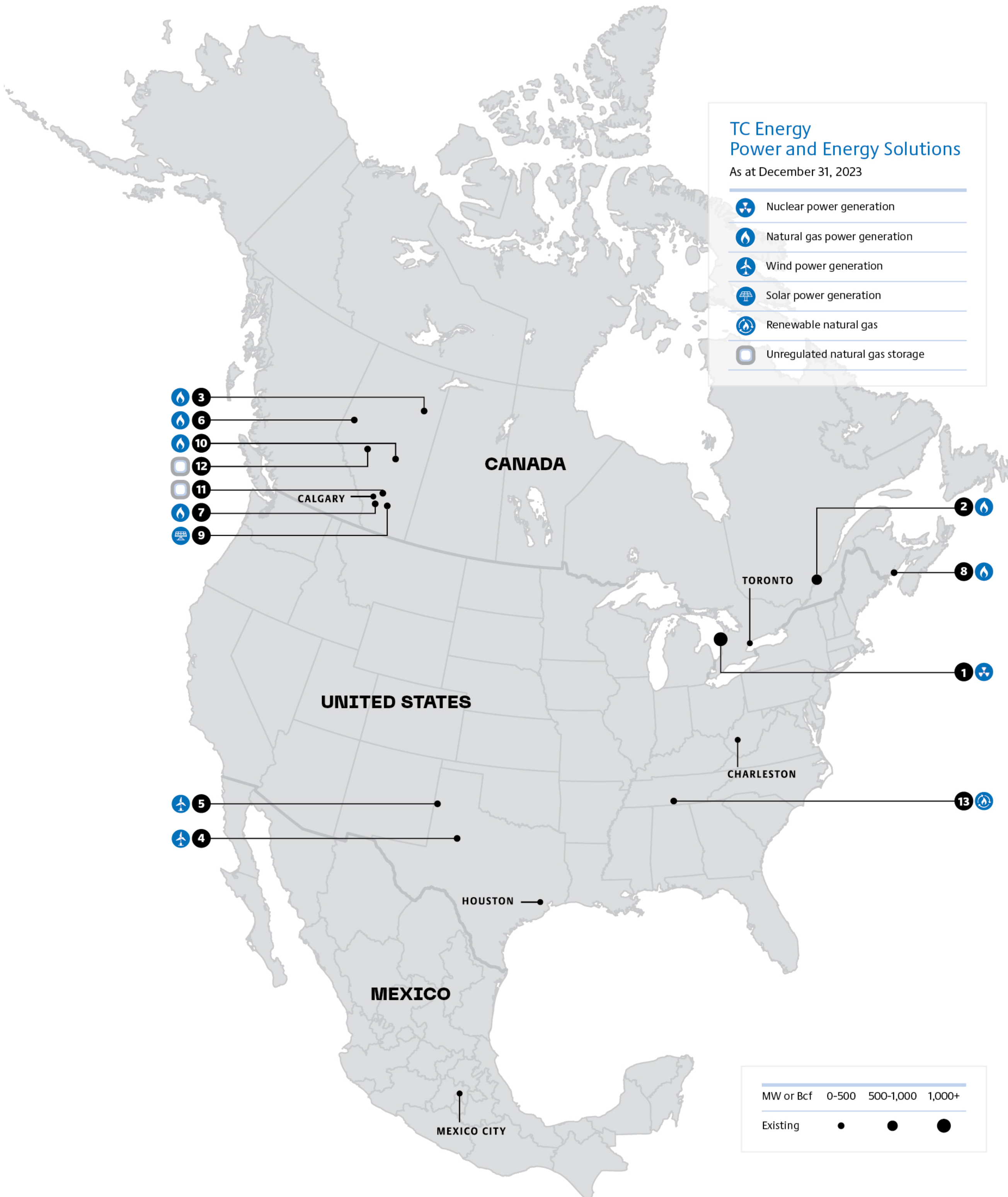
We also own and operate approximately 118 Bcf of non-regulated natural gas storage capacity in Alberta.

Strategy

Our strategy is to maximize the value of our existing portfolio through maintaining safety and operational excellence while enhancing the life cycle and reliability of our assets. Beyond our existing portfolio, we will focus our capital investment in sectors and projects that offer commercial frameworks consistent with TC Energy's value proposition, namely long-term contracts and rate regulation. 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 and will continue to build expertise and capabilities in emerging technologies and markets that we believe will fit these criteria in the future and have synergies with our natural gas business.

Recent highlights

- under the Bruce Power life extension program, the Unit 6 MCR was completed and successfully placed in commercial operations in third quarter 2023, ahead of schedule and within budget. In March 2023, Unit 3 was removed from service and began its MCR construction starting in second quarter 2023. The final basis of estimate for the Unit 4 MCR was filed with the IESO in fourth quarter 2023, and received approval on February 8, 2024
- acquired 100 per cent of the Class B Membership Interests in the 155 MW Fluvanna Wind Farm and 148 MW Blue Cloud Wind Farm
- completed construction of the 81 MW Saddlebrook Solar project, with full commercial operation commencing on January 5, 2024
- announced we will continue to advance the OPSP with our prospective partner, the Saugeen Ojibway Nation.


TC Energy
Power and Energy Solutions
As at December 31, 2023
Nuclear power generation
Natural gas power generation
Wind power generation
Solar power generation
Renewable natural gas
Unregulated natural gas storage
CANADA
UNITED STATES
MEXICO
CALGARY
TORONTO
CHARLESTON
HOUSTON
MEXICO CITY
1
2
3
4
5
6
7
8
9
10
11
12
13
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 4,642 MW. 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	Fluvanna[2]	155	wind	Wind farm located near Scurry County, Texas.	100%
5	Blue Cloud[2]	148	wind	Wind farm located near Bailey County, Texas.	100%
6	Bear Creek	100	natural gas	Cogeneration plant in Grande Prairie, Alberta.	100%
7	Carseland	95	natural gas	Cogeneration plant in Carseland, Alberta.	100%
8	Grandview	90	natural gas	Cogeneration plant in Saint John, New Brunswick.	100%
9	Saddlebrook Solar	81	solar	Hybrid solar generation facility near Aldersyde, Alberta.	100%
10	Redwater	46	natural gas	Cogeneration plant in Redwater, Alberta.	100%
	Canadian non-regulated natural gas storage				
11	Crossfield	68 Bcf		Underground facility connected to the NGTL System near Crossfield, Alberta.	100%
12	Edson	50 Bcf		Underground facility connected to the NGTL System near Edson, Alberta.	100%
	Under construction				
	Other energy solutions				
13	Lynchburg		RNG	RNG production facility in Lynchburg, Tennessee.	30%

1 Our share of power generation capacity.

2 TC Energy owns 100 per cent of the Class B Membership Interests and has a tax equity investor that owns 100 per cent of the Class A Membership Interests, to which a percentage of earnings, tax attributes and cash flows are allocated under the provisions of each tax equity agreement. Refer to the Power and Energy Solutions – Significant events section for additional information.

UNDERSTANDING OUR POWER AND ENERGY SOLUTIONS BUSINESS

Canadian Power

Canadian Power Generation & Marketing

We own and operate approximately 1,200 MW of power supply in Canada, excluding our investment in Bruce Power. In Alberta we own five facilities: four natural gas-fired cogeneration and one solar. 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 6,560 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 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, the first of the six-unit MCR life extension program, commenced in January 2020 and was placed back into commercial operation in third quarter 2023 ahead of schedule and within budget despite challenges associated with the COVID-19 pandemic. The Unit 3 MCR, the second unit in the MCR program, commenced in first quarter 2023 and has an expected completion in 2026. In the fourth quarter 2023, the Unit 4 MCR final cost and schedule estimate was submitted to the IESO and approved on February 8, 2024. We expect the Unit 4 MCR to commence in first quarter 2025 with expected completion in 2028. 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.

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, 2023, and no operating cost efficiencies were realized for the 2019 to 2021 period.

Bruce Power is a global supplier of Cobalt-60, a medical isotope used in the sterilization of medical equipment and to treat certain types of cancer. Cobalt-60 is produced during Bruce Power's generation of electricity, harvested during certain planned maintenance outages and provided for medical use in the treatment of brain tumours and breast cancer. In addition, Bruce Power continues to advance a project to expand isotope production from its reactors with a focus on Lutetium-177, another medical isotope used in the treatment of prostate cancer and neuroendocrine tumors. This project 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 approximately 400 MW of wind and solar generation PPAs and associated environmental attributes in Alberta. These PPAs allow us to generate incremental earnings by offering renewable power products to our customers.

U.S. Power

Power Generation & Marketing – U.S.

We own approximately 300 MW of wind generation located in Texas which operate in the Electric Reliability Council of Texas (ERCOT) and Southwest Power Pool (SPP) markets. A portion of this power generation is sold under a long-term, fixed price contract.

Our U.S. Power and emissions commercial trading and marketing business optimizes the value of our assets and leverages physical and financial products in the power and environmental markets with a focus on risk management.

Power Purchase Agreements – U.S.

We have approximately 400 MW of wind generation PPAs and associated environmental attributes in the U.S. These PPAs allow us to generate incremental earnings by offering renewable power products to our customers.

Other Energy Solutions

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

SIGNIFICANT EVENTS

Bruce Power Life Extension

The Unit 6 MCR, which began in January 2020, was declared commercially operational on September 14, 2023, ahead of schedule and within budget despite challenges from the COVID-19 pandemic.

On March 1, 2023, Unit 3 was removed from service and began its MCR construction in second quarter 2023 with a return to service expected in 2026.

The final cost and schedule estimate for the Unit 4 MCR program was submitted to the IESO on December 13, 2023, and received approval on February 8, 2024. The Unit 4 MCR is expected to commence in first quarter 2025 with an expected completion in 2028.

Renewable Energy Contracts and/or Investment Opportunities

In second quarter 2023, we finalized contracts to sell 50 MW under our 24-by-7 carbon-free power offering in Alberta. Contract terms range from 15 to 20 years and are expected to commence in 2025.

In November 2023, a majority of the 297 MW Sharp Hills Wind Farm achieved commercial operation resulting in the commencement of our 15-year PPA for 100 per cent of the power produced and the rights to all environmental attributes from the facility.

Texas Wind Farm Acquisitions

On March 15, 2023, we acquired 100 per cent of the Class B Membership Interests in the 155 MW Fluvanna Wind Farm located in Scurry County, Texas for US$99 million, before post-closing adjustments. Additionally, on June 14, 2023, we acquired 100 per cent of the Class B Membership Interests in the 148 MW Blue Cloud Wind Farm located in Bailey County, Texas for US$125 million, before post-closing adjustments.

Each of these operating assets has a tax equity investor which owns 100 per cent of the Class A Membership Interests, to which a percentage of earnings, tax attributes and cash flows are allocated under the provisions of each tax equity agreement and are recorded in Net income attributable to non-controlling interests in the Consolidated statement of income.

Saddlebrook Solar

On October 25, 2023, we completed construction of Saddlebrook Solar, an 81 MW facility located near Aldersyde, Alberta and began commissioning activities including supplying generation to the Alberta market. Full commercial operation was achieved on January 5, 2024. The project was partially supported with funding from Emissions Reduction Alberta and Lockheed Martin.

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.

The table below reflects 100 per cent of comparable EBITDA on assets we own or partially own and fully consolidate, as well as equity income for assets we own an equity interest in and do not consolidate.

year ended December 31 (millions of $)	**2023**	**2022**	**2021**
Bruce Power[1]	**680**	552	397
Canadian Power	**334**	322	253
Natural Gas Storage and other[2]	**6**	33	19
Comparable EBITDA	**1,020**	907	669
Depreciation and amortization	**(92)**	(72)	(78)
Comparable EBIT	**928**	835	591
Specific items:			
Bruce Power unrealized fair value adjustments	**7**	(17)	14
Gain on sale of Ontario natural gas-fired power plants	**—**	—	17
Risk management activities	**69**	15	6
Segmented earnings (losses)	**1,004**	833	628

1 Includes our share of equity income from Bruce Power.
2 Includes non-controlling interest in the Texas Wind Farms, which comprises Class A Membership Interests. Refer to the Corporate - Financial results section for additional information.

Power and Energy Solutions segmented earnings increased by $171 million in 2023 compared to 2022 and increased by $205 million in 2022 compared to 2021 and included the following specific items, which have been excluded from our calculation of comparable EBITDA and comparable EBIT:

- 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
- 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 $113 million in 2023 compared to 2022 primarily due to:

- higher contributions from Bruce Power primarily due to a higher contract price, reduced outage costs with fewer planned outage days and lower depreciation expense, partially offset by lower generation and increased operating expenses. Additional financial and operating information on Bruce Power is provided below
- increased Canadian Power financial results primarily from lower natural gas fuel costs and higher realized power prices
- decreased Natural Gas Storage and other results due to increased business development costs across the segment.

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

- 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.

Depreciation and amortization

Depreciation and amortization increased by $20 million in 2023 compared to 2022 primarily due to the acquisition of the Texas Wind Farms in the first half of 2023. Depreciation was lower by $6 million in 2022 compared to 2021 as a result of certain adjustments in 2022.

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)	**2023**	**2022**	**2021**
Items included in comparable EBITDA and comparable EBIT are comprised of:			
Revenues[1]	**1,941**	1,848	1,642
Operating expenses	**(917)**	(924)	(922)
Depreciation and other	**(344)**	(372)	(323)
Comparable EBITDA and comparable EBIT[2]	**680**	552	397
Bruce Power – other information			
Plant availability[3,4]	**92%**	86%	86%
Planned outage days[4]	**106**	302	321
Unplanned outage days	**62**	34	22
Sales volumes (GWh)[5]	**20,447**	20,610	20,542
Realized power price per MWh[6]	**$94**	$89	$80

1 Net of amounts recorded to reflect operating cost efficiencies shared with the IESO, if applicable.
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 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, which began in 2020, was declared commercially operational on September 14, 2023, ahead of schedule and within budget. The Unit 3 MCR commenced on March 1, 2023 with a return to service expected in 2026.

A planned outage on Unit 4 was completed in second quarter 2023 and on Unit 8 in fourth quarter 2023. The final cost and schedule estimate for the Unit 4 MCR program was submitted to the IESO on December 13, 2023, and received approval on February 8, 2024.

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.

OUTLOOK

Comparable EBITDA

Power and Energy Solutions comparable EBITDA in 2024 is expected to be higher than 2023 primarily from increased Bruce Power equity income due to the full year impact of Unit 6 after its return to service in September 2023 and the expected April 1, 2024 contract price increase. Lower Alberta power prices in 2024 are expected, reducing contributions from Canadian Power.

Planned maintenance at Bruce Power in 2024 is currently scheduled to begin on Unit 1 in the first quarter and on Units 5 to 8 in the second quarter. The average 2024 plant availability percentage, excluding the Unit 3 MCR program, is expected to be in the low-90 per cent range.

Capital expenditures

We incurred $0.9 billion in 2023 for our share of the Unit 3 and Unit 6 MCR programs for Bruce Power, construction of Saddlebrook Solar and other maintenance capital projects across the segment. We expect to incur approximately $0.9 billion in 2024 primarily related to our share of Bruce Power's Unit 3 and Unit 4 MCR programs.

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 – Risk oversight and 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 participants 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

2016 Columbia Pipeline Acquisition Lawsuit

In June 2023, the Delaware Chancery Court (the Court) issued its decision in the class action lawsuit commenced by former shareholders of Columbia Pipeline Group Inc. (CPG) related to the acquisition of CPG by TC Energy in 2016. The Court found that the former CPG executives breached their fiduciary duties, that the former CPG Board breached its duty of care in overseeing the sale process and that TC Energy aided and abetted those breaches. The Court awarded US$1 per share in damages to the plaintiffs and total damages, which are presently estimated at US$400 million plus statutory interest. Post-trial briefing and argument has concluded and a decision from the Court allocating liability as between TC Energy and the former CPG executives is expected sometime in the first half of 2024. Management expects to proceed with an appeal following the Court's determination of total damages and TC Energy's allocated share.

Focus Project

In late 2022, we launched the Focus Project to identify opportunities to improve safety, productivity and cost-effectiveness. To date, we have identified a broad set of opportunities expected to further enhance safety, as well as improve operational and financial performance over the long term.

Certain initiatives have been implemented in 2023, including launching a new simplified operational management system in support of enhanced safety performance, efficiencies in certain processes related to capital projects and reducing corporate costs. We expect to continue to implement additional initiatives beyond 2023, primarily in our Natural Gas Pipelines business, with benefits in the form of enhanced productivity, lower costs, and higher revenues, with the majority of these benefits expected to be realized by our customers. We also have additional safety initiatives as part of a three-year safety improvement plan.

At December 31, 2023, we have incurred pre-tax costs of $124 million for the Focus Project primarily related to external consulting and severance costs, of which $65 million was recorded in Plant operating costs and other in the Consolidated statement of income and was removed from comparable amounts. Of the remaining costs incurred, $23 million was recorded in Plant operating costs and other with offsetting revenues in the Consolidated statement of income related to costs recoverable through regulatory and commercial tolling structures, the net effect of which had no impact on net income. An additional $36 million was allocated to capital projects. No material consulting costs are expected to be incurred in 2024.

Asset Divestiture Program

On October 4, 2023, TC Energy successfully completed the sale of a 40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf which significantly accelerated our deleveraging goal. We continue to evaluate incremental capital rotation opportunities to further strengthen our financial position.

2023 Canada Federal Budget

On March 28, 2023, the Canadian Federal Government delivered its 2023 Budget. As part of this budget, several changes were announced to interest deductibility rules, global minimum tax proposals and other tax measures. We do not expect a material impact on our financial performance and cash flows in the near term, but we will continue to monitor any developments.

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 $)	2023	2022	2021
Comparable EBITDA and comparable EBIT	**(14)**	(20)	(24)
Specific items:			
Focus Project costs	**(65)**	—	—
Liquids Pipelines business separation costs	**(37)**	—	—
Foreign exchange gains – inter-affiliate loans[1]	**—**	28	41
Voluntary Retirement Program	**—**	—	(63)
Segmented earnings (losses)	**(116)**	8	(46)

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

In 2023, Corporate segmented losses were $116 million compared to segmented earnings of $8 million in 2022. In 2022, Corporate segmented earnings were $8 million compared to segmented losses of $46 million in 2021.

Corporate segmented earnings (losses) included the following specific items which have been excluded from our calculation of comparable EBITDA and comparable EBIT:

- a pre-tax charge of $65 million recorded in 2023 related to Focus Project costs. Refer to the Corporate – Significant events section for additional information
- a pre-tax charge of $37 million incurred in 2023 due to Liquids Pipelines business separation costs related to the spinoff Transaction. Refer to the Liquids Pipelines – Significant events section for additional information
- foreign exchange gains in 2022 and 2021 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 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 losses on the inter-affiliate loan receivable included in Foreign exchange gains (losses), net. Refer to the Other Information – Related party transactions section for additional information
- a pre-tax charge of $63 million in 2021 for the VRP offered in 2021.

Comparable EBITDA and comparable EBIT for Corporate increased by $6 million in 2023 from a loss of $20 million in 2022 due to lower litigation costs. Comparable EBITDA and comparable EBIT for Corporate in 2022 was generally consistent with 2021.

OTHER INCOME STATEMENT ITEMS

Interest expense

year ended December 31 (millions of $)	2023	2022	2021
Interest expense on long-term debt and junior subordinated notes			
Canadian dollar-denominated	**(895)**	(776)	(712)
U.S. dollar-denominated	**(1,692)**	(1,267)	(1,259)
Foreign exchange impact	**(592)**	(383)	(320)
	(3,179)	(2,426)	(2,291)
Other interest and amortization expense	**(261)**	(189)	(85)
Capitalized interest	**187**	27	22
Interest expense included in comparable earnings	**(3,253)**	(2,588)	(2,354)
Specific items:			
Keystone regulatory decisions	**(10)**	—	—
Keystone XL preservation and other	**—**	—	(6)
Interest expense	**(3,263)**	(2,588)	(2,360)

Interest expense increased by $675 million in 2023 compared to 2022 and increased by $228 million in 2022 compared to 2021. The following specific items have been removed from our calculation of interest expense included in comparable earnings:

- carrying charges of $10 million in 2023 as a result of a pre-tax charge related to the FERC Administrative Law Judge initial decision on Keystone. This decision was issued in February 2023 in respect of a tolling-related complaint pertaining to amounts recognized from 2018 to 2022
- a $6 million charge in 2021 related to the Keystone XL project-level credit facility for the period following the revocation of the Presidential Permit for the Keystone XL pipeline project.

Interest expense included in comparable earnings in 2023 increased by $665 million compared to 2022 primarily due to the net effect of:

- long-term debt issuances, net of maturities
- the foreign exchange impact from a stronger U.S. dollar on translation of U.S. dollar-denominated interest expense
- higher interest rates on our long-term debt that bears interest at a floating rate
- higher capitalized interest, largely due to funding related to our investment in Coastal GasLink LP. Refer to Note 8, Coastal GasLink, of our 2023 Consolidated financial statements for additional information.

Interest expense included in comparable earnings in 2022 increased by $234 million compared to 2021 mainly 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
- the foreign exchange impact from a stronger U.S. dollar on translation of U.S. dollar-denominated interest expense.

Refer to the Financial Condition section for additional information.

Allowance for funds used during construction

year ended December 31 (millions of $)	2023	2022	2021
Allowance for funds used during construction			
Canadian dollar-denominated	**102**	157	140
U.S. dollar-denominated	**350**	161	101
Foreign exchange impact	**123**	51	26
Allowance for funds used during construction	**575**	369	267

AFUDC increased by $206 million in 2023 compared to 2022. The decrease in Canadian dollar-denominated AFUDC is primarily related to NGTL System expansion projects placed in service. The increase in U.S. dollar-denominated AFUDC is the result of 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 in 2023, partially offset by projects placed in service on our U.S. natural gas pipelines. Due to the delay of an FID, effective November 1, 2023, we have suspended recording AFUDC on the assets under construction for the Tula pipeline project.

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.

Foreign exchange gains (losses), net

year ended December 31 (millions of $)	2023	2022	2021
Foreign exchange gains (losses), net included in comparable earnings	**118**	(8)	254
Specific items:			
Foreign exchange gains (losses), net – intercompany loan	**(44)**	—	—
Foreign exchange losses – inter-affiliate loan	**—**	(28)	(41)
Risk management activities	**246**	(149)	(203)
Foreign exchange gains (losses), net	**320**	(185)	10

Foreign exchange gains were $320 million in 2023 compared to foreign exchange losses of $185 million in 2022 and foreign exchange gains of $10 million in 2021. The following specific items have been removed from our calculation of Foreign exchange gains (losses), net included in comparable earnings:

- unrealized foreign exchange gains and losses on the peso-denominated intercompany loan between TCPL and TGNH beginning in second quarter 2023. Refer to the Non-GAAP measures section for additional information
- unrealized gains and losses from changes in the fair value of derivatives used to manage our foreign exchange risk
- 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. The interest income and interest expense on the peso-denominated inter-affiliate loan was included in comparable earnings with all amounts offsetting and resulting in no impact on consolidated net income.

Refer to the Other Information – Financial risks, financial instruments and related party transactions sections for additional information.

Foreign exchange gains included in comparable earnings were $118 million in 2023 compared to foreign exchange losses of $8 million in 2022. The change was primarily due to the net effect of:

- higher realized gains on derivatives used to manage our foreign exchange exposure to net liabilities in Mexico
- higher net realized losses on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- higher foreign exchange losses on the revaluation of our peso-denominated net monetary liabilities to U.S. dollars.

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

- net realized losses in 2022 compared to 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 our peso-denominated net monetary liabilities to U.S. dollars
- higher realized gains on derivatives used to manage our foreign exchange exposure to net liabilities in Mexico.

Interest income and other

year ended December 31 (millions of $)	**2023**	**2022**	**2021**
Interest income and other included in comparable earnings	**278**	146	190
Specific item:			
Milepost 14 insurance expense	**(36)**	—	—
Interest income and other	**242**	146	190

Interest income and other increased by $96 million in 2023 compared to 2022 and decreased by $44 million in 2022 compared to 2021. Interest income and other in 2023 included a $36 million accrued insurance expense related to the Milepost 14 incident, which is an estimate of the insurance proceeds for environmental remediation that we expect to receive from our wholly-owned captive insurance subsidiary. This expense has been removed from our calculation of Interest income and other included in comparable earnings. Refer to the Non-GAAP measures section for additional information.

Interest income and other included in comparable earnings increased by $132 million in 2023 compared to 2022 due to higher interest earned on short-term investments and the change in fair value of other restricted investments, partially offset by lower interest income in 2023 due to the repayment of the inter-affiliate loan receivable from Sur de Texas joint venture in July 2022.

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

Income tax (expense) recovery

year ended December 31 (millions of $)	2023	2022	2021
Income tax expense included in comparable earnings	**(1,037)**	(813)	(830)
Specific items:			
Coastal GasLink impairment charge	**157**	405	—
Keystone regulatory decisions	**15**	7	—
Focus Project costs	**17**	—	—
Liquids Pipelines business separation costs	**6**	—	—
Keystone XL preservation and other	**4**	6	12
Expected credit loss provision on net investment in leases and certain contract assets in Mexico	**(25)**	49	—
Keystone XL asset impairment charge and other	**14**	(123)	641
Great Lakes goodwill impairment charge	**—**	40	—
Settlement of Mexico prior years' income tax assessments	**—**	(196)	—
Voluntary Retirement Program	**—**	—	15
Sale of Northern Courier	**—**	—	6
Sale of Ontario natural gas-fired power plants	**—**	—	(10)
Bruce Power unrealized fair value adjustments	**(2)**	4	(3)
Risk management activities	**(91)**	32	49
Income tax (expense) recovery	**(942)**	(589)	(120)

Income tax expense in 2023 increased by $353 million compared to 2022 and increased by $469 million in 2022 compared to 2021.

In addition to the income tax impacts on other specific items referenced elsewhere in this MD&A, Income tax expense also includes the following specific items, which have been removed from our calculation of Income tax expense included in comparable earnings:

2023

- a $157 million income tax recovery related to the impairment of our equity investment in Coastal GasLink LP
- a $14 million U.S. minimum tax recovery on the 2021 Keystone XL asset impairment charge and other related to the termination of the Keystone XL pipeline project.

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 expense related to the settlement of prior years' income tax assessments related to our operations in Mexico
- 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.

2021

- income tax impact of the Keystone XL pipeline project asset impairment charge and other.

Income tax expense included in comparable earnings in 2023 increased by $224 million compared to 2022 primarily due to higher earnings subject to income tax, Mexico foreign exchange exposure and lower foreign income tax rate differentials, partially offset by lower flow-through income taxes and lower Mexico inflation adjustments. Refer to the Foreign exchange section for additional information.

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.

Net (income) loss attributable to non-controlling interests

year ended December 31 (millions of Canadian $)	Non-Controlling Interests Ownership at December 31, 2023	2023	2022	2021
Columbia Gas and Columbia Gulf[1]	40.0%	**(143)**	—	—
Portland Natural Gas Transmission System	38.3%	**(41)**	(37)	(30)
Texas Wind Farms	100% [2]	**38**	—	—
TC PipeLines, LP	nil [3]	**—**	—	(60)
Redeemable non-controlling interest	nil	**—**	—	(1)
Net (income) loss attributable to non-controlling interests		**(146)**	(37)	(91)

1 On October 4, 2023, we completed the sale of a 40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf to GIP.

2 The Texas Wind Farms have tax equity investors that own 100 per cent of the Class A Membership Interests, to which a percentage of earnings, tax attributes and cash flows are allocated.

3 Prior to the March 3, 2021 acquisition, the non-controlling interest in TC PipeLines, LP was 74.5 per cent.

Net income attributable to non-controlling interests increased by $109 million in 2023 compared to 2022 due to the net effect of the sale of a 40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf and the acquisition of the Texas Wind Farms. Refer to the U.S. Natural Gas Pipelines – Significant events and Power and Energy Solutions – Significant events sections for additional information.

Net income attributable to non-controlling interests decreased by $54 million in 2022 compared to 2021 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 $)	2023	2022	2021
Preferred share dividends	**(93)**	(107)	(140)

Preferred share dividends decreased by $14 million in 2023 compared to 2022 and $33 million in 2022 compared to 2021 primarily due to the redemption of preferred shares in 2022 and 2021, partially offset by higher floating dividend rates on certain series of preferred shares.

Foreign exchange

Foreign exchange related to U.S. dollar dominated operations

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, 2023, 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. Natural Gas Pipelines 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$)	**2023**	**2022**	**2021**
Comparable EBITDA			
U.S. Natural Gas Pipelines	**3,248**	3,142	3,075
Mexico Natural Gas Pipelines[1]	**596**	602	602
Liquids Pipelines	**796**	754	884
	4,640	4,498	4,561
Depreciation and amortization	**(954)**	(952)	(911)
Interest on long-term debt and junior subordinated notes	**(1,692)**	(1,267)	(1,259)
Allowance for funds used during construction	**350**	161	101
Non-controlling interests and other	**(156)**	(101)	(66)
	2,188	2,339	2,426
Average exchange rate – U.S. to Canadian dollars	**1.35**	1.30	1.25

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.

Foreign exchange related to Mexico Natural Gas Pipelines

Changes in the value of the Mexican peso against the U.S. dollar can affect our comparable earnings as a portion of our Mexico Natural Gas Pipelines monetary assets and liabilities are peso-denominated, while our financial results are denominated in U.S. dollars for our Mexico operations. These peso-denominated balances are revalued to U.S. dollars, creating foreign exchange gains and losses that are included in Income (loss) from equity investments and Foreign exchange (gains) losses, net in the Consolidated statement of 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. This exposure increases as our U.S. dollar-denominated net monetary liabilities grow. 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 revolving credit facility with a third party, which resulted in an additional peso-denominated income tax expense compared to 2022.

The above exposures are managed using foreign exchange derivatives, although some unhedged exposure remains. The impacts of the foreign exchange derivatives are recorded in Foreign exchange (gains) losses, net in the Consolidated statement of income. Refer to the Financial risks and financial instruments section for additional information.

The period end exchange rates for one U.S. dollar to Mexican pesos were as follows:

December 31, 2023	**16.91**
December 31, 2022	19.50
December 31, 2021	20.48

A summary of the impacts of transactional foreign exchange gains and losses from changes in the value of the Mexican peso against the U.S. dollar and associated derivatives is set out in the table below:

year ended December 31 (millions of $)	**2023**	**2022**	**2021**
Comparable EBITDA – Mexico Natural Gas Pipelines[1]	**(83)**	(32)	1
Foreign exchange gains (losses), net included in comparable earnings	**224**	54	15
Income tax (expense) recovery included in comparable earnings	**(133)**	(11)	4
	8	11	20

1 Includes the foreign exchange impacts from the Sur de Texas joint venture recorded in Income (loss) from equity investments in the Consolidated statement of income.

Financial condition

We strive to maintain financial strength and flexibility in all parts of the economic cycle. We rely on our operating cash flows to sustain our business, pay dividends and fund a portion of our growth. In addition, we access capital markets and engage in portfolio management activities to meet our financing needs and to manage our capital structure and 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.sedarplus.ca).

We believe we have the financial capacity to fund our existing capital program through predictable and growing cash flows from operations, access to capital markets, portfolio management activities, 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 $31 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, as deemed appropriate, including common shares issued from treasury under our DRP and discrete common equity issuances.

Balance sheet analysis

At December 31, 2023, our current assets totaled $11.4 billion and current liabilities amounted to $11.8 billion, leaving us with a working capital deficit of $0.4 billion compared to $9.6 billion at December 31, 2022. The change in working capital is primarily due to proceeds received from the sale of a 40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf, which also resulted in the reduction of short-term borrowings. 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 $9.6 billion of committed revolving credit facilities available for short-term borrowing capacity, of which no amounts have been drawn. We also have arrangements in place for a further $2.0 billion of demand credit facilities on which $1.0 billion remains available as of December 31, 2023
- additional $1.5 billion committed revolving credit facilities at certain of our subsidiaries and affiliates, on which no amounts have been drawn
- our access to capital markets, including through securities issuances, incremental credit facilities, our asset divestiture program and DRP, if deemed appropriate.

Our total assets at December 31, 2023 were $125.0 billion compared to $114.3 billion at December 31, 2022 with the increase primarily reflecting our capital spending program, working capital, increased equity investments, partially offset by depreciation and a weaker U.S. dollar at December 31, 2023 compared to December 31, 2022 on translation of our U.S. dollar-denominated assets.

At December 31, 2023 our total liabilities were $86.0 billion, compared to $80.2 billion at December 31, 2022 due to the net effect of movements in debt, working capital and a weaker U.S. dollar at December 31, 2023 compared to December 31, 2022 on translation of our U.S. dollar-denominated liabilities.

Our equity at December 31, 2023 was $39.0 billion compared to $34.1 billion at December 31, 2022. The increase is primarily due to the sale of a 40 per cent non-controlling equity interest in Columbia Gulf and Columbia Gas, partially offset by net income, net of common and preferred dividends paid, and lower other comprehensive income.

Consolidated capital structure

The following table summarizes the components of our capital structure.

at December 31 (millions of $, unless otherwise noted)	2023	Per cent of total	2022	Per cent of total
Notes payable	**—**	**—**	6,262	7
Long-term debt, including current portion	**52,914**	**54**	41,543	45
Cash and cash equivalents	**(3,678)**	**(4)**	(620)	(1)
	49,236	**50**	47,185	51
Junior subordinated notes	**10,287**	**10**	10,495	11
Preferred shares	**2,499**	**3**	2,499	3
Common shareholders' equity	**27,054**	**27**	31,491	35
Non-controlling interests	**9,455**	**10**	126	—
	98,531	**100**	91,796	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, 2023.

Cash flows

The following tables summarize our consolidated cash flows.

year ended December 31 (millions of $)	2023	2022	2021
Net cash provided by operations	**7,268**	6,375	6,890
Net cash (used in) provided by investing activities	**(12,287)**	(7,009)	(7,712)
Net cash (used in) provided by financing activities	**8,093**	487	(88)
	3,074	(147)	(910)
Effect of foreign exchange rate changes on cash and cash equivalents	**(16)**	94	53
Increase (decrease) in cash and cash equivalents	**3,058**	(53)	(857)

Cash provided by operating activities

year ended December 31 (millions of $)	2023	2022	2021
Net cash provided by operations	**7,268**	6,375	6,890
Increase (decrease) in operating working capital	**(207)**	639	287
Funds generated from operations	**7,061**	7,014	7,177
Specific items:			
Current income tax expense on disposition of equity interest[1]	**736**	—	—
Focus Project costs, net of current income tax	**54**	—	—
Keystone regulatory decisions, net of current income tax	**53**	27	—
Liquids Pipelines business separation costs	**40**	—	—
Milepost 14 insurance expense	**36**	—	—
Settlement of Mexico prior years' income tax assessments	**—**	196	—
Keystone XL preservation and other, net of current income tax	**14**	20	40
Current income tax expense on Keystone XL asset impairment charge and other	**(14)**	96	140
Voluntary Retirement Program, net of current income tax	**—**	—	49
Comparable funds generated from operations	**7,980**	7,353	7,406

1 Current income tax expense related to applying an approximate 24 per cent tax rate to the tax gain on sale of a 40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf. This is offset by a corresponding deferred tax recovery resulting in no net impact to tax expense.

Net cash provided by operations

Net cash provided by operations increased by $893 million in 2023 compared to 2022 primarily due to the amount and timing of working capital changes and higher funds generated from 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.

Comparable funds generated from operations

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

Comparable funds generated from operations increased by $627 million in 2023 compared to 2022 primarily due to higher comparable EBITDA, increased distributions from our equity investments, higher interest earned on short-term investments and net realized gains on derivatives used to manage our foreign exchange exposures, partially offset by higher interest expense.

Comparable funds generated from operations decreased by $53 million in 2022 compared to 2021 primarily due to higher interest expense and net realized losses on derivatives used to manage our foreign exchange exposures, partially offset by higher comparable EBITDA.

Cash (used in) provided by investing activities

year ended December 31 (millions of $)	2023	2022	2021
Capital spending			
Capital expenditures	**(8,007)**	(6,678)	(5,924)
Capital projects in development	**(142)**	(49)	—
Contributions to equity investments	**(4,149)**	(2,234)	(1,210)
	(12,298)	(8,961)	(7,134)
Acquisitions, net of cash acquired	**(307)**	—	—
Loans to affiliate (issued) repaid, net	**250**	(11)	(239)
Keystone XL contractual recoveries	**10**	571	—
Proceeds from sales of assets, net of transaction costs	**33**	—	35
Other distributions from equity investments	**23**	1,433	73
Deferred amounts and other	**2**	(41)	(447)
Net cash (used in) provided by investing activities	**(12,287)**	(7,009)	(7,712)

Net cash used in investing activities increased from $7.0 billion in 2022 to $12.3 billion in 2023 as a result of higher contributions to equity investments primarily related to Coastal GasLink LP, as well as increased capital spending in 2023.

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.

Capital spending[1]

The following table summarizes capital spending by segment.

year ended December 31 (millions of $)	2023	2022	2021
Canadian Natural Gas Pipelines	**6,184**	4,719	2,737
U.S. Natural Gas Pipelines	**2,660**	2,137	2,820
Mexico Natural Gas Pipelines	**2,292**	1,027	129
Liquids Pipelines	**49**	143	571
Power and Energy Solutions	**1,080**	894	842
Corporate	**33**	41	35
	12,298	8,961	7,134

1 Capital spending reflects cash flows associated with our Capital expenditures, Capital projects in development and Contributions to equity investments. Refer to Note 5, Segmented information, of our 2023 Consolidated financial statements for the financial statement line items that comprise total capital spending.

Capital expenditures
Capital expenditures in 2023 were incurred primarily for the advancement of the Southeast Gateway pipeline, the NGTL System expansion and NGTL System/Foothills West Path Delivery programs, Columbia Gas and ANR projects, as well as maintenance capital expenditures. Higher capital expenditures in 2023 compared to 2022 reflect spending for the advancement of the Southeast Gateway pipeline, Gillis Access and Columbia Gas projects, partially offset by reduced spending on expansion of the NGTL System.

Capital projects in development
Costs incurred during 2023 on Capital projects in development were attributable to spending on projects in the Power and Energy Solutions segment.

Contributions to equity investments
Contributions to equity investments increased in 2023 compared to 2022 mainly due to the draws of $2,520 million on the subordinated loan by Coastal GasLink LP in 2023 which are accounted for as in-substance equity contributions.

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. This was partially offset by lower 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 Consolidated statement of cash flows. Refer to the Other Information – Related party transactions section for additional information.

Acquisitions
On March 15, 2023, we acquired 100 per cent of the Class B Membership Interests in the Fluvanna Wind Farm located in Scurry County, Texas for US$99 million, before post-closing adjustments. On June 14, 2023, we acquired 100 per cent of the Class B Membership Interests in the Blue Cloud Wind Farm located in Bailey County, Texas for US$125 million, before post-closing adjustments. Refer to the Significant Events – Power and Energy Solutions section for additional information.

Loans to affiliate
Loans to affiliate (issued) repaid, net 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 Coastal GasLink project. Refer to the Other Information – Related party transactions section for additional information.

Keystone XL contractual recoveries
In 2023, we received $10 million (2022 – $571 million) of contractual recoveries with respect to the Keystone XL pipeline project termination in 2021.

Proceeds from sales of assets
In 2023, we completed the sale of a 20.1 per cent equity interest in Port Neches Link LLC to its joint venture partner, Motiva Enterprises, for gross proceeds of $33 million (US$25 million).

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

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 2023 and 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 (used in) provided by financing activities

year ended December 31 (millions of $)	2023	2022	2021
Notes payable issued (repaid), net	**(6,299)**	766	1,003
Long-term debt issued, net of issue costs	**15,884**	2,508	10,730
Long-term debt repaid	**(3,772)**	(1,338)	(7,758)
Disposition of equity interest, net of transaction costs	**5,328**	—	—
Junior subordinated notes issued, net of issue costs	**—**	1,008	495
Redeemable non-controlling interest repurchased	**—**	—	(633)
Dividends and distributions paid	**(3,052)**	(3,385)	(3,548)
Common shares issued, net of issue costs	**4**	1,905	148
Preferred shares redeemed	**—**	(1,000)	(500)
Gains (losses) on settlement of financial instruments	**—**	23	(10)
Acquisition of TC PipeLines, LP transaction costs	**—**	—	(15)
Net cash (used in) provided by financing activities	**8,093**	487	(88)

Net cash provided by financing activities increased by $7.6 billion in 2023 compared to 2022 primarily due to higher net issuances of long-term debt and repayments of notes payable, as well as the receipt of the $5.3 billion (US$3.9 billion) proceeds upon sale of a 40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf. Refer to the U.S. Natural Gas Pipelines – Significant events section for additional information.

Net cash provided by financing activities increased by $0.6 billion 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.

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 2023.

(millions of Canadian $, unless otherwise noted)					
Company	**Issue date**	**Type**	**Maturity date**	**Amount**	**Interest rate**
TRANSCANADA PIPELINES LIMITED					
	May 2023	Senior Unsecured Term Loan[1]	May 2026	US 1,024	Floating
	March 2023	Senior Unsecured Notes	March 2026[2]	US 850	6.20%
	March 2023	Senior Unsecured Notes	March 2026[2]	US 400	Floating
	March 2023	Medium Term Notes	July 2030	1,250	5.28%
	March 2023	Medium Term Notes	March 2026[2]	600	5.42%
	March 2023	Medium Term Notes	March 2026[2]	400	Floating
COLUMBIA PIPELINES OPERATING COMPANY LLC[3]					
	August 2023	Senior Unsecured Notes	November 2033	US 1,500	6.04%
	August 2023	Senior Unsecured Notes	November 2053	US 1,250	6.54%
	August 2023	Senior Unsecured Notes	August 2030	US 750	5.93%
	August 2023	Senior Unsecured Notes	August 2043	US 600	6.50%
	August 2023	Senior Unsecured Notes	August 2063	US 500	6.71%
COLUMBIA PIPELINES HOLDING COMPANY LLC[3]					
	August 2023	Senior Unsecured Notes	August 2028	US 700	6.04%
	August 2023	Senior Unsecured Notes	August 2026	US 300	6.06%
GAS TRANSMISSION NORTHWEST LLC					
	June 2023	Senior Unsecured Notes	June 2030	US 50	4.92%
TC ENERGÍA MEXICANA, S. DE R.L. DE C.V.					
	January 2023	Senior Unsecured Term Loan	January 2028	US 1,800	Floating
	January 2023	Senior Unsecured Revolving Credit Facility	January 2028	US 500	Floating

1 This loan was fully repaid and retired in September 2023. Related unamortized debt issue costs of $3 million were included in Interest expense in the Consolidated statement of income.
2 Callable at par in March 2024 or at any time thereafter.
3 On October 4, 2023, TC Energy completed the sale of a 40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf. Refer to Note 24, Non-controlling interests, of our 2023 Consolidated financial statements for additional information.

On January 9, 2024, Columbia Pipelines Holding Company LLC issued US$500 million senior unsecured notes due January 2034, bearing interest at a fixed rate of 5.68 per cent.

Long-term debt repaid/retired

The following table outlines significant long-term debt repaid/retired in 2023.

(millions of Canadian $, unless otherwise noted) Company	Retirement date	Type	Amount	Interest rate
TRANSCANADA PIPELINES LIMITED				
	October 2023	Senior Unsecured Notes	US 625	3.75%
	September 2023	Senior Unsecured Term Loan[1]	US 1,024	Floating
	July 2023	Medium Term Notes	750	3.69%
TUSCARORA GAS TRANSMISSION COMPANY				
	November 2023	Unsecured Term Loan	US 32	Floating
NOVA GAS TRANSMISSION LTD.				
	April 2023	Debentures	US 200	7.88%
TC ENERGÍA MEXICANA, S. DE R.L. DE C.V.				
	Various	Senior Unsecured Revolving Credit Facility	US 315	Floating

1 In May 2023, we entered into a US$1,024 million senior unsecured term loan and the full amount was drawn. The loan was fully repaid and retired in September 2023. Related unamortized debt issue costs of $3 million were included in Interest expense in the Consolidated statement of income.

For more information about long-term debt and junior subordinated notes issued and long-term debt repaid in 2023, 2022 and 2021, refer to the notes to our 2023 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 plan

Under the DRP, eligible holders of common and preferred shares of TC Energy can reinvest their dividends and make optional cash payments to obtain additional TC Energy common shares. From August 31, 2022 to July 31, 2023, common shares were issued from treasury at a discount of two per cent to market prices over a specified period. The participation rate by common shareholders in the DRP in 2023 was approximately 39 per cent (2022 – 33 per cent), resulting in $737 million (2022 – $607 million) reinvested in common equity under the program.

Commencing with the dividends declared on July 27, 2023, common shares purchased under TC Energy's DRP are acquired on the open market at 100 per cent of the weighted average purchase price.

Share information

at February 9, 2024		
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**
	7 million	4 million

For more information on preferred shares refer to the notes to our 2023 Consolidated financial statements.

Dividends

year ended December 31	2023	2022	2021
Dividends declared			
per common share	$3.72	$3.60	$3.48
per Series 1 preferred share	$0.86975	$0.86975	$0.86975
per Series 2 preferred share	$1.62659	$0.82611	$0.50997
per Series 3 preferred share	$0.4235	$0.4235	$0.4235
per Series 4 preferred share	$1.46703	$0.66655	$0.34997
per Series 5 preferred share	$0.48725	$0.48725	$0.48725
per Series 6 preferred share	$1.55993	$0.80668	$0.41622
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	$0.83775
per Series 13 preferred share	—	—	$0.34375
per Series 15 preferred share	—	$0.30625	$1.225

On February 13, 2024, we increased the quarterly dividend on our outstanding common shares by 3.2 per cent to $0.96 per common share for the quarter ending March 31, 2024 to shareholders of record at the close of business on March 28, 2024, which equates to an annual dividend of $3.84 per common share.

Credit facilities

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

At February 9, 2024, we had a total of $11.8 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 commercial paper program and for general corporate purposes	December 2028	3.0	2.8
TCPL / TCPL USA	Supports commercial paper programs and for general corporate purposes of the borrowers, guaranteed by TCPL	December 2024	US 2.5	US 2.3
TCPL / TCPL USA	Supports commercial paper programs and for general corporate purposes of the borrowers, guaranteed by TCPL	December 2026	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	2.0 [2]	1.0 [2]

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

At February 9, 2024, our operated affiliates had an additional $1.5 billion of undrawn capacity on third-party demand and committed credit facilities.

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, 2023 (millions of $)	Total	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Long-term debt and junior subordinated notes[1]	63,503	2,938	8,066	9,328	43,171
Operating leases[2]	548	72	134	117	225
Purchase obligations and other	4,988	2,649	813	517	1,009
	69,039	5,659	9,013	9,962	44,405

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 at December 31, 2023 was nil (2022 – $6.3 billion).

Long-term debt and junior subordinated notes

At December 31, 2023, we had $52.9 billion (2022 – $41.5 billion) of long-term debt and $10.3 billion (2022 – $10.5 billion) of junior subordinated notes.

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 18 years.

Interest payments

At December 31, 2023, scheduled interest payments related to our long-term debt and junior subordinated notes were as follows:

at December 31, 2023 (millions of $)	Total	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Long-term debt	25,439	2,373	4,323	3,612	15,131
Junior subordinated notes	50,734	611	1,318	1,678	47,127
	76,173	2,984	5,641	5,290	62,258

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 2024 to 2038, that require the purchase of generated energy and associated environmental attributes. At December 31, 2023, the total planned capacity secured under the PPAs is approximately 800 MW with the generation subject to operating availability and capacity factors. These PPAs do not meet the definition of a lease or derivative. 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.

Purchase obligations and other

At December 31, 2023, payments for purchase obligations and other were as follows:

at December 31, 2023 (millions of $)	Total	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Canadian Natural Gas Pipelines					
Transportation by others[1]	1,685	177	363	341	804
Capital spending[2]	226	197	20	7	2
U.S. Natural Gas Pipelines					
Transportation by others[1]	546	142	216	94	94
Capital spending[2]	340	314	26	—	—
Mexico Natural Gas Pipelines					
Capital spending[2]	1,312	1,312	—	—	—
Liquids Pipelines					
Transportation by others[1]	43	26	17	—	—
Capital spending[2]	6	6	—	—	—
Other	3	3	—	—	—
Power and Energy Solutions					
Capital spending[2]	231	200	31	—	—
Other[3]	187	22	28	28	109
Corporate					
Other	395	236	112	47	—
Capital spending[2]	14	14	—	—	—
	4,988	2,649	813	517	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 2024, with the annual option to extend for one year periods ending in 2053.

At December 31, 2023, our share of potential exposure under the Sur de Texas pipeline guarantees was estimated to be $97 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 2025 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, 2023, 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, 2023 to be approximately $80 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 2023, we made funding contributions of $28 million to our defined benefit pension plans, $9 million for other post-retirement benefit plans and $64 million for the savings plan and defined contribution plans. Total letters of credit provided for the funding of solvency requirements to the Canadian defined benefit plan at December 31, 2023 was $244 million (2022 – $322 million; 2021 – $322 million).

In 2024, we expect to make no contributions for the defined benefits pension plans, funding contributions of approximately $6 million for other post-retirement benefit plans and approximately $70 million for the savings plans and defined contribution pension plans. We do not expect to issue additional letters of credit to the Canadian DB Plan for the funding of solvency requirements.

The net benefit cost for our defined benefit and other post-retirement plans decreased to $20 million in 2023 from $57 million in 2022 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

RISK OVERSIGHT AND ENTERPRISE RISK MANAGEMENT

Risk management is embedded in all activities at TC Energy and 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 tolerances. We manage risk through a centralized Enterprise Risk Management (ERM) program that systematically identifies enterprise risks, including sustainability-related risks, which could materially impact the achievement of our strategic objectives.

The purpose of the ERM program is to address risks to, or yielding from, the execution of our business strategies, as well as enabling practices that allow us to identify and monitor emerging risks. Specifically, the ERM program and framework provides an end-to-end process for risk identification, analysis, evaluation and mitigation, and the ongoing monitoring and reporting to the Board, CEO and Executive Vice-Presidents, including the Chief Risk Officer.

Our Board retains general oversight of all enterprise risks, as identified below, and specifically has direct oversight of reputation and relationships, political and regulatory uncertainty, capital allocation strategy, project 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. It 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 sustainability-related risks, 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 risks, including climate-related risks
- the Audit Committee oversees management's role in managing financial risk, including market risk, counterparty credit risk and cybersecurity.

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 and opportunities, metrics and targets are outlined in our comprehensive TCFD alignment section of our Report on Sustainability. A summary of enterprise-wide risks with potential to impact our strategic objectives can be found below. 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.

As part of our commitment to continuous improvement of the ERM program, we identified and are working towards adopting Key Risk Indicators (KRIs) for risk events that may impact our ability to achieve our strategic objectives. These metrics will establish a set of appropriate indicators that will provide quantifiable metrics and objective rationale, as well as meaningful trending, for each enterprise risk. Going forward, KRIs will be used to inform our annual in-depth review of our enterprise risks conducted by the Board.

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, contracts or 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, provides structured requirements and processes for our day-to-day work to protect us, our co-workers, our workplace and assets, the communities we work in and the environment. TOMS establishes operational risk management practices to minimize risk exposure and operational failures and is continually improved based on new knowledge from performance monitoring of our assets, learnings from external incidents and collaborative work with industry and regulators. 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. Although we have a comprehensive insurance program to mitigate a certain portion of our risk, insurance does not cover all events in all circumstances.
Cybersecurity		
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 cybersecurity risks and could be subject to cybersecurity events directed against our information technology or physical assets. This risk has been elevated with the increased pace of technology adoption, as well as evolving geopolitical conflicts. 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, bringing novel or unexpected vulnerabilities. This has resulted in stricter cybersecurity regulations in the jurisdictions in which we operate.	A cyberattack could expose our business to a wide range of losses, including misuse or interruption of critical information and functions. It could also affect our operations by damaging our assets, resulting in potential safety and/or environmental incidents. A significant attack could also cause reputational harm, competitive disadvantage, regulatory enforcement actions and potential litigation, which could have a material adverse effect on our operations and/or financial position.	We maintain a comprehensive cybersecurity strategy and program which aligns with regulatory and industry standards. Our strategy is regularly reviewed and updated, and the status of our cybersecurity 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 cybersecurity awareness program for employees and contractors. We have insurance which may cover losses from physical damage to our facilities as a result of a cybersecurity event; however, insurance does not cover all events in all circumstances.
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, government agencies and environmental non-governmental organizations.	Inadequately managing stakeholder expectations and concerns, including those related to climate and sustainability, 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, innovation, responsibility, collaboration and integrity – 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. Further, our management of climate-related governance, strategy, risks and opportunities, metrics and targets are outlined in our annual Report on Sustainability.

Risk and description	Impact	Monitoring and mitigation
Political and regulatory uncertainty		
Our ability to construct and operate energy infrastructure requires regulatory approvals and is dependent on evolving policies and regulations by federal, state, provincial and local government agencies. This includes changes in regulation that may impact our projects and operations into the future, which could affect the financial performance of our assets.	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, due to complying with new or more stringent regulations, 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 including customer, regulatory and government decisions, as well as innovative technology development and report to 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 and changes in investor and lender sentiment could affect our ability to access capital at a competitive cost. Geopolitical instability, higher interest rates, and persistent inflation could put further pressures on the cost of capital into the future.	A higher cost of capital could negatively impact our ability to deliver an attractive return on our investments or inhibit both short and long-term growth. Significant increases to interest rates could result in a higher cost of borrowing and therefore negatively impact our earnings.	We operate within our financial means and risk tolerances, maintain a diverse array of funding levers and also utilize asset divestitures as a 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 sustainability-related updates. Sustainability remains a key consideration in determining strategy, capital allocation and engagement with capital markets. We conduct research annually around the evolving sustainability preferences of our investors and financial partners which we consider in our decision making.
Capital allocation strategy		
To be competitive, we must offer integral energy infrastructure services in supply and demand areas, and in forms of energy that are attractive to customers. We continue to adapt our strategy to protect and enhance the incumbency of our businesses.	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 effectively rotate capital while adhering to our risk preferences and focus on per share metrics. We conduct analyses to confirm the longer-term resilience of the supply and demand markets we serve 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 to respond to changing market conditions.
Project 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.

Risk and description	Impact	Monitoring and mitigation
Talent attraction, retention, and succession planning		
Critical skills are required to execute our strategy which include a deep understanding of the energy industry, geopolitical environment and various regulatory regimes in the areas we operate. The talent landscape is undergoing high degrees of change necessitating adaptation, flexibility and constant monitoring of enterprise-wide talent strategies.	Talent challenges could significantly impact the organization through increased costs, decreased productivity, and the ability to effectively compete in the marketplace. It could also result in a failure to achieve our strategic objectives.	We assess our talent risk using a framework based on people data and trends, which we examine for level of criticality. We use the outcome of this assessment to determine which talent programs will yield the best results to attract, retain and develop talent. Plans to enhance our workforce planning initiatives are underway.

Climate change

Physical and transition risks associated with climate change have the potential to intensify the enterprise risks outlined above. Our business, operations, financial condition and performance may be impacted by climate change policies and its associated impacts. We report and monitor material climate policy and related developments through our ERM program to ensure Management and our Board of Directors have visibility to the broader perspective, and that mitigation plans are applied in a holistic and consistent manner.

Physical Risks

Physical risks to assets could include, but are not limited to severe weather events, wildfires, and longer-term shifts in climate patterns, temperature and precipitation; however, it is difficult to predict the timing, frequency, or severity of such events. Physical risks from climate change could carry financial implications, such as costs resulting from direct damage to our assets, loss of revenues due to business interruption or indirect effects such as value chain disruption. We may experience increased insurance premiums and deductibles, or a decrease in available coverage, for our assets in areas subject to severe weather.

Our engineering standards are regularly reviewed to ensure assets continue to be designed and operated to withstand the potential impacts of climate change. Our emergency response plans are focused on quickly and effectively responding to emergencies and mitigating impacts in a timely manner. We also maintain insurance as a mitigative measure to reduce the financial impact associated with damage to our assets due to extreme weather events.

Transition Risks

Transition risks arise as a result of the global shift to a more sustainable, lower GHG emissions economy. Transition risks include policy, legal, technological, market and reputational risks. These risks include but are not limited to: changes in energy supply and demand trajectories, the pace and reliability of technological advancements, changes in decarbonization policies and regulations, and stakeholder perceptions of our role in the transition to a lower GHG emissions intensive economy. Financial implications from transition risks could include asset impairment due to new or amended climate-related regulations, increased climate change reporting requirements, increased commodity price volatility, reduced demand for fossil fuels, challenges in permitting projects and limited access to and or increased cost of capital. Our financial performance could also be impacted by shifting consumer demands and the development and deployment of new technology.

Our exposure to climate change related transition risk and resulting policy changes is managed through our business model, which is based on a long-term, low-risk strategy whereby much of our earnings are underpinned by regulated cost-of-service arrangements and/or long-term contracts. We factor transition risks into our capital planning, financial risk management and operational activities and are working towards reducing the GHG emissions intensity of our existing operations.

We also evaluate the financial resilience of our asset portfolio against a range of future outcomes as part of our strategic planning process. We are exploring technologies, implementing strategies, and incorporating our GHG emissions reduction targets in our capital allocation framework and decision-making process.

Information on how we manage climate-related risks and opportunities can be found in our annual Report on Sustainability.

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, standards and procedures.

TC Energy's Operational Management System, TOMS, leverages industry best practices and standards and incorporates applicable regulatory requirements. TOMS governs health, safety, environment, and operational integrity matters at TC Energy. It is applicable across Canada, U.S. and Mexico throughout the lifecycle of our assets and employs a continuous improvement cycle. 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.

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

- overall HSSE corporate governance
- operational performance
- asset integrity
- significant occupational safety and process safety incidents
- occupational and process safety performance metrics
- occupational health, safety and industrial hygiene, which includes physical and mental health, as well as psychological safety
- emergency preparedness, incident response and evaluation
- environment, including 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, which 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 and the Reconciliation Action Plan.

To enhance our overall governance structure, we have evolved our corporate HSSE committee into two separate committees that report to the Board HSSE Committee:

- a Sustainability Management Committee that provides strategic leadership and direction on sustainability issues
- an Operating Committee that is responsible for making enterprise decisions in support of management system governance, strategic system enhancements and operational risk management related to safety and environmental considerations.

Focus on sustainability

Starting in 2022, we embedded sustainability goals into our corporate scorecard to progress and advance key strategic priorities including growth and energy transition. Our 2023 corporate scorecard includes goals on safety, diversity of women and visible minorities in leadership and management of our GHG emissions. Our approach to sustainability is guided by our nine commitments that align to the United Nations (UN) Sustainable Development Goals, with tangible targets to measure and drive performance in areas including emissions reductions, women in leadership, biodiversity and safety. We are committed to ensuring balanced and transparent disclosure of our progress against these targets annually in our Report on Sustainability.

Another way in which we demonstrate our commitment to sustainability is through our pursuit of voluntary initiatives. In May 2023, we joined Catalyst, a global non-profit organization supporting companies with solutions and strategies to accelerate progress for women through workplace inclusion. In June 2023, we completed a pilot of the Taskforce for Nature-based Financial Disclosures framework to support the development of an approach to disclosure of nature-related dependencies, impacts, risks and opportunities. In July 2023, we signed the UN Women's Empowerment Principles (WEPs), furthering our commitment to foster an inclusive, safe and productive workplace for all our staff. By signing the WEPs, we are committing to align with the seven core principles and take steps to advance gender equality in our workplace and community.

Our Reconciliation Action Plan, including the 2022 update, outlines six measurable goals of action to help advance reconciliation, both internally and in the communities where we operate. Throughout 2023, our Indigenous Advisory Council, established with members representing Indigenous perspectives across Canada, has advised on strategies, approaches, and tactics in support of pillar areas of focus including: talent and employment, hiring and contracting, and relationships and partnerships.

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, commissioned, operated and maintained 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 2023, we spent $2.1 billion (2022 – $1.6 billion) for pipeline integrity on the natural gas and liquids pipelines we operate, which includes expenditures related to our modernization program within our U.S. Natural Gas Pipelines business. Pipeline integrity spending will fluctuate based on the results of on-going 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 integrity 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 Risk oversight and enterprise risk management section 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 of TOMS, 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. Occupational health, safety and industrial hygiene 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 wellbeing, health education, leader support and improved working conditions to sustain a productive workforce
- increase mental wellbeing awareness, provide various health and wellness supports and training to employees and leaders, measure the success of programs and improve psychological safety
- foster a positive safety culture by building human and organizational performance to strengthen our cultural defenses and develop error-tolerant systems to better protect our people.

Environmental risk, compliance and liabilities

Through the implementation of TOMS, TC Energy proactively and systematically manages environmental hazards and risks throughout the lifecycle of our assets. 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 offsets 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.

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, which 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, which 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.

TOMS includes requirements for TC Energy to 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, 2023, accruals related to these obligations, with the exception of the accrual related to the Milepost 14 incident, totaled $19 million (2022 – $20 million) representing the estimated amount we will need to manage our currently known material environmental liabilities. Refer to the Liquids Pipelines – Significant events section for additional information. 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 2023, we incurred $109 million (2022 – $118 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 levels 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. 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 and across our footprint. Changes in regulations may result in higher operating costs, other expenses or capital expenditures to comply with new or changing regulations. 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 Government of Canada has developed the Clean Fuel Regulations (CFR) to achieve reductions in GHG emissions with a narrowed scope including only liquid fuels, which will not directly impact TC Energy. CFR does allow for credit generation opportunities for gaseous fuel stream to incentivize GHG emission reduction opportunities. The CFR was finalized in June 2022 and came into effect in July 2023. Regulated parties and credit generators expressed concerns over uncertainties about credit availability and recognition for the 2023 and 2024 periods, stemming from ongoing updates like the incomplete Land Use and Biodiversity Guidance and the anticipated ECCC Life Cycle Assessment model update in July 2024. Amidst these updates, there are concerns about the timely processing of Carbon Intensity applications, the limited number of CFR-accredited verification bodies, and the overall clarity regarding key elements for the successful implementation of the CFR. We continue to closely monitor this file and engage with Canadian policymakers, assessing impacts as further information is available
- *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 currently in effect in the province of Manitoba. 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. The current level of carbon pricing is $65/tonne, increasing by $15/tonne every year 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 (OEPS) program. The OEPS program applies to our Canadian Mainline operations in the province and costs under this program are recovered in tolls
- *Saskatchewan:* In September 2022, the Saskatchewan and Federal governments reached an agreement whereby the Federal OBPS in Saskatchewan was replaced on January 1, 2023 by the Saskatchewan Emissions Performance Standards (SEPS) program for pipeline transmission sector assets. The SEPS apply to our Canadian Mainline and Foothills operations in the province and costs under this program are recovered in tolls.

U.S. jurisdictions

- *Federal:* On December 2, 2023, the United States Environmental Protection Agency (USEPA) released a final rule that amends and supplements the New Source Performance Standards – Subpart OOOO series of volatile organic compound and methane emissions regulations for the oil and natural gas industry. The rule, collectively referred to as the "Methane Rule," sets performance standards for new, modified, or reconstructed sources after December 6, 2022 (OOOOb) and establishes emission guidelines (EGs) for existing sources prior to December 6, 2022 (OOOOc). Under OOOOc, the states will submit their plans to meet the EGs for existing sources to the USEPA within 24 months after publication of the final rule, and existing compressor stations would be required to comply with a state's new EGs no later than 36 months after the state plan is submitted to USEPA. The Methane Rule includes fugitive component LDAR requirements, a zero-emission process (pneumatic) controller standard, emission limitations for reciprocating and centrifugal compressors, and a third-party reporting program facilitated by USEPA for identifying large gas release events (Super Emitter program). The OOOOb standards will apply to a relatively limited number of facilities and the costs of compliance are anticipated to be incorporated into new and modified facilities moving forward. The OOOOc standards would apply to a larger number of existing facilities, but impacts of the rule are still subject to further evaluation and assessment, and actual compliance deadlines for existing sources will vary based on state and/or location
- *Federal*: Final "Good Neighbor Plan" for Ozone National Ambient Air Quality Standards. The USEPA released a final version of the Good Neighbor Rule on March 15, 2023, effective August 4, 2023, that specifies new limits for emissions of nitrogen oxides (NOx) from reciprocating internal combustion engines by May 1, 2026. Based on assessments completed thus far, the final rule could require installation of catalytic controls or retrofit of engines with low emission combustion controls at a cost exceeding US$500 million. However, seven Federal Circuit courts have granted stays of the Rule within their jurisdictions until decisions are made on the merits in those proceedings[1] and an emergency stay request remains pending before the U.S. Supreme Court
- *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:* In April 2022, the Pennsylvania Department of Environmental Protection (PADEP) published its final Reasonable Available Control Technologies (RACT) requirements and emission limitations for major stationary sources of NOx and volatile organic compounds (VOCs) statewide. Columbia Gas Transmission has four facilities impacted by the rule, and initial notifications and case by case evaluations were submitted to PADEP for these facilities by December 31, 2022. The purpose of the case-by-case evaluations was to determine whether sources could be re-permitted to the lower emission rate or if installation of controls would be necessary to comply. Columbia Gas Transmission facilities were able to re-permit to the lower emission rate based on historic stack test data such that no control installations were needed to comply
- *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. Columbia Gas Transmission has four facilities in the Cleveland non-attainment area, with two facilities impacted by the rule. A RACT Study was submitted for one of the stations subject to the rule, outlining the steps and cost necessary to install controls by March 2025 to comply with the rule. The other facility subject to the rule is required to perform annual tune-ups to achieve compliance

[1] The seven circuit courts that have granted judicial stays for the entirety of litigation are as follows: 4th Circuit (West Virginia), 5th Circuit (Texas, Louisiana, Mississippi), 6th Circuit (Kentucky), 8th Circuit (Arkansas, Missouri, Minnesota), 9th Circuit (Nevada), 10th Circuit (Oklahoma, Utah) and the 11th Circuit (Alabama).

- *Oregon:* The Governor of Oregon issued an executive order to reduce and regulate GHG emissions 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*: In late 2022, the Washington Department of Ecology adopted the Cap-and-Invest Program (CIP), which became effective in January 2023 and established a comprehensive, market-based program to reduce carbon pollution and achieve the GHG emissions reduction goals established by the State legislature. The CIP sets a declining limit, or cap, on overall carbon emissions in the state and requires businesses to obtain allowances equal to their covered GHG emissions. Under the CIP, companies are incented to reduce emissions to avoid higher compliance costs, as the cost to obtain allowances will increase as the supply of allowances decreases over time. GTN has three impacted compressor station facilities, and cost exposure under the CIP is mainly driven by throughput and fuel forecast data, as well as price volatility in the newly established CIP allowance market. As an active participant in the CIP allowance market, GTN met its base compliance obligation for 2023
- *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
- *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, and an initial compliance period commencing January 1, 2023. Part 203 regulates VOCs and methane emissions from the oil and gas sector. Compliance obligations include leak detection and repair at operated storage wells, compressor stations, and city gate meter and regulator sites; blowdown notifications; and reporting of pigging activities, as well as a baseline inventory for all assets in New York.

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 GHG emission reductions from prevention and control activities. This regulation requires the PPCIEM, through which operational and technological practices are adopted, to determine a GHG emissions intensity 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:* ECCC committed to expand on the current methane reduction regulations and released draft amendments in December 2023 to reduce Canada's oil and gas sector methane emissions by at least 75 per cent below 2012 levels by 2030. The draft amendments introduce a risk-based approach for the detection and repair of fugitive emissions, prohibit all venting with specific exceptions and offer an alternative performance-based approach using continuous monitoring. TC Energy has identified several areas for improvement and clarification. We will seek clarifications and adjustments and, in collaboration with industry associations, will participate in the public consultation process. The updated regulations are expected to come into force January 1, 2027, with phased requirements through 2030. We will continue to refine our internal emissions management strategies and update our compliance plans to align with the anticipated regulatory changes

- *Federal:* In December 2023, ECCC released a Regulatory Framework for an Oil and Gas Sector Greenhouse Gas Emissions Cap that builds on a July 2022 discussion paper to contribute to 2030 climate goals and achieve net-zero by 2050. The framework proposes to implement a national cap-and-trade system to cap upstream and LNG sub-sector emissions between 35 per cent to 38 per cent below 2019 levels, with some compliance flexibility up to 20 per cent to 23 per cent below the same baseline year. Although transmission pipelines are excluded from the proposed regulatory framework, there is a possibility of cascading effects and unintended consequences. The draft regulations are expected to be released in mid-2024, with final publication in 2025. The regulations are expected to be phased in between 2026 and 2030. We will continue to monitor, assess, and provide feedback to ECCC on the proposed emissions cap, as appropriate
- *Federal*: On August 19, 2023, ECCC published the draft Clean Electricity Regulations (CERs), targeting a net-zero electricity system by 2035. The CERs, effective from January 1, 2025, mandate a GHG emissions intensity standard of 30 tonnes CO_2/GWh for fossil fuel power generation units with a capacity of 25 MW or more, though there are exemptions and limited compliance flexibilities. The draft regulations, enacted under the Canadian Environmental Protection Act, could potentially affect energy affordability and reliability and have a significant operational and financial impact to our business; as drafted, our current cogeneration fleet would be required to meet this new standard by 2035. Throughout the consultation process, we are actively engaging with the ECCC, providing feedback and collaborating with other industry stakeholders. We will continue monitoring and providing feedback to ECCC as this file progresses
- *British Columbia*: Currently, British Columbia is formulating a new carbon pricing model, the British Columbia OBPS. This system mirrors the federal OBPS system and is forecasted to reduce the carbon tax payments in the near future. However, the British Columbia OBPS proposes a considerably more stringent threshold compared to the federal OBPS or other analogous jurisdictions like the Alberta Technology Innovation and Emissions Reduction Regulations. The specifics of the British Columbia OBPS are still under deliberation and any costs associated with are expected to be recoverable through tolls. We are proactively observing the developments and offering our feedback. Concurrently, British Columbia is laying the groundwork for an oil and gas emission cap within the province. We are actively involved in these discussions, providing feedback pertinent to our operations in British Columbia, with a focus on concerns related to energy affordability and reliability.

U.S. jurisdictions

- *Federal:* The U.S. Senate passed the PHMSA reauthorization bill, the PIPES Act of 2020, which required PHSMA to promulgate gas pipeline leak detection and repair regulations. On May 4, 2023, PHMSA released a Notice of Proposed Rulemaking (NPRM) to regulate methane emissions from new and existing gas transmission, distribution, and gas gathering pipelines, and underground storage and LNG facilities. PHMSA's NPRM provides limited exemption for compressor stations recognizing USEPA's current and proposed methane standards. The cost of compliance due to the proposed PHMSA regulations is expected to increase significantly due to new monitoring and repair requirements on the entire natural gas transmission system
- *Federal:* In May 2023, USEPA released amendments to the previously released June 2022 proposal regarding the GHG Reporting program that would go into effect on January 1, 2025 and be included in Reporting Year 2024 for GHG reporting due to the USEPA by March 31, 2025. This proposal includes reporting of a new reporting category (Subpart B – Energy Consumption) and revisions to global warming potentials. USEPA released another supplemental proposal in August 2023. This 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. These proposed revisions would be implemented with reports prepared for Reporting Year 2025 for GHG reporting due to the USEPA by March 31, 2026. TC Energy reports to the USEPA as required by the GHG Reporting rule (40 CFR 98)
- *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 US$900/tonne for 2024, US$1,200/tonne for 2025 and US$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 or 2022 emissions. The IRA also instructs USEPA to revise Subpart W by August 2024 to ensure GHG reporting is based on empirical data

- *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. The California Air Resources Board posted a notice of public availability on November 2, 2023 for proposed amendments to Sub article 13: Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities. The amendments consolidated the Delay of Repair (DOR) provisions into a dedicated section and elaborated on the justification requirements for DOR requests. The proposed amendments if adopted would require development of an implementation plan for three affected facilities and training for operations personnel
- *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 July 18, 2019, the Climate Leadership and Community Protection Act (Climate Act) was signed into law, requiring New York to reduce economy-wide GHG emissions by 40 per cent by 2030 and no less than 85 per cent by 2050 from 1990 levels. The New York State Department of Environmental Conservation (DEC) and New York State Energy Research and Development Authority (NYSERDA) are developing New York's Cap-and-Invest Program (NYCI), proposed in 2023, to meet the Climate Act's GHG reduction and equity requirements. The NYCI will set an annual cap on the amount of GHG emissions that are permitted to be emitted in the state. The program is currently in the stakeholder engagement phase, with compliance aimed to commence in 2025. NYCI will potentially impact TC Energy owned/operated assets in New York, but impacts will be further evaluated once a draft rule is published, which is expected in 2024.

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.

In addition to the above, there are new mandatory climate-related disclosure requirements being issued in jurisdictions in which we operate. These disclosure requirements may impact how we report our climate-related risks and opportunities, strategy, risk management and GHG emission metrics and targets. We continue to monitor these developments and progress activities in anticipation of these new requirements.

Other sustainability related regulations

There are also mandatory cybersecurity and human rights-related disclosure requirements being issued in jurisdictions in which we operate. While these disclosure requirements do not necessarily apply to us, they may impact how we report on non-climate related sustainability risks, opportunities, strategies, governance and incidents. We continue to monitor these developments and progress activities related to these new and anticipated requirements.

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.

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.

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 directly affect our comparable EBITDA and may also impact comparable earnings.

A portion of our Mexico Natural Gas Pipelines monetary assets and liabilities are peso-denominated, while our Mexico operations' financial results are denominated in U.S. dollars. Therefore, 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 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 a portion of our foreign exchange risk using foreign exchange derivatives. Refer to the Foreign exchange section for additional information.

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 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
- net investment in leases and certain contract assets in Mexico.

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, 2023 and 2022, we had no significant credit risk concentrations and no significant amounts past due or impaired. We recorded an $80 million recovery for the year ended December 31, 2023 on the expected credit loss provision before tax recognized on the TGNH net investment in leases and certain contract assets in Mexico (2022 – $163 million loss). Other than the expected credit loss provision noted above, we had no significant credit losses at December 31, 2023 and 2022. Refer to Note 29, Risk management and financial instruments, of our 2023 Consolidated financial statements for additional information.

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. Our portfolio of financial sector exposure consists primarily of highly-rated investment grade, systemically important financial institutions.

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 additional information.

Legal proceedings

TC Energy and its subsidiaries are subject to various legal proceedings, arbitrations and actions arising in the normal course of business. We assess all legal matters on an ongoing basis, including those of our equity investments. With the potential exception of the matters discussed in Note 32, Commitments, contingencies and guarantees, of our 2023 Consolidated financial statements, for which the claims are material and there is a reasonable possibility of loss, but have not been assessed as probable and a reasonable estimate of loss cannot be made, it is the opinion of management that the ultimate resolution of such proceedings and actions will not 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, 2023, 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, 2023, 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, 2023, the internal control over financial reporting was effective.

Our internal control over financial reporting as of December 31, 2023 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their attestation report which is included in our 2023 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 2023 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 2023 Consolidated financial statements for additional information.

Impairment of equity investment in Coastal GasLink LP

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. The revised estimate of total project costs and our corresponding future funding requirements were indicators that a decrease in the value of our equity investment had occurred. A valuation assessment was completed at December 31, 2022 and at each reporting period through September 30, 2023 and we concluded that the fair value of TC Energy's investment was below its carrying value at each period an assessment was performed. We determined that there was an other-than-temporary impairment of our equity investment in Coastal GasLink LP, which resulted in a pre-tax impairment charge of $2,100 million ($1,943 million after tax) for the year ended December 31, 2023, in Impairment of equity investment in the Consolidated statement of income in the Canadian Natural Gas Pipelines segment. The impairment charge reflected the net impact of changes in the subordinated loan for the nine months ended September 30, 2023, along with TC Energy's proportionate share of unrealized gains and losses on interest rate derivatives in Coastal GasLink LP and other changes to the equity investment. The cumulative pre-tax impairment charge recognized to date at December 31, 2023 is $5,148 million ($4,586 million after tax). The impairment of the subordinated loan resulted in unrealized non-taxable capital losses that are not recognized. Refer to Note 8, Coastal GasLink, of our 2023 Consolidated financial statements for additional information.

The fair value of TC Energy's investment in Coastal GasLink LP at September 30, 2023 was estimated using a 40-year discounted cash flow model and incorporated assumptions related to the capital cost estimates, discount rates and long-term financing plans.

At December 31, 2023, there were no events or changes in circumstances from September 30, 2023 indicating a significant adverse impact on the estimated fair value of our investment in Coastal GasLink LP, therefore there was no other-than-temporary impairment that existed at December 31, 2023. Refer to our 2023 Consolidated financial statements for additional information.

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 at December 31, 2023, we evaluated qualitative factors impacting the fair value of the underlying reporting units for all reporting units other than for the Tuscarora and North Baja reporting units, which are described below. It was determined that it was more likely than not that the fair value of these reporting units exceeded their carrying amounts, including goodwill.

Sale of a 40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf

In conjunction with the process leading up to the sale of a 40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf, we performed a quantitative goodwill impairment test for the Columbia Pipeline Group, Inc. (Columbia) reporting unit at June 30, 2023. Refer to the U.S. Natural Gas Pipelines – Significant events section for additional information on this sale transaction.

In the determination of the fair value utilized in the quantitative goodwill impairment test for the Columbia reporting unit, we performed a discounted cash flow analysis using projections of future cash flows and applied a risk-adjusted discount rate and terminal value multiple which involved significant estimates and judgments. It was determined that the fair value of the Columbia reporting unit exceeded its carrying value, including goodwill. Although goodwill was not impaired, the estimated fair value in excess of the carrying value was less than 10 per cent. There is a risk that reductions in future cash flow forecasts and adverse changes in other key assumptions could result in a future impairment of a portion of the goodwill balance relating to Columbia.

North Baja and Tuscarora

We elected to proceed directly to a quantitative annual impairment test at December 31, 2023 for the $63 million of goodwill related to the North Baja reporting unit due to the passage of time from the previous quantitative test at December 31, 2018. We also elected to proceed directly to a quantitative annual impairment test for the $30 million of goodwill related to the Tuscarora reporting unit due to the passage of time from the previous quantitative test at December 31, 2018, and subsequent to the Tuscarora Section 4 rate case settlement in 2023. It was determined that the fair values of North Baja and Tuscarora exceeded their carrying values, including goodwill, at December 31, 2023.

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 liabilities or regulatory assets 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 $)	**2023**	**2022**
Other current assets	**1,285**	614
Other long-term assets	**155**	91
Accounts payable and other	**(1,143)**	(871)
Other long-term liabilities	**(106)**	(151)
	191	(317)

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, 2023 (millions of $)	**Total fair value**	**< 1 year**	**1 - 3 years**	**4 - 5 years**	**> 5 years**
Derivative instruments held for trading	181	142	75	24	(60)
Derivative instruments in hedging relationships	10	—	(2)	5	7
	191	142	73	29	(53)

Unrealized and realized gains (losses) on derivative instruments

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

year ended December 31 (millions of $)	2023	2022	2021
Derivative Instruments Held for Trading[1]			
Unrealized gains (losses) in the year			
Commodities	**96**	14	9
Foreign exchange	**246**	(149)	(203)
Realized gains (losses) in the year			
Commodities	**811**	759	287
Foreign exchange	**155**	(2)	240
Derivative Instruments in Hedging Relationships[2]			
Realized gains (losses) in the year			
Commodities	**(2)**	(73)	(44)
Interest rate	**(43)**	(3)	(32)

1 Realized and unrealized gains (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 (losses) on foreign exchange held-for-trading derivative instruments are included on a net basis in Foreign exchange (gains) losses, net in the Consolidated statement of income.

2 In 2023, there were no gains or losses included in Net income (loss) relating to discontinued cash flow hedges where it was probable that the anticipated transaction would not occur (2022 – nil; 2021 – realized loss of $10 million).

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 29, Risk management and financial instruments, of our 2023 Consolidated financial statements.

RELATED PARTY TRANSACTIONS

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

Coastal GasLink LP

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 Subordinated Loan Agreement

TC Energy has a subordinated loan agreement with Coastal GasLink LP under which draws by Coastal GasLink LP will fund the remaining $0.9 billion (December 31, 2022 – $3.3 billion) equity requirement related to the estimated capital cost to complete the Coastal GasLink pipeline. At December 31, 2023, the total capacity committed by TC Energy under this subordinated loan agreement was $3.4 billion.

Any amounts outstanding on this loan will be repaid by Coastal GasLink LP to TC Energy, once final project 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 contractual terms, these additional equity contributions will be predominantly funded by TC Energy but will not result in a change to our 35 per cent ownership. The total amount drawn on this loan at December 31, 2023 was $2,520 million (December 31, 2022 – $250 million). Due to impairment charges recognized during the year, the carrying value of this loan was $500 million at December 31, 2023 (2022 – nil).

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, 2023 (December 31, 2022 – nil). This revolver was not impacted by the impairment charge recognized to date.

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. On March 15, 2022, as part of refinancing activities with the Sur de Texas joint venture, the peso-denominated inter-affiliate loan was replaced with a new U.S. dollar-denominated inter-affiliate loan from us for 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.

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 $)	**2023**	**2022**	**2021**	**Affected line item in the Consolidated statement of income**
Interest income[1]	—	19	87	Interest income and other
Interest expense[2]	—	(19)	(87)	Income from equity investments
Foreign exchange losses[1]	—	(28)	(41)	Foreign exchange (gains) losses, net
Foreign exchange gains[1]	—	28	41	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.

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 2023 Consolidated financial statements.

QUARTERLY RESULTS

Selected quarterly consolidated financial data

2023 (millions of $, except per share amounts)	Fourth	Third	Second	First
Revenues	**4,236**	**3,940**	**3,830**	**3,928**
Net income (loss) attributable to common shares	**1,463**	**(197)**	**250**	**1,313**
Comparable earnings	**1,403**	**1,035**	**981**	**1,233**
Share statistics:				
Net income (loss) per common share – basic	**$1.41**	**($0.19)**	**$0.24**	**$1.29**
Comparable earnings per common share	**$1.35**	**$1.00**	**$0.96**	**$1.21**
Dividends declared per common share	**$0.93**	**$0.93**	**$0.93**	**$0.93**

2022 (millions of $, except per share amounts)	Fourth	Third	Second	First
Revenues	4,041	3,799	3,637	3,500
Net income (loss) attributable to common shares	(1,447)	841	889	358
Comparable earnings	1,129	1,068	979	1,103
Share statistics:				
Net income (loss) 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

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 addition to the factors below, our revenues and segmented earnings (losses) are impacted by fluctuations in foreign exchange rates, mainly related to our U.S. dollar-denominated operations and our peso-denominated exposure.

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 (losses) 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
- 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. We also exclude 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 fourth quarter 2023, comparable earnings also excluded:

- a $74 million income tax recovery related to a revised assessment of the valuation allowance and non-taxable capital losses on our equity investment in Coastal GasLink LP
- an $18 million after-tax recovery related to the net impact of a U.S. minimum tax recovery on the 2021 Keystone XL asset impairment charge and other and a gain on the sale of Keystone XL project assets, offset partially by adjustments to the estimate for contractual and legal obligations related to termination activities
- an after-tax unrealized foreign exchange loss of $55 million on the peso-denominated intercompany loan between TCPL and TGNH
- a $25 million after-tax loss on the expected credit loss provision related to the TGNH net investment in leases and certain contract assets in Mexico
- an after-tax charge of $23 million due to Liquids Pipelines business separation costs related to the spinoff Transaction
- a $9 million after-tax expense related to Focus Project costs
- carrying charges of $4 million after tax as a result of a charge related to the FERC Administrative Law Judge initial decision on Keystone issued in February 2023 in respect of a tolling-related complaint pertaining to amounts recognized from 2018 to 2022
- preservation and other costs for Keystone XL pipeline project assets of $4 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge.

In third quarter 2023, comparable earnings also excluded:

- an after-tax impairment charge of $1,179 million related to our equity investment in Coastal GasLink LP
- a $14 million after-tax expense related to Focus Project costs
- an after-tax charge of $11 million due to Liquids Pipelines business separation costs related to the spinoff Transaction
- preservation and other costs for Keystone XL pipeline project assets of $2 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge
- an after-tax net unrealized foreign exchange gain of $20 million on the peso-denominated intercompany loan between TCPL and TGNH.

In second quarter 2023, comparable earnings also excluded:

- an after-tax impairment charge of $809 million related to our equity investment in Coastal GasLink LP
- a $36 million after-tax accrued insurance expense related to the Milepost 14 incident
- a $25 million after-tax expense related to Focus Project costs
- an after-tax net unrealized foreign exchange loss of $9 million on the peso-denominated intercompany loan between TCPL and TGNH
- preservation and other costs for Keystone XL pipeline project assets of $4 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge
- an $8 million after-tax recovery on the expected credit loss provision related to the TGNH net investment in leases and certain contract assets in Mexico.

In first quarter 2023, comparable earnings also excluded:

- a $72 million after-tax recovery on the expected credit loss provision related to the TGNH net investment in leases and certain contract assets in Mexico
- $48 million after-tax charge as a result of the FERC Administrative Law Judge initial decision on Keystone issued in February 2023 in respect of a tolling-related complaint pertaining to amounts recognized from 2018 to 2022 which consists of a one-time pre-tax charge of $57 million and accrued pre-tax carrying charges of $5 million
- an after-tax impairment charge of $29 million related to our equity investment in Coastal GasLink LP
- preservation and other costs for Keystone XL pipeline project assets of $4 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge.

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
- 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.

FOURTH QUARTER 2023 HIGHLIGHTS

Consolidated results

three months ended December 31 (millions of $, except per share amounts)	2023	2022
Canadian Natural Gas Pipelines	**692**	(2,592)
U.S. Natural Gas Pipelines	**955**	882
Mexico Natural Gas Pipelines	**150**	96
Liquids Pipelines	**309**	322
Power and Energy Solutions	**263**	298
Corporate	**(42)**	(4)
Total segmented earnings (losses)	**2,327**	(998)
Interest expense	**(845)**	(722)
Allowance for funds used during construction	**132**	115
Foreign exchange gains (losses), net	**89**	132
Interest income and other	**121**	53
Income (loss) before income taxes	**1,824**	(1,420)
Income tax (expense) recovery	**(209)**	4
Net income (loss)	**1,615**	(1,416)
Net (income) loss attributable to non-controlling interests	**(128)**	(9)
Net income (loss) attributable to controlling interests	**1,487**	(1,425)
Preferred share dividends	**(24)**	(22)
Net income (loss) attributable to common shares	**1,463**	(1,447)
Net income (loss) per common share – basic	**$1.41**	($1.42)

Net income (loss) attributable to common shares increased by $2.9 billion or $2.83 per common share for the three months ended December 31, 2023 compared to the same period in 2022. The significant increase for the three months ended December 31, 2023 is primarily due to the net effect of the specific items mentioned below. Net income per common share in both periods also reflect the impact of common shares issued in 2023 and 2022.

Fourth quarter 2023 results included:

- a $74 million income tax recovery related to a revised assessment of the valuation allowance and non-taxable capital losses on our equity investment in Coastal GasLink LP
- an $18 million after-tax recovery related to the net impact of a U.S. minimum tax recovery on the 2021 Keystone XL asset impairment charge and other and a gain on the sale of Keystone XL project assets, offset partially by adjustments to the estimate for contractual and legal obligations related to termination activities
- an after-tax unrealized foreign exchange loss of $55 million on the peso-denominated intercompany loan between TCPL and TGNH
- a $25 million after-tax loss on the expected credit loss provision related to the TGNH net investment in leases and certain contract assets in Mexico
- an after-tax charge of $23 million due to Liquids Pipelines business separation costs related to the spinoff Transaction
- a $9 million after-tax expense related to Focus Project costs
- carrying charges of $4 million after tax as a result of a charge related to the FERC Administrative Law Judge initial decision on Keystone issued in February 2023 in respect of a tolling-related complaint pertaining to amounts recognized from 2018 to 2022
- preservation and other costs for Keystone XL pipeline project assets of $4 million after tax, which could not be accrued as part of the Keystone XL asset impairment charge.

Fourth quarter 2022 results included:

- an after-tax impairment charge of $2.6 billion related to our equity investment in Coastal GasLink LP
- 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 U.S. minimum tax, partially offset by the gain on the sale of Keystone XL project assets and adjustments 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.

Net income in each period 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 (loss) attributable to common shares to comparable earnings is shown in the following table.

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

three months ended December 31 (millions of $, except per share amounts)	2023	2022
Net income (loss) attributable to common shares	**1,463**	(1,447)
Specific items (net of tax):		
Coastal GasLink impairment charge	**(74)**	2,643
Keystone XL asset impairment charge and other	**(18)**	5
Foreign exchange (gains) losses, net – intercompany loan	**55**	—
Expected credit loss provision on net investment in leases and certain contract assets in Mexico	**25**	64
Liquids Pipelines business separation costs	**23**	—
Focus Project costs	**9**	—
Keystone regulatory decisions	**4**	20
Keystone XL preservation and other	**4**	8
Milepost 14 insurance expense	**—**	—
Settlement of Mexico prior years' income tax assessments	**—**	1
Bruce Power unrealized fair value adjustments	**(5)**	(9)
Risk management activities[1]	**(83)**	(156)
Comparable earnings	**1,403**	1,129
Net income (loss) per common share	**$1.41**	($1.42)
Specific items (net of tax):		
Coastal GasLink impairment charge	**(0.07)**	2.60
Keystone XL asset impairment charge and other	**(0.02)**	—
Foreign exchange (gains) losses, net – intercompany loan	**0.05**	—
Expected credit loss provision on net investment in leases and certain contract assets in Mexico	**0.03**	0.06
Liquids Pipelines business separation costs	**0.02**	—
Focus Project costs	**0.01**	—
Keystone regulatory decisions	**—**	0.02
Keystone XL preservation and other	**—**	0.01
Milepost 14 insurance expense	**—**	—
Settlement of Mexico prior years' income tax assessments	**—**	—
Bruce Power unrealized fair value adjustments	**—**	(0.01)
Risk management activities	**(0.08)**	(0.15)
Comparable earnings per common share	**$1.35**	$1.11

1

three months ended December 31 (millions of $)	2023	2022
U.S. Natural Gas Pipelines	**(29)**	(28)
Liquids Pipelines	**20**	(38)
Canadian Power	**(6)**	30
U.S. Power	**4**	5
Natural Gas Storage	**18**	67
Foreign exchange	**104**	172
Income tax attributable to risk management activities	**(28)**	(52)
Total unrealized gains (losses) from risk management activities	**83**	156

Comparable EBITDA to comparable earnings

Comparable EBITDA represents segmented earnings (losses) adjusted for the specific items described above and excludes charges for depreciation and amortization.

three months ended December 31 (millions of $, except per share amounts)	2023	2022
Comparable EBITDA		
Canadian Natural Gas Pipelines	**1,034**	768
U.S. Natural Gas Pipelines	**1,225**	1,141
Mexico Natural Gas Pipelines	**208**	211
Liquids Pipelines	**379**	364
Power and Energy Solutions	**266**	203
Corporate	**(5)**	(4)
Comparable EBITDA	**3,107**	2,683
Depreciation and amortization	**(717)**	(670)
Interest expense included in comparable earnings	**(840)**	(722)
Allowance for funds used during construction	**132**	115
Foreign exchange gains (losses), net included in comparable earnings	**40**	(40)
Interest income and other included in comparable earnings	**121**	53
Income tax (expense) recovery included in comparable earnings	**(288)**	(259)
Net (income) loss attributable to non-controlling interests	**(128)**	(9)
Preferred share dividends	**(24)**	(22)
Comparable earnings	**1,403**	1,129
Comparable earnings per common share	**$1.35**	$1.11

Comparable EBITDA – 2023 versus 2022

Comparable EBITDA increased by $424 million for the three months ended December 31, 2023 compared to the same period in 2022 primarily due to the net effect of the following:

- increased EBITDA in Canadian Natural Gas Pipelines mainly as a result of higher contributions from Coastal GasLink related to the recognition of a $200 million incentive payment upon meeting certain milestones and higher flow-through costs and increased rate-base earnings on the NGTL System
- increased Power and Energy Solutions EBITDA attributable to higher realized Alberta natural gas storage spreads, higher contributions from Bruce Power and increased Canadian Power financial results due to higher contributions from marketing activities
- increased U.S. dollar-denominated EBITDA from U.S. Natural Gas Pipelines as a result of incremental earnings from growth and modernization projects placed in service and higher net earnings from additional contract sales, along with certain fourth quarter 2022 adjustments, partially offset by higher operational costs reflective of increased utilization and lower commodity prices related to our mineral rights business
- increased EBITDA from Liquids Pipelines primarily due to higher volumes on the Keystone Pipeline System, partially offset by the negative impact of the CER decision issued in December 2022 in respect of a tolling-related complaint pertaining to amounts invoiced in 2022
- decreased U.S. dollar-denominated EBITDA from Mexico Natural Gas Pipelines attributable to lower earnings from Guadalajara due to lower fixed revenue and higher operating costs due to a weather event, partially offset by earnings from the lateral section of the Villa de Reyes pipeline which was placed in commercial service in third quarter 2023.

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 – 2023 versus 2022

Comparable earnings increased by $274 million or $0.24 per common share for the three months ended December 31, 2023 compared to the same period in 2022 and was primarily the net effect of:

- changes in comparable EBITDA described above
- higher interest expense primarily due to long-term debt issuances, net of maturities, the foreign exchange impact on translation of increased U.S. dollar-denominated interest expense, partially offset by higher capitalized interest and reduced levels of short-term borrowings
- higher depreciation and amortization on the NGTL System from expansion facilities that were placed in service
- higher AFUDC primarily due to capital expenditures on the Southeast Gateway pipeline project, partially offset by the impact of NGTL System expansion projects that were placed in service and the suspension of AFUDC on the Tula pipeline project, effective November 1, 2023, due to the delay of an FID
- increased income tax expense due to the impact of higher comparable earnings subject to income tax and Mexico foreign exchange exposure, partially offset by lower flow-through income taxes, higher foreign income tax rate differentials and lower Mexico inflation adjustments
- impact of derivatives used to manage our net exposure to foreign exchange rate fluctuation on U.S. dollar-denominated income and our foreign exchange exposure to net liabilities in Mexico
- higher interest income and other due to higher interest earned on short-term investments and the change in fair value of other restricted investments
- higher net income attributable to non-controlling interests primarily due to the net effect of the sale of a 40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf and the acquisition of the Texas Wind Farms.

Comparable earnings per common share for the three months ended December 31, 2023 reflect the dilutive effect of common shares issued in 2023 and 2022.

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, 2023, 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. Natural Gas Pipelines 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$)	**2023**	**2022**
Comparable EBITDA		
U.S. Natural Gas Pipelines	**900**	842
Mexico Natural Gas Pipelines	**153**	156
Liquids Pipelines	**204**	204
	1,257	1,202
Depreciation and amortization	**(241)**	(237)
Interest expense on long-term debt and junior subordinated notes	**(473)**	(323)
Allowance for funds used during construction	**81**	55
Non-controlling interests and other	**(92)**	(44)
	532	653
Average exchange rate - U.S. to Canadian dollars	**1.36**	1.36

Foreign exchange related to Mexico Natural Gas Pipelines

Changes in the value of the Mexican peso against the U.S. dollar can affect our comparable earnings as a portion of our Mexico Natural Gas Pipelines monetary assets and liabilities are peso-denominated, while our financial results are denominated in U.S. dollars for our Mexico operations. These peso-denominated balances are revalued to U.S. dollars, creating foreign exchange gains and losses that are included in Income (loss) from equity investments and Foreign exchange (gains) losses, net in the Consolidated statement of 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. This exposure increases as our U.S. dollar-denominated net monetary liabilities grow. 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 revolving credit facility with a third party, which resulted in an additional peso-denominated income tax expense compared to 2022.

The above exposures are managed using foreign exchange derivatives, although some unhedged exposure remains. The impacts of the foreign exchange derivatives are recorded in Foreign exchange (gains) losses, net in the Consolidated statement of income. Refer to the Financial risks and financial instruments section for additional information.

The period end exchange rates for one U.S. dollar to Mexican pesos were as follows:

December 31, 2023	**16.91**
December 31, 2022	19.50
December 31, 2021	20.48

A summary of the impacts of transactional foreign exchange gains and losses from changes in the value of the Mexican peso against the U.S. dollar and associated derivatives is set out in the table below:

three months ended December 31		
(millions of $)	**2023**	**2022**
Comparable EBITDA - Mexico Natural Gas Pipelines[1]	**(16)**	(15)
Foreign exchange gains (losses), net included in comparable earnings	**64**	34
Income tax (expense) recovery included in comparable earnings	**(38)**	(9)
	10	10

1 Includes the foreign exchange impacts from the Sur de Texas joint venture recorded in Income (loss) from equity investments in the Consolidated statement of income.

Highlights by business segment

Canadian Natural Gas Pipelines

For the three months ended December 31, 2023, Canadian Natural Gas Pipelines segmented earnings were $0.7 billion compared to segmented losses of $2.6 billion for the same period in 2022. Segmented losses included a pre-tax impairment charge of $3.0 billion, for the three months ended December 31, 2022, related to our equity investment in Coastal GasLink LP, which has been excluded from our calculation of comparable EBITDA and comparable EBIT. Refer to Note 8, Coastal GasLink, of our 2023 Consolidated financial statements for additional information.

Net income for the NGTL System increased by $13 million for the three months ended December 31, 2023 compared to the same period in 2022 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, 2023 was consistent with the same period in 2022. 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 $266 million for the three months ended December 31, 2023 compared to the same period in 2022 due to the net effect of:

- earnings from Coastal GasLink related to the recognition of a $200 million incentive payment upon meeting certain milestones. Refer to the Canadian Natural Gas Pipelines – Significant events section for additional information
- higher flow-through financial charges, depreciation and income taxes, as well as higher rate-base earnings on the NGTL System.

Depreciation and amortization increased by $30 million for the three months ended December 31, 2023 compared to the same period in 2022 reflecting incremental depreciation on the NGTL System from expansion facilities that were placed in service and on the Canadian Mainline due to assets placed in service on a section with higher depreciation rates per the terms of the 2021-2026 Mainline Settlement.

U.S. Natural Gas Pipelines

U.S. Natural Gas Pipelines segmented earnings increased by $73 million for the three months ended December 31, 2023 compared to the same period in 2022 and included unrealized gains and losses from changes in the fair value of derivatives related to our U.S. natural gas marketing business, which has been excluded from our calculation of comparable EBITDA and comparable EBIT.

Higher U.S. dollar-denominated segmented earnings for the three months ended December 31, 2023 had a positive impact on the Canadian dollar equivalent segmented earnings from our U.S. operations compared to the same period in 2022.

Comparable EBITDA for U.S. Natural Gas Pipelines increased by US$58 million for the three months ended December 31, 2023 compared to the same period in 2022 and was primarily due to the net effect of:

- incremental earnings from growth and modernization projects placed in service
- a net increase in earnings from additional contract sales on Columbia Gas, ANR and Great Lakes along with certain fourth quarter 2022 adjustments related to ANR regulatory deferrals
- increased equity earnings from Iroquois
- reduced earnings from our mineral rights business due to lower commodity prices
- decreased earnings due to higher operational costs, reflective of increased system utilization across our footprint, as well as higher property taxes related to projects in service.

Depreciation and amortization increased by US$5 million for the three months ended December 31, 2023 compared to the same period in 2022 due to new projects placed in service.

Mexico Natural Gas Pipelines

Mexico Natural Gas Pipelines segmented earnings increased by $54 million for the three months ended December 31, 2023 compared to the same period in 2022 and included a loss of $36 million (2022 – loss of $92 million) on the expected credit loss provision related to the TGNH net investment in leases and certain contract assets in Mexico, which has been excluded from our calculation of comparable EBITDA and comparable EBIT. Refer to Note 29, Risk management and financial instruments, of our 2023 Consolidated financial statements for additional information.

Comparable EBITDA for Mexico Natural Gas Pipelines decreased by US$3 million for the three months ended December 31, 2023 compared to the same period in 2022 due to the net effect of:

- lower earnings from Guadalajara primarily due to lower fixed revenue in accordance with the current transportation contract and higher operating costs associated with a disruption of service due to a weather event
- higher earnings in TGNH primarily related to the lateral section of the Villa de Reyes pipeline which was placed in commercial service in third quarter 2023.

Depreciation and amortization was consistent for the three months ended December 31, 2023 compared to the same period in 2022.

Liquids Pipelines

Liquids Pipelines segmented earnings decreased by $13 million for the three months ended December 31, 2023 compared to the same period in 2022 and included the following specific items, which have been excluded from our calculation of comparable EBITDA and comparable EBIT:

- pre-tax preservation and other costs for Keystone XL pipeline project assets of $5 million for the three months ended December 31, 2023 (2022 – $10 million), which could not be accrued as part of the Keystone XL asset impairment charge
- a pre-tax charge of $3 million incurred in fourth quarter 2023 due to Liquids Pipelines business separation costs related to the spinoff Transaction
- a $4 million pre-tax adjustment for the three months ended December 31, 2023 (2022 – $118 million) to the 2021 Keystone XL asset impairment charge and other resulting from the net effect of the gain on sale of Keystone XL project assets and adjustments 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 2022
- unrealized gains and losses from changes in the fair value of derivatives related to our liquids marketing business.

Comparable EBITDA for Liquids Pipelines increased by $15 million for the three months ended December 31, 2023 compared to the same period in 2022 primarily due to the net effect of:

- higher contracted volumes on the U.S. Gulf Coast section of the Keystone Pipeline System
- higher uncontracted volumes on the Keystone Pipeline System
- the negative impact of the CER decision issued in December 2022 in respect of a tolling-related complaint pertaining to amounts invoiced in 2022.

Depreciation and amortization was consistent for the three months ended December 31, 2023 compared with the same period in 2022.

Power and Energy Solutions

Power and Energy Solutions segmented earnings decreased by $35 million for the three months ended December 31, 2023 compared to the same period in 2022 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 $63 million for the three months ended December 31, 2023 compared to the same period in 2022 primarily due to the net effect of:

- increased Natural Gas Storage and other results from higher realized Alberta natural gas storage spreads
- higher contributions from Bruce Power primarily due to realized gains on funds invested for post-retirement benefits, an increased contract price and lower operating expenses, partially offset by lower generation
- increased Canadian Power financial results due to higher net contributions from marketing activities, partially offset by lower realized power prices.

Depreciation and amortization increased by $7 million for the three months ended December 31, 2023 compared to the same period in 2022 primarily due to the acquisition of the Texas Wind Farms in the first half of 2023.

Corporate

Corporate segmented losses increased by $38 million for the three months ended December 31, 2023 compared to the same period in 2022 and included the following specific items, which have been excluded from our calculation of comparable EBITDA and comparable EBIT:

- a pre-tax charge of $22 million incurred in fourth quarter 2023 due to Liquids Pipelines business separation costs related to the spinoff Transaction
- a pre-tax charge of $15 million for the three months ended December 31, 2023 related to Focus Project costs.

Comparable EBITDA and EBIT for Corporate remained consistent for the three months ended December 31, 2023 compared to the same period in 2022.

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

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
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
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
WCSB	Western Canadian Sedimentary basin

Accounting terms

AFUDC	Allowance for funds used during construction
U.S.GAAP / GAAP	U.S. generally accepted accounting principles
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 Energía, 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
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