Management's discussion and analysis

February 13, 2025

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, 2024.

This MD&A should also be read in conjunction with our December 31, 2024 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 138. All information is as of February 13, 2025 and all amounts are in Canadian dollars, unless noted otherwise.

On July 27, 2023, TC Energy announced plans to separate into two independent, investment-grade, publicly listed companies through the spinoff of its Liquids Pipelines business. TC Energy shareholders voted to approve the spinoff in June 2024 and, on October 1, 2024, TC Energy completed the spinoff of its Liquids Pipelines business into a new public company, South Bow Corporation (South Bow) (the Spinoff Transaction). Upon completion of the Spinoff Transaction, the Liquids Pipelines business was accounted for as a discontinued operation. To allow for a meaningful comparison, discussions throughout this MD&A are based on continuing operations unless otherwise noted. Prior year results have been recast to reflect the split between continuing and discontinued operations. Discontinued operations reflect nine months of Liquids Pipelines earnings for the year ended December 31, 2024 compared to a full year of Liquids Pipelines earnings in 2023 and 2022. Refer to Note 4, Discontinued operations, of our 2024 Consolidated financial statements for additional information.

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 regarding the size, structure, timing, conditions and outcome of ongoing and future transactions
- 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
- 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, including statements related to our GHG emissions intensity reduction goals
- expected industry, market and economic conditions, and ongoing trade negotiations, 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 and divestitures, including the Spinoff Transaction
- regulatory decisions and outcomes
- planned and unplanned outages and the utilization of our pipelines, power and storage assets
- integrity and reliability of our assets
- anticipated construction costs, schedules and completion dates
- access to capital markets, including portfolio management
- expected industry, market and economic conditions, including the impact of these on our customers and suppliers
- inflation rates, commodity and labour prices
- interest, tax and foreign exchange rates
- nature and scope of hedging.

Risks and uncertainties

- realization of expected benefits from acquisitions and divestitures, including the 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 including climate-related risks and the impact of energy transition on our business
- economic and political conditions, and ongoing trade negotiations 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.

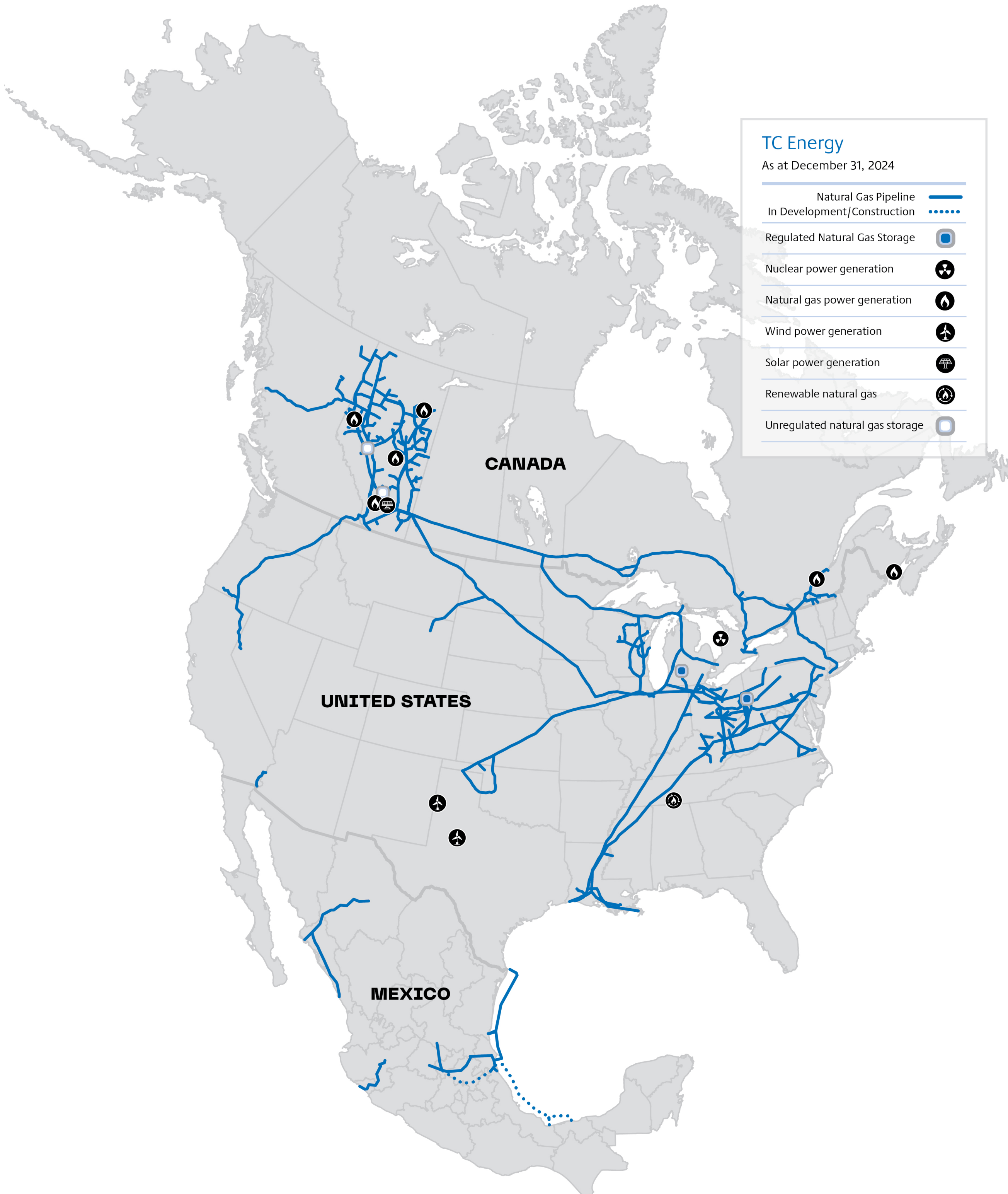
As actual results could vary significantly from the forward-looking information, you should not put undue reliance on forward-looking information and should not use future-oriented information or financial outlooks for anything other than their intended purpose. We do not update our forward-looking statements 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).

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 pipelines, power generation and natural gas storage facilities.



OUR CORE BUSINESSES

We operate in two core businesses – Natural Gas 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 four operating segments: Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines, Mexico Natural Gas 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.

TC Energy completed the Spinoff Transaction on October 1, 2024 and subsequently accounted for the Liquids Pipelines business as a discontinued operation. Refer to the Discontinued operations section on page 94 for additional information.

Year at-a-glance

at December 31 (millions of $)	2024	2023[1]
Total assets by segment		
Canadian Natural Gas Pipelines	**31,167**	29,782
U.S. Natural Gas Pipelines	**56,304**	50,499
Mexico Natural Gas Pipelines	**15,995**	12,003
Power and Energy Solutions	**10,217**	9,525
Corporate	**4,189**	7,715
	117,872	109,524
Discontinued Operations	**371**	15,510
	118,243	125,034

1 Prior year results have been recast to reflect the split between continuing and discontinued operations.

year ended December 31 (millions of $)	2024	2023
Total revenues from continuing operations by segment[1]		
Canadian Natural Gas Pipelines	**5,600**	5,173
U.S. Natural Gas Pipelines	**6,339**	6,229
Mexico Natural Gas Pipelines	**870**	846
Power and Energy Solutions	**954**	1,019
Corporate	**8**	—
	13,771	13,267

1 Excludes revenues of $2,217 million and $2,667 million for the years ended December 31, 2024 and 2023, respectively, related to discontinued operations, which represents nine months of Liquids Pipelines earnings in 2024 compared to a full year of Liquids Pipelines earnings in 2023.

year ended December 31 (millions of $)	2024	2023
Comparable EBITDA from continuing operations by segment[1,2]		
Canadian Natural Gas Pipelines	**3,388**	3,335
U.S. Natural Gas Pipelines	**4,511**	4,385
Mexico Natural Gas Pipelines	**999**	805
Power and Energy Solutions	**1,214**	1,020
Corporate	**(63)**	(73)
	10,049	9,472

1 Comparable EBITDA is a non-GAAP measure and does not have any standardized meaning as prescribed by U.S. GAAP and therefore may not be comparable to similar measures presented by other companies. The most directly comparable GAAP measure is segmented earnings (losses). Refer to the Financial results sections for each business segment for a reconciliation to comparable EBITDA as well as the About our business - Non-GAAP measures section for additional information.

2 Excludes Comparable EBITDA from discontinued operations of $1,145 million and $1,516 million for the years ended December 31, 2024 and 2023, respectively, which represents nine months of Liquids Pipelines earnings in 2024 compared to a full year of Liquids Pipelines earnings in 2023. For further information on the reconciliation of segmented earnings to comparable EBITDA, refer to the Financial results sections for each business segment and the Discontinued operations section.

OUR STRATEGY

Our vision is to be the trusted leader in North America's energy infrastructure, committed to excellence in safety, performance and stakeholder relationships. Our mission is to safely and efficiently move, generate and store the critical energy that North America and the world rely on. We are a team of energy problem solvers working to deliver energy in a safe, reliable, secure and affordable manner, while seeking to uphold our value proposition: to deliver solid growth with low risk and repeatable performance, year after year.

Our business consists of natural gas transportation and storage, as well as power generation assets:

- we deliver natural gas to Canada, the U.S. and Mexico, including to export terminals that ship LNG globally
- we generate electricity in Canada and the U.S., primarily from nuclear energy, but also from natural gas, wind and solar assets
- we store natural gas in Canada and the U.S. through regulated and non-regulated businesses.

These long-life infrastructure assets are anchored by our conservative risk preferences and are generally supported by long-term commercial arrangements and/or rate regulation. We believe that our assets will generate predictable and sustainable cash flows and earnings, providing the cornerstones of our low-risk value proposition. Our long-term strategy is driven by the following key beliefs:

- natural gas will continue to play a pivotal role in North America's energy future and support global GHG emissions reduction
- the need for reliable, on-demand energy sources will continue to grow
- energy assets will become increasingly valuable in a world with growing energy demand and existing challenges in developing new infrastructure.

Allocation of comparable EBITDA from continuing operations[1]

year ended December 31	2024	2023[2]
Comparable EBITDA from continuing operations by segment[3]		
Canadian Natural Gas Pipelines	**33%**	35%
U.S. Natural Gas Pipelines	**45%**	46%
Mexico Natural Gas Pipelines	**10%**	8%
Power and Energy Solutions	**12%**	11%
	100%	100%

1 Refer to the Financial highlights section for an allocation of segmented earnings by business segment.
2 Prior year results have been recast to reflect continuing operations only.
3 Excludes losses from Corporate comparable EBITDA from continuing operations of $63 million and $73 million for the years ended December 31, 2024 and 2023, respectively.

Our asset mix will continue to evolve with the North American energy mix. We anticipate the following trends in capital allocation over the next several years:

- Natural Gas Pipelines will continue to attract capital to meet growing customer demand, driven by coal-to-gas conversion, LNG exports and data centre buildouts
- Power and Energy Solutions' capital will primarily be allocated to extending the life and increasing the capacity of the nuclear business. We will make measured investment in emerging technologies to develop capabilities that are complementary to our core businesses, without taking significant commodity price risk, volumetric risk or utilizing unproven technologies
- additional discretionary investment will fund select high-grade opportunities in our development projects portfolio and incremental opportunities around existing assets across our businesses.

Key components of our strategy

Maximize the value of our assets through safety and operational excellence

- Maintaining safe and reliable operations by maximizing availability of assets and ensuring asset integrity, while minimizing environmental impacts, continues to be the foundation of our business
- Our extensive network of natural gas pipeline assets connect long-life, low-cost supply basins with premium North American and export markets, which we believe will generate 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
- We continually seek to enhance and protect the value of each of our assets using operational, commercial and other levers while pursuing revenue enhancements such as creating additional capacity in our systems and leveraging commercial marketing activities.

Execute our selective portfolio of growth projects

- Safety, executability, profitability and reliability are fundamental to our investments
- We develop high quality, long-life assets, largely underpinned by long-term contracts or rate regulation. We expect that these investments will contribute to incremental earnings and cash flows as they are placed in service
- We believe that our incumbent positions in regions with natural gas and power demand growth are expected to present us with a steady cadence of growth opportunities
- We strive to develop projects and manage construction risk in a disciplined manner that maximizes capital efficiency and returns to shareholders
- We seek to prudently manage development costs, minimizing capital at risk in a project's early stages
- We rely on our experience, as well as our policy, regulatory, commercial, financial, legal and operational expertise to permit, fund, build and integrate new pipelines and other energy infrastructure
- We will advance selected opportunities, including lower carbon growth initiatives, in emerging sub-sectors where we are likely to build a strong competitive position, market conditions are appropriate, technology is proven and project risks and returns are known and acceptable.

Ensure financial strength and agility

- Disciplined capital allocation supports our ability to maximize asset value over the short, medium and long term while protecting and growing our network of assets. We seek to allocate capital in a manner that improves the cost competitiveness and returns of our portfolio, while extending the life of our assets
- Our capital allocation process is designed to ensure that we remain within the annual target for net capital spend, while maximizing the expected returns of the projects that we sanction
- We assess opportunities to develop and acquire energy infrastructure that complements our existing portfolio, protects and grows our business, enhances future resilience under a changing energy mix and diversifies access to attractive supply and market regions within our risk preferences
- 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 we believe will contribute to our resilience, strengthen our asset base and/or improve diversification
- We believe that our high-quality, diversified portfolio of energy infrastructure assets results in predictable, low-risk cash flows and positions us well to succeed under various energy transition scenarios and across all economic cycles
- We continually seek to enhance our core competencies in safety, operational excellence, investment opportunity origination, project execution, stakeholder relations and sustainability to ensure we deliver shareholder value.

How we operate our business

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 connect the world to the energy it needs. We will do this 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 in an industry 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. Our 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 lower-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 safety and operational excellence and a commitment to the environment in the communities we serve 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 competitively-priced capital to support new investments while preserving financial flexibility, including portfolio management, to fund our operations in all market conditions. We aim to deliver a balance of dividend income and share price growth
- **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, installing electric compression and/or switching gas compression to electrification and currently assessing development of grid-scale, flexible and clean energy storage
- **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 to all rights holders and stakeholders on sustainability-related topics and publish annually our corporate GHG emissions intensity in our Report on Sustainability. We continue to focus on our sustainability commitments, which reflect the interests of our business, Indigenous rights holders and stakeholders; positioning us for long-term success. We are committed to collectively advancing a lower-emissions energy system and expect to provide an update on our interim GHG emission reduction target in 2025 to reflect the impact of the Liquids Pipelines business spinoff and projected increased utilization across our systems. We remain focused on our long-term goal of positioning to reach net-zero emissions from our operations by 2050 and acknowledge that achieving this goal requires accelerated changes in global energy policies, regulations and support for new technologies. We continue to focus on our nine sustainability commitments and associated metrics and targets 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
- **culture and people:** our people are our most important asset and living our company values of safety, personal accountability, working as one team and active learning. These values shape how we do business and, in turn, deliver on our commitments.

Our risk preferences

The following is an overview of our risk philosophy:

- **financial strength and flexibility:** rely on internally generated cash flows, existing debt capacity, partnerships and portfolio management to finance new initiatives
- **known and acceptable project risks:** select investments with known, acceptable and manageable project execution risk, including stakeholder considerations, partnership agreements, human capital and capability 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.

2024 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 and comparable earnings per common share from continuing and discontinued operations and comparable funds generated from operations are all non-GAAP measures. Refer to page 24 for more information about the non-GAAP measures we use, as well as the Financial results section in each business segment and Discontinued operations section for reconciliations to the most directly comparable GAAP measures.

As discussed on page 10 of the About this document section, results of the Liquids Pipelines business are reported as a discontinued operation. To allow for a meaningful comparison, discussions throughout this MD&A are based on continuing operations unless otherwise noted. Prior year results have been recast to reflect the split between continuing and discontinued operations. Discontinued operations reflect nine months of Liquids Pipelines earnings for the year ended December 31, 2024 compared to a full year of Liquids Pipelines earnings in 2023 and 2022. Refer to the Discontinued operations section for additional information.

year ended December 31 (millions of $, except per share amounts)	**2024**	**2023**[1]	**2022**[1]
Income			
Revenues	**13,771**	13,267	12,309
Net income (loss) attributable to common shares	**4,594**	2,829	641
from continuing operations	4,199	2,217	8
from discontinued operations[2]	395	612	633
Net income (loss) per common share – basic	**$4.43**	$2.75	$0.64
from continuing operations	$4.05	$2.15	$0.01
from discontinued operations[2]	$0.38	$0.60	$0.63
Comparable EBITDA[3]	**11,194**	10,988	9,901
from continuing operations	10,049	9,472	8,483
from discontinued operations[2]	1,145	1,516	1,418
Comparable earnings[3]	**4,430**	4,652	4,279
from continuing operations	3,865	3,896	3,618
from discontinued operations[2]	565	756	661
Comparable earnings per common share[3]	**$4.27**	$4.52	$4.30
from continuing operations	$3.73	$3.78	$3.64
from discontinued operations[2]	$0.54	$0.74	$0.66

1 Prior year results have been recast to reflect the split between continuing and discontinued operations.
2 Represents nine months of Liquids Pipelines earnings in 2024 compared to a full year of Liquids Pipelines earnings in 2023 and 2022. Refer to the Discontinued operations section for additional information.
3 Additional information on the most directly comparable GAAP measure can be found on page 24.

year ended December 31			
(millions of $)	**2024**	**2023**	**2022**
Cash flows[1]			
Net cash provided by operations[2]	**7,696**	7,268	6,375
Comparable funds generated from operations[2,3]	**7,890**	7,980	7,353
Capital spending[4]	**7,904**	12,298	8,961
Acquisitions, net of cash acquired	—	(307)	—
Proceeds from sales of assets, net of transaction costs	**791**	33	—
Disposition of equity interest, net of transaction costs[5]	**419**	5,328	—

1 Includes continuing and discontinued operations.
2 Represents nine months of Liquids Pipelines earnings in 2024 compared to a full year of Liquids Pipelines earnings in 2023 and 2022. Refer to the Discontinued operations section for additional information.
3 Additional information on the most directly comparable GAAP measure can be found on page 24.
4 Capital spending reflects cash flows associated with our Capital expenditures, Capital projects in development and Contributions to equity investments net of Other distributions from equity investments of $3.1 billion in 2024 in the Canadian Natural Gas Pipelines segment (2023 - nil, 2022 - $1.2 billion in the Corporate segment). Refer to Note 5, Segmented information, Note 7, Coastal GasLink and Note 12, Loans receivable from affiliates, of our 2024 Consolidated financial statements for additional information.
5 Included in the Financing activities section of the Consolidated statement of cash flows, of our 2024 Consolidated financial statements.

at December 31 (unless otherwise noted)			
(millions of $, except per share amounts)	**2024**	**2023**	**2022**
Balance sheet			
Total assets[1]	**118,243**	125,034	114,348
Long-term debt, including current portion	**47,931**	52,914	41,543
Junior subordinated notes	**11,048**	10,287	10,495
Preferred shares	**2,499**	2,499	2,499
Non-controlling interests	**10,768**	9,455	126
Common shareholders' equity	**25,093**	27,054	31,491
Dividends declared[2]			
per common share[3]	**$3.7025**	$3.72	$3.60
Basic common shares (millions)			
– weighted average for the year ended	**1,038**	1,030	995
– issued and outstanding at end of year	**1,039**	1,037	1,018

1 At December 31, 2024, includes assets of $371 million (2023 - $15,510 million; 2022 - $15,587 million), related to discontinued operations. Refer to Note 4, Discontinued operations, of our 2024 Consolidated financial statements for additional information.
2 For the year ended.
3 Dividends declared in fourth quarter 2024 reflect TC Energy’s proportionate allocation following the Spinoff Transaction. Refer to the Discontinued operations section for additional information.

Consolidated results

year ended December 31 (millions of $, except per share amounts)	2024	2023[1]	2022[1]
Canadian Natural Gas Pipelines	**2,016**	(90)	(1,440)
U.S. Natural Gas Pipelines	**4,053**	3,531	2,617
Mexico Natural Gas Pipelines	**929**	796	491
Power and Energy Solutions	**1,102**	1,004	833
Corporate	**(136)**	(144)	(51)
Total segmented earnings (losses)	**7,964**	5,097	2,450
Interest expense	**(3,019)**	(2,966)	(2,300)
Allowance for funds used during construction	**784**	575	369
Foreign exchange gains (losses), net	**(147)**	320	(185)
Interest income and other	**324**	272	140
Income (loss) from continuing operations before income taxes	**5,906**	3,298	474
Income tax (expense) recovery from continuing operations	**(922)**	(842)	(322)
Net income (loss) from continuing operations	**4,984**	2,456	152
Net income (loss) from discontinued operations, net of tax[2]	**395**	612	633
Net income (loss)	**5,379**	3,068	785
Net (income) loss attributable to non-controlling interests	**(681)**	(146)	(37)
Net income (loss) attributable to controlling interests	**4,698**	2,922	748
Preferred share dividends	**(104)**	(93)	(107)
Net income (loss) attributable to common shares	**4,594**	2,829	641
Net income (loss) per common share – basic	**$4.43**	$2.75	$0.64
from continuing operations	**$4.05**	$2.15	$0.01
from discontinued operations[2]	**$0.38**	$0.60	$0.63

1 Prior year results have been recast to reflect the split between continuing and discontinued operations.

2 Represents nine months of Liquids Pipelines earnings in 2024 compared to a full year of Liquids Pipelines earnings in 2023 and 2022. Refer to the Discontinued operations section for additional information.

year ended December 31 (millions of $)	2024	2023[1]	2022[1]
Amounts attributable to common shares			
Net income (loss) from continuing operations	**4,984**	2,456	152
Net (income) loss attributable to non-controlling interests	**(681)**	(146)	(37)
Net income (loss) attributable to controlling interests from continuing operations	**4,303**	2,310	115
Preferred share dividends	**(104)**	(93)	(107)
Net income (loss) attributable to common shares from continuing operations	**4,199**	2,217	8
Net income (loss) from discontinued operations, net of tax[2]	**395**	612	633
Net income (loss) attributable to common shares	**4,594**	2,829	641

1 Prior year results have been recast to reflect the split between continuing and discontinued operations.

2 Represents nine months of Liquids Pipelines earnings in 2024 compared to a full year of Liquids Pipelines earnings in 2023 and 2022. Refer to the Discontinued operations section for additional information.

Net income attributable to common shares from continuing operations in 2024 was $4.2 billion or $4.05 per share (2023 – $2.2 billion or $2.15 per share; 2022 – $8 million or $0.01 per share), an increase of $2.0 billion or $1.90 per share compared to 2023 and an increase of $2.2 billion or $2.14 per share in 2023 compared to 2022. Refer to the About our business - Non-GAAP measures section for a listing of specific items included in Net income attributable to common shares from continuing operations, which have been excluded from our calculation of comparable measures.

Refer to the Discontinued operations - Non-GAAP measures section for a listing of specific items included in Net income (loss) from discontinued operations, net of tax, which have been excluded from our calculation of comparable measures.

Cash flows

Net cash provided by operations of $7.7 billion in 2024 was six per cent higher than 2023 primarily due to higher funds generated from continuing operations and the amount and timing of working capital changes. Comparable funds generated from operations of $7.9 billion in 2024 were one per cent lower than 2023 primarily due to lower comparable earnings, partially offset by increased distributions from our equity investments.

Funds used in investing activities

Capital spending[1]

year ended December 31 (millions of $)	2024	2023	2022
Canadian Natural Gas Pipelines	**2,100**	6,184	4,719
U.S. Natural Gas Pipelines	**2,575**	2,660	2,137
Mexico Natural Gas Pipelines	**2,228**	2,292	1,027
Power and Energy Solutions	**824**	1,080	894
Corporate	**50**	33	41
	7,777	12,249	8,818
Discontinued operations	**127**	49	143
	7,904	12,298	8,961

1 Capital spending reflects cash flows associated with our Capital expenditures, Capital projects in development and Contributions to equity investments net of Other distributions from equity investments of $3.1 billion in 2024 in the Canadian Natural Gas Pipelines segment (2023 - nil, 2022 - $1.2 billion in the Corporate segment). Refer to Note 5, Segmented information, Note 7, Coastal GasLink and Note 12, Loans receivable from affiliates, of our 2024 Consolidated financial statements, for additional information.

In 2024 and 2023, we invested $7.9 billion and $12.3 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 2024 and 2023 included contributions of $1.5 billion (net of distributions) and $4.1 billion, respectively, to our equity investments, predominantly related to Coastal GasLink Limited Partnership (Coastal GasLink LP) and Bruce Power.

Proceeds from sales of assets

In 2024, TC Energy and its partner, Northern New England Investment Company, Inc., a subsidiary of Énergir L.P. (Énergir), completed the sale of Portland Natural Gas Transmission System (PNGTS) to a third party. Our share of the proceeds was $743 million (US$546 million), net of transaction costs.

In 2024, we also completed the sale of other non-core assets for gross proceeds of $48 million.

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). As part of the Spinoff Transaction on October 1, 2024, our remaining interest in Port Neches Link LLC was transferred to South Bow.

Acquisitions

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

Balance sheet

We continue to maintain a solid financial position while growing our total assets, excluding discontinued operations, by $8.3 billion in 2024. At December 31, 2024, common shareholders' equity and non-controlling interests, represented 37 per cent (2023 – 37 per cent) of our capital structure, while other subordinated capital, in the form of junior subordinated notes and preferred shares, represented an additional 14 per cent (2023 – 13 per cent). Refer to the Financial Condition section for additional information.

Dividends

Commencing with the dividends payable on January 31, 2025 to shareholders of record at the close of business on December 31, 2024, the amounts reflect TC Energy's proportionate allocation following the Spinoff Transaction. Refer to the Discontinued operations section for additional information.

On February 14, 2025, we announced a quarterly dividend on our outstanding common shares of $0.85 per common share for the quarter ending March 31, 2025, which represents an increase of 3.3 per cent from TC Energy's proportionate allocation of the dividend following the Spinoff Transaction. This equates to an annual dividend of $3.40 per common share. This was the twenty-fifth 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.

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 $)	**2024**	**2023**	**2022**
Common shares	**3,953**	2,787	3,192
Preferred shares	**99**	92	106

NON-GAAP MEASURES

This MD&A references non-GAAP measures, which are described in the table below. 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. These measures are reviewed regularly by our President and Chief Executive Officer, management and the Board of Directors in assessing our performance and making decisions regarding the ongoing operations of our business and its ability to generate cash flows. Some or all of these measures may also be used by investors and other external users of our financial statements as a supplemental measure to provide decision-useful information regarding our period-over-period performance and ability to generate earnings that are core to our ongoing operations. 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 to adjust for a specific item in reporting comparable measures is subjective and made after careful consideration. We maintain a consistent approach to adjustments, which generally fall into the categories described below:

- by their nature are unusual, infrequent and separately identifiable from our normal business operations and in our view are not reflective of our underlying operations in the period and generally include the following:
  - gains or losses on sales of assets or assets held for sale; impairment of goodwill, plant, property and equipment, equity investments and other assets; legal, contractual and other infrequent settlements; acquisition, integration and restructuring costs; expected credit loss provisions on net investment in leases and certain contract assets in Mexico; impacts resulting from changes in legislation and enacted tax rates and unusual tax refunds/payments and valuation allowance adjustments
- unrealized gains and losses related to fair value adjustments that do not reflect realized earnings or losses or cash impacts incurred in the current period from our underlying operations and generally include the following:
  - unrealized gains and losses from changes in the fair value of derivatives related to financial and commodity price risk management activities; unrealized fair value adjustments related to our proportionate share of Bruce Power's risk management activities and its funds invested for post-retirement benefits; unrealized fair value adjustments on intercompany loans that impact consolidated earnings.

The following table identifies our non-GAAP measures against their most directly comparable GAAP measures. These measures are applicable to each of our continuing operations and discontinued operations. Quantitative reconciliations of our comparable measures to their GAAP measures and a discussion of specific adjustments made for 2024 and comparative periods can be found on pages 26 and 27, the Financial results section in each business segment, and the Financial condition section. Non-GAAP measures for discontinued operations are found in the Discontinued operations section on page 96.

Non-GAAP 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

Comparable EBITDA and comparable EBIT

Comparable EBITDA represents segmented earnings (losses) adjusted for specific items described in the Comparable measures section, 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 each business segment and the Discontinued operations section for a reconciliation to segmented earnings (losses).

Funds generated from operations and comparable funds generated from operations

Funds generated from operations reflects net cash provided by operations before changes in operating working capital. The components of changes in working capital are disclosed in Note 29, Changes in operating working capital, of our 2024 Consolidated financial statements. Comparable funds generated from operations is adjusted for the cash impact of specific items described in the Comparable measures section. We believe funds generated from operations and comparable funds generated from operations are useful measures of our consolidated operating cash flows because they exclude fluctuations from working capital balances, which do not necessarily reflect underlying operations in the same period, and are used to provide a consistent measure of the cash-generating ability of our businesses. Refer to the Financial condition section for a reconciliation to Net cash provided by operations.

Comparable earnings and comparable earnings per common share

Comparable earnings represents earnings attributable to common shareholders on a consolidated basis, adjusted for specific items described in the Comparable measures section. 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 on our Consolidated statement of income, adjusted for specific items. We use comparable earnings 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. Refer to page 27 and the Discontinued operations section for reconciliations to Net income (loss) attributable to common shares and Net income (loss) per common share for our continuing operations and discontinued operations.

Comparable earnings and comparable earnings per common share - from continuing operations

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

2024

- a pre-tax gain of $572 million (after-tax $456 million) related to the sale of PNGTS which was completed on August 15, 2024
- a pre-tax net gain on debt extinguishment of $228 million (after-tax $178 million) related to the purchase and cancellation of certain senior unsecured notes and medium term notes and the retirement of outstanding callable notes in October 2024
- pre-tax unrealized foreign exchange gains, net of $143 million (after-tax $153 million) on the peso-denominated intercompany loan between TransCanada PipeLines Limited (TCPL) and Transportadora de Gas Natural de la Huasteca (TGNH), net of non-controlling interest
- a pre-tax gain of $48 million (after-tax $63 million) related to the sale of non-core assets in U.S. Natural Gas Pipelines and Canadian Natural Gas Pipelines
- a pre-tax recovery of $22 million (after-tax $15 million) on the expected credit loss provision related to TGNH net investment in leases and certain contract assets in Mexico, net of non-controlling interest
- a deferred income tax expense of $96 million resulting from the revaluation of remaining deferred tax balances following the Spinoff Transaction
- a pre-tax impairment charge of $36 million (after-tax $27 million) related to development costs incurred on Project Tundra, a next-generation technology carbon capture and storage project, following our decision to end our collaboration on the project
- a pre-tax expense of $34 million (after-tax $26 million) related to a non-recurring third-party settlement
- a pre-tax expense of $24 million (after-tax $18 million) related to Focus Project costs
- pre-tax costs of $10 million (after-tax $42 million) related to the NGTL System Ownership Transfer.

2023

- a pre-tax impairment charge of $2.1 billion (after-tax $1.9 billion) related to our equity investment in Coastal GasLink LP. Refer to Note 7, Coastal GasLink, of our 2024 Consolidated financial statements for additional information
- a pre-tax expense of $65 million (after-tax $48 million) related to Focus Project costs
- pre-tax unrealized foreign exchange losses, net, of $44 million (after-tax $44 million) on the peso-denominated intercompany loan between TCPL and TGNH
- a pre-tax recovery of $80 million (after-tax $55 million) on the expected credit loss provision related to TGNH net investment in leases and certain contract assets in Mexico.

2022

- a pre-tax impairment charge of $3.0 billion (after-tax $2.6 billion) related to our equity investment in Coastal GasLink LP
- a pre-tax goodwill impairment charge of $571 million (after-tax $531 million) related to Great Lakes
- a $196 million expense related to the settlement of prior years' income tax assessments related to our operations in Mexico
- a pre-tax expected credit loss provision of $163 million (after-tax $114 million) related to TGNH net investment in leases and certain contract assets in Mexico.

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

Reconciliation of net income (loss) attributable to common shares to comparable earnings - from continuing operations

year ended December 31 (millions of $, except per share amounts)	2024	2023[1]	2022[1]
Net income (loss) attributable to common shares from continuing operations	**4,199**	2,217	8
Specific items (pre tax):			
Gain on sale of PNGTS	**(572)**	—	—
Net gain on debt extinguishment[2]	**(228)**	—	—
Foreign exchange (gains) losses, net – intercompany loan[3]	**(143)**	44	—
Gain on sale of non-core assets	**(48)**	—	—
Expected credit loss provision on net investment in leases and certain contract assets in Mexico[4]	**(22)**	(80)	163
Project Tundra impairment charge	**36**	—	—
Third-party settlement	**34**	—	—
Focus Project costs[5]	**24**	65	—
NGTL System ownership transfer costs	**10**	—	—
Coastal GasLink impairment charge	**—**	2,100	3,048
Great Lakes goodwill impairment charge	**—**	—	571
Bruce Power unrealized fair value adjustments	**(8)**	(7)	17
Risk management activities[6]	**433**	(395)	149
Taxes on specific items[7]	**150**	(48)	(338)
Comparable earnings from continuing operations	**3,865**	3,896	3,618
Net income (loss) per common share from continuing operations	**$4.05**	$2.15	$0.01
Specific items (net of tax)	**(0.32)**	1.63	3.63
Comparable earnings per common share from continuing operations	**$3.73**	$3.78	$3.64

1 Prior year results have been recast to reflect continuing operations only.

2 In October 2024, TCPL commenced and completed our cash tender offers to purchase and cancel certain senior unsecured notes and medium term notes at a 7.73 per cent weighted average discount. In addition, we retired outstanding callable notes at par. These extinguishments of debt resulted in a pre-tax net gain of $228 million, primarily due to fair value discounts and unamortized debt issue costs. The net gain on debt extinguishment was recorded in Interest expense in the Consolidated statement of income. Refer to the Financial condition section for additional information.

3 In 2023, TCPL and TGNH became party to an unsecured revolving credit facility. 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 revaluation and translation of the loan receivable and loan payable to TC Energy's reporting currency. As the amounts do not accurately reflect what will be realized at settlement, we exclude 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, net of non-controlling interest.

4 In 2022, TGNH and the CFE executed agreements which consolidate several natural gas pipelines under one TSA. As this TSA contains a lease, we have recognized amounts in net investment in leases on our Consolidated balance sheet. As required by U.S. GAAP, we have recognized an expected credit loss provision related to net investment in leases and certain contract assets in Mexico, which will fluctuate from period to period based on changing economic assumptions and forward-looking information. This provision is an estimate of losses that may occur over the duration of the TSA through 2055. This provision does not reflect losses or cash outflows that were incurred under this lease arrangement in the current period or from our underlying operations, and therefore, we have excluded any unrealized changes, net of non-controlling interest, from comparable measures. Refer to Note 28, Risk management and financial instruments, of our 2024 Consolidated financial statements for additional information.

5 In 2022, we launched the Focus Project 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, for external consulting and severance, some of which are not recoverable through regulatory and commercial tolling structures. Refer to the Corporate – Significant events section for additional information.

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year ended December 31			
(millions of $)	**2024**	**2023**	**2022**
U.S. Natural Gas Pipelines	**(113)**	80	(15)
Canadian Power	**84**	(31)	4
U.S. Power	**(10)**	9	—
Natural Gas Storage	**(57)**	91	11
Interest rate	**(71)**	—	—
Foreign exchange	**(266)**	246	(149)
	(433)	395	(149)
Income tax attributable to risk management activities	**105**	(99)	36
Total unrealized gains (losses) from risk management activities	**(328)**	296	(113)

7 Refer to the Corporate - Financial results section for additional information.

Comparable EBITDA to comparable earnings - from continuing operations

Comparable EBITDA from continuing operations represents segmented earnings (losses) from continuing operations 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)	**2024**	**2023**[1]	**2022**[1]
Comparable EBITDA from continuing operations			
Canadian Natural Gas Pipelines	**3,388**	3,335	2,806
U.S. Natural Gas Pipelines	**4,511**	4,385	4,089
Mexico Natural Gas Pipelines	**999**	805	753
Power and Energy Solutions	**1,214**	1,020	907
Corporate	**(63)**	(73)	(72)
Comparable EBITDA from continuing operations	**10,049**	9,472	8,483
Depreciation and amortization	**(2,535)**	(2,446)	(2,262)
Interest expense included in comparable earnings	**(3,176)**	(2,966)	(2,300)
Allowance for funds used during construction	**784**	575	369
Foreign exchange gains (losses), net included in comparable earnings	**(85)**	118	(8)
Interest income and other	**324**	272	140
Income tax (expense) recovery included in comparable earnings	**(772)**	(890)	(660)
Net (income) loss attributable to non-controlling interests included in comparable earnings	**(620)**	(146)	(37)
Preferred share dividends	**(104)**	(93)	(107)
Comparable earnings from continuing operations	**3,865**	3,896	3,618
Comparable earnings per common share from continuing operations	**$3.73**	$3.78	$3.64

1 Prior year results have been recast to reflect continuing operations only.

Comparable EBITDA from continuing operations

2024 versus 2023

Comparable EBITDA from continuing operations in 2024 increased by $577 million compared to 2023 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 higher generation and a higher contract price, and Natural Gas Storage and other due to higher realized Alberta natural gas storage spreads, partially offset by decreased Canadian Power earnings primarily due to lower realized power prices net of lower natural gas fuel costs
- higher U.S. dollar-denominated EBITDA from Mexico Natural Gas Pipelines mainly due to increased equity earnings from Sur de Texas as a result of peso-denominated financial exposure and lower income tax expense
- increased EBITDA from Canadian Natural Gas Pipelines primarily due to higher flow-through costs and increased rate-base earnings on the NGTL System and Foothills, partially offset by lower earnings from Coastal GasLink related to the recognition of a $200 million incentive payment in 2023
- higher U.S. dollar-denominated EBITDA from U.S. Natural Gas Pipelines due to incremental earnings from growth projects placed in service and additional contract sales, partially offset by higher operational costs and decreased earnings as a result of the sale of PNGTS, which was completed on August 15, 2024
- 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 79, U.S. dollar-denominated comparable EBITDA from continuing operations increased by US$180 million compared to 2023, which was translated to Canadian dollars at an average rate of 1.37 in 2024 versus 1.35 in 2023. Refer to the Foreign exchange section for additional information.

2023 versus 2022

Comparable EBITDA from continuing operations in 2023 increased by $989 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
- 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 79,U.S. dollar-denominated comparable EBITDA from continuing operations increased by US$100 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.

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 from continuing operations

2024 versus 2023

Comparable earnings from continuing operations in 2024 were $31 million or $0.05 per common share lower than in 2023, and were primarily the net result of:

- changes in comparable EBITDA from continuing operations described above
- higher depreciation and amortization reflecting expansion facilities and new projects placed in service
- higher interest expense primarily due to long-term debt issuances, net of maturities, the foreign exchange impact of a stronger U.S. dollar in 2024 compared to 2023, higher interest rates on short-term borrowings in 2024 and the impact of interest expense allocated to discontinued operations for nine months in 2024 compared to a full year in 2023
- higher AFUDC predominantly due to spending on the Southeast Gateway pipeline project, partially offset by projects placed in service and the cessation of AFUDC on Tula in fourth quarter 2023
- risk management activities used to manage our foreign exchange exposure to net liabilities in Mexico and to U.S. dollar-denominated income and the revaluation of our peso-denominated net monetary liabilities to U.S. dollars
- higher interest income and other due to higher interest earned on short-term investments and a reduction in insurance-related provisions
- decreased income tax expense due to the impact of Mexico foreign exchange exposure and lower comparable earnings subject to income tax, partially offset by lower foreign income tax rate differentials and higher flow-through income taxes
- 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) in fourth quarter 2023 and the 13.01 per cent non-controlling equity interest in TGNH to the CFE, completed in second quarter 2024.

2023 versus 2022

Comparable earnings from continuing operations in 2023 were $278 million or $0.14 per common share higher than in 2022, and were primarily the net result of:

- changes in comparable EBITDA from continuing operations described above
- higher depreciation and amortization reflecting expansion facilities and new projects placed in service and the acquisition of the Texas Wind Farms, partially offset by the discontinuance of depreciation expense on TGNH assets in Mexico accounted for as leases
- 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
- 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
- risk management activities used to manage our foreign exchange exposure to net liabilities in Mexico and to U.S. dollar-denominated income; and the revaluation of our peso-denominated net monetary liabilities to U.S. dollars
- higher interest income and other due to higher interest earned on short-term investments
- increased income tax expense due to the impact of higher comparable 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
- 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 reflect the dilutive effect of common shares issued. Refer to the Financial condition section for additional information.

SUPPLEMENTARY FINANCIAL MEASURE

Net capital expenditures

Net capital expenditures represents capital costs incurred for 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. Net capital expenditures reflect capital costs incurred during the period, excluding the impact of timing of cash payments. We use net capital expenditures as a key measure in evaluating our performance in managing our capital spending activities in comparison to our capital plan.

Net capital expenditures does not include an adjustment related to the CFE's minority interest in TGNH capital expenditures until after the in-service of the projects included as part of the 2022 strategic alliance between TGNH and the CFE, including Villa de Reyes, Southeast Gateway and Tula. The CFE's contribution in second quarter 2024 to obtain a 13.01 per cent equity interest in TGNH included consideration of its proportionate share of required capital contributions for approved projects. Net capital expenditures will be adjusted for any new capital projects approved in TGNH going forward.

OUTLOOK

Comparable EBITDA and comparable earnings - continuing operations

We expect our 2025 comparable EBITDA to be higher than 2024 comparable EBITDA due to the net impact of the following:

- new projects anticipated to be placed in service in 2025, including the Southeast Gateway pipeline, along with the full-year impact of projects placed in service in 2024
- higher contributions from the NGTL System resulting from the five-year negotiated revenue requirement settlement
- reduced generation from Bruce Power due to the commencement of the Unit 4 Major Component Replacement (MCR) outage.

Our 2025 comparable earnings per common share is expected to be lower than 2024 comparable earnings per common share considering the net impact of the following:

- increase in comparable EBITDA described above
- lower AFUDC due to the Southeast Gateway pipeline expected to be placed in service on May 1, 2025
- lower interest income as a result of lower cash balances and lower interest rates
- increased depreciation rates on the NGTL System related to the five-year negotiated revenue requirement settlement
- reduced capitalized interest due to the Coastal GasLink pipeline commercial in-service
- higher effective tax rates.

Consolidated capital expenditures

In 2024, we incurred approximately $8.2 billion in gross capital expenditures on our secured capital program and projects under development, as well as capitalized interest and AFUDC, where applicable. Net capital expenditures after adjusting for the capital expenditures attributable to the non-controlling interests of entities we control was $7.4 billion.

The majority of our 2025 capital program is focused on the advancement of secured projects including U.S. Natural Gas Pipelines projects, NGTL System expansions, the Southeast Gateway pipeline, Bruce Power MCR programs and normal course maintenance capital expenditures. Prior to adjustments for non-controlling interests, we expect to incur gross capital expenditures of approximately $6.1 to $6.6 billion in 2025. We anticipate our net capital expenditures in 2025 to be approximately $5.5 to $6.0 billion.

Refer to the Outlook section in each business segment for additional details on expected earnings and capital expenditures for 2025.

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 growth in earnings and cash flows.

Our capital program consists of approximately $25 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.

During 2024, we placed approximately $6.8 billion of projects into service, which included natural gas pipeline capacity projects along our extensive North American asset footprint and our share of equity contributions related to the Coastal GasLink pipeline, as well as progress on the Bruce Power life extension program. In addition, approximately $2.3 billion of maintenance capital expenditures were incurred and $0.3 billion of modernization capital expenditures were placed in service.

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.

(billions of $)	Expected in-service date	Estimated project cost	Project costs incurred at December 31, 2024
Canadian Natural Gas Pipelines[1]			
NGTL System	2026	0.7 [2]	0.2
	2027+	0.2 [2]	—
Regulated maintenance capital expenditures	2025-2027	2.5	—
U.S. Natural Gas Pipelines			
VR project	2025	US 0.5	US 0.3
WR project	2025	US 0.7	US 0.3
Heartland project	2027	US 0.9	US 0.1
Pulaski and Maysville projects	2029	US 0.7	—
Gillis Access – Extension	2026-2027	US 0.4	US 0.1
Southeast Virginia Energy Storage project	2030	US 0.3	—
Other capital	2025-2028	US 1.5	US 0.4
Regulated maintenance capital expenditures	2025-2027	US 2.3	—
Mexico Natural Gas Pipelines			
Villa de Reyes – South section[3]	—	US 0.4	US 0.3
Tula[4]	—	US 0.4	US 0.3
Southeast Gateway	2025	US 3.9	US 3.7
Power and Energy Solutions			
Bruce Power – Unit 3 MCR	2026	1.1	0.9
Bruce Power – Unit 4 MCR	2028	0.9	0.2
Bruce Power – life extension[5]	2025-2031	1.8	0.6
Other			
Non-recoverable maintenance capital expenditures[6]	2025-2027	0.4	—
		19.6	7.4
Foreign exchange impact on secured projects[7]		5.3	2.4
Total secured projects (Cdn$)		24.9	9.8

1 Our share of committed equity to fund the estimated cost of the Coastal GasLink - Cedar Link project is $37 million. Refer to the Canadian Natural Gas Pipelines – Significant events section for additional information.
2 Includes amounts related to projects within the Multi-Year Growth Plan (MYGP) that have received FID.
3 We are working with the CFE on completing the remaining section of the Villa de Reyes pipeline. The in-service date will be determined upon resolution of outstanding stakeholder issues. 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 an 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 related to our Power and Energy Solutions and Corporate assets.
7 Reflects U.S./Canada foreign exchange rate of 1.44 at December 31, 2024.

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. New growth opportunities will be assessed within our disciplined capital allocation framework in order to fit within our annual capital expenditure parameters. As these new opportunities advance and reach required 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 sanctioned in-corridor expansions, providing connectivity to LNG export terminals, connecting growing WCSB gas supplies to domestic and export markets and other opportunities, including progressing our Multi-Year Growth Plan (MYGP). The MYGP is comprised of multiple distinct projects with targeted in-service dates between 2027 and 2030 that are subject to final corporate and regulatory approvals.

U.S. Natural Gas Pipelines

We are currently pursuing a variety of projects that are expected to replace, upgrade, expand and extend our U.S. Natural Gas Pipelines footprint. The enhanced facilities associated with these projects are expected to improve the reliability of our systems, reduce GHG emissions intensity and provide additional transportation capacity under long-term contracts. We continue to see growing demand across multiple segments, driving potential expansion projects to support new natural gas-fired power generation, coal to natural gas conversions, LDC growth and data centres. Our footprint is well positioned to supply natural gas through our existing utility customer base or by way of direct connections. Additional opportunities include RNG through direct interconnects, continued LNG development in proximity to our footprint and LDC peak day growth.

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 the completion of the MCR program in 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. Refer to the Power and Energy Solutions – Significant events section for additional information.

The Unit 5 MCR final cost and schedule estimate was submitted to the IESO on January 31, 2025.

Energy Solutions

Ontario Pumped Storage

With our prospective partners, Saugeen Ojibway Nation, we continue to advance the Ontario Pumped Storage Project, an energy storage facility located in Meaford, Ontario. The 1,000 MW project is expected to provide enough electricity to power one million homes for up to 11 hours, while enhancing the reliability and efficiency of Ontario's electricity system.

Using water and gravity, the project is like a natural battery that will store surplus electricity when demand is low and later redeploy it during periods of high demand. The project will support the planned buildout of Ontario's nuclear fleet and can deliver Ontario's clean nuclear power on demand.

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. We are continuing to advance discussions on a commercial agreement with customers that aligns with our risk preferences.

Other Energy Solutions Projects

Our focus in Energy Solutions includes piloting new technologies like hydrogen and carbon capture for our natural gas business, continued partnerships and investments in emerging technologies and the selective development of decarbonization solutions for customers, allowing us to stay ahead of technological adoption trends. If successful, these technologies are expected to enable us to build capabilities that will allow us to reduce the emissions intensity from our existing assets, which will help enhance and preserve the value of our natural gas networks while also capitalizing on lower-carbon investment opportunities that are underpinned by commercial models that meet our risk preferences.

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 30 per cent of continental daily natural gas needs through:
- wholly-owned natural gas pipelines – 63,322 km (39,345 miles)
- partially-owned natural gas pipelines – 30,365 km (18,868 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 maximize 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
- minimizing our GHG and methane emissions through operational excellence.

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 helping solve the energy trilemma - energy security, affordability and sustainability. We believe natural gas provides a reliable, high-efficiency energy source that is helping to support the displacement of coal-fired power while backstopping the intermittency of renewable power sources across North America. We continue to improve operational efficiencies and factor ESG considerations 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, rights holders and other stakeholders in alignment with our values and sustainability commitments.

Recent highlights

Canadian Natural Gas Pipelines

- approximately $0.6 billion of capacity capital projects related to the NGTL System were placed into service in 2024
- Coastal GasLink pipeline was declared commercially in service in fourth quarter 2024
- Coastal GasLink LP approved the Cedar Link project in second quarter 2024
- construction activities commenced on the Valhalla North and Berland River (VNBR) project in fourth quarter 2024
- received Board of Directors' approval to allocate approximately $3.3 billion of capital towards the MYGP for expansion facilities on the NGTL System, subject to final company and regulatory approvals
- achieved record throughput volumes on the NGTL System
- continued strong throughput and contracting on Canadian Mainline
- CER approved a five-year negotiated settlement on the NGTL System (2025-2029 NGTL Settlement).

U.S. Natural Gas Pipelines

- placed approximately US$1.9 billion of capital projects in service in 2024, including the Gillis Access project, Virginia Electrification and GTN XPress projects as well as completion of the Columbia Gas Modernization III program and maintenance capital
- sanctioned US$1.5 billion of capital projects including the Maysville and Pulaski projects on Columbia Gulf, Southeast Virginia Energy Storage project on Columbia Gas and the extension of Gillis Access
- Columbia Gas filed a Section 4 Rate Case with FERC in September 2024 requesting an increase to maximum transportation rates effective April 1, 2025, subject to refund. The rate case is progressing as expected as we continue to pursue a collaborative process through settlement negotiations
- the sale of our 61.7 per cent equity interest in PNGTS was completed on August 15, 2024
- 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 we continue to be aligned with the CFE on finalizing the remaining project completion activities for achieving an in-service date of May 1, 2025
- the CFE became a partner in TGNH with a 13.01 per cent equity interest in second quarter 2024
- 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 41 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, 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 U.S. markets including the Midwest, Gulf Coast and U.S. Northeast from the WCSB and, through interconnects, from the Appalachian basin.

Coastal GasLink: This pipeline supplies WCSB natural gas from interconnections with the NGTL System and other pipelines to the LNG Canada facility on the coast of British Columbia. This pipeline will also feed the Cedar LNG project once built later this decade. We have a 35 per cent equity interest and are the operator of this pipeline.

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 have a 60 per cent ownership 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 have a 60 per cent ownership interest and are the operator of this pipeline.

Other U.S. Natural Gas Pipelines: We have ownership interests in nine 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 2024 supplied approximately 17 per cent of Mexico's total natural gas imports via pipelines. We have 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 Tamazunchale pipeline and the Tula, Villa de Reyes and Southeast Gateway pipelines with sections that are either in-service or currently under construction. This system supplies, or will supply, several power plants and industrial facilities in Campeche, Yucatán, 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. The TGNH System is part of a strategic alliance with the CFE, Mexico's state-owned electric utility, which holds a 13.01 per cent ownership interest in the system. We have an 86.99 per cent ownership interest and are the operator of these pipelines.

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 and FERC in the U.S. In Mexico, the regulation of our natural gas pipelines is being transitioned from the CRE to a new regulatory body under the Secretaría de Energía (SENER). 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 150 Bcf/d by 2028, reflecting an increase of approximately 28 Bcf/d from 2023 levels.

As the world shifts toward a lower-carbon economy, we believe that further retirements of coal-fired power generation as well as 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 our 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, including for use in emerging data centres
- 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 natural 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 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

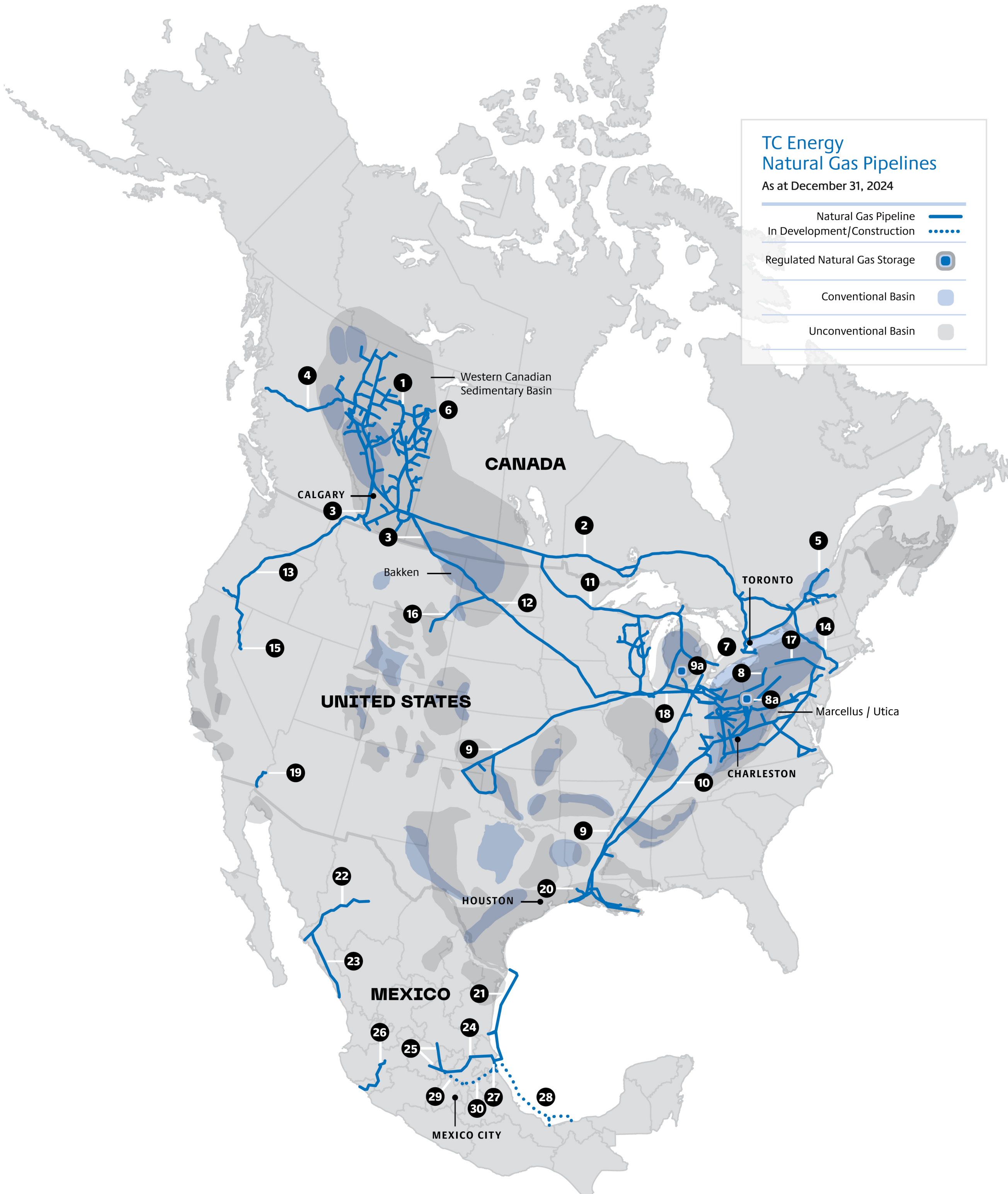
Changes in supply and demand levels and locations have resulted in increased competition to provide transportation services throughout North America. Our well-distributed footprint of natural gas pipelines, particularly in the low-cost WCSB and the Appalachian basin, both of which are connected to North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

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. In 2025, we will continue to focus on the execution of our existing capital program that includes completing construction on our Southeast Gateway pipeline in Mexico, advancing the Cedar Link project which is an expansion of the Coastal GasLink pipeline, investment in the NGTL System and the initiation and completion of new U.S. pipeline projects. We will remain focused on capital discipline as we continue to pursue the next wave of growth opportunities.

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, 2024
Natural Gas Pipeline
In Development/Construction
Regulated Natural Gas Storage
Conventional Basin
Unconventional Basin
Western Canadian Sedimentary Basin
CANADA
CALGARY
Bakken
TORONTO
UNITED STATES
Marcellus / Utica
CHARLESTON
HOUSTON
MEXICO
MEXICO CITY
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We are the operator of all of the following natural gas pipelines and regulated natural gas storage assets except for Iroquois.

		Length	Description	Ownership
	Canadian pipelines			
1	NGTL System	24,233 km (15,058 miles)	Receives, transports and delivers natural gas within Alberta and British Columbia, and connects with Canadian Mainline, Coastal GasLink, Foothills and third-party pipelines.	100%
2	Canadian Mainline	14,087 km (8,753 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	1,289 km (801 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	Coastal GasLink	671 km (417 miles)	Transports natural gas from the Montney gas producing region to LNG Canada's liquefaction facility near Kitimat, British Columbia.	35%
5	Trans Québec & Maritimes (TQM)	648 km (403 miles)	Connects with the Canadian Mainline near the Ontario/Québec border to transport natural gas to the Montréal to Québec City corridor and interconnects with a third-party pipeline at the U.S. border.	50%
6	Ventures LP	133 km (83 miles)	Transports natural gas to the oil sands region near Fort McMurray, Alberta.	100%
7	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			
8	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%
8a	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
9	ANR[1]	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%
9a	ANR Storage	247 Bcf	Provides regulated underground natural gas storage service from several facilities (not all shown) to customers in key mid-western markets.	
10	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%
11	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%
12	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%
13	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%
14	Iroquois	669 km (416 miles)	Connects with the Canadian Mainline and serves markets in New York.	50%
15	Tuscarora	491 km (305 miles)	Transports natural gas from GTN at Malin, Oregon to markets in northeastern California and northwestern Nevada.	100%

		Length	Description	Ownership
16	Bison	488 km (303 miles)	Transports natural gas from the Powder River basin in Wyoming to Northern Border in North Dakota.	100%
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[1]	138 km (86 miles)	Transports natural gas between Arizona and California and connects with a third-party pipeline on the California/Mexico border.	100%
20	Gillis Access	68 km (42 miles)	A pipeline system that connects supplies from the Haynesville basin at Gillis, Louisiana to markets elsewhere in Louisiana.	100%
	Mexico pipelines			
21	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%
22	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%
23	Mazatlán	430 km (267 miles)	Transports natural gas from El Oro to Mazatlán, Sinaloa, interconnects with third-party pipelines and connects to the Topolobampo pipeline at El Oro.	100%
24	Tamazunchale	370 km (230 miles)	Transports natural gas from Naranjos, Veracruz and Higueros (Sur de Texas-Tuxpan System) to Tamazunchale, San Luis Potosi and on to El Sauz, Querétaro in central Mexico.	86.99%
25	Villa de Reyes – North and Lateral sections	316 km (196 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.	86.99%
26	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%
27	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.	86.99%
	Under construction			
	Canadian pipelines			
	NGTL System 2025+ Facilities[2,3]	50 km (31 miles)	The VNBR project, along with other facilities expected to be placed in service in 2026.	100%
	Coastal GasLink – Cedar Link project[2,3]	n/a	The Cedar Link project is an expansion of the Coastal GasLink pipeline that is expected to enable delivery of up to 0.4 Bcf/d of natural gas to the Cedar LNG facility. This includes the addition of a new compressor station, connector pipeline and meter station to Coastal GasLink's existing pipeline infrastructure, which is expected to be placed in service in 2028.	35%

	Under construction (continued)	Length	Description	Ownership
	U.S. pipelines			
	East Lateral XPress[1,2]	n/a	An expansion project on Columbia Gulf through compressor station modifications and additions expected to be placed in service in 2025.	60%
	VR Project[1,2]	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[1,2]	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[1,2]	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%
	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, which is expected to be placed in service on May 1, 2025.	86.99%
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.	86.99%
	Permitting and pre-construction phase			
	Canadian pipelines			
	NGTL System – MYGP[2,3,4]	n/a	A plan of multiple distinct projects for expansion facilities on the NGTL System with targeted in-service dates between 2027 and 2030.	100%
	U.S. pipelines			
	Bison XPress Project[1,2]	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
	Heartland Project[1,2]	n/a	An 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%
	Gillis Access – Extension[2,3]	63 km (39 miles)	An extension of Gillis Access to further connect supplies from Haynesville basin at Gillis with anticipated in-service dates starting in late 2026.	100%
	Pulaski Project[2,3]	64 km (40 miles)	A pipeline extension project on Columbia Gulf designed to serve existing power plants. The project is expected to be placed in service in 2029.	60%
	Maysville Project[2,3]	64 km (40 miles)	A pipeline extension project on Columbia Gulf designed to serve existing power plants. The project is expected to be placed in service in 2029.	60%
	Southeast Virginia Energy Storage Project[2]	1.1 Bcf	An LNG storage facility located on our Columbia Gas system in southeast Virginia designed to serve an existing LDC's growing market. The project is expected to be placed in service in 2030.	60%

	Permitting and pre-construction phase (continued)	Length	Description	Ownership
	Mexico pipelines			
30	Tula[3]	100 km (62 miles)	TC Energy and the CFE are assessing options to complete the remaining sections of the pipeline, which are subject to an FID.	86.99%

1 Includes compressor station modifications, additions and/or expansion projects with no additional pipe length.
2 Facilities and some pipelines are not shown on the map.
3 Final pipe lengths are subject to change during construction and/or final design considerations.
4 Includes projects within the MYGP that have received FID.

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 was declared commercially in service in fourth quarter 2024 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 operated under the previous five-year revenue requirement settlement for 2020-2024, which included an incentive mechanism for certain operating costs and the opportunity to increase depreciation rates if tolls fall below specified levels. As of January 1, 2025, the NGTL System is operating under a new five-year revenue requirement settlement. Refer to the Canadian Natural Gas Pipelines – Significant events section for additional information. The Canadian Mainline is operating under the 2021-2026 Mainline settlement, which includes an incentive to decrease costs and increase revenues.

SIGNIFICANT EVENTS

NGTL System

In the year ended December 31, 2024, the NGTL System placed approximately $0.6 billion of capacity projects in service.

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. All assets have been placed in service, with a capital cost for the expansion of $0.5 billion.

NGTL System Revenue Requirement Settlement and Multi-Year Growth Plan

On September 26, 2024, the CER approved a five-year negotiated revenue requirement settlement on the NGTL System (2025-2029 NGTL Settlement) commencing on January 1, 2025.

The 2025-2029 NGTL Settlement enables an investment framework that supports our Board of Directors' approval to allocate approximately $3.3 billion of capital towards progression of the MYGP for expansion facilities on the NGTL System. It is comprised of multiple distinct projects with targeted in-service dates between 2027 and 2030, subject to final company and regulatory approvals. The completion of the MYGP is expected to enable approximately 1.0 Bcf/d of incremental system throughput.

This settlement maintains an ROE of 10.1 per cent on 40 per cent deemed common equity while increasing NGTL System depreciation rates, with an incentive that allows the NGTL System the opportunity to further increase depreciation rates if tolls fall below specified levels, or if growth projects are undertaken. It also introduces a new incentive mechanism to reduce both physical emissions and emissions compliance costs, which builds on the incentive mechanism for certain operating costs where variances from projected amounts and emissions savings are shared with our customers. A provision for review by customers exists in the settlement if tolls exceed a pre-determined level or if final company approvals of the MYGP are not obtained.

Sale of Equity Interest in the NGTL System and Foothills Pipeline Assets

The previously announced equity interest purchase agreement in respect of the sale by TC Energy of a 5.34 per cent interest in the NGTL System and Foothills Pipeline assets to an Indigenous-owned investment partnership was terminated by TC Energy on February 6, 2025.

Valhalla North and Berland River Project

The VNBR project will serve aggregate system requirements and connect migrating supply to key demand markets, designed to provide incremental capacity on the NGTL System of approximately 428 TJ/d (400 MMcf/d). With an estimated capital cost of $0.5 billion, the project consists of approximately 33 km (21 miles) of new pipeline, one new non-emitting electric compressor unit and associated facilities. Construction activities commenced in late 2024 with anticipated in-service dates commencing in second quarter 2026.

Coastal GasLink

Coastal GasLink Pipeline

The Coastal GasLink pipeline is a 671 km (417 mile) pipeline that transports natural gas from a receipt point in the Dawson Creek area of British Columbia to LNG Canada's (LNGC) natural gas liquefaction facility near Kitimat, B.C. Transportation service on the pipeline is underpinned by 25-year TSAs (with renewal provisions) with each of the five LNGC participants (LNGC Participants). We hold a 35 per cent ownership interest in Coastal GasLink LP, the entity that owns the Coastal GasLink pipeline. Additionally, we hold a 100 per cent ownership interest in the general partner of Coastal GasLink LP, the entity that is contracted to develop, construct and operate the pipeline.

The Coastal GasLink pipeline project achieved mechanical completion in 2023 and began delivering commissioning gas to the LNGC facility in late third quarter 2024. Post-construction reclamation activities are expected to be complete in 2025 and the project remains on track with its capital cost estimate of approximately $14.5 billion.

Coastal GasLink LP continues to pursue cost recovery, including certain arbitration proceedings which involve claims by, and the defense of certain claims against, Coastal GasLink LP. With the exception of settlements made with respect to certain contractor disputes, these claims have not yet been conclusively determined, but our expectation is that these proceedings are likely to result in net cost recoveries. Refer to Note 31, Commitments, contingencies and guarantees, of our 2024 Consolidated financial statements for additional information.

In June 2024, Coastal GasLink LP successfully completed a $7.15 billion refinancing of its existing construction credit facility through a private placement bond offering of senior secured notes to Canadian and U.S. investors. Proceeds from the offering were used to repay the majority of the outstanding $8.0 billion balance on Coastal GasLink LP’s construction credit facility. The remaining balance on the credit facility was settled through the use of proceeds from the unwinding of certain hedging arrangements associated with the construction facility.

In November 2024, Coastal GasLink LP executed a commercial agreement with LNGC and LNGC Participants that declared commercial in-service for the pipeline, allowing for the collection of tolls from customers retroactive to October 1, 2024. The agreement also includes a one-time payment of $199 million from LNGC Participants to TC Energy in recognition of the completion of certain work and the final settlement of costs. The payment is to be made by LNGC Participants upon the earlier of three months after the declared in-service of the LNGC facility, or December 15, 2025. The payment accrues in full to TC Energy in accordance with the contractual terms between the Coastal GasLink LP partners and has been accounted for as an in-substance distribution from Coastal GasLink LP.

In December 2024, following the commercial in-service of the pipeline, Coastal GasLink LP repaid the $3,147 million balance owing to TC Energy under the subordinated loan agreement. Our share of equity contributions required by Coastal GasLink LP to fund repayment of the loan amounted to $3,137 million. At December 31, 2024, our total share of partner equity contributions to fund the capital cost of the project was $5.3 billion. While unused capacity of $228 million remains available under the subordinated loan agreement, we do not anticipate that Coastal GasLink LP will draw on a significant portion of the remaining availability.

Cedar Link Expansion

In June 2024, Coastal GasLink LP sanctioned the Cedar Link project following a positive FID for the construction of the Cedar LNG facility by the Cedar LNG joint venture partners, Haisla Nation and Pembina Pipeline Corporation. The Cedar LNG facility is a proposed floating liquefied natural gas facility to be constructed in Kitimat, British Columbia. The Cedar Link project is an expansion of the Coastal GasLink pipeline that is expected to enable delivery of up to 0.4 Bcf/d of natural gas to the Cedar LNG facility. With an estimated cost of $1.2 billion, the expansion project includes the addition of a new compressor station, connector pipeline and meter station to the existing Coastal GasLink pipeline infrastructure.

Funding for the expansion will be provided through project-level credit facilities of up to $1.4 billion secured by Coastal GasLink LP in June 2024, equity funding to be provided by Coastal GasLink LP partners, including us, and the recovery of construction carrying costs from LNGC Participants who have elected to make payments on a quarterly basis throughout construction. The incremental funds available through the project-level credit facilities and recovery of carrying charges provide additional contingency to mitigate future funding requirements for Coastal GasLink LP should costs exceed initial estimates of $1.2 billion. TC Energy has entered into an equity contribution agreement to fund up to a maximum of $37 million for its proportionate share of the equity requirements related to the Cedar Link project.

All major regulatory permits have been received and construction began in July 2024. The planned in-service date for the Cedar Link project is 2028, subject to the completion of plant commissioning activities at the Cedar LNG facility.

Indigenous Equity Option

In March 2022, we announced the signing of option agreements to sell up to a 10 per cent equity interest in Coastal GasLink LP to Indigenous communities across the project corridor, from our current 35 per cent equity ownership. The equity option is exercisable after commercial in-service of the Coastal GasLink pipeline, subject to customary regulatory approvals and consents, including the consent of LNGC. As a result of the commercial agreement with LNGC and LNGC Participants, which has allowed for an earlier commercial in-service than the LNGC plant, we are actively collaborating with the Indigenous communities to establish a mutually agreeable timeframe in which the option can be exercised.

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 24 for more information on non-GAAP measures we use.

year ended December 31 (millions of $)	2024	2023	2022
NGTL System	**2,393**	2,201	1,853
Canadian Mainline	**787**	789	770
Other Canadian pipelines[1]	**208**	345	183
Comparable EBITDA	**3,388**	3,335	2,806
Depreciation and amortization	**(1,382)**	(1,325)	(1,198)
Comparable EBIT	**2,006**	2,010	1,608
Specific items:			
Gain on sale of non-core assets	**10**	—	—
Coastal GasLink impairment charge	**—**	(2,100)	(3,048)
Segmented earnings (losses)	**2,016**	(90)	(1,440)

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.

In 2024, Canadian Natural Gas Pipelines segmented earnings were $2.0 billion compared to segmented losses of $0.1 billion and $1.4 billion in 2023 and 2022, respectively, and included the following specific items, which have been excluded from our calculation of comparable EBITDA and comparable EBIT:

- a pre-tax gain on sale of non-core assets of $10 million in second quarter 2024
- a pre-tax impairment charge in 2023 of $2.1 billion (2022 – $3.0 billion) related to our equity investment in Coastal GasLink LP. Refer to Note 7, Coastal GasLink, of our 2024 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 $)	2024	2023	2022
Net income			
NGTL System	**775**	770	708
Canadian Mainline	**244**	230	223
Average investment base			
NGTL System	**19,334**	19,008	17,493
Canadian Mainline	**3,697**	3,709	3,735

Net income for the NGTL System increased by $5 million in 2024 compared to 2023 and increased by $62 million in 2023 compared to 2022 mainly due to a higher average investment base resulting from continued system expansions, partially offset by an incentive loss. The NGTL System was operating under the 2020-2024 Revenue Requirement Settlement, which included an approved ROE of 10.1 per cent on 40 per cent deemed common equity. This settlement provided 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. Refer to the Canadian Natural Gas Pipelines - Significant events section for additional information on the 2025 - 2029 NGTL Settlement.

Net income for the Canadian Mainline increased by $14 million in 2024 compared to 2023 and increased by $7 million in 2023 compared to 2022 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 $53 million higher in 2024 compared to 2023 primarily due to the net effect of:

- higher flow-through income taxes, depreciation and financial charges, as well as higher rate-base earnings on the NGTL System due to continued system expansions
- higher flow-through income taxes, financial charges and depreciation, as well as higher rate-base earnings on Foothills primarily due to the NGTL System/Foothills West Path Delivery Program completed in 2023
- earnings from Coastal GasLink in 2023 related to the recognition of a $200 million incentive payment upon meeting certain milestones.

Comparable EBITDA for Canadian Natural Gas Pipelines in 2023 was $529 million higher than 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
- higher flow-through depreciation, financial charges and higher incentive earnings, partially offset by lower flow-through income taxes on the Canadian Mainline.

Depreciation and amortization

Depreciation and amortization was $57 million higher in 2024 compared to 2023, primarily reflecting incremental depreciation on the NGTL System from expansion facilities that were placed in service. 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.

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 2025 is expected to be higher than 2024 mainly due to higher contributions from the NGTL System resulting from the 2025-2029 NGTL Settlement. 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 2025 for the NGTL System and the Canadian Mainline to be consistent with 2024.

Capital expenditures

We incurred $1.3 billion of capital expenditures in 2024 in our Canadian Natural Gas Pipelines business on growth projects and maintenance capital expenditures. We expect to incur approximately $1.3 billion in 2025, primarily on NGTL System expansion projects and maintenance capital expenditures, all of which are immediately reflected in investment base and related earnings.

We also made a net contribution of $0.6 billion to our investment in Coastal GasLink LP in 2024, which was declared commercially in service in fourth quarter 2024. Significant equity contributions are not anticipated in 2025.

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 Pipeline Safety Regulations

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

Portland Natural Gas Transmission System

On March 4, 2024, we announced that TC Energy and its partner Northern New England Investment Company, Inc., a subsidiary of Énergir, entered into a purchase and sale agreement to sell PNGTS to BlackRock, through a fund managed by its Diversified Infrastructure business, and investment funds managed by Morgan Stanley Infrastructure Partners (the Purchaser). On August 15, 2024, we completed the sale of PNGTS for a gross purchase price of approximately $1.6 billion (US$1.1 billion), which included US$250 million of senior notes outstanding held at PNGTS and assumed by the Purchaser. A pre-tax gain of $572 million (US$408 million) and an after-tax gain of $456 million (US$323 million) were recognized for the year ended December 31, 2024. We are providing customary transition services and will continue to work jointly with the Purchaser to facilitate the safe and orderly transition of this natural gas system. Refer to Note 30, Strategic alliance, acquisitions and dispositions, of our 2024 Consolidated financial statements for additional information.

Gillis Access Project

In March 2024, the Gillis Access project, a 68 km (42 mile) greenfield pipeline system that connects gas production sourced from the Gillis hub to downstream markets in southeast Louisiana, was placed in service. The capital cost of this project was approximately US$0.3 billion.

In February 2023, we approved the 63 km (39 mile), 1.4 Bcf/d extension of the Gillis Access project to further connect supplies from Haynesville basin at Gillis. Effective September 1, 2024, all remaining shipper conditions have expired and the project expanded to 1.9 Bcf/d. The project has anticipated in-service dates starting in late 2026 and total estimated costs of US$0.4 billion.

Columbia Gas Section 4 Rate Case

In September 2024, Columbia Gas filed a Section 4 Rate Case with FERC requesting an increase to the maximum transportation rates expected to become effective April 1, 2025, subject to refund. We will pursue a collaborative process to find a mutually beneficial outcome with our customers through settlement.

Southeast Virginia Energy Storage Project

In November 2024, we approved the US$0.3 billion Southeast Virginia Energy Storage Project. This is an LNG peaking facility in southeast Virginia that will serve an existing LDC's growing winter peak day load and mitigate its peak day pricing exposure, as well as increase operational flexibility on the Columbia Gas system. The project has an anticipated in-service date of 2030.

Pulaski and Maysville Projects

In November 2024, we approved the Pulaski and Maysville projects on our Columbia Gulf System. These mainline extension projects off Columbia Gulf will facilitate full coal-to-gas conversion at two existing power plants and are each expected to provide 0.2 Bcf/d of capacity for incremental gas-fired generation. The projects have anticipated in-service dates in 2029 and total estimated costs of US$0.7 billion.

GTN XPress Project

In December 2024, the GTN XPress project, 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, was placed in service.
The capital cost of this project was approximately US$0.1 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 24 for more information on non-GAAP measures we use.

year ended December 31 (millions of US$, unless otherwise noted)	2024	2023	2022
Columbia Gas[1]	**1,600**	1,530	1,511
ANR	**642**	650	582
Columbia Gulf[1]	**235**	208	207
Great Lakes	**204**	183	178
GTN	**188**	202	184
PNGTS[1,2]	**66**	104	101
Other U.S. pipelines[3]	**359**	371	379
Comparable EBITDA	**3,294**	3,248	3,142
Depreciation and amortization	**(697)**	(692)	(681)
Comparable EBIT	**2,597**	2,556	2,461
Foreign exchange impact	**959**	895	742
Comparable EBIT (Cdn$)	**3,556**	3,451	3,203
Specific items:			
Gain on sale of PNGTS	**572**	—	—
Gain on sale of non-core assets	**38**	—	—
Great Lakes goodwill impairment charge	**—**	—	(571)
Risk management activities	**(113)**	80	(15)
Segmented earnings (losses) (Cdn$)	**4,053**	3,531	2,617

1 Includes non-controlling interest. Refer to the Corporate - Financial results section for additional information.
2 The sale of PNGTS was completed on August 15, 2024. Refer to the U.S. Natural Gas Pipelines – Significant events section for additional information.
3 Reflects comparable EBITDA from our ownership in our mineral rights business (CEVCO), North Baja, Gillis Access, 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 2024 increased by $522 million compared to 2023 and increased by $914 million in 2023 compared to 2022 and included the following specific items, which have been excluded from our calculation of comparable EBITDA and comparable EBIT:

- a pre-tax gain of $572 million related to the sale of PNGTS on August 15, 2024
- a pre-tax gain on sale of a non-core asset of $38 million in second quarter 2024
- 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 2024 and 2023 had a positive impact on the Canadian dollar equivalent segmented earnings from our U.S. dollar-denominated operations. 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$46 million higher in 2024 than 2023 primarily due to the net effect of:

- incremental earnings from growth and modernization projects placed in service, as well as increased earnings from additional contract sales on ANR and Great Lakes
- increased equity earnings from Northern Border
- decreased earnings due to higher operational costs, reflective of increased system utilization across our footprint
- decreased earnings as a result of the sale of our 61.7 per cent equity interest in PNGTS, which was completed on August 15, 2024
- lower realized earnings related to our U.S. natural gas marketing business primarily due to lower margins
- reduced earnings from our mineral rights business due to lower commodity prices.

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.

Depreciation and amortization

Depreciation and amortization was US$5 million higher in 2024 compared to 2023 and US$11 million higher in 2023 compared to 2022. The increase in depreciation is primarily due to new projects placed in service, partially offset by the impact of the sale of PNGTS in 2024.

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 regulatory decisions, as well as customer credit risk.

U.S. Natural Gas Pipelines comparable EBITDA in 2025 is expected to be slightly higher than 2024 due to an anticipated increase in transportation rates on Columbia Gas, which is dependent on the outcome of the Section 4 Rate Case filed with FERC. In addition, revenues are expected to increase following the completion of expansion projects in 2025 on the Columbia Gas, Columbia Gulf and ANR systems, as well as full year in-service of the Gillis Access project. Our pipeline systems continue to see historically strong demand for service and we anticipate that during 2025, our assets will maintain the high utilization levels experienced in 2024. These positive results are expected to be partially offset by higher operational costs, reflective of continued increases to system utilization across our footprint, the impact of the sale of our 61.7 per cent equity interest in PNGTS in 2024 and an anticipated increase in property taxes from capital projects placed in service.

Capital expenditures

We incurred a total of US$2.2 billion of capital expenditures in 2024 on our U.S. natural gas pipelines and expect to incur approximately US$2.5 billion in 2025 primarily on our Columbia Gas, ANR and Columbia Gulf expansion projects and Bison XPress equity contributions, 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 2025 to be approximately US$2.0 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 primary 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. Our Mexico pipelines also have regulatory 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. We continue to be aligned with the CFE on finalizing the remaining project completion activities for achieving an in-service date of May 1, 2025. The estimated project cost for the Southeast Gateway pipeline is approximately US$3.9 billion, which is lower than the initial cost estimate of US$4.5 billion.

During second quarter 2024, upon the CFE's equity injection of US$340 million as well as non-cash consideration in recognition of the completion of certain contractual obligations, including land acquisition and permitting support, the CFE became a partner in TGNH with a 13.01 per cent equity interest. Provided that the CFE's contractual commitments are met related to land acquisition, community relations and permitting support, the CFE's equity in TGNH would build up to a maximum of 15 per cent with the in-service of the Southeast Gateway pipeline and will increase to approximately 35 per cent upon expiry of the contract in 2055. Refer to Note 30, Strategic alliance, acquisitions and dispositions, of our Consolidated financial statements for additional information.

Tula

In third quarter 2022, we placed the east section of the Tula pipeline into commercial service and we reached an agreement with the CFE to jointly develop and complete the remaining segments of the Tula pipeline, with the central segment subject to an FID. Due to the delay of an FID, recording AFUDC on the assets under construction for the Tula pipeline project was suspended in late 2023.

Villa de Reyes

We placed the north and lateral sections of the Villa de Reyes pipeline into commercial service in third quarter 2022 and third quarter 2023, respectively. We continue to work with our partner, the CFE, to complete the south section of the Villa de Reyes pipeline. The in-service date will be determined upon resolution of outstanding stakeholder issues.

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 24 for more information on non-GAAP measures we use.

year ended December 31 (millions of US$, unless otherwise noted)	2024	2023	2022
TGNH[1,2]	**231**	232	164
Sur de Texas[3]	**220**	75	112
Topolobampo	**156**	157	161
Guadalajara	**56**	61	73
Mazatlán	**67**	71	67
Comparable EBITDA	**730**	596	577
Depreciation and amortization	**(67)**	(66)	(76)
Comparable EBIT	**663**	530	501
Foreign exchange impact	**244**	186	153
Comparable EBIT (Cdn$)	**907**	716	654
Specific item:			
Expected credit loss provision on net investment in leases and certain contract assets in Mexico[2]	**22**	80	(163)
Segmented earnings (losses) (Cdn$)	**929**	796	491

1 Includes the operating sections of the Tamazunchale, Villa de Reyes and Tula pipelines.
2 Includes non-controlling interest. Refer to the Corporate - Financial results section for additional information.
3 Represents equity income from our 60 per cent interest and fees earned from the construction and operation of the pipeline.

Mexico Natural Gas Pipelines segmented earnings in 2024 increased by $133 million compared to 2023 and increased by $305 million in 2023 compared to 2022 and included the impact of a $22 million unrealized recovery in 2024 (2023 – $80 million unrealized recovery; 2022 – $163 million unrealized 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 28, Risk management and financial instruments, of our 2024 Consolidated financial statements for additional information.

A stronger U.S. dollar in 2024 and 2023 had a positive impact on the Canadian dollar equivalent segmented earnings from our U.S. dollar-denominated operations in Mexico. Refer to the Foreign exchange section for additional information.

Comparable EBITDA for Mexico Natural Gas Pipelines increased by US$134 million in 2024 compared to 2023 mainly due to the net effect of:

- higher equity earnings in Sur de Texas primarily due to foreign exchange impacts upon the revaluation of peso-denominated liabilities as a result of a weaker Mexican peso and lower income tax expense mainly due to foreign exchange impacts. 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
- lower earnings from Guadalajara primarily due to lower fixed revenue in accordance with the current transportation contract and higher operating costs.

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

- higher earnings in TGNH primarily related to the commercial in-service of the north section of the Villa de Reyes pipeline and the east section of the Tula pipeline in third quarter 2022, as well as the commercial in-service of the lateral section of the Villa de Reyes pipeline 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.

Depreciation and amortization

Depreciation and amortization was generally consistent in 2024 compared to 2023. Depreciation and amortization was US$10 million lower in 2023 compared to 2022 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 equity 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 2025 is expected to be higher than 2024 due to the Southeast Gateway project that is expected to be placed into commercial service on May 1, 2025.

Capital expenditures

We incurred US$1.5 billion of capital expenditures in 2024 primarily related to the construction of the Southeast Gateway and Villa de Reyes pipelines. We expect to incur approximately US$0.4 billion in 2025 to finalize 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 102 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, aggregate natural gas demand across all sectors, including LNG exports, 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 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 and/or carbon pricing 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 safe and reliable operations.

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 lower carbon solutions for our customers and industry.

Our Power and Energy Solutions business includes approximately 4,650 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 Canada and approximately 350 MW of PPAs in the U.S. from wind and solar facilities.

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 and expanding profit margins through cost efficiency and revenue enhancement. 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. In the long term, we believe there will be a growing need for a reliable supply of resources as the energy mix evolves. We are positioning ourselves to play a vital role in decarbonizing energy sources 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

- Bruce Power completed planned outages on Unit 1 and Unit 7 and completed a Vacuum Building inspection where Units 5, 6 and 8 were also shut down in 2024. On January 31, 2025, Unit 4 was removed from service to commence its MCR program
- The Unit 5 MCR final cost and schedule estimate was submitted to the IESO on January 31, 2025
- Executed contract extensions of five years at Mackay River and 10 years at Grandview cogeneration plants
- TC Energy and prospective partners Saugeen Ojibway Nation will advance pre-development work on the Ontario Pumped Storage Project following the Ontario Government's recent announcement on January 24, 2025 to invest up to $285 million. With the Ontario Government’s investment, the project can now advance critical development work, including the completion of a detailed cost estimate, the commencement of federal and provincial environmental assessments, advanced design and engineering and continued community engagement. It is expected that the Board of Directors, Saugeen Ojibway Nation and the Ontario Government will each make a final decision on the project following further definition and completion of a detailed cost estimate.

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 6,580 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 have a 48.3 per cent equity 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, was completed in third quarter 2023. The Unit 3 MCR, the second unit in the MCR program, commenced in first quarter 2023 and has an expected completion in 2026. The Unit 4 MCR final cost and schedule estimate was approved by the IESO on February 8, 2024. Unit 4 was removed from service on January 31, 2025 to commence its MCR program with expected completion in 2028. Investments in the remaining three units' MCR programs are expected to continue through 2033. The Unit 5 MCR final cost and schedule estimate was submitted to the IESO on January 31, 2025. 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 (capability) of 7,000 MW by 2033 in support of the province of Ontario's 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 site capability. Project 2030 is being implemented in three stages with the first two stages and Stage 3a fully approved for execution. The program commenced in 2019 with a site capability of 6,430 MW and closed out 2024 at approximately 6,580 MW; a net gain of approximately 150 MW. Upon completion of Stage 1, 2 and 3a, the site is projected to reach 6,840 MW. All three stages are being implemented in parallel to the MCR program.

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, 2024 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 plans to expand Lutetium-177 isotope production used in the treatment of prostate cancer and neuroendocrine tumours. 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. Furthermore, Bruce Power and its partners in the production of medical isotopes have committed to building a hot cell facility in Bruce County, expediting their ability to process short-lived lutetium-177 to ensure it reaches cancer patients around the world in a timely fashion.

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 350 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

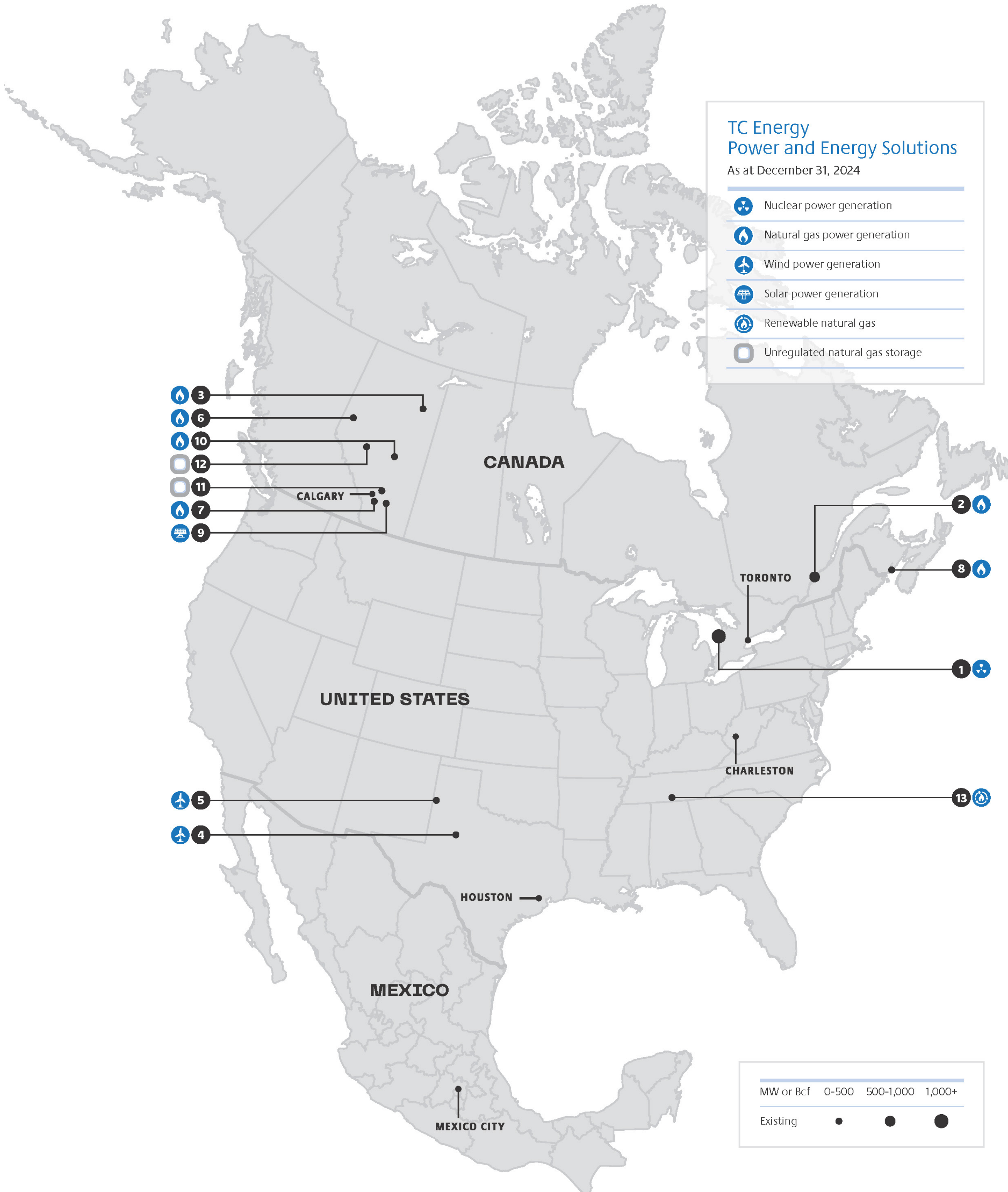
Canadian Natural Gas Storage

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.


TC Energy
Power and Energy Solutions
As at December 31, 2024
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 4,652 MW. We operate each facility except for Bruce Power.

		Generating capacity (MW)	Type of fuel	Description	Ownership
	Power assets				
1	Bruce Power[1]	3,180	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.

SIGNIFICANT EVENTS

Bruce Power Life Extension

On January 31, 2025, Unit 4 was removed from service to commence its MCR program, with a return to service expected in 2028.

The Unit 5 MCR final cost and schedule estimate was submitted to the IESO on January 31, 2025.

Uprate Initiative

On November 19, 2024, we announced that Bruce Power is progressing with Stage 3a of Project 2030, which is designed to provide incremental capacity of approximately 90 MW at the site. TC Energy's share of the capital required is approximately $175 million. Bruce Power will not be requesting an incremental capital call for this stage. By optimizing its existing Units through this program, when complete, Project 2030 is expected to increase the Bruce Power site peak output to 7,000 MW. All of this output will be sold under Bruce Power's long-term contract with the IESO.

Ontario Pumped Storage

TC Energy and prospective partners Saugeen Ojibway Nation will advance pre-development work on the Ontario Pumped Storage Project following the Ontario Government's recent announcement on January 24, 2025 to invest up to $285 million. With the Ontario Government's investment, the project can now advance critical development work, including the completion of a detailed cost estimate, the commencement of federal and provincial environmental assessments, advanced design and engineering and continued community engagement.

It is expected that TC Energy's Board of Directors, Saugeen Ojibway Nation and the Ontario Government will each make a final decision on the project following further definition and completion of a detailed cost estimate.

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 24 for more information on non-GAAP measures we use.

year ended December 31 (millions of $)	2024	2023	2022
Bruce Power[1]	**890**	680	552
Canadian Power	**273**	334	322
Natural Gas Storage and other[2]	**51**	6	33
Comparable EBITDA	**1,214**	1,020	907
Depreciation and amortization	**(101)**	(92)	(72)
Comparable EBIT	**1,113**	928	835
Specific items:			
Project Tundra impairment charge	**(36)**	—	—
Bruce Power unrealized fair value adjustments	**8**	7	(17)
Risk management activities	**17**	69	15
Segmented earnings (losses)	**1,102**	1,004	833

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 $98 million in 2024 compared to 2023 and increased by $171 million in 2023 compared to 2022 and included the following specific items, which have been excluded from our calculation of comparable EBITDA and comparable EBIT:

- a pre-tax impairment charge of $36 million related to development costs incurred on Project Tundra, a next-generation technology carbon capture and storage project, following our decision to end our collaboration on the project
- 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 $194 million in 2024 compared to 2023 primarily due to the net effect of:

- higher contributions from Bruce Power primarily due to higher generation resulting from fewer outage days in 2024 and a higher contract price, partially offset by increased operating expenses and higher depreciation expense. Additional financial and operating information on Bruce Power is provided below
- increased Natural Gas Storage and other results primarily due to higher realized Alberta natural gas storage spreads and higher contributions from our U.S. marketing business, partially offset by increased business development costs in 2024
- decreased Canadian Power financial results primarily from lower realized power prices, partially offset by lower natural gas fuel costs.

Comparable EBITDA for Power and Energy Solutions increased by $113 million in 2023 compared to 2022 primarily due to the net effect of:

- 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
- 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.

Depreciation and amortization

Depreciation and amortization increased by $9 million in 2024 compared to 2023 and increased by $20 million in 2023 compared to 2022 and were primarily due to the acquisition of the Texas Wind Farms in the first half of 2023.

Bruce Power results

Bruce Power results reflect our proportionate share. Comparable EBITDA and comparable EBIT are non-GAAP measures. Refer to page 24 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)	2024	2023	2022
Items included in comparable EBITDA and comparable EBIT are comprised of:			
Revenues[1]	**2,242**	1,941	1,848
Operating expenses	**(984)**	(917)	(924)
Depreciation and other	**(368)**	(344)	(372)
Comparable EBITDA and comparable EBIT[2]	**890**	680	552
Bruce Power – other information			
Plant availability[3,4]	**92%**	92%	86%
Planned outage days[4]	**160**	106	302
Unplanned outage days	**32**	62	34
Sales volumes (GWh)[5]	**22,209**	20,447	20,610
Realized power price per MWh[6]	**$100**	$94	$89

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.

Bruce Power's 2024 planned maintenance, on Units 5 to 8, excluding the MCR program, was completed in second quarter. A planned outage on Unit 4 was completed in second quarter 2023 and on Unit 8 in fourth quarter 2023. In 2022, planned maintenance was completed on all units.

OUTLOOK

Comparable EBITDA

Power and Energy Solutions comparable EBITDA in 2025 is expected to be lower than 2024 primarily from decreased Bruce Power equity income due to the removal of Unit 4 from service on January 31, 2025 to commence its MCR outage, partially offset by a higher contract price and fewer non-MCR planned outage days. Lower Alberta power prices and higher natural gas prices in 2025 are expected to reduce contributions from Canadian Power. These reductions are expected to be partially offset by lower business development activities in 2025.

Planned maintenance at Bruce Power in 2025 is currently scheduled to begin on Unit 5 in the first quarter and on Unit 2 in the third quarter. The average 2025 plant availability percentage, excluding the Unit 3 and Unit 4 MCR programs, is expected to be in the low-90 per cent range.

Capital expenditures

We incurred $0.8 billion of capital expenditures in 2024 primarily on our share of the Unit 3 MCR program at Bruce Power and maintenance capital projects across the segment. We expect to incur approximately $0.9 billion in 2025 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 102 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.

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 Canada and the U.S. in both regulated and deregulated power markets. 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. Fluctuations in seasonal weather patterns or temperature can affect 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 lower-carbon economy in North America and, as a result, we face competition in building lower-carbon energy solutions.

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

NGTL System Ownership Transfer

On April 1, 2024, ownership of the NGTL System was transferred from Nova Gas Transmission Ltd. to NGTL GP Ltd. on behalf of NGTL Limited Partnership as part of an ordinary course corporate reorganization to support business optimization and facilitate future minority ownership of the NGTL System, including participation from Indigenous groups. Refer to the Canadian Natural Gas Pipelines – Significant events section for additional information. The reorganization will not impact the operations of the NGTL System. As a limited partnership, NGTL LP is not subject to Canadian corporate income taxes. The related income tax obligations are those of the partners.

For the year ended December 31, 2024, we incurred costs of $42 million after tax related to the NGTL System Ownership Transfer, which has been excluded from comparable measures.

2016 Columbia Pipeline Acquisition Lawsuit

In 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.

On May 15, 2024, the Court allocated responsibility for the total sale process damages of US$398 million in the amount of 50 per cent to the former Columbia CEO and CFO, collectively, and 50 per cent to TC Energy. Pursuant to the Final Order and Judgment (Final Judgment), TC Energy's allocated share of the sale process claim damages is US$199 million, plus US$153 million in interest as of June 14, 2024. The Court also entered judgment related to a disclosure claim for which TC Energy's allocated share of damages is US$84 million, plus US$64 million in interest as of June 14, 2024. The damages for the two claims are not cumulative and TC Energy would only be required to pay the greater of the sale process damages and disclosure claim damages after final determination of those amounts on appeal, including any additional interest assessed to the date of payment.

TC Energy disagrees with many of the Court's findings and believes the Court's ruling departs from established Delaware law. TC Energy has filed a notice of appeal, which is scheduled to be heard by the Delaware Supreme Court on March 12, 2025. A final decision is expected in mid-2025. During the appeal process, in lieu of paying the judgment, TC Energy posted an appeal bond in the amount of US$380 million, which approximates the amount of the Final Judgment plus nine months of post-judgment interest. Our legal assessment is that it is not probable that TC Energy will incur a loss upon completion of the appeal process, and therefore, we have not accrued a provision for this claim at December 31, 2024.

Focus Project

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

The expected impacts of project initiatives have been included in our outlook for 2025 and no significant incremental project costs are expected beyond 2024. The program will wind down in 2025 as we finalize implementation of certain initiatives. The core elements of the project are embedded into our business processes to sustain performance improvements over the long term.

For the year ended December 31, 2024 we have incurred pre-tax costs of $45 million (2023 – $124 million) for the Focus Project primarily related to severance costs, of which $24 million (2023 – $65 million, primarily external consulting) was recorded in Plant operating costs and other in the Consolidated statement of income and was excluded from comparable measures. An additional $14 million for the year ended December 31, 2024 (2023 – $23 million) was recorded in Plant operating costs and other with offsetting revenues related to costs recoverable through regulatory and commercial tolling structures, the net effect of which had no impact on net income. For the year ended December 31, 2024, $7 million (2023 – $36 million) was allocated to capital projects.

Asset Divestiture Program

Our asset divestiture program, which included completing the sale of PNGTS and the CFE's equity injection resulting in a 13.01 per cent equity interest in TGNH in 2024, as well as the sale of a 40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf in 2023, collectively contributed to our deleveraging goal. Any further capital rotation opportunities will be assessed in the normal course of our business.

2024 Canadian Legislation

On June 20, 2024, two pieces of Canadian legislation, Bill C-59 and Bill C-69 were enacted into law, which, among other things, included the excessive interest and financing expenses limitation (EIFEL) rules and the Global Minimum Tax Act. We do not expect a material impact on our financial performance and cash flows as a result of the new legislation.

TC Energy has disallowed interest expense related to the EIFEL legislation and expects further restrictions on interest deductibility. However, through on-going monitoring and management, we expect the disallowed interest to be utilized. We will also continue to monitor developments related to EIFEL legislation and assess its impacts to the business.

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 24 for more information on non-GAAP measures we use.

year ended December 31 (millions of $)	2024	2023[1]	2022[1]
Comparable EBITDA	**(63)**	(73)	(72)
Depreciation and amortization	**(5)**	(6)	(7)
Comparable EBIT	**(68)**	(79)	(79)
Specific items:			
Third-party settlement	**(34)**	—	—
Focus Project costs	**(24)**	(65)	—
NGTL System ownership transfer costs	**(10)**	—	—
Foreign exchange gains – inter-affiliate loans[2]	**—**	—	28
Segmented earnings (losses)	**(136)**	(144)	(51)

1 Prior year results have been recast to reflect continuing operations only.
2 Reported in Income (loss) from equity investments in the Consolidated statement of income.

In 2024, Corporate segmented losses were $136 million compared to $144 million and $51 million in 2023 and 2022, respectively, and included the following specific items which have been excluded from our calculation of comparable EBITDA and comparable EBIT:

- a pre-tax expense of $34 million (US$25 million) in 2024 related to a non-recurring third-party settlement
- a pre-tax charge of $24 million recorded in 2024 (2023 – $65 million) related to Focus Project costs. Refer to the Corporate – Significant events section for additional information
- a pre-tax charge of $10 million in 2024 related to the NGTL System Ownership Transfer. Refer to the Corporate – Significant events section for additional information
- foreign exchange gains in 2022 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.

Comparable EBITDA for Corporate was a loss of $63 million in 2024 compared to a loss of $73 million in 2023, primarily due to shared costs in 2024 and 2023 related to TC Energy's corporate services and governance functions that were not allocated to discontinued operations in accordance with U.S. GAAP. Refer to the Discontinued operations section for additional information. Comparable EBITDA for Corporate in 2023 was generally consistent compared to 2022.

Depreciation and amortization

Depreciation and amortization was generally consistent between 2024 and 2023 and between 2023 and 2022.

OTHER INCOME STATEMENT ITEMS

Interest expense

year ended December 31 (millions of $)	2024	2023[1]	2022[1]
Interest expense on long-term debt and junior subordinated notes			
Canadian dollar-denominated	**(856)**	(895)	(776)
U.S. dollar-denominated	**(1,855)**	(1,692)	(1,267)
Foreign exchange impact	**(685)**	(592)	(383)
	(3,396)	(3,179)	(2,426)
Other interest and amortization expense	**(147)**	(261)	(189)
Capitalized interest	**191**	187	27
Interest expense allocated to discontinued operations	**176**	287	288
Interest expense included in comparable earnings	**(3,176)**	(2,966)	(2,300)
Specific items:			
Net gain on debt extinguishment	**228**	—	—
Risk management activities	**(71)**	—	—
Interest expense	**(3,019)**	(2,966)	(2,300)

1 Prior year results have been recast to reflect continuing operations only.

Interest expense increased by $53 million in 2024 compared to 2023 and increased by $666 million in 2023 compared to 2022.

The following specific items have been removed from our calculation of interest expense included in comparable earnings:

- pre-tax net gain on debt extinguishment of $228 million was recorded related to the purchase and cancellation of certain senior unsecured notes and medium term notes and the retirement of outstanding callable notes in October 2024. Refer to the Financial condition section for additional information
- unrealized gains and losses on derivatives used to manage our interest rate risk. Refer to the Other information - Financial risks and financial instruments sections for additional information.

Interest expense included in comparable earnings in 2024 increased by $210 million compared to 2023 primarily due to the net effect of:

- long-term debt issuances and maturities
- interest expense allocated to discontinued operations for nine months in 2024 compared to a full year in 2023. Refer to the Discontinued operations section for additional information
- the foreign exchange impact from a stronger U.S. dollar on translation of U.S. dollar-denominated interest expense
- reduced levels of short-term borrowing.

Interest expense included in comparable earnings in 2023 increased by $666 million compared to 2022 mainly due to the net effect of:

- long-term debt issuances and 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 7, Coastal GasLink, of our 2024 Consolidated financial statements for additional information.

Refer to the Financial condition section for additional information.

Allowance for funds used during construction

year ended December 31 (millions of $)	2024	2023	2022
Allowance for funds used during construction			
Canadian dollar-denominated	**34**	102	157
U.S. dollar-denominated	**546**	350	161
Foreign exchange impact	**204**	123	51
Allowance for funds used during construction	**784**	575	369

AFUDC increased by $209 million in 2024 compared to 2023. 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 primarily due to capital expenditures on the Southeast Gateway pipeline project and U.S. natural gas pipeline projects in 2024, partially offset by the suspension of AFUDC on the assets under construction for the Tula pipeline project due to the delay of an FID and placing the lateral section of Villa de Reyes pipeline in service in August 2023.

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. Effective November 1, 2023, AFUDC was suspended on the assets under construction for the Tula pipeline project, due to the delay of an FID.

Foreign exchange gains (losses), net

year ended December 31 (millions of $)	2024	2023	2022
Foreign exchange gains (losses), net included in comparable earnings	**(85)**	118	(8)
Specific items:			
Foreign exchange gains (losses), net – intercompany loan[1]	**204**	(44)	—
Foreign exchange losses – inter-affiliate loan	**—**	—	(28)
Risk management activities	**(266)**	246	(149)
Foreign exchange gains (losses), net	**(147)**	320	(185)

1 Includes non-controlling interest. Refer to Net (income) loss attributable to non-controlling interests for additional information.

Foreign exchange losses, net were $147 million in 2024 compared to foreign exchange gains, net of $320 million in 2023 and foreign exchange losses, net of $185 million in 2022. 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
- 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 – Related party transactions section for additional information
- unrealized gains and losses from changes in the fair value of derivatives used to manage our foreign exchange risk. Refer to the Other information – Financial risks and Financial instruments sections for additional information.

Foreign exchange losses, net included in comparable earnings were $85 million in 2024 compared to foreign exchange gains, net of $118 million in 2023. The change was primarily due to the net effect of:

- risk management activities used to manage our foreign exchange exposure to net liabilities in Mexico and to U.S. dollar-denominated income
- foreign exchange gains in 2024 compared to foreign exchange losses in 2023 on the revaluation of our peso-denominated net monetary liabilities to U.S. dollars
- a net realized gain in the second quarter 2024 on the partial repayment of the peso-denominated intercompany loan between TCPL and TGNH.

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

- risk management activities used to manage our foreign exchange exposure to net liabilities in Mexico and to U.S. dollar-denominated income
- higher foreign exchange losses on the revaluation of our peso-denominated net monetary liabilities to U.S. dollars.

Interest income and other

year ended December 31			
(millions of $)	**2024**	**2023**[1]	**2022**[1]
Interest income and other	**324**	272	140

1 Prior year results have been recast to reflect continuing operations only.

Interest income and other increased by $52 million in 2024 compared to 2023 due to higher interest earned on short-term investments and a reduction in insurance-related provisions.

Interest income and other 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.

Income tax (expense) recovery

year ended December 31 (millions of $)	2024	2023[1]	2022[1]
Income tax (expense) recovery included in comparable earnings	**(772)**	(890)	(660)
Specific items:			
Gain on sale of PNGTS	**(116)**	—	—
Revaluation of deferred tax balances	**(96)**	—	—
Net gain on debt extinguishment	**(50)**	—	—
Foreign exchange gains (losses), net – intercompany loan	**10**	—	—
Gain on sale of non-core assets	**15**	—	—
Expected credit loss provision on net investment in leases and certain contract assets in Mexico	**(7)**	(25)	49
Third-party settlement	**8**	—	—
Project Tundra impairment charge	**9**	—	—
Focus Project costs	**6**	17	—
NGTL System ownership transfer costs	**(32)**	—	—
Coastal GasLink impairment charge	**—**	157	405
Great Lakes goodwill impairment charge	**—**	—	40
Settlement of Mexico prior years' income tax assessments	**—**	—	(196)
Bruce Power unrealized fair value adjustments	**(2)**	(2)	4
Risk management activities	**105**	(99)	36
Income tax (expense) recovery	**(922)**	(842)	(322)

1 Prior year results have been recast to reflect continuing operations only.

Income tax expense in 2024 increased by $80 million compared to 2023 and increased by $520 million in 2023 compared to 2022.

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

2024

- a deferred income tax expense of $96 million resulting from the revaluation of remaining deferred tax balances following the Spinoff Transaction.

2023

- a $157 million income tax recovery related to the impairment of our equity investment in Coastal GasLink LP.

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.

Income tax expense included in comparable earnings in 2024 decreased by $118 million compared to 2023 primarily due to Mexico foreign exchange exposure and lower earnings subject to income tax, partially offset by lower foreign income tax rate differentials and higher flow-through income taxes. Refer to the Foreign exchange section for additional information.

Income tax expense included in comparable earnings in 2023 increased by $230 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 inflationary adjustments. Refer to the Foreign exchange section for additional information.

Net (income) loss attributable to non-controlling interests

year ended December 31 (millions of Canadian $)	Non-Controlling Interests Ownership at December 31, 2024	2024	2023	2022
Columbia Gas and Columbia Gulf[1]	40 %	**(571)**	(143)	—
PNGTS[2]	nil	**(30)**	(41)	(37)
Texas Wind Farms[3]	100 %	**29**	38	—
TGNH[4]	13.01 %	**(48)**	—	—
Net (income) loss attributable to non-controlling interests included in comparable earnings		**(620)**	(146)	(37)
Specific item:				
Foreign exchange (gains) losses, net – intercompany loan		**(61)**	—	—
Net (income) loss attributable to non-controlling interests		**(681)**	(146)	(37)

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 Global Infrastructure Partners.
2 The sale of PNGTS was completed on August 15, 2024. Refer to the U.S. Natural Gas Pipelines – Significant events section for additional information.
3 Tax equity investors own 100 per cent of the Class A Membership Interests, to which a percentage of earnings, tax attributes and cash flows are allocated. We own 100 per cent of the Class B Membership Interests.
4 In second quarter 2024, the CFE became a partner in TGNH with a 13.01 per cent equity interest in TGNH. Refer to the Mexico Natural Gas Pipelines – Significant events section for additional information.

Net income attributable to non-controlling interests increased by $535 million in 2024 compared to 2023 and includes the non-controlling interest portion of the unrealized foreign exchange gains and losses on the TGNH peso-denominated intercompany loan payable to TCPL, which has been removed from our calculation of Net (income) loss attributable to non-controlling interests included in comparable earnings. Net income attributable to non-controlling interests included in comparable earnings increased by $474 million primarily due to the sale of a 40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf to Global Infrastructure Partners in fourth quarter 2023 and the 13.01 per cent non-controlling equity interest in TGNH to the CFE, which was completed in second quarter 2024. Refer to the Mexico Natural Gas Pipelines – Significant events section for additional information.

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.

Preferred share dividends

year ended December 31 (millions of $)	2024	2023	2022
Preferred share dividends	**(104)**	(93)	(107)

Preferred share dividends increased by $11 million in 2024 compared to 2023 primarily due to the dividend rate resets on Series 7 preferred shares and Series 9 preferred shares on April 30, 2024 and October 30, 2024, respectively. Preferred share dividends decreased $14 million in 2023 compared to 2022 primarily due to the redemption of preferred shares in 2022, partially offset by higher floating dividend rates on certain series of preferred shares.

Foreign exchange

Foreign exchange related to U.S. dollar-denominated 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. A portion of the remaining 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, 2024, 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. Comparable EBITDA is a non-GAAP measure.

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

year ended December 31 (millions of US$)	**2024**	**2023**[1]	**2022**[1]
Comparable EBITDA			
U.S. Natural Gas Pipelines	**3,294**	3,248	3,142
Mexico Natural Gas Pipelines[2]	**730**	596	602
	4,024	3,844	3,744
Depreciation and amortization	**(764)**	(758)	(757)
Interest on long-term debt and junior subordinated notes	**(1,855)**	(1,692)	(1,267)
Interest expense allocated to discontinued operations	**125**	189	182
Allowance for funds used during construction	**546**	350	161
Net income (loss) attributable to non-controlling interests included in comparable earnings and other	**(481)**	(156)	(101)
	1,595	1,777	1,962
Average exchange rate – U.S. to Canadian dollars	**1.37**	1.35	1.30

1 Prior year results have been recast to reflect continuing operations only.

2 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, Foreign exchange (gains) losses, net and Net income (loss) attributable to non-controlling interests 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.

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 Other information – Financial risks and Financial instruments sections for additional information.

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

December 31, 2024	**20.87**
December 31, 2023	16.91
December 31, 2022	19.50

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 $)	**2024**	**2023**	**2022**
Comparable EBITDA – Mexico Natural Gas Pipelines[1]	**115**	(83)	(32)
Foreign exchange gains (losses), net included in comparable earnings	**(53)**	224	54
Income tax (expense) recovery included in comparable earnings	**110**	(133)	(11)
Net (income) loss attributable to non-controlling interests included in comparable earnings[2]	**(11)**	—	—
	161	8	11

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.

2 Represents the non-controlling interest portion related to TGNH. Refer to the Corporate - Financial results section for additional information.

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 continuing operations, access to capital markets, portfolio management activities, joint ventures, asset-level financing, cash on hand and substantial committed credit facilities. Annually, in the fourth quarter, we renew and extend our credit facilities as required.

Financial Plan

Our capital program is comprised of approximately $25 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 which may include:

- senior debt
- hybrid securities
- preferred shares
- asset divestitures and capital rotation
- 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 - from continuing operations

At December 31, 2024, excluding discontinued operations, our current assets totaled $5.5 billion and current liabilities amounted to $10.3 billion, leaving us with a working capital deficit of $4.8 billion compared to $0.8 billion at December 31, 2023. 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 $8.0 billion of committed revolving credit facilities available for short-term borrowing capacity, of which $7.6 billion of short-term borrowing capacity remains available, net of $0.4 billion backstopping outstanding commercial paper balances. We also have arrangements in place for a further $2.0 billion of demand credit facilities on which $1.1 billion remains available as of December 31, 2024
- additional $2.2 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, capital rotation and DRP, if deemed appropriate.

Our total assets from continuing operations at December 31, 2024 were $117.9 billion compared to $109.5 billion at December 31, 2023. The increase primarily reflects our capital spending program, increased equity investments and a stronger U.S. dollar at December 31, 2024 compared to December 31, 2023 on translation of our U.S. dollar-denominated assets, partially offset by depreciation and working capital.

At December 31, 2024 our total liabilities from continuing operations were $79.6 billion, compared to $82.1 billion at December 31, 2023 due to the net effect of a reduction in debt, working capital and a stronger U.S. dollar at December 31, 2024 compared to December 31, 2023 on translation of our U.S. dollar-denominated liabilities.

Consolidated capital structure - from continuing operations

The following table summarizes the components of our capital structure for continuing operations.

at December 31 (millions of $, unless otherwise noted)	2024	Per cent of total	2023	Per cent of total
Notes payable	**387**	**1**	—	—
Long-term debt, including current portion	**47,931**	**49**	52,914	54
Cash and cash equivalents	**(801)**	**(1)**	(3,678)	(4)
	47,517	**49**	49,236	50
Junior subordinated notes	**11,048**	**11**	10,287	10
Preferred shares	**2,499**	**3**	2,499	3
Common shareholders' equity	**25,093**	**26**	27,054	27
Non-controlling interests	**10,768**	**11**	9,455	10
	96,925	**100**	98,531	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, 2024.

Cash flows[1,2]

The following tables summarize our consolidated cash flows.

year ended December 31 (millions of $)	2024	2023	2022
Net cash provided by operations	**7,696**	7,268	6,375
Net cash (used in) provided by investing activities	**(6,909)**	(12,287)	(7,009)
Net cash (used in) provided by financing activities	**(3,874)**	8,093	487
	(3,087)	3,074	(147)
Effect of foreign exchange rate changes on cash and cash equivalents	**210**	(16)	94
Increase (decrease) in cash and cash equivalents	**(2,877)**	3,058	(53)

1 Includes continuing and discontinued operations.

2 Represents nine months of Liquids Pipelines earnings in 2024 compared to a full year of Liquids Pipelines earnings in 2023 and 2022. Refer to the Discontinued operations section for additional information.

Cash provided by operating activities[1,2]

year ended December 31 (millions of $)	2024	2023	2022
Net cash provided by operations	**7,696**	7,268	6,375
Increase (decrease) in operating working capital	**(199)**	(207)	639
Funds generated from operations	**7,497**	7,061	7,014
Specific items:			
Liquids Pipelines business separation costs, net of current income tax	**185**	40	—
Current income tax (recovery) expense on sale of PNGTS and non-core assets	**148**	—	—
Third-party settlement, net of current income tax	**26**	—	—
Focus Project costs, net of current income tax	**21**	54	—
NGTL System ownership transfer costs	**10**	—	—
Current income tax (recovery) expense on risk management activities	**9**	—	—
Current income tax (recovery) expense on Keystone XL asset impairment charge and other	**(3)**	(14)	96
Current income tax (recovery) expense on Keystone regulatory decisions	**(3)**	53	27
Current income tax expense on disposition of equity interest[3]	**—**	736	—
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
Comparable funds generated from operations	**7,890**	7,980	7,353

1 Includes continuing and discontinued operations.

2 Represents nine months of Liquids Pipelines earnings in 2024 compared to a full year of Liquids Pipelines earnings in 2023 and 2022. Refer to the Discontinued operations section for additional information.

3 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 $428 million in 2024 compared to 2023 primarily due to higher funds generated from 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.

Comparable funds generated from operations

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

Comparable funds generated from operations decreased by $90 million in 2024 compared to 2023 primarily due to lower comparable earnings, partially offset by increased distributions from our equity investments.

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.

Cash (used in) provided by investing activities[1]

year ended December 31 (millions of $)	2024	2023	2022
Capital spending[2]			
Capital expenditures	**(6,308)**	(8,007)	(6,678)
Capital projects in development	**(50)**	(142)	(49)
Contributions to equity investments	**(1,546)**	(4,149)	(2,234)
	(7,904)	(12,298)	(8,961)
Proceeds from sales of assets, net of transaction costs	**791**	33	—
Other distributions from equity investments	**549**	23	1,433
Deferred amounts and other	**(352)**	2	(41)
Keystone XL contractual recoveries	**7**	10	571
Acquisitions, net of cash acquired	**—**	(307)	—
Loans to affiliate (issued) repaid, net	**—**	250	(11)
Net cash (used in) provided by investing activities	**(6,909)**	(12,287)	(7,009)

1 Includes continuing and discontinued operations.

2 Capital spending reflects cash flows associated with our Capital expenditures, Capital projects in development and Contributions to equity investments net of Other distributions from equity investments of $3.1 billion in 2024 in the Canadian Natural Gas Pipelines segment (2023 - nil, 2022 - $1.2 billion in the Corporate segment). Refer to Note 5, Segmented information, Note 7, Coastal GasLink and Note 12, Loans receivable from affiliates, of our 2024 Consolidated financial statements for additional information.

Net cash used in investing activities decreased from $12.3 billion in 2023 to $6.9 billion in 2024 primarily as a result of decreased capital spending and lower contributions to equity investments primarily related Coastal GasLink LP and in part by higher proceeds from the sales of assets and distributions from equity investments.

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.

Capital spending[1]

The following table summarizes capital spending by segment.

year ended December 31 (millions of $)	2024	2023	2022
Canadian Natural Gas Pipelines	**2,100**	6,184	4,719
U.S. Natural Gas Pipelines	**2,575**	2,660	2,137
Mexico Natural Gas Pipelines	**2,228**	2,292	1,027
Power and Energy Solutions	**824**	1,080	894
Corporate	**50**	33	41
	7,777	12,249	8,818
Discontinued operations	**127**	49	143
	7,904	12,298	8,961

1 Capital spending reflects cash flows associated with our Capital expenditures, Capital projects in development and Contributions to equity investments net of Other distributions from equity investments of $3.1 billion in 2024 in the Canadian Natural Gas Pipelines segment (2023 - nil, 2022 - $1.2 billion in the Corporate segment). Refer to Note 5, Segmented information, Note 7, Coastal GasLink and Note 12, Loans receivable from affiliates, of our 2024 Consolidated financial statements for additional information.

Capital expenditures
Capital expenditures in 2024 were incurred primarily for the advancement of the Southeast Gateway pipeline, Columbia Gas and ANR projects, the NGTL System expansion as well as maintenance capital expenditures. Lower capital expenditures in 2024 compared to 2023 reflect reduced spending on NGTL System expansion and the Southeast Gateway pipeline.

Capital projects in development
Costs incurred during 2024 on Capital projects in development were primarily attributable to spending on projects in the Power and Energy Solutions segment.

Contributions to equity investments
Contributions to equity investments decreased in 2024 compared to 2023 mainly due to lower funds advanced to Coastal GasLink LP through the subordinated loan agreement.

On December 17, 2024, following the declared commercial in-service of the pipeline, Coastal GasLink LP repaid the $3,147 million balance owing to us under the subordinated loan agreement. Our share of equity contributions required to fund Coastal GasLink LP's repayment of the outstanding loan balance amounted to $3,137 million. The Contributions to equity investments and Other distributions from equity investments with respect to these 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 Note 7, Coastal GasLink, of our 2024 Consolidated financial statements for additional information.

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 were accounted for as in-substance equity contributions.

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.

Proceeds from sales of assets
In 2024, TC Energy and its partner, Northern New England Investment Company, Inc., a subsidiary of Énergir, completed the sale of PNGTS to a third party. Our share of the proceeds was $743 million (US$546 million), net of transaction costs.

In 2024, we also completed the sale of other non-core assets for gross proceeds of $48 million.

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). As part of the Spinoff Transaction on October 1, 2024, our remaining interest in Port Neches Link LLC was transferred to South Bow.

Other distributions from equity investments
Other distributions from equity investments primarily relate to distributions from Millennium as a result of its debt financing program in 2024, as well as the return of capital from our equity investment in Iroquois.

In 2022, other distributions from equity investments primarily relates to our proportionate share of the Sur de Texas debt repayments. Subsequent to the refinancing activities with the 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.

Acquisitions
In 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. We also 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.

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.

Cash (used in) provided by financing activities[1]

year ended December 31 (millions of $)	2024	2023	2022
Notes payable issued (repaid), net	**341**	(6,299)	766
Long-term debt issued, net of issue costs	**8,089**	15,884	2,508
Long-term debt repaid	**(9,273)**	(3,772)	(1,338)
Disposition of equity interest, net of transaction costs	**419**	5,328	—
Junior subordinated notes issued, net of issue costs	**1,465**	—	1,008
Cash transferred to South Bow, net of debt settlement	**(244)**	—	—
Dividends and distributions paid	**(4,807)**	(3,052)	(3,385)
Contributions from non-controlling interests	**21**	—	—
Common shares issued, net of issue costs	**88**	4	1,905
Preferred shares redeemed	**—**	—	(1,000)
Gains (losses) on settlement of financial instruments	**27**	—	23
Net cash (used in) provided by financing activities	**(3,874)**	8,093	487

1 Includes continuing and discontinued operations.

Net cash provided by financing activities decreased by $12.0 billion in 2024 compared to 2023 primarily due to lower issuances and higher repayments of long-term debt, the receipt of the $5.3 billion (US$3.9 billion) proceeds in 2023 upon sale of a 40 per cent non-controlling equity interest in Columbia Gas and Columbia Gulf, as well as higher dividends and distributions paid in 2024, partially offset by net issuances of notes payable in 2024 compared to net repayments in 2023.

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.

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 2024.

(millions of Canadian $, unless otherwise noted) Company	Issue date	Type	Maturity date	Amount	Interest rate
TRANSCANADA PIPELINES LIMITED					
	August 2024	Term Loan[1]	August 2024	US 1,242	Floating
COLUMBIA PIPELINES OPERATING COMPANY LLC					
	September 2024	Senior Unsecured Notes	October 2054	US 400	5.70%
COLUMBIA PIPELINES HOLDING COMPANY LLC					
	September 2024	Senior Unsecured Notes	October 2031	US 400	5.10%
	January 2024	Senior Unsecured Notes	January 2034	US 500	5.68%

1 In August 2024, TCPL entered into a term loan to facilitate the Spinoff Transaction and, in August 2024, the term loan was fully repaid and retired upon delivery of senior unsecured notes issued by 6297782 LLC, which was a wholly-owned subsidiary of TC Energy at the time. Refer to the Discontinued operations section for additional information.

Long-term debt retired/repaid

The following table outlines significant long-term debt retired/repaid in 2024.

(millions of Canadian $, unless otherwise noted) Company	Retirement/ repayment date	Type	Amount	Interest rate
TRANSCANADA PIPELINES LIMITED				
	October 2024	Senior Unsecured Notes	US 1,250	1.00%
	October 2024	Senior Unsecured Notes[1]	US 850	6.20%
	October 2024	Senior Unsecured Notes[2]	US 739	2.50%
	October 2024	Senior Unsecured Notes[2]	US 441	4.88%
	October 2024	Senior Unsecured Notes[1]	US 400	Floating
	October 2024	Senior Unsecured Notes[2]	US 313	4.75%
	October 2024	Senior Unsecured Notes[2]	US 201	5.00%
	October 2024	Senior Unsecured Notes[2]	US 180	5.10%
	October 2024	Medium Term Notes[1]	600	5.42%
	October 2024	Medium Term Notes[2]	575	4.18%
	October 2024	Medium Term Notes[1]	400	Floating
	August 2024	Term Loan[3]	US 1,242	Floating
	June 2024	Medium Term Notes	750	Floating
NOVA GAS TRANSMISSION LTD.				
	March 2024	Debentures	100	9.90%
ANR PIPELINE COMPANY				
	February 2024	Senior Unsecured Notes	US 125	7.38%
TC ENERGÍA MEXICANA, S. DE R.L. DE C.V.				
	Various 2024	Senior Unsecured Term Loan	US 430	Floating
	Various 2024	Senior Unsecured Revolving Credit Facility	US 185	Floating

1 In October 2024, callable notes were retired at par.

2 In October 2024, TCPL purchased and cancelled notes at a 7.73 per cent weighted average discount, as a settlement of the cash tender offers.

3 In August 2024, TCPL entered into a term loan to facilitate the Spinoff Transaction and, in August 2024 the term loan was fully repaid and retired upon delivery of senior unsecured notes issued by 6297782 LLC, which was a wholly-owned subsidiary of TC Energy at the time. Refer to the Discontinued operations section for additional information.

In October 2024, TCPL commenced and completed our cash tender offers to purchase and cancel certain senior unsecured notes and medium term notes at a 7.73 per cent weighted average discount. In addition, the Company repaid and retired outstanding callable notes at par. These extinguishments of debt resulted in a pre-tax net gain of $228 million, primarily due to the fair value discount and recognition of unamortized debt issue costs related to these notes. The net gain on debt extinguishment was recorded in Interest expense, in the Consolidated statement of income and has been excluded from comparable measures.

For more information about long-term debt and junior subordinated notes issued and long-term debt repaid in 2024, 2023 and 2022, refer to the notes to our 2024 Consolidated financial statements.

Dividend reinvestment plan

Under the DRP, eligible holders of common and preferred shares of TC Energy can reinvest their dividends and make optional cash payments to obtain additional TC Energy common shares. From 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.

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 7, 2025		
Common Shares	**issued and outstanding**	
	1.0 billion	
Preferred Shares	**issued and outstanding**	**convertible to**
Series 1	18.4 million	Series 2 preferred shares
Series 2	3.6 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	16.7 million	Series 10 preferred shares
Series 10	1.3 million	Series 9 preferred shares
Series 11	10 million	Series 12 preferred shares
Options to buy common shares	**outstanding**	**exercisable**
	4.4 million	3.1 million

On December 31, 2024, 42,200 Series 1 preferred shares were converted, on a one-for-one basis, into Series 2 preferred shares and 3,889,020 Series 2 preferred shares were converted, on a one-for-one basis, into Series 1 preferred shares.

On October 30, 2024, 1,297,203 Series 9 preferred shares were converted, on a one-for-one basis, into Series 10 preferred shares.

For more information on preferred shares refer to the notes to our 2024 Consolidated financial statements.

Dividends

year ended December 31	2024	2023	2022
Dividends declared			
per common share[1]	$3.7025	$3.72	$3.60
per Series 1 preferred share	$0.86975	$0.86975	$0.86975
per Series 2 preferred share	$1.68134	$1.62659	$0.82611
per Series 3 preferred share	$0.4235	$0.4235	$0.4235
per Series 4 preferred share	$1.52046	$1.46703	$0.66655
per Series 5 preferred share	$0.48725	$0.48725	$0.48725
per Series 6 preferred share	$1.55132	$1.55993	$0.80668
per Series 7 preferred share	$1.36613	$0.97575	$0.97575
per Series 9 preferred share	$1.02288	$0.9405	$0.9405
per Series 10 preferred share	$0.39807	—	—
per Series 11 preferred share	$0.83775	$0.83775	$0.83775
per Series 15 preferred share	—	—	$0.30625

1 Dividends declared for fourth quarter 2024 reflect TC Energy's proportionate allocation following the Spinoff Transaction.

Commencing with the dividends payable on January 31, 2025 to shareholders of record at the close of business on December 31, 2024, the amounts reflect TC Energy's proportionate allocation following the Spinoff Transaction. Refer to the Discontinued operations section for additional information.

On February 14, 2025, we announced a quarterly dividend on our outstanding common shares of $0.85 per common share for the quarter ending March 31, 2025, which represents an increase of 3.3 per cent from TC Energy's proportionate allocation of the dividend following the Spinoff Transaction. This equates to an annual dividend of $3.40 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 7, 2025, total committed revolving and demand credit facilities were $12.2 billion. These unsecured credit facilities included the following:

(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 2029	3.0	2.2
TCPL / TCPL USA	Supports commercial paper programs and for general corporate purposes of the borrowers, guaranteed by TCPL	December 2025	US 1.0	US 0.2
TCPL / TCPL USA	Supports commercial paper programs and for general corporate purposes of the borrowers, guaranteed by TCPL	December 2027	US 2.5	US 2.5
Columbia Pipelines Holding Company LLC[2]	Supports commercial paper program and general corporate purposes of the borrower	December 2027	US 1.5	US 1.5
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 [3]	1.1 [3]

1 Unused capacity is net of commercial paper outstanding and facility draws.
2 Columbia Pipelines Holding Company LLC is a partially owned subsidiary of TC Energy with 40 per cent non-controlling interest.
3 Or the U.S. dollar equivalent.

Contractual obligations

Our contractual obligations include our notes payable, long-term debt and junior subordinated notes, operating leases, purchase obligations and other liabilities incurred in our business such as cash contributions to the employee pension and post-retirement benefit plans.

Payments due (by period)

at December 31, 2024 (millions of $)	Total	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Notes payable	387	387	—	—	—
Long-term debt and junior subordinated notes[1]	59,319	2,955	5,968	7,416	42,980
Operating leases[2]	614	73	139	127	275
Purchase obligations and other[3]	5,024	1,407	949	526	2,142
	65,344	4,822	7,056	8,069	45,397

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.

3 Includes an estimated $110 million related to the transfer of pension assets to South Bow. The final transfer will be adjusted for investment returns and benefit payments from October 1, 2024, to the transfer date. Refer to the Obligations - pension and other post-retirement benefit plans section for more information.

Notes payable

Total notes payable outstanding at December 31, 2024 was $387 million (2023 – nil).

Long-term debt and junior subordinated notes

At December 31, 2024, we had $47.9 billion (2023 – $52.9 billion) of long-term debt and $11.0 billion (2023 – $10.3 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.

At December 31, 2024, scheduled interest payments related to our long-term debt and junior subordinated notes were as follows:

at December 31, 2024 (millions of $)	Total	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Long-term debt	25,071	2,379	4,308	3,729	14,655
Junior subordinated notes	50,755	660	1,557	1,742	46,796
	75,826	3,039	5,865	5,471	61,451

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 2025 to 2038, that require the purchase of generated energy and associated environmental attributes. At December 31, 2024, the total planned capacity secured under the PPAs is approximately 750 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.

At December 31, 2024, payments for purchase obligations and other were as follows:

at December 31, 2024 (millions of $)	Total	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Canadian Natural Gas Pipelines					
Transportation by others[1]	168	34	57	40	37
Transportation by others - TQM[1,2]	2,598	148	302	300	1,848
Capital spending[3]	253	246	4	2	1
U.S. Natural Gas Pipelines					
Transportation by others[1]	628	159	230	93	146
Capital spending[3]	418	314	89	15	—
Mexico Natural Gas Pipelines					
Capital spending[3]	207	207	—	—	—
Power and Energy Solutions					
Capital spending[3]	166	125	32	9	—
Other	226	30	46	40	110
Corporate					
Capital spending[3]	7	7	—	—	—
South Bow pension plan assets held in trust[4]	110	—	110	—	—
Other	243	137	79	27	—
	5,024	1,407	949	526	2,142

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 Includes 100 per cent of the contracted obligation for the Canadian Mainline to transport volumes for its shippers utilizing the TQM pipeline to 2042, which we have a 50 per cent ownership interest in. The cost of the contracts flow through to the Canadian Mainline shippers and is determined based on the revenue requirement outlined in the current 2024-2025 TQM settlement agreement.

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

4 Related to the transfer of pension assets to South Bow. The final transfer will be adjusted for investment returns and benefit payments from October 1, 2024, to the transfer date. Refer to the Obligations - pension and other post-retirement benefit plans section for more information.

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 2025, with the annual option to extend for one year periods ending in 2053.

At December 31, 2024, our share of potential exposure under the Sur de Texas pipeline guarantees was estimated to be $93 million with a carrying amount of less than $1 million.

Bruce Power

We and our joint venture partner on Bruce Power, BPC Generation Infrastructure Trust, have each severally guaranteed certain contingent financial obligations of Bruce Power related to a lease agreement. The Bruce Power guarantee has a term that can be renewed in December 2027 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, 2024, 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. The guarantees have terms ranging to 2032.

Our share of the potential exposure under these assurances was estimated at December 31, 2024 to be approximately $59 million with a carrying amount of $1 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 2024, we made no funding contributions to our defined benefit pension plans (DB Plans), $8 million for other post-retirement benefit plans and $71 million for the savings plan and defined contribution plans. Total letters of credit provided for the funding of solvency requirements to the Canadian DB plan at December 31, 2024 was $111 million (2023 – $244 million; 2022 – $322 million).

In 2025, we expect to make no contributions for the DB Plans, funding contributions of approximately $6 million for other post-retirement benefit plans and approximately $71 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 DB Plans and other post-retirement plans decreased to $19 million in 2024 from $20 million in 2023 primarily due to a change in Canadian post-retirement benefits.

South Bow - transition of pension assets

As part of the Spinoff Transaction, certain TC Energy employees became employees of South Bow. Prior to the Spinoff Transaction, these employees in Canada and the U.S. participated in the DB Plans, DC Plans and savings plans, as applicable. As part of the Spinoff Transaction, the benefit obligations under the DB Plans in respect of the employees moving from TC Energy to South Bow were transferred to South Bow. An asset transfer application related to the Canadian DB Plan will be prepared in early 2025 outlining the proposed transfer of assets from TC Energy to South Bow. The Canadian DB Plan's assets to be transferred to South Bow are subject to regulatory approval and will be transferred when approval is received. As of December 31, 2024, these assets remain in the TC Energy DB Plan trust and have been reflected as Long-term assets of discontinued operations and a corresponding obligation to South Bow has been reflected as Long-term liabilities of discontinued operations on the Consolidated balance sheet. The assets related to the U.S. DB Plan were fully transferred to South Bow as at December 31, 2024.

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.

Discontinued operations

On July 27, 2023, TC Energy announced plans to separate into two independent, investment-grade, publicly listed companies through the Spinoff Transaction. TC Energy shareholders voted to approve the spinoff in June 2024 and, on October 1, 2024, TC Energy completed the spinoff of its Liquids Pipelines business into the new public company, South Bow Corporation. TC Energy shareholders as of September 25, 2024 received one new TC Energy common share and 0.2 of a South Bow common share in exchange for each TC Energy common share held. TC Energy common shares resumed regular way trading on the TSX and NYSE on October 2, 2024. South Bow's common shares commenced regular way trading on the TSX on October 2, 2024 and on the NYSE on October 8, 2024, under the ticker symbol SOBO. Refer to Note 4, Discontinued operations, for additional information.

Agreements

TC Energy and South Bow have executed a series of agreements to outline the parameters and guidelines that govern their ongoing relationship and to specify the separation of assets and liabilities between the two corporations. A Transition Services Agreement has been established, the primary purpose of which is to specify certain services that TC Energy will provide to South Bow, for compensation, for a period of up to two years. These services primarily include access to and support of systems that South Bow will continue to use until it has fully implemented new systems to support its business processes and warehouse management services.

As part of the Spinoff Transaction, a Tax Matters Agreement was executed to govern TC Energy and South Bow's tax rights and obligations after the Spinoff Transaction. The agreement imposes certain restrictions on both TC Energy and South Bow in order to preserve the tax-free status of the spinoff and allocates tax liabilities in the event the Spinoff Transaction is not tax-free.

TC Energy and South Bow entered into a Separation Agreement setting forth the terms of the separation of the Liquids Pipelines business from the business of TC Energy, including the transfer of certain assets related to the Liquids Pipelines business from TC Energy to South Bow and the allocation of certain liabilities and obligations related to the Liquids Pipelines business between TC Energy and South Bow. The Separation Agreement provides, among other things, that TC Energy will indemnify South Bow for 86 per cent of total net liabilities and costs arising from the Milepost 14 incident that occurred on the Keystone Pipeline System in December 2022 and the existing variable toll disputes on the Keystone Pipeline System (excluding any future impacts to the variable toll after October 1, 2024) subject to a maximum liability to South Bow of $30 million, in aggregate, for those two matters. Due to the inherent uncertainties of the final amounts to be settled under these indemnities, any amounts that may ultimately be payable in respect of these net liabilities to South Bow could differ materially from those reported at December 31, 2024.

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. South Bow will maintain the commitment for long-term reclamation and environmental monitoring activities.

At December 31, 2023, we accrued a life-to-date environmental liability for the Milepost 14 incident of $794 million, before expected insurance recoveries and not including potential fines and penalties, which were indeterminable. Prior to the Spinoff Transaction, for the nine months ended September 30, 2024, amounts paid for the environmental remediation liability were $92 million (twelve months ended December 31, 2023 – $676 million). For the year ended December 31, 2024, we received $99 million (2023 – $575 million) from insurance policies related to the costs for environmental remediation.

We received insurance proceeds of $36 million related to the Milepost 14 incident that were collected from our wholly-owned captive insurance subsidiary and resulted in an impact to net income in the consolidated financial results of TC Energy. This amount has been excluded from comparable measures from discontinued operations. As part of the Separation Agreement, all future insurance recoveries will remain with TC Energy.

In fourth quarter 2024, we recorded a pre-tax expense of $37 million for our current estimate of potential incremental costs related to the Milepost 14 incident, which has been excluded from comparable measures from discontinued operations. This amount represents our 86 per cent share pursuant to the indemnity provisions in the Separation Agreement.

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, of which $27 million pertained to amounts reflected in 2021 and 2020 and was excluded from comparable measures from discontinued operations. 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.

On July 25, 2024, FERC released its Order on Initial Decision in respect of the complaint. For the year ended December 31, 2024, we recognized an additional pre-tax charge of $12 million (2023 – $67 million including carrying charges) with respect to the decision, which has been excluded from comparable measures from discontinued operations. On October 8, 2024, South Bow submitted a compliance filing, which is subject to final FERC approval.

Subsequent rulings from both the CER and FERC, if any, will be subject to the indemnity provisions as outlined in the Separation Agreement.

Separation Costs
Liquids Pipelines business separation costs primarily include internal costs related to separation activities, legal, income tax, audit and other consulting fees, insurance provisions and net financial charges related to debt issued and held in escrow. For the years ended December 31, 2024 and 2023, Liquids Pipelines business separation costs of $197 million ($167 million after tax) and $40 million ($34 million after tax), respectively, were included in Net income (loss) from discontinued operations, net of tax in the Consolidated statement of income and have been excluded from our calculation of comparable measures from discontinued operations.

South Bow Debt
On August 28, 2024, South Bow Canadian Infrastructure Holdings Ltd. and 6297782 LLC, which were wholly-owned subsidiaries of TC Energy at the time, completed an offering of approximately $7.9 billion Canadian-dollar equivalent of senior unsecured notes and junior subordinated notes. Approximately $6.2 billion Canadian-dollar equivalent of the net proceeds was placed in escrow pending the completion of the Spinoff Transaction on October 1, 2024 and US$1.3 billion of senior unsecured notes were used to repay a TCPL term loan. Upon completion of the Spinoff Transaction, the escrowed funds were released to South Bow and used to repay indebtedness owed by South Bow and its subsidiaries to TC Energy and its subsidiaries. Liquids Pipelines business separation costs also included interest expense of $42 million and interest income of $28 million related to senior unsecured notes and junior subordinated notes issued on August 28, 2024 and held in escrow, which have been excluded from our calculation of comparable measures from discontinued operations.

Presentation of Discontinued Operations
Upon completion of the Spinoff Transaction, the Liquids Pipelines business was accounted for as a discontinued operation. Our presentation of discontinued operations includes revenues and expenses directly attributable to the Liquids Pipelines business. As such, the results of discontinued operations excludes shared costs related to TC Energy's corporate services and governance functions that had provided support, and whose costs had been historically allocated, to the Liquids Pipelines segment. Depreciation expense related to Corporate shared assets has also been excluded from the results of discontinued operations. We have elected to allocate a portion of the interest expense incurred at the corporate level to discontinued operations. In 2024, discontinued operations represented nine months of Liquids Pipelines earnings compared to a full year of Liquids Pipelines earnings in 2023 and 2022. Prior year amounts have been recast to present the Liquids Pipelines business as a discontinued operation.

RESULTS FROM DISCONTINUED OPERATIONS

year ended December 31 (millions of $, except per share amounts)	2024[1]	2023[2]	2022[2]
Segmented earnings (losses) from discontinued operations	**716**	1,039	1,182
Interest expense	**(218)**	(297)	(288)
Interest income and other	**21**	(30)	6
Income (loss) from discontinued operations before income taxes	**519**	712	900
Income tax (expense) recovery	**(124)**	(100)	(267)
Net income (loss) from discontinued operations, net of tax	**395**	612	633
Net income (loss) per common share from discontinued operations – basic	**$0.38**	$0.60	$0.63

1 Represents nine months of Liquids Pipelines earnings in 2024 compared to a full year of Liquids Pipelines earnings in 2023 and 2022.
2 Prior year results have been recast to reflect the Liquids Pipelines business as a discontinued operation as a result of the Spinoff Transaction.

Net income (loss) from discontinued operations, net of tax in 2024 was $395 million or $0.38 per share (2023 – $612 million or $0.60 per share; 2022 – $633 million or $0.63 per share), a decrease of $217 million or $0.22 per share compared to 2023 and a decrease of $21 million or $0.03 per share in 2023 compared to 2022.

NON-GAAP MEASURES

This MD&A references non-GAAP measures, which are described on page 24. 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.

The following specific items were recognized in Net income (loss) from discontinued operations, net of tax and were excluded from comparable earnings from discontinued operations:

2024

- a pre-tax charge of $197 million (after-tax $167 million) from Liquids Pipelines business separation costs related to the Spinoff Transaction, of which $173 million was recognized in segmented earnings (losses) from discontinued operations, $42 million was recorded in interest expense and $18 million was recorded in interest income
- a pre-tax expense of $37 million (after-tax $28 million) related to our current estimate of potential incremental costs resulting from the Milepost 14 incident. This amount represents our 86 per cent share pursuant to the indemnity provisions in the Separation Agreement
- a pre-tax expense of $21 million (after-tax $16 million) related to Keystone XL asset disposition and termination activities
- a pre-tax charge of $12 million (after-tax $10 million) as a result of the FERC Administrative Law Judge decision on Keystone in respect of a tolling-related complaint pertaining to amounts recognized in prior periods.

2023

- a pre-tax charge of $67 million (after-tax $52 million) as a result of the FERC Administrative Law Judge decision on Keystone in respect of a tolling-related complaint pertaining to amounts recognized in prior periods, which consists of a one-time pre-tax charge of $57 million and included accrued pre-tax carrying charges of $10 million
- a pre-tax charge of $40 million(after-tax $34 million) from Liquids Pipelines business separation costs related to the Spinoff Transaction
- a pre-tax accrued insurance expense of $36 million (after-tax $36 million) related to the Milepost 14 incident
- pre-tax preservation and other costs of $18 million (after-tax $14 million) related to the preservation and storage of the Keystone XL pipeline project assets
- a pre-tax recovery of $4 million (after-tax $18 million) 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

- a pre-tax recovery of $118 million (after-tax expense $5 million) 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
- a pre-tax charge of $27 million (after-tax $20 million) due to the CER decision on Keystone issued in December 2022 in respect of a tolling-related complaint pertaining to amounts reflected in prior periods
- pre-tax preservation and other costs of $25 million (after-tax $19 million) related to the preservation and storage of the Keystone XL pipeline project assets.

Reconciliation of net income (loss) from discontinued operations, net of tax to comparable earnings from discontinued operations

year ended December 31 (millions of $, except per share amounts)	**2024**[1]	**2023**[2]	**2022**[2]
Net income (loss) from discontinued operations, net of tax	**395**	612	633
Specific items (pre tax):			
Liquids Pipelines business separation costs	**197**	40	—
Milepost 14 incremental costs	**37**	—	—
Keystone XL asset impairment charge and other	**21**	(4)	(118)
Keystone regulatory decisions	**12**	67	27
Milepost 14 insurance expense	**—**	36	—
Keystone XL preservation and other	**—**	18	25
Risk management activities	**(67)**	34	(20)
Taxes on specific items[3]	**(30)**	(47)	114
Comparable earnings from discontinued operations	**565**	756	661
Net income (loss) per common share from discontinued operations	**$0.38**	$0.60	$0.63
Specific items (net of tax)	**0.16**	0.14	0.03
Comparable earnings per common share from discontinued operations	**$0.54**	$0.74	$0.66

1 Represents nine months of Liquids Pipelines earnings in 2024 compared to a full year of Liquids Pipelines earnings in 2023 and 2022.
2 Prior year results have been recast to reflect the Liquids Pipelines business as a discontinued operation as a result of the Spinoff Transaction.
3 Refer to page 101 for additional information.

Comparable EBITDA to comparable earnings - from discontinued operations

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

year ended December 31 (millions of $, except per share amounts)	2024[1]	2023[2]	2022[2]
Comparable EBITDA from discontinued operations	**1,145**	1,516	1,418
Depreciation and amortization	**(253)**	(332)	(322)
Interest expense included in comparable earnings[3]	**(176)**	(287)	(288)
Interest income and other included in comparable earnings[4]	**3**	6	6
Income tax (expense) recovery included in comparable earnings[5]	**(154)**	(147)	(153)
Comparable earnings from discontinued operations	**565**	756	661
Comparable earnings per common share from discontinued operations	**$0.54**	$0.74	$0.66

1 Represents nine months of Liquids Pipelines earnings in 2024 compared to a full year of Liquids Pipelines earnings in 2023 and 2022.

2 Prior year results have been recast to reflect the Liquids Pipelines business as a discontinued operation as a result of the Spinoff Transaction.

3 Excludes pre-tax Liquids Pipelines business separation costs of $42 million related to interest expense on the South Bow debt issuance in third quarter 2024 and carrying charges of $10 million for the year ended December 31, 2023 as a result of a pre-tax charge related to the FERC Administrative Law Judge decision on Keystone in respect of a tolling-related complaint pertaining to amounts recognized in prior periods.

4 Excludes pre-tax income of $18 million for the year ended December 31, 2024 related to the net impact of interest income on proceeds from the South Bow debt issuance on August 28, 2024, which were held in escrow and insurance provisions as well as a $36 million pre-tax insurance expense recorded in 2023 related to the Milepost 14 incident.

5 Excludes the impact of income taxes related to the specific items mentioned above as well as a $14 million U.S. minimum tax recovery in 2023 on the Keystone XL asset impairment charge and other related to the termination of the Keystone XL pipeline project and a $123 million income tax expense in 2022 as part of the Keystone XL asset impairment charge and other.

Comparable EBITDA from discontinued operations

Comparable EBITDA from discontinued operations was $371 million lower in 2024 compared to 2023 primarily due to the net effect of:

- nine months of Liquids Pipelines earnings included in 2024 compared to a full year of Liquids Pipelines earnings in 2023
- higher contracted and uncontracted volumes across the Keystone Pipeline System in 2024
- lower contributions from the liquids marketing business due to lower realized margins.

Comparable EBITDA from discontinued operations was $98 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.

Comparable earnings from discontinued operations

Comparable earnings from discontinued operations in 2024 were $191 million or $0.20 per common share lower than in 2023, and were primarily due to the impact of nine months of Liquids Pipelines business earnings in 2024 compared to a full year in 2023.

Comparable earnings from discontinued operations in 2023 were $95 million or $0.08 per common share higher than in 2022, and were primarily due to changes in comparable EBITDA from discontinued operations described above.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA from discontinued operations and comparable EBIT from discontinued operations (our non-GAAP measures) to segmented earnings (losses) from discontinued operations (the most directly comparable GAAP measure). Refer to page 24 for more information on non-GAAP measures we use.

year ended December 31 (millions of $)	2024[1]	2023[2]	2022[2]
Keystone Pipeline System	**1,098**	1,453	1,356
Intra-Alberta pipelines[3]	**52**	70	71
Other	**(5)**	(7)	(9)
Comparable EBITDA from discontinued operations	**1,145**	1,516	1,418
Depreciation and amortization	**(253)**	(332)	(322)
Comparable EBIT from discontinued operations	**892**	1,184	1,096
Specific items (pre tax):			
Liquids Pipelines business separation costs	**(173)**	(40)	—
Milepost 14 incremental costs	**(37)**	—	—
Keystone XL asset impairment charge and other	**(21)**	4	118
Keystone regulatory decisions	**(12)**	(57)	(27)
Keystone XL preservation and other	**—**	(18)	(25)
Risk management activities	**67**	(34)	20
Segmented earnings (losses) from discontinued operations	**716**	1,039	1,182

1 Represents nine months of Liquids Pipelines earnings in 2024 compared to a full year of Liquids Pipelines earnings in 2023 and 2022.
2 Prior year results have been recast to reflect the Liquids Pipelines business as a discontinued operation as a result of the Spinoff Transaction.
3 Intra-Alberta pipelines includes Grand Rapids and White Spruce.

Segmented earnings from discontinued operations decreased by $323 million in 2024 compared to 2023 and decreased by $143 million in 2023 compared to 2022 and included the specific items mentioned in the table above, which have been excluded from our calculation of comparable EBITDA from discontinued operations and comparable EBIT from discontinued operation. Refer to page 96 for additional information.

A stronger U.S. dollar in 2024 and 2023 had a positive impact on the Canadian dollar equivalent segmented earnings from our U.S. operations compared to 2023 and 2022, respectively.

Depreciation and amortization

Depreciation and amortization was $79 million lower in 2024 compared to 2023 due to nine months of Liquids Pipelines operations in 2024 compared to a full year of Liquids Pipelines operations in 2023 and $10 million higher in 2023 compared to 2022 primarily as a result of a stronger U.S. dollar.

OTHER INCOME STATEMENT ITEMS

Interest expense

year ended December 31 (millions of $)	2024[1]	2023[2]	2022[2]
Interest expense included in comparable earnings from discontinued operations	**(176)**	(287)	(288)
Specific items:			
Liquids Pipelines business separation costs	**(42)**	—	—
Keystone regulatory decisions	**—**	(10)	—
Interest expense from discontinued operations[3]	**(218)**	(297)	(288)

1 Represents nine months of Liquids Pipelines allocated interest expense in 2024 compared to a full year of Liquids Pipelines allocated interest expense in 2023 and 2022.
2 Prior year results have been recast to reflect the Liquids Pipelines business as a discontinued operation as a result of the Spinoff Transaction.
3 We have elected to allocate a portion of the interest expense incurred at the corporate level to discontinued operations. Refer to page 95 for additional information.

Interest expense included in comparable earnings from discontinued operations decreased by $111 million in 2024 compared to 2023 due to nine months of interest expense included in 2024 compared to a full year in 2023 and was generally consistent in 2023 compared to 2022.

Interest income and other

year ended December 31 (millions of $)	2024[1]	2023[2]	2022[2]
Interest income and other included in comparable earnings from discontinued operations	**3**	6	6
Specific items:			
Liquids Pipelines business separation costs	**18**	—	—
Milepost 14 insurance expense	**—**	(36)	—
Interest income and other from discontinued operations	**21**	(30)	6

1 Represents nine months of Liquids Pipelines earnings in 2024 compared to a full year of Liquids Pipelines earnings in 2023 and 2022.
2 Prior year results have been recast to reflect the Liquids Pipelines business as a discontinued operation as a result of the Spinoff Transaction.

Interest income and other included in comparable earnings from discontinued operations was generally consistent in 2024 compared to 2023 and in 2023 compared to 2022.

Income tax (expense) recovery

year ended December 31 (millions of $)	2024[1]	2023[2]	2022[2]
Income tax (expense) recovery included in comparable earnings from discontinued operations	**(154)**	(147)	(153)
Specific items:			
Liquids Pipelines business separation costs	**30**	6	—
Milepost 14 incremental costs	**9**	—	—
Keystone XL asset impairment charge and other	**5**	14	(123)
Keystone regulatory decisions	**2**	15	7
Keystone XL preservation and other	**—**	4	6
Risk management activities	**(16)**	8	(4)
Income tax (expense) recovery from discontinued operations	**(124)**	(100)	(267)

1 Represents nine months of Liquids Pipelines earnings in 2024 compared to a full year of Liquids Pipelines earnings in 2023 and 2022.

2 Prior year results have been recast to reflect the Liquids Pipelines business as a discontinued operation as a result of the Spinoff Transaction.

Income tax expense included in comparable earnings from discontinued operations increased by $7 million in 2024 compared to 2023 primarily due to lower foreign income tax rate differentials largely offset by lower earnings; and decreased by $6 million in 2023 compared to 2022 primarily due to higher foreign income tax rate differentials largely offset by higher earnings.

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 ensures that risks and related exposures are aligned with our business objectives and risk tolerances. We achieve this through a centralized Enterprise Risk Management (ERM) program, which systematically identifies and assesses risks that could materially impact our strategic objectives.

The ERM program addresses risks related to executing our business strategies and supports practices for identifying and monitoring emerging risks. Specifically, the ERM framework offers a comprehensive process for risk identification, analysis, evaluation and mitigation. It also ensures ongoing monitoring and reporting to the Board of Directors, CEO, Executive Vice-Presidents and the Chief Risk Officer.

Board and Committee Oversight

Our Board of Directors retains general oversight over all enterprise risks. Annually, the Board reviews the enterprise risk register and receives quarterly updates on emerging risks and their management and mitigation in accordance with TC Energy's risk appetite and tolerances. Additionally, the Board receives detailed presentations on enterprise risks quarterly, with specific themes addressed during regular financial updates and strategic meetings. Special presentations are also delivered as needed or upon request.

The Governance Committee of our Board oversees the ERM program, ensuring comprehensive oversight of our risk management activities. In addition, other Board committees oversee specific risk types within their mandates:

- 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 mitigating financial risk, including market risk, counterparty credit risk and cybersecurity risk.

Executive Leadership and Risk Management

Our Executive Leadership team is responsible for developing and implementing risk management plans and actions, with effective risk management reflected in their compensation. Each identified enterprise risk has a governance owner from the executive leadership team. Risk execution is overseen by an accountable Business Unit President or Senior Vice-President. These risk owners provide in-depth risk reviews to the Board annually.

Segment-Specific Risks

Key segment-specific financial, health, safety, and environment-related risks are covered in their respective sections of this MD&A. Further, our Report on Sustainability provides information on our approach to sustainability, including the oversight of sustainability-related risks and opportunities.

Enterprise Risk Monitoring and Key Risk Indicators

Risks related to our key enterprise risk themes are continuously monitored through our ERM program. The program includes a network of emerging risk liaisons strategically positioned across the organization, responsible for identifying potential enterprise-level risks and reporting them quarterly to the Board of Directors.

Additionally, as part of our ongoing commitment to enhancing the ERM program, we have identified and are adopting Key Risk and Performance Indicators (KRIs) for risk events that could impact our strategic objectives. These KRIs provide quantifiable metrics, objective rationale and meaningful trends for each enterprise risk, helping to inform the annual in-depth review of enterprise risks conducted by the Board.

Operational risk

TC Energy operates a vast natural gas transmission network across North America, including numerous facilities, gas storage reservoirs and power-generation plants. Operational risks include the potential for significant ruptures or failures, especially in regions where pipelines traverse populated areas. Key factors contributing to these risks include integrity threats such as corrosion, cracking and manufacturing defects. Additionally, aging infrastructure and the potential for extreme weather conditions and other external forces further increase the likelihood of significant ruptures or operational failures.

The consequences of a significant rupture or operational failure can be severe and multifaceted. Potential impacts include loss of human life or severe injuries, environmental damage and extensive operational disruptions. Financial repercussions are also considerable, encompassing costs related to incident response, repairs, fines and penalties. Furthermore, such incidents can lead to incremental regulatory enforcement and reputational harm, which may strain customer relationships and jeopardize future projects.

To ensure the safe and reliable operation of its assets, TC Energy employs a robust Operational Management System, TOMS, that integrates comprehensive risk management and asset integrity practices. Current measures include a quantitative operational risk assessment process, integrity management programs and advanced inline inspection technologies. We also conduct failure investigations and root cause analyses to drive continuous improvement. Governance and oversight by senior management, along with an Emergency Management Program, ensure preparedness and effective response to potential incidents. TOMS standards, processes and procedures are continually improved based on lessons learned from internal and external incidents, as well as collaborative work with industry peers and regulators.

Regulatory risk

TC Energy operates in a highly regulated industry across North America, requiring various permits and approvals from federal, state, provincial and local government agencies. The regulatory landscape is highly complex, with overlapping and sometimes conflicting requirements from various levels of government. Changes in government can further introduce uncertainty and delays in obtaining necessary permits. Additionally, opposition groups can influence regulatory decisions through organized protests, legal challenges and negative media campaigns.

Failure to obtain or maintain regulatory approvals for energy infrastructure projects can lead to substantial financial and operational consequences. These include delays or cancellations of critical projects, increased operating costs due to additional compliance requirements and disruptions to existing infrastructure. Financial impacts also encompass lost development costs, reduced investor confidence and higher capital costs. Moreover, negative publicity and public opposition can damage our reputation, erode public trust and hinder our ability to operate effectively. These challenges can ultimately affect our competitive position and ability to meet growth objectives.

To address this risk, we have implemented several monitoring and mitigation strategies. These include proactive efforts to monitor the evolving regulatory environment, engage in strategic advocacy across all levels of government, cultivate enduring trust and alignment with stakeholders and respond promptly to emerging issues and concerns. These activities are designed to secure necessary approvals to support our growth objectives and mitigate potential delays and disruptions.

Access to capital at a competitive cost

We require significant capital in the form of debt and equity to finance our growth projects and manage maturing debt obligations. It is essential that we secure this capital at costs lower than the returns on our investments. Deterioration in market conditions, changes in investor and lender sentiment, geopolitical instability, higher interest rates and persistent inflation could adversely affect our access to and cost of capital. Additionally, factors such as investor ESG exclusionary screening, capacity limitations in capital markets and economic uncertainties can further compound these risks, potentially leading to higher borrowing costs and constrained growth.

A higher cost of capital can negatively impact our ability to deliver attractive returns on investments and inhibit both short and long-term growth. This could adversely affect our earnings and undermine the viability of capital projects. Additionally, higher costs can negatively impact investor confidence, the reported value of assets and liabilities and our overall financial performance.

TC Energy employs a comprehensive strategy to monitor and mitigate these risks. Current mitigations include maintaining a high-quality and diversified banking syndicate, proactive engagement with lenders and credit rating agencies and balancing issuance strategies across multiple capital markets. We also actively manage our foreign exchange risk through hedging strategies and maintain a balanced debt portfolio to manage interest rate exposure. Ongoing mitigations involve developing new lending relationships and enhancing engagement with ESG-focused investors. Additionally, TC Energy continuously monitors government policies and industry developments to proactively address potential influences on capital flows.

Capital allocation

To remain competitive, TC Energy must provide essential energy infrastructure services in both supply and demand areas, offering solutions that appeal to our customers, while maintaining alignment with our strategic objectives. Capital allocation challenges include balancing investments to defend our existing footprint and service our customer base, investing in the highest-return, lowest-risk opportunities within our discretionary annual net capital limit and shaping the capital program to optimally utilize available capital. Additionally, there is a risk of diversifying into lower-carbon opportunities before they have adequately developed commercial and regulatory constructs.

Inefficient capital allocation can lead to the misallocation of financial resources to projects that do not align with our strategic objectives, increase exposure to high-risk projects and reduce financial performance. Additionally, failure to adapt to changing energy supply and demand fundamentals, including those related to lower-carbon forms of energy, may result in reputational damage, regulatory risks and the potential for stranded assets. Overall, these risks can cause strategic misalignment and diminish shareholder value.

We have a rigorous governance process to maintain capital allocation discipline. We limit annual net capital expenditures and high-grade our project development pipeline for purposes of pursuing lower risk and higher value opportunities. We also conduct analyses to confirm the resilience of the supply and demand markets we serve as part of our strategic reviews and regularly monitor industry trends and regulatory developments. Continuous improvements to the capital allocation process include enhanced investment review and due diligence, as well as conducting long-term scenario analyses to understand the portfolio effects of capital allocation choices.

Capital recovery risk

Capital recovery risk pertains to the challenge of both earning an acceptable return on invested capital and recovering the initial investment. This risk arises from potential misalignment between deal structures and our risk preferences, leading to capital exposure. Key contributors include inadequate risk assessments, difficulties in stakeholder collaboration, unforeseen changes in project scope or environment, financial constraints, macroeconomic volatility, counterparty risk and evolving public policy. Collectively, these factors threaten our financial stability and strategic objectives.

The inability to recover a return on capital can lead to unexpected capital expenditures, significant financial losses and reduced returns. It can erode trust and credibility with partners, investors, regulators and other key stakeholders. Additionally, poorly structured deals may divert management's focus from core business activities to address arising issues, further impacting operational efficiency. The broader consequences include potential damage to our reputation and investor confidence, which are crucial for sustaining long-term growth and stability and preserving shareholder value.

TC Energy employs a robust due diligence process that includes comprehensive risk assessments and detailed contract negotiations. Continuous monitoring of risk exposures and mitigation measures is conducted throughout the lifecycle of each deal, high-grading our project development pipeline to the lowest-risk, highest value opportunities. Proactive engagement with counterparties and strategic partnerships helps manage and share risks effectively. Depreciation is recovered through regulated pipeline rates, allowing us to accelerate or decelerate the return of capital from our assets. Additionally, we leverage our diversified asset base and long-term contracts to stabilize cash flows and reduce exposure to market volatility.

Project execution

Investing in large infrastructure projects requires significant capital commitments and carries considerable project execution risks. Potential shortages of skilled labour and expertise, supply chain lead times and disruptions and increasing project and regulatory complexity are among these risks. Collectively, these factors can lead to cost overruns, schedule delays, suboptimal project performance and increased safety vulnerabilities, ultimately impacting our financial performance, reputation and strategic growth.

Failure to effectively manage these risks can result in significant financial and operational consequences. Cost overruns and schedule delays can undermine the profitability and feasibility of projects, leading to increased contractual claims and disputes. Additionally, inadequate project execution can damage our reputation, reduce investor confidence and hinder future growth opportunities.

To help mitigate these risks, our Project Delivery System is integrated with our capital allocation process and is aligned with TOMS, optimizing project execution for safe, timely and on-budget performance. We develop projects to a sufficient maturity level to fully understand scope, cost, schedule and execution risk prior to sanctioning. This approach enables us to identify and consult stakeholders and proactively address project-specific constraints and risks. Commercial contracts are structured to recover development costs and minimize the impact of potential cost overruns, explicitly sharing execution risk where warranted. Additionally, we leverage project financing and partner involvement to manage capital at risk.

Talent risk

TC Energy's success hinges on attracting, retaining and developing a talented workforce with a deep understanding of the energy industry, geopolitical environment and various regulatory regimes across North America. Key talent-related risks include the loss of critical personnel, difficulties in securing and retaining talent in a highly competitive market and health and wellness issues that could impact workforce productivity.

Failure to manage talent-related risk can lead to several adverse outcomes, including a decline in employee morale and engagement, resulting in reduced productivity, efficiency and quality of work. High resignation rates, particularly among top talent, can disrupt operations and continuity, leading to increased recruitment and training costs. The organization may also face reputational damage if perceived as failing to address employee concerns, impacting its ability to attract and retain future talent. Furthermore, operational disruptions and a disengaged workforce can pose health and safety risks, ultimately affecting our overall performance and strategic execution.

To mitigate these risks, TC Energy employs a comprehensive talent risk management framework to assess needs and prioritize initiatives. We focus on employee development, engagement and well-being to foster a positive work environment and retain top talent. Our company-wide Pay Equity Plan promotes fairness in compensation practices, while our succession planning process ensures a steady pipeline of talented individuals are prepared to assume critical roles. Regular employee engagement surveys provide valuable insights and inform targeted recommendations. Additionally, we have integrated Diversity, Equity and Inclusion initiatives into our talent management strategies and implemented a hybrid work schedule to offer greater flexibility. Collectively, this approach promotes employee retention, minimizes the impact of potential talent losses and guides targeted development actions.

Enterprise security

Ensuring the security of our stakeholders, staff, and our digital and physical assets is paramount to maintaining the safety and reliability of our operations. Security risks encompass potential cyberattacks on industrial control systems and corporate digital assets, unauthorized data disclosures and physical attacks on our infrastructure. These risks are heightened by the increasing sophistication of cyber tactics, rising geopolitical tensions and the critical nature of our infrastructure.

A security incident can result in the misuse or disruption of critical information and functions, cause damage to our assets and potentially lead to safety and/or environmental incidents and inability to provide services. Resulting service interruptions may have cascading effects on supply chains, customer relationships and strategic goals. Additionally, such incidents can harm our reputation and trigger regulatory enforcement actions or litigation, negatively impacting our operations and/or financial position.

TC Energy maintains an enterprise security program covering cyber and physical security. Our program is based on standards, assurance, risk management and prevention and mitigation activities. Our cyber and physical security risk preventative efforts include deploying security technology, defining secure processes, enhanced security measures for high-risk staff or facilities, and cyber and physical security awareness programs. Our mitigative activities include proactive monitoring for and responding to potential security incidents. We also maintain and regularly test incident response plans to manage and mitigate the impact of potential security incidents including cyberattacks. To further mitigate potential risks, we maintain appropriate insurance coverage against cyber and physical security incidents. To mitigate risks associated with third-party vendors and suppliers, we conduct vendor risk assessments which includes risk assessments focused on security standards, contractual safeguards, and ongoing monitoring.

We collaborate with government security agencies, law enforcement, and industry to stay informed and be proactive on evolving threats. Our prevention and mitigation strategies for both cyber and physical security are regularly reviewed and updated to align with regulatory and industry standards. The status of our enterprise security program is reported to the Audit Committee quarterly.

TC Energy remains committed to continually improving our security posture and adapting to the ever-evolving threat landscape. By prioritizing security and investing in technologies and practices, we strive to protect our stakeholders, staff, assets, operations, and ensure the long-term sustainability of our business.

Climate-related risks

Our business, operations, financial condition and performance may be impacted by both the physical risks associated with climate change and the transition risks arising from the global transition to a lower-carbon economy. Climate-related risks, including climate policy and related developments, may intersect with and influence the enterprise risks outlined above. Therefore, these risks are systematically considered and assessed as part of the Enterprise Risk Management Framework.

Physical Risks

Climate change has the potential to create both acute and chronic physical risks that can negatively impact our operations. Acute physical risks could include extreme weather events such as hurricanes, wildfires and floods, whereas chronic physical risks could include longer-term shifts in climate patterns, temperature, precipitation and sea levels. Due to the complex nature of climate systems, it is difficult to predict the timing, frequency or severity of such events.

The physical risks from climate change could have significant financial implications, such as unexpected costs resulting from direct damage to our assets, loss of revenues due to business interruption or indirect effects such as value chain disruption. To mitigate these physical risks, we take climate change into account in the design and evaluation of our facilities and operating assets. Our engineering standards are regularly reviewed to ensure assets continue to be designed and operated to withstand the potential impacts of climate change. Additionally, our emergency response plans focus on quickly and effectively responding to severe weather events to minimize impacts.

As a further risk mitigation measure, we maintain insurance coverage to reduce the financial impact associated with damage to our assets due to extreme weather events. We may experience an increase in insurance premiums and deductibles, or a decrease in available coverage for our assets in areas subject to severe weather.

Transition Risks

Transition risks arise from the global shift to a lower-carbon 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-carbon economy. Financial implications from transition risks could include asset impairments due to new or amended climate-related regulations, 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, insolvency of our significant customers and the development and deployment of new technologies.

Our exposure to climate-related transition risks and resulting policy changes is mitigated through our long-term, low-risk business strategy whereby much of our earnings are underpinned by regulated cost-of-service arrangements and/or long-term contracts with credit-worthy counterparties. Additional information on how we manage climate-related risks and opportunities can be found in the comprehensive TCFD and IFRS S2 alignment sections of our annual Report on Sustainability.

Health, safety, sustainability and environmental matters

The Board's HSSE Committee oversees operational risk, major project execution risk, occupational and process safety, sustainability, security of personnel, environmental and climate-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, the U.S. and Mexico throughout the lifecycle of our assets and employs a continuous improvement cycle. The TOMS framework leverages continuous improvement through an annual management review process. This ensures the ongoing effectiveness of our overarching management system and supports a tiered assurance structure across all business units. The TC Energy assurance model is designed to provide effective management of health, safety, environmental, and operational integrity risks. Lessons learned are consistently shared and applied across our system where applicable. Additionally, any findings or insights from periodic audits conducted by our external regulators are also shared across the elements of our management system to ensure continuous improvement.

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-related risks and opportunities, as well as related non-regulatory public disclosures such as our annual Report on Sustainability and our Reconciliation Action Plan.

There are two separate committees that report to the Board HSSE Committee:

- a Sustainability Management Committee, comprised of senior leaders, that provides strategic leadership and direction on environmental, social and governance issues to integrate sustainability principles across the company’s operations and projects
- an Operating Committee that is comprised of senior leaders, that is responsible for making enterprise decisions in support of safety improvements, management system governance and operational risk management.

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 2024, we spent $2.0 billion (2023[1] – $2.0 billion) for pipeline integrity on the natural gas 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. 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, Business Continuity and Security element 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.

[1] Prior year results have been recast to reflect continuing operations only.

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 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.

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, 2024, accruals related to these obligations totaled $8 million (2023 – $19 million) representing the estimated amount we will need to manage our currently known material environmental liabilities. We believe we have considered all necessary contingencies and established appropriate reserves for environmental liabilities; however, a risk exists that unforeseen matters may arise requiring us to set aside additional amounts. We adjust reserves regularly to account for changes in liabilities.

Climate change and related regulation

We own assets and have business interests in a number of regions subject to GHG emissions regulations, including GHG emissions management and carbon pricing policies. In 2024, we incurred $141 million (2023 – $109 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, participate in the regulatory review process as appropriate and submit formal comments to regulators as initiatives are undertaken and as policies are implemented. We support transparent climate change policies that promote environmentally and economically responsible natural resource development. Our assets in specific geographies are currently subject to GHG regulations. While near-term government policy objectives may influence the pace of GHG regulations, 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 more stringent 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:* The Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (VOCs) took effect in January 2020 to reduce the oil and gas sector's methane emissions by 40 to 45 per cent below 2012 levels by 2025. Alberta, British Columbia and Saskatchewan have released their own methane regulations that replace the federal regulations for provincially-regulated assets. For federally-regulated facilities in these jurisdictions, the federal methane regulations are applicable. Compliance with the regulations requires leak detection and repair (LDAR) surveys and a reduction of vented emissions from specific equipment. Power facilities are not affected by this regulation at the current time
- *Federal:* The Federal OBPS regulation imposes carbon pricing for larger industrial facilities and sets federal benchmarks for GHG emissions for various industry sectors. This regulation applies to our assets in 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 through tolls. In 2024, the carbon price was $80/tonne, currently scheduled to increase by $15/tonne every year to $170/tonne in 2030
- *Federal:* On December 19, 2024, ECCC published the final Clean Electricity Regulations (CERs), targeting a net-zero electricity system by 2050. The CERs mandate an annual GHG emissions limit based on 65 tonnes CO_2/GWh for fossil fuel power generation units with a capacity of 25 MW or more starting in 2035 and 0 tonnes CO_2/GWh in 2050. Though there are limited compliance flexibilities, concerns persist on the CERs' potential effect on energy affordability and reliability in certain jurisdictions. We continue to evaluate the operational and financial impact on our cogeneration fleet
- *British Columbia:* As of April 2024, British Columbia implemented a provincial OBPS in place of the carbon tax, for taxing GHG emissions from fossil fuel combustion at industrial facilities. The B.C. OBPS applies to our assets in British Columbia and compliance costs are recovered through tolls. With the implementation of the B.C. OBPS, the CleanBC Industrial Incentive Program, which offered carbon tax rebates to low emitting industrial facilities, will be phased out as of 2025
- *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 a portion of Bécancour's compliance requirements. The remaining requirements are 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 to comply with the WCI requirements with these compliance costs being recovered through tolls
- *Ontario:* 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:* The Federal OBPS in Saskatchewan was replaced on January 1, 2023 by the Saskatchewan Output-Based Performance Standard program for pipeline transmission sector assets. The regulation applies 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 2022 (OOOOb) and establishes emission guidelines (EGs) for existing sources prior to December 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 will be subject to the requirements of yet to be issued state EG proposals and actual compliance deadlines, which will vary based on state and/or location
- *Federal:* The USEPA "Good Neighbor Plan", effective August 2023, sets new limits for emissions of nitrogen oxides (NOx) from reciprocating internal combustion engines (RICE) by May 2026. The rule could cost TC Energy over US$500 million in mitigation measures, but Federal Circuit courts have granted stays in 12 states, including eight states in which TC Energy has affected RICE, reducing our compliance obligations pending the outcomes of these proceedings. Additionally, TC Energy, among other peer companies and industry groups, is party to ongoing legal proceedings in the D.C. Circuit and on June 27, 2024, the Supreme Court granted a nationwide emergency stay of the Rule that will last for the duration of the pending litigation in the D.C. Circuit and until the Supreme Court resolves petitions for certiorari (if any are filed). The D.C. Circuit is expected to issue a final decision in the second half of 2025. If the rule is ultimately upheld, the USEPA is expected, but not required, to provide industry with additional time beyond its May 1, 2026 compliance deadline to come into compliance
- *Federal*: USEPA finalized changes to the Greenhouse Gas Reporting Program (GHGRP) for how oil and gas sources tally and report their methane emissions (Subpart W) on May 6, 2024. The Final Rule finalizes previously proposed GHGRP amendments and also addresses USEPA's mandate, as defined in the Inflation Reduction Act (IRA), to amend Subpart W for the purposes of improving methane emission estimates associated with the IRA waste emissions charge for natural gas operations. USEPA did not finalize changes in the GHGRP for how oil and gas sources tally and report their energy consumption (Subpart B) via a final rule at this time. The Final Rule effects various changes that would add new reporting sources, modify calculation and reporting methodologies and drive more granular data collection. The Final Rule is still being assessed, but the methodological changes could result in material changes to TC Energy's publicly reported emissions
- *Federal:* The IRA was passed and signed into law in August 2022. The IRA instructed 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. In response, on November 8, 2024, USEPA finalized a rule to implement the methane Waste Emissions Charge ("WEC") program. 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 WEC 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 be no fee impact to TC Energy based on 2023 emissions. Over the longer term, potential WEC liability is expected to be low as U.S. natural gas facilities are anticipated to become eligible for a regulatory exemption afforded by compliance with the Methane Rule
- *California:* On September 27, 2024, California signed into law bill SB-219, which amends portions of Sections 38532 and 38533 of the California Health and Safety Code that were established in previous bills SB-253 and SB-261. SB-253 and SB-261 require public and private U.S. companies that perform certain business activities in California to disclose their GHG emissions and climate-related financial risks, respectively. Entities within the scope of SB-261 must prepare and make available on their public websites a climate-related financial risk report by January 1, 2026. Applicability to TC Energy is under evaluation

- *California:* California Air Resource Board has revised Subarticle 13 of the Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities. The regulation applies to three Tuscarora facilities. The revised regulation required a new LDAR monitoring plan by July 1, 2024. The regulation also now requires monitoring and repair of components less than or equal to 0.5 inch and added new requirements for remotely detected plumes
- *California:* 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. However, power trading activities in the state do trigger compliance thresholds. These requirements are met with GHG instruments purchased at auctions or secondary markets
- *Pennsylvania:* The Pennsylvania Department of Environmental Protection has an LDAR program for new source installations which require leak repair within 15 days of discovery
- *Ohio:* Effective March 2022, the Ohio Environmental Protection Agency (OEPA) finalized Reasonable Available Control Technologies (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
- *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 first base compliance obligation for 2023 and projected obligation for 2024. Electricity imports are also covered under the CIP, however these remained below compliance thresholds in 2024
- *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, reporting of pigging activities, as well as a baseline inventory for all assets in New York
- *Michigan:* In April 2023, the Michigan Department of Environment, Great Lakes and Energy (EGLE) published its final RACT requirements and emission limitations for major stationary sources of VOCs in specific counties of the state (2015 ozone non-attainment area). Specifically, storage vessels at two ANR compressor stations are impacted by this rule. Future storage vessels installed at compressor stations in specific counties in the state may require additional controls depending on their size and throughput.

Mexico jurisdictions

- *Federal:* 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 GHG emissions 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. The LGCC has the objective to reduce national emissions, through policies and programs that promote the transition to a sustainable, competitive and lower-carbon economy, including market instruments, incentives and other alternatives that improve the cost-efficiency of specific mitigation measures, reducing their economic costs and promoting competitiveness, technology transfer and the promotion of technological development. This law requires annual reporting of our GHG emissions

- *Federal:* The Government of Mexico published a regulation in 2018 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
- *Federal*: 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 functioned 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. The Emission Rights Tracking System is the electronic platform where the emission rights and compensation credits are issued, transacted and cancelled, through which the participants interact to fulfill their obligations. It has already been formally established and it is possible that we will have to participate as a company if we exceed 100 ktCO_2e in any of our systems. However, currently all our systems in Mexico are below the emissions threshold, so this instrument has not been used
- *Federal:* The Mexican accounting and sustainability standard setter, Consejo Mexicano de Normas de Información Financiera y Sostenibilidad (CINIF), published the Mexican sustainability standards (Normas de Información de Sostenibilidad or NIS) applicable to all private entities that report their financial statements under Mexican Financial Reporting Standards. The NIS requires the disclosure of 30 sustainability indicators across environmental, social and governance topics for fiscal years beginning on or after January 1, 2025. These requirements will apply to certain TC Energy Mexican entities.

Anticipated policies

Canadian jurisdictions

- *Federal:* ECCC committed to expand on the current methane reduction regulations and released draft amendments in December 2023 to reduce the 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 participated in the 2024 public consultation process and provided recommendations, in collaboration with industry associations. 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:* On November 9, 2024, ECCC published draft Oil and Gas Sector Greenhouse Gas Emissions Cap Regulations. The draft regulations introduce a cap-and-trade system to reduce GHG emissions from the oil and gas sector, covering upstream activities and LNG production. The initial 2030-2032 compliance period will limit emissions to 27 per cent below 2026 emissions levels with some limited compliance flexibilities. Canada would be the first major oil and gas producing country to impose such limits. Although transmission pipelines are excluded from the draft regulations, there is a possibility of cascading effects and unintended consequences to our business. The draft regulations are set to be finalized in 2025 and phased-in between 2026-2029. We continue to monitor, assess and provide feedback to ECCC, as appropriate
- *British Columbia:* The BC Energy Regulator is implementing amended regulations effective January 1, 2025 to further reduce methane emissions from the province's upstream oil and gas sector, in support of the CleanBC Roadmap to 2030 target of a 75 per cent reduction. The amendments update the Drilling and Production Regulation, Oil and Gas Processing Facility Regulation and Pipeline Regulation under the Energy Resource Activities Act. These amendments will be applicable to Coastal GasLink operations.

U.S. jurisdictions

- *Federal:* The U.S. Senate passed the PHMSA reauthorization bill, the PIPES Act of 2020, which required PHMSA 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 Methane Rule requirements. The cost of compliance due to the proposed PHMSA regulations is subject to issuance of a final rule, which remains pending, but is expected to increase significantly due to new monitoring and repair requirements applicable to the entire natural gas transmission system. On January 17, 2025, PHMSA transmitted the final rule to the Federal Register; however, it was not published prior to the inauguration of the incoming administration. On January 20, 2025, an Executive Order was issued placing a freeze on all pending regulations not published to the Federal Register for review. At this time, the final release date of the Leak Detection and Repair Rule is uncertain. TC Energy will continue to monitor the potential outcome of the regulations following federal direction and additional industry level discussions
- *Federal:* On November 22, 2024, the USEPA proposed amendments to the Standards of Performance for new, modified, and reconstructed stationary gas turbines (under 40 CFR Part 60, Subpart KKKKa). These amendments aim to limit emissions of criteria air pollutants, particularly nitrogen oxide (NOx), by establishing size-based subcategories and recognizing distinctions between turbines operating at varying loads or capacity factors. The USEPA also proposes that the best system of emission reduction for NOX emissions includes combustion controls with post-combustion selective catalytic reduction ("SCR"). Potential impacts to TC Energy could include additional costs for installation of SCR and other ancillary costs for operational maintenance for new gas turbines that operate at low temperatures and high utilization. However, the proposed rule is still being assessed, and there is currently no effective date for the proposed rule
- *Michigan:* The Michigan Department of Environment, Great Lakes and Energy (EGLE) is currently evaluating RACT requirements and emission limitations for major stationary sources of NOx in specific counties of the state (2015 ozone non-attainment area). This will lead to the development of laws and regulations that affect TC Energy through impacted ANR and Great Lakes facilities in the state
- *New York:* 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 is anticipated to set an annual cap on the amount of GHG emissions that are permitted to be emitted in the state. Publication of a draft rule was expected in early 2025, but on January 15, 2025, New York Governor Hochul announced a pause to allow for additional information gathering and enhanced engagement, such that a compliance commencement date is indeterminate at this time. NYCI will potentially impact TC Energy owned/operated assets in New York, but impacts will be further evaluated once a draft rule is published
- *Oregon:* The state has reintroduced rules for its Climate Protection Plan. The previous version was struck down by a state court on technical grounds. Like the previous rule, the draft language appears to exclude TC Energy emissions in the state, as it would exempt "Emissions from an air contamination source that is owned or operated by an interstate natural gas pipeline and that is operating under authority of a certificate of public convenience and necessity issued by the Federal Energy Regulatory Commission".

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. USEPA finalized the rule in August 2023 and the rule became effective February 26, 2024. We will continue to assess the impact of the rule on future projects on a case-by-case basis, which will depend on the site- and project-specific considerations and remediation efforts on each project.

In addition to the policies 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

- In 2024, the Government of Canada passed Bill C-59 including a provision to amend the Competition Act targeting unsubstantiated claims about the environmental benefits of products or business activities, commonly known as "greenwashing." The Bill C-59 greenwashing provision affects a wide range of industries and companies, including TC Energy. Following the passage of Bill C-59, the Competition Bureau of Canada conducted a public consultation on implementation guidance and enforcement of the greenwashing provision. TC Energy participated in the public consultation process and will continue to seek clarity on how the new legislation will be interpreted and applied.

There are other sustainability-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 power business, 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 or 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 (loss) from equity investments and Income tax expense (recovery) in the Consolidated statement of income.

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
- 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, 2024 and 2023, we had no significant credit risk concentrations, with the exception of the CFE, which represents approximately 33 per cent of the gross exposure. Gross exposure is measured as the unmitigated full-term contract revenue exposure discounted in accordance with each contract’s discount rate, as applicable. At this time, there were no significant amounts past due or impaired. We recorded a pre-tax recovery of $22 million for the year ended December 31, 2024 on the expected credit loss provision before tax recognized on TGNH net investment in leases and certain contract assets in Mexico (2023 – $80 million recovery). Other than the expected credit loss provision noted above, we had no significant credit losses at December 31, 2024 and 2023. Refer to Note 28, Risk management and financial instruments, of our 2024 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 to determine if they meet the requirements for disclosure or accrual of a contingent loss. With the potential exception of the matters discussed in Note 31, Commitments, contingencies and guarantees, of our 2024 Consolidated financial statements, 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. The claims discussed in Note 31, Commitments, contingencies and guarantees, are material and there is a reasonable possibility of loss; however, they have not been assessed as probable and a reasonable estimate of loss cannot be made.

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, 2024, 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, 2024, 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, 2024, the internal control over financial reporting was effective.

Our internal control over financial reporting as of December 31, 2024 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their attestation report which is included in our 2024 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 2024 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.

On October 1, 2024, we completed the Spinoff Transaction. In connection with the Spinoff Transaction, the internal controls associated with the Liquids Pipelines business were transferred to South Bow. We are contractually obligated to maintain adequate controls post-spinoff for the provision of services under the Transition Services Agreement.

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 2024 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.

In the determination of the fair value utilized in the quantitative goodwill impairment test performed in 2023 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.

In March 2022, an impairment loss was recognized for the excess carrying value over the estimated fair value of our Great Lakes reporting unit. There is a risk that reductions in future cash flow forecasts and adverse changes in other key assumptions could result in future impairment of the remaining goodwill balance.

Qualitative goodwill impairment indicators

As part of the annual goodwill impairment assessment at December 31, 2024, we evaluated qualitative factors impacting the fair value of the underlying reporting units. It was determined that it was more likely than not that the fair value of these reporting units exceeded their carrying amounts, including goodwill.

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 $)	**2024**	**2023**
Other current assets	**347**	589
Other long-term assets	**122**	155
Accounts payable and other	**(507)**	(415)
Other long-term liabilities	**(209)**	(106)
	(247)	223

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, 2024 (millions of $)	**Total fair value**	**< 1 year**	**1 - 3 years**	**4 - 5 years**	**> 5 years**
Derivative instruments held for trading	(122)	(147)	3	25	(3)
Derivative instruments in hedging relationships	(125)	(15)	(35)	(42)	(33)
	(247)	(162)	(32)	(17)	(36)

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 $)	2024	2023	2022
Derivative Instruments Held for Trading[1]			
Unrealized gains (losses) in the year			
Commodities	**(71)**	132	(11)
Foreign exchange	**(266)**	246	(149)
Interest rate	**(71)**	—	—
Realized gains (losses) in the year			
Commodities	**199**	192	46
Foreign exchange	**(152)**	155	(2)
Interest rate	**29**	—	—
Derivative Instruments in Hedging Relationships[2]			
Realized gains (losses) in the year			
Commodities	**33**	(2)	(73)
Interest rate	**(52)**	(43)	(3)

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. Realized and unrealized gains (losses) on interest rate derivatives are included on a net basis in Interest expense in the Consolidated statement of income.

2 In 2024, unrealized gains of $6 million were reclassified to Net Income (loss) from AOCI related to discontinued cash flow hedges (2023 and 2022 – nil).

For further details on our non-derivative and derivative financial instruments, including classification assumptions made in the calculation of fair value and additional discussion of exposure to risks and mitigation activities, refer to Note 28, Risk management and financial instruments, of our 2024 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.

We have a subordinated loan agreement with Coastal GasLink LP under which we advance non-revolving interest-bearing loans subject to floating market-based rates. In December 2024, following the commercial in-service of the pipeline, Coastal GasLink LP repaid the $3,147 million balance outstanding to TC Energy under the subordinated loan agreement. This repayment reduced our funding commitment under the subordinated loan agreement to $228 million at December 31, 2024.

We also have a subordinated demand revolving credit facility agreement with Coastal GasLink LP to provide additional short-term liquidity and funding flexibility to projects under construction.

Refer to Note 7, Coastal GasLink, of our 2024 Consolidated financial statements for additional information about Coastal GasLink LP related party transactions.

Sur de Texas

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

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

year ended December 31 (millions of $)	**2024**	**2023**	**2022**	**Affected line item in the Consolidated statement of income**
Interest income[1]	—	—	19	Interest income and other
Interest expense[2]	—	—	(19)	Income (loss) from equity investments
Foreign exchange losses[1]	—	—	(28)	Foreign exchange (gains) losses, net
Foreign exchange gains[1]	—	—	28	Income (loss) 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 2024 Consolidated financial statements.

QUARTERLY RESULTS

Selected quarterly consolidated financial data

2024 (millions of $, except per share amounts)	Fourth	Third[1]	Second[1]	First[1]
Revenues from continuing operations	**3,577**	**3,358**	**3,327**	**3,509**
Net income (loss) attributable to common shares	**971**	**1,457**	**963**	**1,203**
from continuing operations	1,069	1,349	793	988
from discontinued operations[2]	(98)	108	170	215
Comparable earnings[3]	**1,094**	**1,074**	**978**	**1,284**
from continuing operations	1,094	905	811	1,055
from discontinued operations[2]	—	169	167	229
Share statistics:				
Net income (loss) per common share – basic	**$0.94**	**$1.40**	**$0.93**	**$1.16**
from continuing operations	$1.03	$1.30	$0.77	$0.95
from discontinued operations[2]	($0.09)	$0.10	$0.16	$0.21
Comparable earnings per common share[3]	**$1.05**	**$1.03**	**$0.94**	**$1.24**
from continuing operations	$1.05	$0.87	$0.78	$1.02
from discontinued operations[2]	—	$0.16	$0.16	$0.22
Dividends declared per common share[4]	**$0.8225**	**$0.96**	**$0.96**	**$0.96**

1 Prior quarter results have been recast to reflect the split between continuing and discontinued operations.
2 Represents nine months of Liquids Pipelines earnings in 2024.
3 Additional information on the most directly comparable GAAP measure can be found on page 24.
4 Dividends declared in fourth quarter 2024 reflect TC Energy's proportionate allocation following the Spinoff Transaction. Refer to the Discontinued operations section for additional information.

2023[1] (millions of $, except per share amounts)	Fourth	Third	Second	First
Revenues from continuing operations	3,504	3,225	3,148	3,390
Net income (loss) attributable to common shares	1,463	(197)	250	1,313
from continuing operations	1,249	(325)	76	1,217
from discontinued operations[2]	214	128	174	96
Comparable earnings[3]	1,403	1,035	981	1,233
from continuing operations	1,192	848	767	1,089
from discontinued operations[2]	211	187	214	144
Share statistics:				
Net income (loss) per common share – basic	$1.41	($0.19)	$0.24	$1.29
from continuing operations	$1.20	($0.31)	$0.07	$1.19
from discontinued operations[2]	$0.21	$0.12	$0.17	$0.10
Comparable earnings per common share[3]	$1.35	$1.00	$0.96	$1.21
from continuing operations	$1.15	$0.82	$0.75	$1.07
from discontinued operations[2]	$0.20	$0.18	$0.21	$0.14
Dividends declared per common share	$0.93	$0.93	$0.93	$0.93

1 Prior year results have been recast to reflect the split between continuing and discontinued operations.
2 Represents a full year of Liquids Pipelines earnings in 2023.
3 Additional information on the most directly comparable GAAP measure can be found on page 24.

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.

As discussed on page 10 of the About this document section, results of the Liquids Pipelines business were accounted for as a discontinued operation starting October 1, 2024. To allow for a meaningful comparison, discussions throughout the Quarterly results section are based on continuing operations unless otherwise noted. Prior year results have been recast to reflect the split between continuing and discontinued operations. Discontinued operations reflect nine months of Liquids Pipelines earnings for the year ended December 31, 2024 compared to a full year of Liquids earnings in 2023. Refer to the Discontinued operations section for additional information.

In our Natural Gas Pipelines business, 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 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. Refer to page 24 for more information on non-GAAP measures we use.

In fourth quarter 2024, comparable earnings from continuing operations also excluded:

- a pre-tax net gain on debt extinguishment of $228 million (after-tax $178 million) related to the purchase and cancellation of certain senior unsecured notes and medium term notes and the retirement of outstanding callable notes in October 2024
- pre-tax unrealized foreign exchange gains, net of $143 million (after-tax $153 million) on the peso-denominated intercompany loan between TCPL and TGNH, net of non-controlling interest
- a pre-tax recovery of $3 million (after-tax $2 million) on the expected credit loss provision related to TGNH net investment in leases and certain contract assets in Mexico, net of non-controlling interest
- a deferred income tax expense of $96 million resulting from the revaluation of remaining deferred tax balances following the Spinoff Transaction
- a pre-tax impairment charge of $36 million (after-tax $27 million) related to development costs incurred on Project Tundra, a next-generation technology carbon capture and storage project, following our decision to end our collaboration on the project
- a pre-tax expense of $9 million (after-tax $7 million) related to Focus Project costs.

In third quarter 2024, comparable earnings from continuing operations also excluded:
- a pre-tax gain of $572 million (after-tax $456 million) related to the sale of PNGTS which was completed on August 15, 2024
- pre-tax unrealized foreign exchange losses, net, of $52 million (after-tax $52 million) on the peso-denominated intercompany loan between TCPL and TGNH, net of non-controlling interest
- a pre-tax expense of $5 million (after-tax $4 million) on the expected credit loss provision related to TGNH net investment in leases and certain contract assets in Mexico, net of non-controlling interest
- a pre-tax expense of $5 million (after-tax $3 million) related to Focus Project costs.

In second quarter 2024, comparable earnings from continuing operations also excluded:
- a pre-tax gain of $48 million (after-tax $63 million) related to the sale of non-core assets in U.S. Natural Gas Pipelines and Canadian Natural Gas Pipelines
- pre-tax unrealized foreign exchange losses, net of $3 million (after-tax $3 million) on the peso-denominated intercompany loan between TCPL and TGNH, net of non-controlling interest
- a pre-tax recovery of $3 million (after-tax $2 million) on the expected credit loss provision related to TGNH net investment in leases and certain contract assets in Mexico, net of non-controlling interest
- pre-tax costs of $10 million (after-tax $42 million) related to the NGTL System Ownership Transfer.

In first quarter 2024, comparable earnings from continuing operations also excluded:
- pre-tax unrealized foreign exchange gains, net of $55 million (after-tax $55 million) on the peso-denominated intercompany loan between TCPL and TGNH
- a pre-tax recovery of $21 million (after-tax $15 million) on the expected credit loss provision related to TGNH net investment in leases and certain contract assets in Mexico
- a pre-tax expense of $34 million (after-tax $26 million) related to a non-recurring third-party settlement
- a pre-tax expense of $10 million (after-tax $8 million) related to Focus Project costs.

In fourth quarter 2023, comparable earnings from continuing operations 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
- pre-tax unrealized foreign exchange losses, net of $55 million (after-tax $55 million) on the peso-denominated intercompany loan between TCPL and TGNH
- a pre-tax expense of $36 million (after-tax $25 million) on the expected credit loss provision related to TGNH net investment in leases and certain contract assets in Mexico
- a pre-tax expense of $15 million (after-tax $9 million) related to Focus Project costs.

In third quarter 2023, comparable earnings from continuing operations also excluded:
- a pre-tax impairment charge of $1,244 million (after-tax $1,179 million) related to our equity investment in Coastal GasLink LP
- a pre-tax expense of $18 million (after-tax $14 million) related to Focus Project costs
- pre-tax net unrealized foreign exchange gains, net of $20 million (after-tax $20 million) on the peso-denominated intercompany loan between TCPL and TGNH
- a pre-tax recovery of $1 million (nil after tax) on the expected credit loss provision related to TGNH net investment in leases and certain contract assets in Mexico.

In second quarter 2023, comparable earnings from continuing operations also excluded:
- a pre-tax impairment charge of $843 million (after-tax $809 million) related to our equity investment in Coastal GasLink LP
- a pre-tax expense of $32 million (after-tax $25 million) related to Focus Project costs
- pre-tax unrealized foreign exchange losses, net of $9 million (after-tax $9 million) on the peso-denominated intercompany loan between TCPL and TGNH
- a pre-tax recovery of $11 million (after-tax $8 million) on the expected credit loss provision related to TGNH net investment in leases and certain contract assets in Mexico.

In first quarter 2023, comparable earnings from continuing operations also excluded:
- a pre-tax recovery of $104 million (after-tax $72 million) on the expected credit loss provision related to TGNH net investment in leases and certain contract assets in Mexico
- a pre-tax impairment charge of $13 million (after-tax $29 million) related to our equity investment in Coastal GasLink LP.

FOURTH QUARTER 2024 HIGHLIGHTS

Consolidated results

three months ended December 31 (millions of $, except per share amounts)	2024	2023[1]
Canadian Natural Gas Pipelines	**506**	692
U.S. Natural Gas Pipelines	**918**	955
Mexico Natural Gas Pipelines	**214**	150
Power and Energy Solutions	**276**	263
Corporate	**(16)**	(34)
Total segmented earnings (losses)	**1,898**	2,026
Interest expense	**(679)**	(777)
Allowance for funds used during construction	**233**	132
Foreign exchange gains (losses), net	**(69)**	89
Interest income and other	**120**	119
Income (loss) from continuing operations before income taxes	**1,503**	1,589
Income tax (expense) recovery from continuing operations	**(223)**	(188)
Net income (loss) from continuing operations	**1,280**	1,401
Net income (loss) from discontinued operations, net of tax[2]	**(98)**	214
Net income (loss)	**1,182**	1,615
Net (income) loss attributable to non-controlling interests	**(183)**	(128)
Net income (loss) attributable to controlling interests	**999**	1,487
Preferred share dividends	**(28)**	(24)
Net income (loss) attributable to common shares	**971**	1,463
Net income (loss) per common share – basic	**0.94**	1.41
from continuing operations	**$1.03**	$1.20
from discontinued operations[2]	**($0.09)**	$0.21

1 Prior year results have been recast to reflect the split between continuing and discontinued operations.
2 The Liquids Pipelines business was accounted for as a discontinued operation starting October 1, 2024. Refer to the Discontinued operations section for additional information.

three months ended December 31 (millions of $)	2024	2023[1]
Amounts attributable to common shares		
Net income (loss) from continuing operations	**1,280**	1,401
Net income (loss) attributable to non-controlling interest	**(183)**	(128)
Net income (loss) attributable to controlling interests from continuing operations	**1,097**	1,273
Preferred share dividends	**(28)**	(24)
Net income (loss) attributable to common shares from continuing operations	**1,069**	1,249
Net income (loss) from discontinued operations, net of tax[2]	**(98)**	214
Net income (loss) attributable to common shares	**971**	1,463

1 Prior year results have been recast to reflect the split between continuing and discontinued operations.
2 The Liquids Pipelines business was accounted for as a discontinued operation starting October 1, 2024. Refer to the Discontinued operations section for additional information.

Net income (loss) attributable to common shares from continuing operations decreased by $180 million or $0.17 per common share for the three months ended December 31, 2024 compared to the same period in 2023. The decrease is primarily due to the net effect of the specific items mentioned above.

Reconciliation of net income (loss) attributable to common shares to comparable earnings - from continuing operations

three months ended December 31 (millions of $, except per share amounts)	2024	2023[1]
Net income (loss) attributable to common shares from continuing operations	**1,069**	1,249
Specific items (pre tax):		
Net gain on debt extinguishment[2]	**(228)**	—
Foreign exchange (gains) losses, net – intercompany loan[3]	**(143)**	55
Expected credit loss provision on net investment in leases and certain contract assets in Mexico[4]	**(3)**	36
Project Tundra impairment charge	**36**	—
Focus Project costs[5]	**9**	15
Bruce Power unrealized fair value adjustments	**(2)**	(7)
Risk management activities[6]	**301**	(91)
Taxes on specific items[7]	**55**	(65)
Comparable earnings from continuing operations	**1,094**	1,192
Net income (loss) per common share from continuing operations	**$1.03**	$1.20
Specific items (net of tax)	**0.02**	(0.05)
Comparable earnings per common share from continuing operations	**$1.05**	$1.15

1 Prior year results have been recast to reflect continuing operations only.

2 In October 2024, TCPL commenced and completed our cash tender offers to purchase and cancel certain senior unsecured notes and medium term notes at a 7.73 per cent weighted average discount. In addition, we retired outstanding callable notes at par. These extinguishments of debt resulted in a pre-tax net gain of $228 million, primarily due to fair value discounts and unamortized debt issue costs. The net gain on debt extinguishment was recorded in Interest expense in the Consolidated statement of income. Refer to the Financial condition section for additional information.

3 In 2023, TCPL and TGNH became party to an unsecured revolving credit facility. 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 revaluation and translation of the loan receivable and loan payable to TC Energy's reporting currency. As the amounts do not accurately reflect what will be realized at settlement, we exclude 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, net of non-controlling interest.

4 In 2022, TGNH and the CFE executed agreements which consolidate several natural gas pipelines under one TSA. As this TSA contains a lease, we have recognized amounts in net investment in leases on our Consolidated balance sheet. As required by U.S. GAAP, we have recognized an expected credit loss provision related to net investment in leases and certain contract assets in Mexico, which will fluctuate from period to period based on changing economic assumptions and forward-looking information. This provision is an estimate of losses that may occur over the duration of the TSA through 2055. This provision does not reflect losses or cash outflows that were incurred under this lease arrangement in the current period or from our underlying operations, and therefore, we have excluded any unrealized changes, net of non-controlling interest, from comparable measures. Refer to Note 28, Risk management and financial instruments, for additional information.

5 In 2022, we launched the Focus Project 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, for external consulting and severance, some of which are not recoverable through regulatory and commercial tolling structures. Refer to the Corporate – Significant events section for additional information.

6

three months ended December 31 (millions of $)	2024	2023
U.S. Natural Gas Pipelines	**(37)**	(29)
Canadian Power	**17**	(6)
U.S. Power	**(2)**	4
Natural Gas Storage	**(20)**	18
Interest rate	**(71)**	—
Foreign exchange	**(188)**	104
	(301)	91
Income tax attributable to risk management activities	**72**	(24)
Total unrealized gains (losses) from risk management activities	**(229)**	67

7 Refer to the Corporate - Financial results section for additional information.

Comparable EBITDA to comparable earnings - from continuing operations

Comparable EBITDA from continuing operations 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)	2024	2023[1]
Comparable EBITDA from continuing operations		
Canadian Natural Gas Pipelines	**851**	1,034
U.S. Natural Gas Pipelines	**1,200**	1,225
Mexico Natural Gas Pipelines	**234**	208
Power and Energy Solutions	**341**	266
Corporate	**(7)**	(18)
Comparable EBITDA from continuing operations	**2,619**	2,715
Depreciation and amortization	**(639)**	(632)
Interest expense included in comparable earnings	**(836)**	(777)
Allowance for funds used during construction	**233**	132
Foreign exchange gains (losses), net included in comparable earnings	**(44)**	40
Interest income and other	**120**	119
Income tax (expense) recovery included in comparable earnings	**(168)**	(253)
Net (income) loss attributable to non-controlling interests included in comparable earnings	**(163)**	(128)
Preferred share dividends	**(28)**	(24)
Comparable earnings from continuing operations	**1,094**	1,192
Comparable earnings per common share from continuing operations	**$1.05**	$1.15

1 Prior year results have been recast to reflect continuing operations only.

Comparable EBITDA from continuing operations

Fourth quarter 2024 versus fourth quarter 2023

Comparable EBITDA from continuing operations decreased by $96 million for the three months ended December 31, 2024 compared to the same period in 2023 primarily due to the net effect of the following:

- decreased EBITDA in Canadian Natural Gas Pipelines mainly due to lower earnings from Coastal GasLink related to the recognition of a $200 million incentive payment in 2023, partially offset by higher flow-through costs on the NGTL System
- decreased U.S. dollar-denominated EBITDA from U.S. Natural Gas Pipelines mainly as a result of the sale of PNGTS, which was completed on August 15, 2024, lower realized earnings related to our U.S. natural gas marketing business primarily due to lower margins and lower equity earnings from Iroquois, partially offset by incremental earnings from growth projects placed in service and additional contract sales
- increased Power and Energy Solutions EBITDA primarily attributable to higher contributions from Bruce Power due to higher generation, a higher contract price and lower outage costs, partially offset by decreased Canadian Power earnings primarily due to lower realized power prices, net of lower natural gas fuel costs
- increased U.S. dollar-denominated EBITDA from Mexico Natural Gas Pipelines primarily due to higher equity earnings from Sur de Texas as a result of the impact of peso-denominated financial exposure and lower income tax expense, partially offset by lower earnings in TGNH primarily related to higher operating costs
- the positive foreign exchange impact of a stronger U.S. dollar on the Canadian dollar equivalent comparable EBITDA in our U.S. dollar-denominated operations. U.S. dollar-denominated comparable EBITDA decreased by US$27 million compared to 2023 and was translated at a rate of 1.40 in 2024 versus 1.36 in 2023. 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 from continuing operations

Fourth quarter 2024 versus fourth quarter 2023

Comparable earnings from continuing operations decreased by $98 million or $0.10 per common share for the three months ended December 31, 2024 compared to the same period in 2023 and was primarily the net effect of:

- changes in comparable EBITDA described above
- higher interest expense primarily due to lower capitalized interest, interest expense allocated to discontinued operations in 2023 and lower interest rates on increased levels of short-term borrowing, partially offset by long-term debt repayments, net of issuances and realized gains from risk management activities used to manage our interest rate risk
- higher AFUDC primarily due to spending on the Southeast Gateway pipeline project, partially offset by projects placed in service
- risk management activities used to manage our foreign exchange exposure to net liabilities in Mexico and to U.S. dollar-denominated income and the revaluation of our peso-denominated net monetary liabilities to U.S. dollars
- lower income tax expense due to lower earnings subject to income tax and Mexico foreign exchange exposure, partially offset by lower foreign income tax rate differentials and higher flow-through income taxes
- higher net income attributable to non-controlling interests primarily due to the sale of a 13.01 per cent non-controlling equity interest in TGNH to the CFE completed in second quarter 2024, lower taxable earnings from the Texas Wind Farms and a stronger U.S. dollar on translation of U.S. dollar-denominated net income attributable to non-controlling interests.

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. A portion of the remaining 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, 2024 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. Comparable EBITDA is a non-GAAP measure.

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

three months ended December 31 (millions of US$)	**2024**	**2023**[1]
Comparable EBITDA		
U.S. Natural Gas Pipelines	**859**	900
Mexico Natural Gas Pipelines	**167**	153
	1,026	1,053
Depreciation and amortization	**(191)**	(192)
Interest expense on long-term debt and junior subordinated notes	**(440)**	(473)
Interest expense allocated to discontinued operations	**—**	47
Allowance for funds used during construction	**159**	81
Net (income) loss attributable to non-controlling interests included in comparable earnings and other	**(125)**	(92)
	429	424
Average exchange rate - U.S. to Canadian dollars	**1.40**	1.36

1 Prior year results have been recast to reflect continuing operations only.

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, Foreign exchange (gains) losses, net and Net income (loss) attributable to non-controlling interests 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.

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, 2024	**20.87**
December 31, 2023	16.91
December 31, 2022	19.50

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 $)	**2024**	**2023**
Comparable EBITDA - Mexico Natural Gas Pipelines[1]	**30**	(16)
Foreign exchange gains (losses), net included in comparable earnings	**(21)**	64
Income tax (expense) recovery included in comparable earnings	**27**	(38)
Net (income) loss attributable to non-controlling interests included in comparable earnings[2]	**(3)**	—
	33	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.

2 Represents the non-controlling interest portion related to TGNH. Refer to the Corporate section for additional information.

Highlights by business segment

Canadian Natural Gas Pipelines

Canadian Natural Gas Pipelines segmented earnings decreased by $186 million for the three months ended December 31, 2024 compared to the same period in 2023.

Net income for the NGTL System decreased by $8 million for the three months ended December 31, 2024 compared to the same period in 2023 mainly due to incentive losses. The NGTL System was operating under the 2020-2024 Revenue Requirement Settlement which included an approved ROE of 10.1 per cent on 40 per cent deemed common equity. This settlement provided 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 for the three months ended December 31, 2024 compared to the same period in 2023 mainly due to higher incentive earnings. The Canadian Mainline is operating under the 2021-2026 Mainline Settlement which includes an approved ROE of 10.1 per cent on 40 per cent deemed common equity and an incentive to decrease costs and increase revenues on the pipeline under a beneficial sharing mechanism with our customers.

Comparable EBITDA for Canadian Natural Gas Pipelines decreased by $183 million for the three months ended December 31, 2024 compared to the same period in 2023 due to the net effect of:

- earnings from Coastal GasLink in 2023 related to the recognition of a $200 million incentive payment upon meeting certain milestones
- higher flow-through income taxes and depreciation on the NGTL System, partially offset by incentive losses.

Depreciation and amortization for the three months ended December 31, 2024 was largely consistent with the same period in 2023.

U.S. Natural Gas Pipelines

U.S. Natural Gas Pipelines segmented earnings decreased by $37 million for the three months ended December 31, 2024 compared to the same period in 2023 and included unrealized gains and losses from changes in the fair value of derivatives related to our U.S. natural gas marketing business, which have been excluded from our calculation of comparable EBITDA and comparable EBIT.

A stronger U.S. dollar for the three months ended December 31, 2024 had a positive impact on the Canadian dollar equivalent segmented earnings from our U.S. dollar-denominated operations. Refer to the Foreign exchange section for additional information.

Comparable EBITDA for U.S. Natural Gas Pipelines decreased by US$41 million for the three months ended December 31, 2024 compared to the same period in 2023 and was primarily due to the net effect of:

- decreased earnings as a result of the sale of our 61.7 per cent equity interest in PNGTS, which was completed on August 15, 2024
- lower realized earnings related to our U.S. natural gas marketing business, primarily due to lower margins
- lower equity earnings from Iroquois
- decreased earnings due to higher operational costs, reflective of increased system utilization across our footprint
- incremental earnings from growth and modernization projects placed in service, as well as increased earnings from additional contract sales on ANR.

Depreciation and amortization for the three months ended December 31, 2024 was largely consistent with the same period in 2023.

Mexico Natural Gas Pipelines

Mexico Natural Gas Pipelines segmented earnings increased by $64 million for the three months ended December 31, 2024 compared to the same period in 2023 and included an unrealized recovery of $3 million (2023 – unrealized loss of $36 million), on the expected credit loss provision related to 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 28, Risk management and financial instruments, of our 2024 Consolidated financial statements for additional information.

A stronger U.S. dollar for the three months ended December 31, 2024 had a positive impact on the Canadian dollar equivalent segmented earnings from our U.S. dollar-denominated operations in Mexico. Refer to the Foreign exchange section for additional information.

Comparable EBITDA for Mexico Natural Gas Pipelines increased by US$14 million for the three months ended December 31, 2024 compared to the same period in 2023 due to the net effect of:

- higher equity earnings in Sur de Texas primarily due to the foreign exchange impacts upon the revaluation of peso-denominated liabilities as a result of a weaker Mexican peso and lower income tax expense mainly due to foreign exchange impacts. 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
- lower earnings in TGNH primarily related to higher operating costs from integrity activities performed in fourth quarter 2024.

Depreciation and amortization was consistent for the three months ended December 31, 2024 compared to the same period in 2023.

Power and Energy Solutions

Power and Energy Solutions segmented earnings increased by $13 million for the three months ended December 31, 2024 compared to the same period in 2023 and included the following specific items which have been excluded from our calculation of comparable EBITDA and comparable EBIT:

- a pre-tax impairment charge of $36 million related to development costs incurred on Project Tundra, a next-generation technology carbon capture and storage project, following our decision to end our collaboration on the project
- 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 $75 million for the three months ended December 31, 2024 compared to the same period in 2023 primarily due to the net effect of:

- improved contributions from Bruce Power primarily due to increased generation, a higher contract price and lower outage costs, partially offset by increased operating and depreciation costs. Refer to the Bruce Power section for additional information
- decreased Canadian Power financial results primarily from lower realized power prices, net of lower natural gas fuel costs.

Depreciation and amortization was consistent for the three months ended December 31, 2024 compared to the same period in 2023.

Corporate

Corporate segmented losses decreased by $18 million for the three months ended December 31, 2024 compared to the same period in 2023. Corporate segmented losses included a pre-tax charge of $9 million for the three months ended December 31, 2024 (2023 – $15 million) related to Focus Project costs, which has been excluded from our calculation of comparable EBITDA and comparable EBIT.

Comparable EBITDA for Corporate was a loss of $7 million for the three months ended December 31, 2024 compared to a loss of $18 million for the same period in 2023 and includes shared costs in 2023 related to TC Energy's corporate services and governance functions that were not allocated to discontinued operations in accordance with U.S. GAAP. Refer to the Discontinued operations section for additional information.

Depreciation and amortization for the three months ended December 31, 2024 was largely consistent with the same period in 2023.

QUARTERLY RESULTS - FROM DISCONTINUED OPERATIONS

Factors affecting financial information by quarter

The quarterly results section references non-GAAP measures, which are described on page 24. 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.

In fourth quarter 2024, comparable earnings from discontinued operations also excluded:

- a pre-tax charge of $85 million (after-tax $72 million) from Liquids Pipelines business separation costs related to the Spinoff Transaction, of which $75 million was recognized in segmented earnings and $10 million in interest income
- a pre-tax expense of $37 million (after-tax $28 million) related to our current estimate of potential incremental costs resulting from the Milepost 14 incident. This amount represents our 86 per cent share pursuant to the indemnity provisions in the Separation Agreement
- a pre-tax recovery of $3 million (after-tax $2 million) as a result of the FERC Administrative Law Judge decision on Keystone in respect of a tolling-related complaint pertaining to amounts recognized in prior periods.

In third quarter 2024, comparable earnings from discontinued operations also excluded:

- a pre-tax charge of $67 million (after-tax $56 million) due to Liquids Pipelines business separation costs related to the Spinoff Transaction
- a pre-tax expense of $21 million (after-tax $16 million) related to Keystone XL asset disposition and termination activities
- a pre-tax charge of $15 million (after-tax $12 million) related to the FERC Administrative Law Judge decision on Keystone in respect of a tolling-related complaint pertaining to amounts recognized in prior periods.

In second quarter 2024, comparable earnings from discontinued operations also excluded:

- a pre-tax charge of $29 million (after-tax $26 million) due to Liquids Pipelines business separation costs related to the Spinoff Transaction.

In first quarter 2024, comparable earnings from discontinued operations also excluded:

- a pre-tax charge of $16 million (after-tax $13 million) due to Liquids Pipelines business separation costs related to the Spinoff Transaction.

In fourth quarter 2023, comparable earnings from discontinued operations also excluded:

- a pre-tax charge of $25 million (after-tax $23 million) from Liquids Pipelines business separation costs related to the Spinoff Transaction
- pre-tax preservation and other costs of $5 million (after-tax $4 million) related to the preservation and storage of the Keystone XL pipeline project assets
- pre-tax carrying charges of $5 million (after-tax $4 million) 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 in prior periods
- a pre-tax recovery of $4 million (after-tax $18 million) 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.

In third quarter 2023, comparable earnings from discontinued operations also excluded:

- a pre-tax charge of $15 million (after-tax $11 million) due to Liquids Pipelines business separation costs related to the Spinoff Transaction
- pre-tax preservation and other costs for Keystone XL pipeline project assets of $3 million (after-tax $2 million).

In second quarter 2023, comparable earnings from discontinued operations also excluded:

- a $36 million pre-tax (after-tax $36 million) accrued insurance expense related to the Milepost 14 incident
- pre-tax preservation and other costs for Keystone XL pipeline project assets of $5 million (after-tax $4 million).

In first quarter 2023, comparable earnings from discontinued operations also excluded:

- a $62 million pre-tax (after-tax $48 million) 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 (after-tax $44 million) and accrued pre-tax carrying charges of $5 million (after-tax $4 million)
- pre-tax preservation and other costs for Keystone XL pipeline project assets of $5 million (after-tax $4 million).

Results from discontinued operations

three months ended December 31 (millions of $, except per share amounts)	2024[1]	2023[2]
Segmented earnings (losses) from discontinued operations	**(109)**	301
Interest expense	**—**	(68)
Interest income and other	**(10)**	2
Income (loss) from discontinued operations before income taxes	**(119)**	235
Income tax (expense) recovery	**21**	(21)
Net income (loss) from discontinued operations, net of tax	**(98)**	214
Net income (loss) per common share from discontinued operations - basic	**($0.09)**	$0.21

1 The Liquids Pipelines business was accounted for as a discontinued operation starting October 1, 2024. Refer to the Discontinued operations section for additional information.

2 Prior year results have been recast to reflect the Liquids Pipelines business as a discontinued operation as a result of the Spinoff Transaction.

Net income (loss) from discontinued operations, net of tax was a net loss of $98 million or loss of $0.09 per share for the three months ended December 31, 2024 compared to net income of $214 million or $0.21 per share for the same period in 2023. The decrease reflects the completion of the Spinoff Transaction on October 1, 2024 and the net effect of the specific items mentioned above.

Reconciliation of net income (loss) from discontinued operations, net of tax to comparable earnings from discontinued operations

three months ended December 31 (millions of $, except per share amounts)	2024[1]	2023[2]
Net income (loss) from discontinued operations, net of tax	**(98)**	214
Specific items (pre tax):		
Liquids Pipelines business separation costs	**85**	25
Milepost 14 incremental costs	**37**	—
Keystone regulatory decisions	**(3)**	5
Keystone XL preservation and other	**—**	5
Keystone XL asset impairment charge and other	**—**	(4)
Risk management activities	**—**	(20)
Taxes on specific items[3]	**(21)**	(14)
Comparable earnings from discontinued operations	**—**	211
Net income (loss) per common share from discontinued operations	**($0.09)**	$0.21
Specific items (net of tax)	**0.09**	(0.01)
Comparable earnings per common share from discontinued operations	**—**	$0.20

1 The Liquids Pipelines business was accounted for as a discontinued operation starting October 1, 2024. Refer to the Discontinued operations section for additional information.

2 Prior year results have been recast to reflect the Liquids Pipelines business as a discontinued operation as a result of the Spinoff Transaction.

3 Refer to page 101 for additional information.

Comparable EBITDA to comparable earnings - from discontinued operations

Comparable EBITDA from discontinued operations represents segmented earnings (losses) from discontinued operations 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)	2024[1]	2023[2]
Comparable EBITDA from discontinued operations	—	392
Depreciation and amortization	—	(85)
Interest expense included in comparable earnings[3]	—	(63)
Interest income and other included in comparable earnings[4]	—	2
Income tax (expense) recovery included in comparable earnings[5]	—	(35)
Comparable earnings from discontinued operations	—	211
Comparable earnings per common share from discontinued operations	—	$0.20

1 The Liquids Pipelines business was accounted for as a discontinued operation starting October 1, 2024. Refer to the Discontinued operations section for additional information.
2 Prior year results have been recast to reflect the Liquids Pipelines business as a discontinued operation as a result of the Spinoff Transaction.
3 Excludes pre-tax carrying charges of $5 million for the three months ended December 31, 2023 as a result of a charge related to the FERC Administrative Law Judge decision on Keystone in respect of a tolling-related complaint pertaining to amounts recognized in prior periods.
4 Excludes pre-tax Liquids Pipelines business separation costs of $10 million related to insurance provisions for the three months ended December 31, 2024.
5 Excludes the impact of income taxes related to the specific items mentioned above as well as a $14 million U.S. minimum tax recovery in fourth quarter 2023 on the Keystone XL asset impairment charge and other related to the termination of the Keystone XL pipeline project.

Comparable EBITDA and comparable earnings from discontinued operations

Comparable EBITDA and comparable earnings from discontinued operations were nil for three months ended December 31, 2024 compared to comparable EBITDA of $392 million and comparable earnings of $211 million or $0.20 per common share for the same period in 2023. The decrease reflects the completion of the Spinoff Transaction on October 1, 2024.

Glossary

Units of measure

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
TJ/d	Terajoule per day

General terms and terms related to our operations

CEO	Chief Executive Officer
CFO	Chief Financial Officer
cogeneration facilities	Facilities that produce both electricity and useful heat at the same time
DRP	Dividend Reinvestment and Share Purchase Plan
Empress	A major delivery/receipt point for natural gas near the Alberta/Saskatchewan border
ESG	Environmental, social and governance
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)
IFRS S2	International Financial Reporting Standards S2 Climate-related Disclosures
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
SENER	Secretaría de Energía or Mexican Ministry of Energy
TCFD	Task Force on Climate-Related Financial Disclosures
TNFD	Task Force on Nature-related Financial Disclosures
TSX	Toronto Stock Exchange