FORTIS INC.

St. John's, NL - February 14, 2025

FORTIS INC. REPORTS FOURTH QUARTER & ANNUAL 2024 RESULTS

This news release constitutes a "Designated News Release" incorporated by reference in the prospectus supplement dated December 9, 2024 to Fortis' short form base shelf prospectus dated December 9, 2024.

Fortis Inc. ("Fortis" or the "Corporation") (TSX/NYSE: FTS), a well-diversified leader in the North American regulated electric and gas utility industry, released its 2024 fourth quarter and annual financial results.[1]

Highlights

- Annual net earnings of $1.6 billion, or $3.24 per common share for 2024
- Annual adjusted net earnings per common share[2] of $3.28, up from $3.09 for 2023, representing 6% growth[3]
- Capital expenditures[2] of $5.2 billion, yielding 6% annual rate base growth[3]
- Tranche 2.1 projects approved by MISO; ITC now estimates US$3.7-$4.2 billion in investments, with majority expected post-2029
- 4.2% increase in fourth quarter common share dividend achieving 51 years of common share dividend increases

"In 2024, Fortis extended its track record of strong EPS and rate base growth," said David Hutchens, President and Chief Executive Officer, Fortis Inc. "We executed a $5.2 billion capital program, outperformed industry averages for safety and reliability performance, and continued to be recognized as a leader for our governance practices."

"We remain focused on extending our track record as we execute our $26 billion five-year capital plan in support of our annual dividend growth guidance of 4-6% through 2029," said Mr. Hutchens. "Fortis' strength comes from the dedication and hard work of our people, and we appreciate their efforts in making 2024 another successful year."

Net Earnings

The Corporation reported net earnings attributable to common shareholders ("Net Earnings") of $1.6 billion, or $3.24 per common share for 2024, compared to $1.5 billion, or $3.10 per common share for 2023. Growth in earnings was primarily driven by rate base growth across our utilities. New customer rates at Tucson Electric Power ("TEP") effective September 1, 2023 and Central Hudson effective July 1, 2024, and an unfavourable deferred income tax adjustment recognized by ITC in 2023, also contributed to earnings growth. The increase was partially offset by higher holding company finance costs, unrealized losses on derivative contracts, and a $10 million gain realized upon the disposition of Aitken Creek in 2023. The recognition of a refund liability at ITC in 2024 associated with a reduction in the Midcontinent Independent System Operator ("MISO") base rate of return on common equity ("ROE"), largely reflecting the retroactive impact to prior periods, also unfavourably impacted earnings. An increase in the weighted average number of common shares outstanding related to the Corporation's dividend reinvestment plan, also impacted earnings per common share.

For the fourth quarter of 2024, Net Earnings were $396 million, or $0.79 per common share, compared to $381 million or $0.78 per common share for the same period in 2023. The increase was due to rate base growth as well as new customer rates at Central Hudson effective July 1, 2024. The implementation of new customer rates at Central Hudson shifted the timing of quarterly rate recovery in comparison to related costs, resulting in higher revenue and earnings in the fourth quarter of 2024. The increase in earnings was tempered by the refund liability recognized at ITC, unrealized losses on derivative contracts, and the gain on disposition of Aitken Creek in 2023, as discussed above. Lower earnings in Arizona, driven by higher operating expenses, also unfavourably impacted fourth quarter earnings in comparison to the prior year. Net earnings per common share was also impacted by an increase in the weighted average number of common shares.

---

[1] Financial information is presented in Canadian dollars unless otherwise specified.

[2] Non-U.S. GAAP Measures - Fortis uses financial measures that do not have a standardized meaning under generally accepted accounting principles in the United States of America ("U.S. GAAP") and may not be comparable to similar measures presented by other entities. Fortis presents these non-U.S. GAAP measures because management and external stakeholders use them in evaluating the Corporation's financial performance and prospects. Refer to the Non-U.S. GAAP Reconciliation provided herein.

[3] Growth rates calculated using a constant U.S. dollar-to-Canadian dollar exchange rate.

Adjusted Net Earnings[2]

Adjusted net earnings attributable to common equity shareholders ("Adjusted Net Earnings") of $1.6 billion for 2024, or $3.28 per common share, were $124 million, or $0.19 per common share higher than 2023. Adjusted Net Earnings reflects the removal of items that management excludes in its key decision-making processes and evaluation of operating results. For 2024, Net Earnings was adjusted to remove the $20 million unfavourable prior period impact associated with the reduction in the MISO base ROE. For 2023, Net Earnings was adjusted to exclude the $4 million net favourable impact associated with the disposition of Aitken Creek and the revaluation of deferred income tax assets at ITC. The increase in Adjusted Net Earnings in 2024 reflects these items, as well as the other factors discussed in Net Earnings.[4]

For the fourth quarter of 2024, Adjusted Net Earnings of $416 million, or $0.83 per common share, were $66 million, or $0.11 per common share higher than the same period in 2023. Net Earnings for the fourth quarter of 2024 was adjusted to remove the $20 million prior period impact associated with the MISO base ROE, as discussed above. For the fourth quarter of 2023, Net Earnings was adjusted to exclude the disposition of Aitken Creek, including timing impacts associated with the March 31, 2023 effective date of disposition. The increase in fourth quarter Adjusted Net Earnings largely reflects these items, as well as the other factors discussed in Net Earnings.

Capital Expenditures[2]

Capital expenditures were $5.2 billion for 2024. Growth in capital was due to investments associated with the Eagle Mountain Pipeline project at FortisBC Energy, transmission reliability projects at ITC, and construction of the Roadrunner Reserve battery storage projects at TEP. Capital expenditures increased midyear rate base to $39.0 billion, representing 6% growth over 2023.[3]

In 2024, construction of the Wataynikaneyap Transmission Power project was completed. This project enables the connection of 17 First Nations communities to the Ontario power grid. Previously these communities had inefficient and unreliable access to electricity based on diesel generation, which compromised their economic and social well-being and limited opportunities for growth. The transmission line is majority-owned by 24 First Nations, while Fortis has a 39% ownership interest.

The Corporation's 2025-2029 capital plan of $26.0 billion is $1.0 billion higher than the previous five-year plan. The increase is driven by projects associated with the MISO long-range transmission plan ("LRTP") and resiliency investments at ITC, as well as distribution investments largely due to customer growth at FortisAlberta.

The five-year capital plan is expected to be funded primarily by cash from operations and regulated utility debt. Common equity proceeds are expected to be provided by the Corporation's dividend reinvestment plan, assuming current participation levels. The Corporation's $500 million at-the-market common equity program remains available and provides funding flexibility as required.

Progress continues with respect to the MISO LRTP projects. Total tranche 1 investments expected for ITC remain in the range of US$1.4-$1.8 billion through 2030, of which US$1.2 billion are included in the 2025-2029 capital plan. In December 2024, MISO approved the tranche 2.1 projects. ITC now estimates US$3.7-$4.2 billion in capital expenditures for tranche 2.1 projects located in Michigan and Minnesota where rights of first refusal are in effect and for projects requiring system upgrades in Iowa which are not subject to a competitive bidding process. A majority of the tranche 2.1 investment is expected beyond 2029.

Regulatory Updates

In October 2024, the Federal Energy Regulatory Commission ("FERC") issued an order setting the base ROE for transmission owners operating in the MISO region, including ITC. The order revised the base ROE of ITC's MISO utilities from 10.02% to 9.98% and also directed the payment of certain refunds, with interest, by December 1, 2025. Fortis' 80.1% share of the related after-tax earnings impact was approximately $22 million, of which $20 million related to periods prior to January 1, 2024.

In December 2024, the Arizona Corporation Commission ("ACC") approved a formula rate plan policy statement which allows utilities to propose formula rates with an annual true-up mechanism in future rate cases. A formula rate plan is expected to improve rate stability for customers, while also reducing regulatory lag and the number of existing rate adjusters. In January 2025, UNS Gas filed supplemental material to its general rate application proposing an annual rate adjustment mechanism as a result of the ACC's formula rate policy statement. The timing and outcome of this proceeding are unknown.

---

4 The disposition of Aitken Creek was neutral to Adjusted Net Earnings and EPS for the year.

Outlook

Fortis continues to enhance shareholder value through the execution of its capital plan, the balance and strength of its diversified portfolio of regulated utility businesses, and growth opportunities within and proximate to its service territories. The Corporation's $26.0 billion five-year capital plan is expected to increase midyear rate base from $39.0 billion in 2024 to $53.0 billion by 2029, translating into a five-year compound annual growth rate of 6.5%.[3]

Beyond the five-year capital plan, opportunities to expand and extend growth include: further expansion of the electric transmission grid in the U.S. to support load growth and facilitate the interconnection of cleaner energy; transmission investments associated with the MISO LRTP tranches 1, 2.1 and 2.2 as well as regional transmission in New York; grid resiliency and climate adaptation investments; renewable gas solutions and liquefied natural gas infrastructure in British Columbia; and the acceleration of load growth and cleaner energy infrastructure investments across our jurisdictions.

Fortis expects its long-term growth in rate base will drive earnings that support dividend growth guidance of 4-6% annually through 2029, and is premised on the assumptions and material factors listed under "Forward-Looking Information".

Fortis has reduced its corporate-wide direct greenhouse gas ("GHG") emissions by 34% from a 2019 base year, and has targets to further reduce such GHG emissions by 50% by 2030 and 75% by 2035. The Corporation's additional 2050 net-zero direct GHG emissions target reinforces Fortis' commitment to further decarbonize over the long-term, while continuing our focus on reliability and affordability. The Corporation's ability to achieve the GHG targets may be impacted by federal, state and provincial energy policies, as well as external factors, including significant customer and load growth and the development of clean energy technology.

Non-U.S. GAAP Reconciliation

Periods ended December 31	Quarter			Annual		
($ millions, except earnings per share)	**2024**	2023	Variance	**2024**	2023	Variance
Adjusted Net Earnings						
Net Earnings	**396**	381	15	**1,606**	1,506	100
Adjusting items:						
October 2024 MISO base ROE decision[5]	**20**	—	20	**20**	—	20
Disposition of Aitken Creek[6]	**—**	(31)	31	**—**	(15)	15
Unrealized loss on mark-to-market of derivatives[7]	**—**	—	—	**—**	2	(2)
Revaluation of deferred income tax assets[8]	**—**	—	—	**—**	9	(9)
Adjusted Net Earnings	**416**	350	66	**1,626**	1,502	124
Adjusted Basic EPS *($)*	**0.83**	0.72	0.11	**3.28**	3.09	0.19
Capital Expenditures						
Additions to property, plant and equipment	**1,629**	1,189	440	**5,012**	3,986	1,026
Additions to intangible assets	**64**	61	3	**206**	183	23
Adjusting item:						
Wataynikaneyap Transmission Power Project[9]	**—**	51	(51)	**29**	160	(131)
Capital Expenditures	**1,693**	1,301	392	**5,247**	4,329	918

5 Represents the prior period impact of FERC's October 2024 MISO base ROE decision, net of income tax recovery of $7 million.

6 Aitken Creek was sold on November 1, 2023, with a March 31, 2023 effective date. For the year ended December 31, 2023, the adjustment represents: (i) the $10 million gain on disposition, net of income tax expense of $13 million; and (ii) $5 million of net earnings at Aitken Creek, recognized in accordance with U.S. GAAP, during the March 31, 2023 to November 1, 2023 stub period, net of income tax expense of $2 million. For the three-month period ended December 31, 2023, this adjustment represents: (i) the $10 million gain on disposition; and (ii) $21 million of stub period earnings at Aitken Creek, net of income tax expense of $9 million, including amounts initially included in Adjusted Net Earnings in the second and third quarters of 2023 prior to the close of the transaction.

7 Represents the impact of mark-to-market accounting of natural gas derivatives at Aitken Creek through the March 31, 2023 effective date of disposition, net of income tax recovery of $1 million.

8 Represents the revaluation of deferred income tax assets resulting from the reduction in the corporate income tax rate in the state of Iowa.

9 Represents Fortis' 39% share of capital spending for the Wataynikaneyap Transmission Power Project. Construction was completed in the second quarter of 2024.

About Fortis

Fortis is a well-diversified leader in the North American regulated electric and gas utility industry with 2024 revenue of $12 billion and total assets of $73 billion as at December 31, 2024. The Corporation's 9,800 employees serve utility customers in five Canadian provinces, ten U.S. states and three Caribbean countries.

Forward-Looking Information

Fortis includes forward-looking information in this media release within the meaning of applicable Canadian securities laws and forward-looking statements within the meaning of the U.S. Private Securities Litigation Reform Act of 1995 (collectively referred to as "forward-looking information"). Forward-looking information reflects expectations of Fortis management regarding future growth, results of operations, performance and business prospects and opportunities. Wherever possible, words such as anticipates, believes, budgets, could, estimates, expects, forecasts, intends, may, might, plans, projects, schedule, should, target, will, would, and the negative of these terms, and other similar terminology or expressions, have been used to identify the forward-looking information, which includes, without limitation: forecast capital expenditures for 2025 through 2029; the expected sources of funding for the capital plan, including the source of common equity proceeds; the nature, timing, benefits and expected costs of certain capital projects, including ITC's investments associated with tranches 1 and 2.1 of the MISO LRTP; the expected timing, outcome and impact of legal and regulatory proceedings and decisions; forecast rate base and rate base growth through 2029; the expected nature, timing and benefits of additional opportunities beyond the capital plan, including further expansion of the electric transmission grid in the U.S. to support load growth and facilitate the interconnection of cleaner energy, transmission investments associated with the MISO LRTP tranches 1, 2.1 and 2.2 as well as regional transmission in New York, grid resiliency and climate adaptation investments, renewable gas solutions and liquefied natural gas infrastructure in British Columbia, and the acceleration of load growth and cleaner energy infrastructure investments; the expectation that long-term growth in rate base will drive earnings that support dividend growth guidance of 4-6% annually through 2029; the 2050 net-zero direct GHG emissions target; the 2030 and 2035 direct GHG emissions reduction targets; and the potential impact of federal, state and provincial energy policies and other factors, including significant customer and load growth and the development of clean energy technology, on the Corporation's ability to achieve its GHG emissions reduction targets.

Forward-looking information involves significant risks, uncertainties and assumptions. Certain material factors or assumptions have been applied in drawing the conclusions contained in the forward-looking information, including, without limitation: reasonable outcomes for legal and regulatory proceedings and the expectation of regulatory stability; the successful execution of the capital plan; no material capital project and financing cost overrun; sufficient human resources to deliver service and execute the capital plan; the realization of additional opportunities beyond the capital plan; no significant variability in interest rates; no material changes in the assumed U.S. dollar-to-Canadian dollar exchange rate; the continuation of current participation levels in the Corporation's dividend reinvestment plan; and the Board of Directors of the Corporation exercising its discretion to declare dividends, taking into account the business performance and financial condition of the Corporation. Fortis cautions readers that a number of factors could cause actual results, performance or achievements to differ materially from the results discussed or implied in the forward-looking information. For additional information with respect to certain risk factors, reference should be made to the continuous disclosure materials filed from time to time by the Corporation with Canadian securities regulatory authorities and the Securities and Exchange Commission. All forward-looking information herein is given as of the date of this media release. Fortis disclaims any intention or obligation to update or revise any forward-looking information, whether as a result of new information, future events or otherwise.

Teleconference to Discuss 2024 Annual Results

A teleconference and webcast will be held on February 14, 2025 at 8:30 a.m. (Eastern). David Hutchens, President and Chief Executive Officer and Jocelyn Perry, Executive Vice President and Chief Financial Officer, will discuss the Corporation's 2024 annual results.

Shareholders, analysts, members of the media and other interested parties are invited to listen to the teleconference via the live webcast on the Corporation's website, www.fortisinc.com/investors/events-and-presentations.

Those members of the financial community in Canada and the United States wishing to ask questions during the call are invited to participate toll free by calling 1.844.763.8274. Individuals in other international locations can participate by calling 1.647.484.8814. Please dial in 10 minutes prior to the start of the call. No access code is required.

An archived audio webcast of the teleconference will be available on the Corporation's website two hours after the conclusion of the call until March 14, 2025. Please call 1.855.669.9658 or 1.412.317.0088 and enter access code 9850557#.

Additional Information

This news release should be read in conjunction with the Corporation's Management Discussion and Analysis and Consolidated Financial Statements. This and additional information can be accessed at www.fortisinc.com, www.sedarplus.ca, or www.sec.gov.

For more information, please contact:

Investor Enquiries:

Ms. Stephanie Amaimo
Vice President, Investor Relations
Fortis Inc.
248.946.3572
investorrelations@fortisinc.com

Media Enquiries:

Ms. Karen McCarthy
Vice President, Communications & Government Relations
Fortis Inc.
709.737.5323
media@fortisinc.com

Management Discussion and Analysis

Contents

Dated February 13, 2025

This MD&A has been prepared in accordance with National Instrument 51-102 - *Continuous Disclosure Obligations*. It should be read in conjunction with the 2024 Annual Financial Statements and is subject to the cautionary statement and disclaimer provided under "Forward-Looking Information" on page 40. Further information about Fortis, including its Annual Information Form, can be accessed at www.fortisinc.com, www.sedarplus.ca, or www.sec.gov.

Financial information herein has been prepared in accordance with U.S. GAAP (except for indicated Non-U.S. GAAP Financial Measures) and, unless otherwise specified, is presented in Canadian dollars based, as applicable, on the following U.S. dollar-to-Canadian dollar exchange rates: (i) average of 1.37 and 1.35 for the years ended December 31, 2024 and 2023, respectively; (ii) 1.44 and 1.32 as at December 31, 2024 and 2023, respectively; (iii) average of 1.40 and 1.36 for the quarters ended December 31, 2024 and 2023, respectively; and (iv) 1.30 for all forecast periods. Certain terms used in this MD&A are defined in the "Glossary" on page 41.

ABOUT FORTIS

Fortis (TSX/NYSE: FTS) is a well-diversified leader in the North American regulated electric and gas utility industry, with revenue of $12 billion in 2024 and total assets of $73 billion as at December 31, 2024.

Regulated utilities account for virtually all of the Corporation's assets. The Corporation's 9,800 employees serve 3.5 million utility customers in five Canadian provinces, ten U.S. states and three Caribbean countries. As at December 31, 2024, 66% of the Corporation's assets were located in the U.S., 31% in Canada and the remaining 3% in the Caribbean. Operations in the U.S. accounted for 57% of the Corporation's 2024 revenue, with the remaining 38% in Canada, and 5% in the Caribbean.

Fortis is principally an energy delivery company, with 93% of its assets related to transmission and distribution. The business is characterized by low-risk, stable and predictable earnings and cash flows. Earnings, EPS and TSR are the primary measures of financial performance.

Fortis' regulated utility businesses are: ITC (electric transmission - Michigan, Iowa, Minnesota, Illinois, Missouri, Kansas, Oklahoma and Wisconsin); UNS Energy (integrated electric and natural gas distribution - Arizona); Central Hudson (electric transmission and distribution, and natural gas distribution - New York State); FortisBC Energy (natural gas transmission and distribution - British Columbia); FortisAlberta (electric distribution - Alberta); FortisBC Electric (integrated electric - British Columbia); Newfoundland Power (integrated electric - Newfoundland and Labrador); Maritime Electric (integrated electric - Prince Edward Island); FortisOntario (integrated electric - Ontario); Caribbean Utilities (integrated electric - Grand Cayman); and FortisTCI (integrated electric - Turks and Caicos Islands). Fortis also holds equity investments in Wataynikaneyap Power (electric transmission - Ontario) and Belize Electricity (integrated electric - Belize).

The Corporation's non-regulated business is limited to Fortis Belize (three hydroelectric generation facilities - Belize). The Aitken Creek natural gas storage facility in British Columbia was sold on November 1, 2023 with a March 31, 2023 effective date.

Fortis has a unique operating model with a small corporate office in St. John's, Newfoundland and Labrador and business units that operate on a substantially autonomous basis. Each utility has its own management team and board of directors, with most having a majority of independent board members, which provides effective oversight within the broad parameters of Fortis policies and best practices. Subsidiary autonomy supports constructive relationships with regulators, policy makers, customers and communities. Fortis believes this model enhances accountability, opportunity and performance across the Corporation's businesses, and positions Fortis well for future investment opportunities.

Fortis is focused on providing safe, reliable and cost-effective service to customers. Delivering a cleaner energy future is the Corporation's core purpose. In addition, management is focused on delivering long-term profitable growth for shareholders through the execution of its capital plan and the pursuit of investment opportunities within and proximate to its service territories.

Additional information about the Corporation's business and reporting units is provided in Note 1 in the 2024 Annual Financial Statements.

PERFORMANCE AT A GLANCE

Key Financial Metrics

($ millions, except as indicated)	**2024**	2023	Variance
Common Equity Earnings			
Actual	**1,606**	1,506	100
Adjusted [(1)]	**1,626**	1,502	124
Basic EPS *($)*			
Actual	**3.24**	3.10	0.14
Adjusted [(1)]	**3.28**	3.09	0.19
Dividends			
Paid per common share *($)*	**2.39**	2.29	0.10
Actual Payout Ratio *(%)*	**73.6**	73.7	(0.1)
Adjusted Payout Ratio *(%)* [(1)]	**72.7**	73.9	(1.2)
Weighted average number of common shares outstanding *(# millions)*	**495.0**	486.3	8.7
Operating Cash Flow	**3,882**	3,545	337
Capital Expenditures [(1)]	**5,247**	4,329	918

[(1)] *See "Non-U.S. GAAP Financial Measures" on page 10*

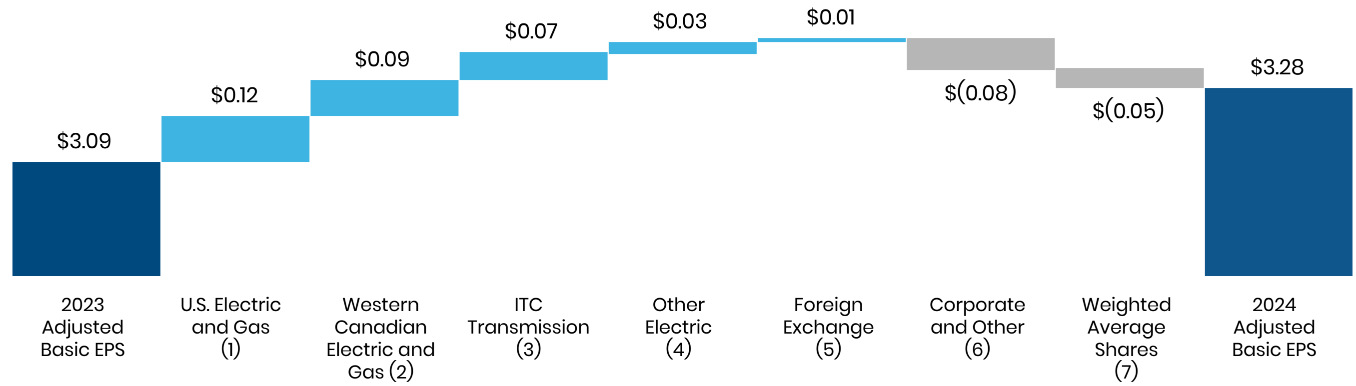
Earnings and EPS

Common Equity Earnings increased by $100 million in comparison to 2023. The increase was due to: (i) Rate Base growth; (ii) higher earnings in Arizona, largely reflecting new customer rates at TEP effective September 1, 2023 and higher production tax credits; (iii) new customer rates and a higher allowed ROE at Central Hudson effective July 1, 2024; and (iv) an unfavourable deferred income tax adjustment recognized by ITC in 2023. The increase was partially offset by higher holding company finance costs, unrealized losses on derivative contracts, and a $10 million gain realized upon the disposition of Aitken Creek in 2023. The recognition of a refund liability at ITC in 2024, due to the reduction in the MISO base ROE as approved by FERC and largely reflecting the retroactive impact to prior periods, also unfavourably impacted earnings.

In addition to the above-noted items impacting earnings, the change in EPS also reflected an increase in the weighted average number of common shares outstanding, largely associated with the Corporation's DRIP.

Adjusted Common Equity Earnings and Adjusted Basic EPS increased by $124 million and $0.19, respectively. Refer to "Non-U.S. GAAP Financial Measures" on page 10 for a reconciliation of these measures. The change in Adjusted Basic EPS is illustrated in the following chart.

CHANGE IN ADJUSTED BASIC EPS



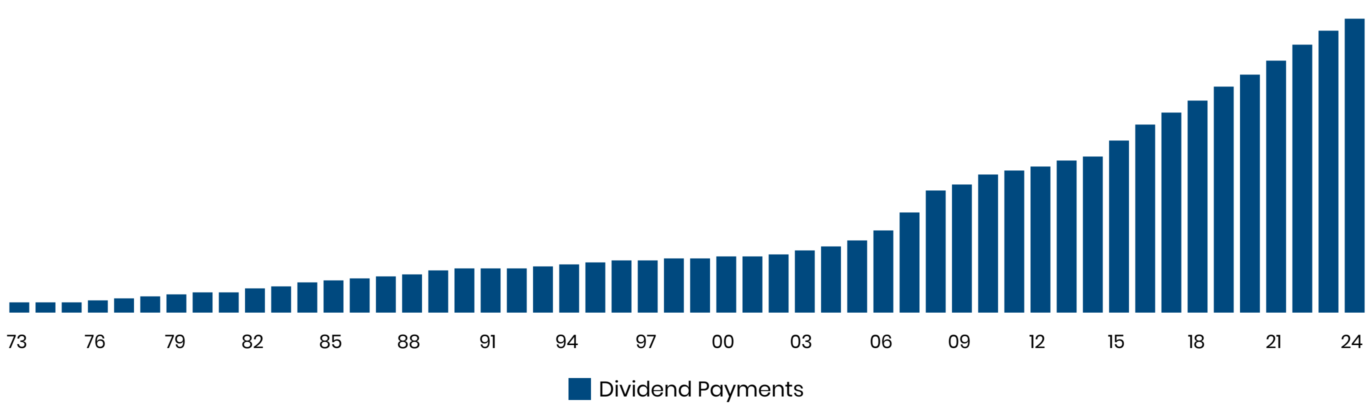
[1] Includes UNS Energy and Central Hudson. Reflects higher earnings at UNS Energy due to new customer rates at TEP effective September 1, 2023, higher production tax credits, and favourable margins on wholesale sales, partially offset by higher operating costs. Also reflects higher earnings at Central Hudson due to Rate Base growth as well as new customer rates and a higher allowed ROE effective July 1, 2024, partially offset by favourable regulatory adjustments recognized in 2023
[2] Includes FortisBC Energy, FortisAlberta and FortisBC Electric. Primarily reflects Rate Base growth, as well as higher earnings at FortisAlberta due to an increase in the allowed ROE, higher demand charges and customer growth, partially offset by higher operating expenses
[3] Primarily reflects Rate Base growth, partially offset by higher holding company finance costs
[4] Primarily reflects Rate Base growth and higher electricity sales
[5] Reflects average foreign exchange rate of 1.37 in 2024 compared to 1.35 in 2023, partially offset by a foreign exchange loss associated with the revaluation of U.S. dollar denominated liabilities at a rate of 1.44 at December 31, 2024
[6] Reflects higher holding company finance costs and unrealized losses on derivative contracts, partially offset by higher hydroelectric production in Belize
[7] Weighted average shares of 495.0 million in 2024 compared to 486.3 million in 2023

Dividends

Fortis paid a dividend of $0.615 per common share in the fourth quarter of 2024, up 4.2% from $0.59 paid in each of the previous four quarters. This marked the Corporation's 51st consecutive year of increases in dividends paid. The Adjusted Payout Ratio was 73% in 2024 and an average of 76% over the five-year period of 2020 through 2024.

Fortis is targeting annual dividend growth of approximately 4-6% through 2029. See "Outlook" on page 40.

51 CONSECUTIVE YEARS OF INCREASES IN DIVIDENDS PAID



Growth in dividends and changes in the market price of the Corporation's common shares have yielded the following TSRs.

TSR [1] *(%)*	**1-Year**	**5-Year**	**10-Year**	**20-Year**
Fortis	**14.1**	**6.1**	**8.4**	**10.3**

[1] Annualized TSR per Bloomberg, as at December 31, 2024

Operating Cash Flow

The $337 million increase in Operating Cash Flow was due to: (i) higher cash earnings, reflecting Rate Base growth, as well as new customer rates and higher sales at TEP; and (ii) the higher collection of flow-through costs at UNS Energy. Deposits received related to the construction of the Eagle Mountain Pipeline project and the receipt of an income tax refund at FortisBC Energy also favourably impacted Operating Cash Flow. The increase was partially offset by: (i) the timing of flow-through costs in customer rates as well as other changes in working capital balances at FortisBC Energy; (ii) the timing of flow-through transmission costs at FortisAlberta; (iii) higher interest payments; and (iv) the disposition of Aitken Creek in November 2023, which contributed approximately $110 million of operating cash flow in 2023.

Capital Expenditures

Capital Expenditures in 2024 were $5.2 billion, consistent with expectations and $0.9 billion higher than 2023. The increase compared to 2023 was primarily due to investments associated with the Eagle Mountain Pipeline project at FortisBC Energy, expenditures on various transmission reliability projects at ITC, and construction of the Roadrunner Reserve battery storage projects at UNS Energy.

Capital Expenditures is a Non-U.S. GAAP financial measure. Refer to "Non-U.S. GAAP Financial Measures" on page 10.

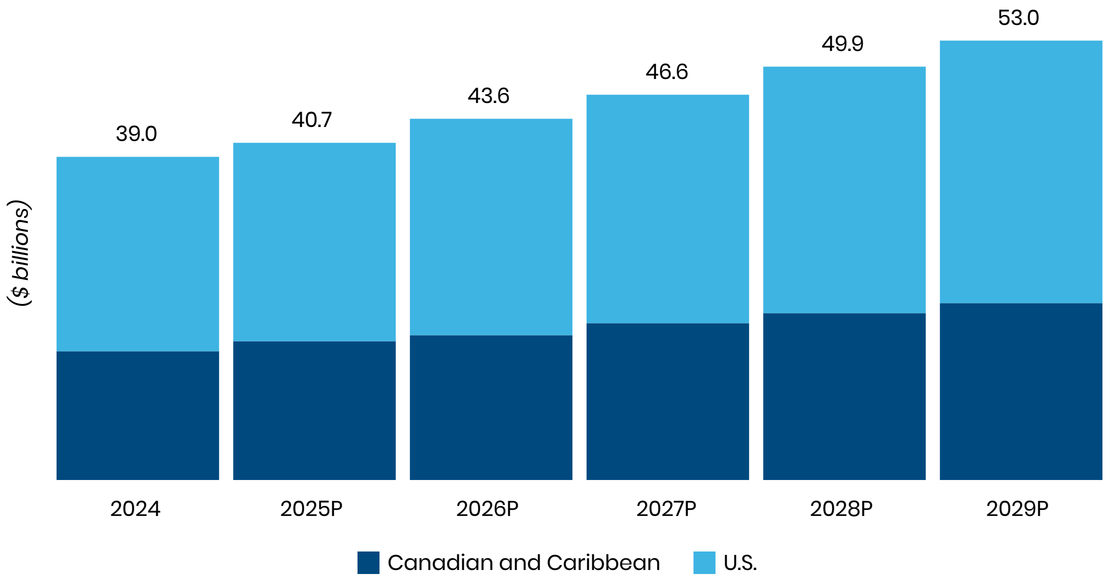
New Five-Year Capital Plan

The Corporation's 2025-2029 capital plan of $26.0 billion is the largest in the Corporation's history and is $1.0 billion higher than the previous five-year plan. The increase is driven by projects associated with the MISO LRTP and resiliency investments at ITC, as well as distribution investments largely due to customer growth at FortisAlberta. For a detailed discussion of the Corporation's capital expenditure program, see "Capital Plan" on page 19.

Funding of the capital plan is expected to be primarily through Operating Cash Flow and debt issued at the regulated utilities. Common equity proceeds are expected to be sourced from the Corporation's DRIP assuming current participation levels. The Corporation's $500 million ATM Program remains available and provides funding flexibility as required.

The five-year capital plan is expected to increase midyear Rate Base from $39.0 billion in 2024 to $53.0 billion by 2029, translating into a five-year CAGR of 6.5%.

PROJECTED RATE BASE [1]



(1) *Reflects average exchange rate of 1.37 for 2024 and exchange rate of 1.30 for 2025-2029. On average, Fortis estimates that a five-cent increase or decrease in the U.S. dollar relative to the Canadian dollar would increase or decrease Rate Base by approximately $1.1 billion over the five-year planning period*

Beyond the five-year capital plan, opportunities to expand and extend growth include: further expansion of the electric transmission grid in the U.S. to support load growth and facilitate the interconnection of cleaner energy; transmission investments associated with the MISO LRTP tranches 1, 2.1 and 2.2 as well as regional transmission in New York; grid resiliency and climate adaptation investments; renewable gas solutions and LNG infrastructure in British Columbia; and the acceleration of load growth and cleaner energy infrastructure investments across our jurisdictions.

THE INDUSTRY

The North American utility industry is undergoing significant transformation due to the need for energy security, the impacts of climate change, the transition to cleaner energy, and projected growth in load driven by data centers, manufacturing and electrification. These factors are creating significant investment opportunities for the sector.

Policy makers and regulators at the federal, state, and provincial levels are increasingly prioritizing matters of energy security, with many continuing to support the transition to cleaner energy. The conjunction of policy and forecasted load growth has resulted in opportunities to invest in renewable and natural gas generation, energy storage systems and transmission infrastructure. Electrification of transportation and heating continues to grow and represents another opportunity to reduce carbon emissions while increasing the output and efficiency of the grid.

Grid resilience continues to grow in importance with the increasing frequency and intensity of weather events such as extreme heat and cold, hurricanes, wildfires, floods and storms. With electricity expected to represent a larger portion of society's energy mix, investments in resiliency are necessary to improve the grid's ability to withstand and recover from climate events.

Diversity of energy supply and enhanced integration of energy systems are vital to deliver the resilience, energy, and capacity needed to support economic growth and energy demand. Electric transmission is a critical enabler of load growth, interconnecting large-scale generation while improving system resilience. Natural gas generation provides a reliable source of energy and capacity that will be an essential resource to meet growing energy needs. Natural gas investments, as well as energy storage solutions, will enable the adoption of additional renewable energy. Increased adoption of RNG and, in the longer-term, hydrogen will further contribute to carbon emissions reduction. The Corporation's utilities are well positioned and actively involved in pursuing these opportunities, which will drive significant capital investment, particularly at ITC, UNS Energy and in Western Canada.

New technology is stimulating change across the Corporation's service territories. Energy delivery systems are becoming more intelligent, with advanced meters, remote sensing, and grid automation. More capable operational technology provides utilities with detailed usage data, enhanced inspection capabilities, and predictive maintenance information, contributing to increased efficiency and more reliable energy delivery. Energy management capabilities are expanding through emerging storage, demand response, and distributed energy management systems.

Fortis' culture of innovation underlies a continuous drive to find better ways to safely, reliably and affordably deliver the energy and services that customers need. Fortis is a partner in Energy Impact Partners, a strategic private venture fund that invests in emerging technologies, products, services and business models that are transforming the industry. The Corporation is also involved in the Low Carbon Resources Initiative, a collaboration between EPRI and GTI Energy, along with other major utilities, to develop and demonstrate the low- and zero-carbon energy technologies needed to enable pathways to decarbonization. Fortis is also a member of EPRI's Climate READi, an initiative involving major North American utilities, regulators, policy makers, and other stakeholders focused on developing an industry-wide best practice framework for managing physical climate risk.

Meaningful customer engagement is important for utilities as customer expectations change. Customers want to make informed energy choices and become active participants in the delivery of their energy. They also expect personalized service, customized self-service offerings, and more real-time, digital communication. To respond to these changes, Fortis' utilities are enhancing customer information systems, adopting digital technologies including AI, and advancing new and modern approaches to customer engagement. At the same time, increased investment in cybersecurity is an ongoing priority in the context of an ever-changing threat landscape. Upgrades to the physical security environment are also required to keep pace with evolving challenges. These technological advancements and challenges offer strategic investment opportunities for Fortis' utilities.

The Corporation's culture and decentralized structure support our utilities' efforts to meet changing customer expectations, and to work constructively with regulators and all stakeholders on policy, energy and service solutions. Fortis is well positioned to support energy security, load growth and the clean energy transition across the Corporation's footprint.

OPERATING RESULTS

($ millions)	2024	2023	Variance FX	Variance Other
Revenue	**11,508**	11,517	108	(117)
Energy supply costs	**3,249**	3,771	32	(554)
Operating expenses	**3,040**	2,889	29	122
Depreciation and amortization	**1,927**	1,773	16	138
Other income, net	**288**	291	(10)	7
Finance charges	**1,406**	1,305	13	88
Income tax expense	**346**	360	1	(15)
Net earnings	**1,828**	1,710	7	111
Net earnings attributable to:				
Non-controlling interests	**148**	137	2	9
Preference equity shareholders	**74**	67	—	7
Common equity shareholders	**1,606**	1,506	5	95
Net earnings	**1,828**	1,710	7	111

Revenue

The decrease in revenue, net of foreign exchange, was due to lower flow-through commodity costs in customer rates at FortisBC Energy and Central Hudson. The decrease was also due to a reduction in the MISO base ROE at ITC, approved by FERC in October 2024, including retroactive application to prior periods (see "Regulatory Highlights - Significant Regulatory Matters" on page 12), and lower short-term wholesale sales revenue at UNS Energy. The decrease was partially offset by Rate Base growth and new customer rates at TEP and Central Hudson, effective September 1, 2023 and July 1, 2024, respectively.

Energy Supply Costs

The decrease in energy supply costs, net of foreign exchange, was due primarily to lower commodity costs, mainly at FortisBC Energy, Central Hudson, and UNS Energy.

Operating Expenses

The increase in operating expenses, net of foreign exchange, was due primarily to general inflationary and employee-related cost increases.

Depreciation and Amortization

The increase in depreciation and amortization, net of foreign exchange, was due to continued investment in energy infrastructure at the Corporation's regulated utilities, and new depreciation rates approved for TEP in September 2023 as part of its general rate application.

Other Income, Net

Other Income, net of foreign exchange, was relatively consistent with 2023. An increase in other income associated with higher AFUDC at UNS Energy and FortisBC Energy was largely offset by the pre-tax gain recognized in 2023 on the sale of Aitken Creek and net unrealized losses on derivative contracts.

Finance Charges

The increase in finance charges, net of foreign exchange, was due to higher debt levels to support the Corporation's capital plan, as well as higher interest rates on new debt issuances.

Income Tax Expense

The decrease in income tax expense, net of foreign exchange, was driven by higher production tax credits at UNS Energy, and the unfavourable $9 million deferred income tax adjustment recognized at ITC in 2023 following a reduction in the corporate income tax rate in the state of Iowa. The decrease was partially offset by higher earnings before taxes.

Net Earnings

See "Performance at a Glance - Earnings and EPS" on page 2.

BUSINESS UNIT PERFORMANCE

Common Equity Earnings

			Variance	
($ millions)	**2024**	2023	FX [1]	Other
Regulated Utilities				
ITC	**542**	508	8	26
UNS Energy	**448**	400	6	42
Central Hudson	**128**	105	3	20
FortisBC Energy	**293**	274	—	19
FortisAlberta	**181**	162	—	19
FortisBC Electric	**72**	68	—	4
Other Electric [2]	**163**	146	—	17
	1,827	1,663	17	147
Non-Regulated				
Corporate and Other [3]	**(221)**	(157)	(12)	(52)
Common Equity Earnings	**1,606**	1,506	5	95

(1) *The reporting currency of ITC, UNS Energy, Central Hudson, Caribbean Utilities, FortisTCI and Fortis Belize is the U.S. dollar. The reporting currency of Belize Electricity is the Belizean dollar, which is pegged to the U.S. dollar at BZ$2.00=US$1.00. Certain corporate and non-regulated holding company transactions, included in the Corporate and Other segment, are denominated in U.S. dollars*

(2) *Consists of the utility operations in eastern Canada and the Caribbean: Newfoundland Power; Maritime Electric; FortisOntario; Wataynikaneyap Power; Caribbean Utilities; FortisTCI; and Belize Electricity*

(3) *Consists of non-regulated holding company expenses, as well as earnings from long-term contracted generation assets in Belize. Also includes earnings from Aitken Creek up to the November 1, 2023 date of disposition*

ITC

			Variance	
($ millions)	**2024**	2023	FX	Other
Revenue [1]	**2,229**	2,085	33	111
Earnings [1]	**542**	508	8	26

(1) *Revenue represents 100% of ITC. Earnings represent the Corporation's 80.1% controlling ownership interest in ITC and reflect consolidated purchase price accounting adjustments.*

Revenue

The increase in revenue, net of foreign exchange, was due primarily to Rate Base growth and higher flow-through costs in customer rates. The increase was partially offset by a decrease in the MISO base ROE from 10.02% to 9.98%, as approved by FERC in October 2024, for the 15-month period from November 2013 through February 2015 and prospectively from September 2016 (See "Regulatory Highlights - Significant Regulatory Matters" on page 12).

Earnings

The increase in earnings, net of foreign exchange, was due primarily to Rate Base growth as well as an unfavourable $9 million deferred income tax adjustment recognized in 2023 following a reduction in the corporate income tax rate in the state of Iowa. The increase was partially offset by: (i) a decrease in the MISO base ROE from 10.02% to 9.98% as discussed above, which resulted in a $22 million reduction in earnings in 2024, including $20 million associated with the retroactive impact to prior periods; and (ii) higher holding company finance costs.

UNS Energy

			Variance	
($ millions, except as indicated)	**2024**	2023	FX	Other
Retail electricity sales *(GWh)*	**10,870**	10,786	—	84
Wholesale electricity sales *(GWh)* [1]	**5,810**	5,387	—	423
Gas sales *(PJ)*	**17**	17	—	—
Revenue	**3,007**	3,006	45	(44)
Earnings	**448**	400	6	42

(1) *Primarily short-term wholesale sales*

Sales

The increase in retail electricity sales was due primarily to warmer weather and customer additions.

The increase in wholesale electricity sales was driven by higher short-term wholesale sales, due to market conditions, partially offset by lower long-term wholesale sales due to the expiration of certain contracts. Revenue from short-term wholesale sales, which relate to contracts that are less than one-year in duration, is primarily credited to customers through the PPFAC mechanism and, therefore, does not materially impact earnings.

Gas sales were consistent with 2023.

Revenue

The decrease in revenue, net of foreign exchange, was due primarily to: (i) lower wholesale sales revenue, largely driven by unfavourable pricing on short-term wholesale sales; (ii) the recovery of overall lower fuel and non-fuel costs through the normal operation of regulatory mechanisms; and (iii) lower transmission revenue. The decrease was partially offset by new customer rates at TEP effective September 1, 2023.

Earnings

The increase in earnings, net of foreign exchange, was due primarily to: (i) new customer rates at TEP effective September 1, 2023, following the conclusion of the general rate application; (ii) higher production tax credits related to the Oso Grande generating facility; and (iii) higher margins on long-term wholesale sales. The increase was partially offset by: (i) higher depreciation expense, due to new depreciation rates also approved as part of the rate application; (ii) higher operating expenses, reflecting labour costs as well as an increase in planned generation maintenance in 2024; and (iii) lower transmission revenue.

Central Hudson

			Variance	
($ millions, except as indicated)	**2024**	2023	FX	Other
Electricity sales *(GWh)*	**5,060**	4,921	—	139
Gas sales *(PJ)*	**25**	24	—	1
Revenue	**1,372**	1,360	22	(10)
Earnings	**128**	105	3	20

Sales

The increase in electricity sales was due primarily to higher average consumption by residential and commercial customers due to warmer weather.

Gas sales were relatively consistent with 2023.

Changes in electricity and gas sales at Central Hudson are subject to regulatory revenue decoupling mechanisms and, therefore, do not materially impact earnings.

Revenue

The decrease in revenue, net of foreign exchange, was due primarily to the flow-through of lower energy supply costs driven by commodity prices, partially offset by the conclusion of Central Hudson's 2024 general rate application and related rebasing of customer rates effective July 1, 2024. Favourable regulatory adjustments recognized in 2023 that did not reoccur in 2024 also contributed to the decrease in revenue.

Earnings

The increase in earnings, net of foreign exchange, was due to Rate Base growth, as well as new customer rates reflecting the rebasing of costs and a higher allowed ROE effective July 1, 2024. The increase was partially offset by favourable regulatory adjustments recognized in 2023 that did not reoccur in 2024.

FortisBC Energy

($ millions, except as indicated)	**2024**	2023	Variance
Gas sales *(PJ)*	**220**	213	7
Revenue	**1,665**	1,955	(290)
Earnings	**293**	274	19

Sales

The increase in gas sales was due primarily to higher average consumption by industrial, residential and commercial customers.

Revenue

The decrease in revenue was due primarily to the recovery of lower flow-through commodity costs and the normal operation of regulatory mechanisms.

Earnings

The increase in earnings was due primarily to higher net investments in regulated assets.

FortisBC Energy earns approximately the same margin regardless of whether a customer contracts for the purchase and delivery of natural gas or only for delivery. Due to regulatory deferral mechanisms, changes in consumption levels and commodity costs do not materially impact earnings.

FortisAlberta

($ millions, except as indicated)	**2024**	2023	Variance
Electricity deliveries *(GWh)*	**17,324**	16,976	348
Revenue	**817**	738	79
Earnings	**181**	162	19

Deliveries

The increase in electricity deliveries was due primarily to customer additions and higher average consumption by industrial customers.

As approximately 85% of FortisAlberta's revenue is derived from fixed or largely fixed billing determinants, changes in quantities of energy delivered are not entirely correlated with changes in revenue. Revenue is a function of numerous variables, many of which are independent of actual energy deliveries. Significant variations in weather conditions, however, can impact revenue and earnings.

Revenue

The increase in revenue was due to: (i) Rate Base growth, including changes associated with the third PBR term beginning January 1, 2024; (ii) an increase in the allowed ROE from 8.50% to 9.28%, as approved by the AUC, effective January 1, 2024; and (iii) higher industrial and commercial demand charges, as well as customer additions.

Earnings

The increase in earnings was due to the higher allowed ROE, Rate Base growth, higher demand charges and customer additions, as discussed above. The increase was partially offset by higher operating expenses, primarily reflecting operational requirements driven by customer growth, including higher labour costs.

FortisBC Electric

($ millions, except as indicated)	**2024**	2023	Variance
Electricity sales *(GWh)*	**3,513**	3,478	35
Revenue	**545**	528	17
Earnings	**72**	68	4

Sales

The increase in electricity sales was due to higher average consumption by industrial customers, partially offset by lower average consumption by commercial customers.

Revenue

The increase in revenue was due primarily to higher electricity sales and Rate Base growth, as well as higher energy supply costs recovered from customers. The increase was partially offset by the normal operation of regulatory mechanisms.

Earnings

The increase in earnings was due primarily to Rate Base growth.

Due to regulatory deferral mechanisms, changes in consumption levels do not materially impact earnings.

Other Electric

($ millions, except as indicated)	2024	2023	Variance FX	Variance Other
Electricity sales *(GWh)*	**9,879**	9,753	—	126
Revenue	**1,838**	1,761	8	69
Earnings	**163**	146	—	17

Sales

The increase in electricity sales was mainly due to higher average consumption by residential and commercial customers, as well as customer additions. Higher average consumption was largely due to the conversion of home heating systems from oil to electric in Eastern Canada and increased tourism-related activities in the Caribbean.

Revenue

The increase in revenue, net of foreign exchange, was due to Rate Base growth, higher electricity sales and the flow-through of higher energy supply costs.

Earnings

The increase in earnings, net of foreign exchange, was due primarily to Rate Base growth and higher electricity sales.

Corporate and Other

($ millions)	2024	2023	Variance FX	Variance Other
Electricity sales *(GWh)* (1)	**215**	164	—	51
Revenue (2)	**35**	84	—	(49)
Net loss (3)	**(221)**	(157)	(12)	(52)

(1) Reflects electricity sales at Fortis Belize
(2) Includes revenue for Fortis Belize as well as revenue for Aitken Creek up to the November 1, 2023 date of disposition
(3) Includes non-regulated holding company expenses, earnings for Fortis Belize, as well as earnings for Aitken Creek up to the November 1, 2023 date of disposition

Sales

The increase in electricity sales reflected higher hydroelectric production in Belize associated with rainfall levels.

Revenue

The decrease in revenue reflected the disposition of Aitken Creek in November 2023, partially offset by higher hydroelectric production in Belize.

Net Loss

The increase in net loss was due to: (i) higher holding company finance costs; (ii) net unrealized losses on derivative contracts, reflecting losses on foreign exchange contracts partially offset by gains on total return swaps; and (iii) the $10 million gain on disposition of Aitken Creek recognized in 2023. The increase in net loss was partially offset by higher hydroelectric production in Belize.

The $12 million foreign exchange impact was largely due to the revaluation of U.S. dollar denominated liabilities following the significant depreciation in the Canadian dollar relative to the U.S. dollar in the fourth quarter of 2024.

NON-U.S. GAAP FINANCIAL MEASURES

Adjusted Common Equity Earnings, Adjusted Basic EPS, Adjusted Payout Ratio and Capital Expenditures are Non-U.S. GAAP Financial Measures and may not be comparable with similar measures used by other entities. They are presented because management and external stakeholders use them in evaluating the Corporation's financial performance and prospects.

Net earnings attributable to common equity shareholders (i.e., Common Equity Earnings) and basic EPS are the most directly comparable U.S. GAAP measures to Adjusted Common Equity Earnings and Adjusted Basic EPS, respectively. The Actual Payout Ratio calculated using Common Equity Earnings is the most comparable U.S. GAAP measure to the Adjusted Payout Ratio. These adjusted measures reflect the removal of items that management excludes in its key decision-making processes and evaluation of operating results.

Capital Expenditures include additions to property, plant and equipment and additions to intangible assets, as shown on the consolidated statements of cash flows. It also included Fortis' 39% share of capital spending for the Wataynikaneyap Transmission Power Project, consistent with Fortis' evaluation of operating results and its role as project manager during the construction of the project.

Non-U.S. GAAP Reconciliation

($ millions, except as indicated)	**2024**	2023	Variance
Adjusted Common Equity Earnings, Adjusted Basic EPS and Adjusted Payout Ratio			
Common Equity Earnings	**1,606**	1,506	100
Adjusting items:			
October 2024 MISO base ROE decision [(1)]	**20**	—	20
Disposition of Aitken Creek [(2)]	**—**	(15)	15
Unrealized loss on mark-to-market of derivatives [(3)]	**—**	2	(2)
Revaluation of deferred income tax assets [(4)]	**—**	9	(9)
Adjusted Common Equity Earnings	**1,626**	1,502	124
Adjusted Basic EPS [(5)] *($)*	**3.28**	3.09	0.19
Adjusted Payout Ratio [(6)] *(%)*	**72.7**	73.9	(1.2)
Capital Expenditures			
Additions to property, plant and equipment	**5,012**	3,986	1,026
Additions to intangible assets	**206**	183	23
Adjusting item:			
Wataynikaneyap Transmission Power Project [(7)]	**29**	160	(131)
Capital Expenditures	**5,247**	4,329	918

(1) Represents the prior period impact of FERC's October 2024 MISO base ROE decision (see "Regulatory Highlights - Significant Regulatory Matters" on page 12), net of income tax recovery of $7 million, included in the ITC segment

(2) Aitken Creek was sold on November 1, 2023, with a March 31, 2023 effective date. For the year ended December 31, 2023, the adjustment represents: (i) the $10 million gain on disposition, net of income tax expense of $13 million; and (ii) $5 million of net earnings at Aitken Creek, recognized in accordance with U.S. GAAP, during the March 31, 2023 to November 1, 2023 stub period, net of income tax expense of $2 million, included in the Corporate and Other segment

(3) Represents the impact of mark-to-market accounting of natural gas derivatives at Aitken Creek through the March 31, 2023 effective date of disposition, net of income tax recovery $1 million, included in the Corporate and Other segment

(4) Represents the revaluation of deferred income tax assets resulting from the reduction in the corporate income tax rate in the state of Iowa, included in the ITC segment

(5) Calculated using Adjusted Common Equity Earnings divided by weighted average common shares of 495.0 million in 2024 (2023 - 486.3 million)

(6) Calculated using dividends paid per common share of $2.39 in 2024 (2023 - $2.29) divided by Adjusted Basic EPS

(7) Represents Fortis' 39% share of capital spending for the Wataynikaneyap Transmission Power Project, included in the Other Electric segment. Construction was completed in the second quarter of 2024

REGULATORY HIGHLIGHTS

General

The earnings of the Corporation's regulated utilities are determined under COS regulation, with some using PBR mechanisms.

Under COS regulation, the regulator sets customer rates to permit a reasonable opportunity for the timely recovery of the estimated costs of providing service, including a fair rate of return on a deemed or targeted capital structure applied to an approved Rate Base. PBR mechanisms generally apply a formula that incorporates inflation and assumed productivity improvements for a set term.

The ability to recover prudently incurred costs of providing service and earn the regulator-approved ROE or ROA may depend on achieving the forecasts established in the rate-setting process. There can be varying degrees of regulatory lag between when costs are incurred and when they are recovered in customer rates. As well, the Corporation's regulated utilities, where applicable, are permitted by their respective regulators to flow through to customers, without markup, the cost of natural gas, fuel and/or purchased power through base customer rates and/or the use of rate stabilization and other mechanisms.

Transmission operations in the U.S. are regulated federally by FERC. Remaining utility operations in the U.S. and Canada are regulated by state or provincial regulators. Utility operations in the Caribbean are regulated by regulatory and governmental authorities.

Additional information about regulation and the regulatory matters discussed below is provided in Note 2 in the 2024 Annual Financial Statements. Also refer to "Business Risks - Utility Regulation" on page 22.

Significant Regulatory Matters

ITC

MISO Base ROE: In 2022, the D.C. Circuit Court issued a decision vacating certain FERC orders that had established the methodology for setting the base ROE for transmission owners operating in the MISO region, including ITC, and remanded the matter to FERC for further process. This matter dates back to complaints filed at FERC in 2013 and 2015 challenging the MISO base ROE then in effect.

In October 2024, FERC issued an order that removed the use of the risk premium model from the calculation of the base ROE, while maintaining other modifications to the methodology. The updated methodology revised the base ROE from 10.02% to 9.98%, with a maximum ROE inclusive of incentives not to exceed 12.58%. The order also directed the payment of certain refunds, with interest, by December 2025, for the 15-month period from November 2013 through February 2015, and prospectively from September 2016. A regulatory liability of $39 million (US$27 million) associated with the refunds has been recognized by ITC as of December 31, 2024. Fortis' 80.1% share of the related after-tax earnings impact was approximately $22 million, of which $20 million related to periods prior to January 1, 2024.

Certain MISO transmission owners, including ITC, filed a request for rehearing with FERC in November 2024, and filed an appeal of the order with the D.C. Circuit Court in January 2025. The requests for rehearing and appeal primarily focus on the refund period and the related interest. The timing and outcome of these filings are unknown.

Transmission Incentives: In 2021, FERC issued a supplemental NOPR on transmission incentives modifying the proposal in the initial NOPR released by FERC in 2020. The supplemental NOPR proposes to eliminate the 50-basis point RTO ROE incentive adder for RTO members that have been members for longer than three years. Although the timing and outcome of this proceeding remain unknown, every 10-basis point change in ROE at ITC impacts Fortis' annual EPS by approximately $0.01.

Transmission ROFR: In December 2023, the Iowa District Court ruled that the manner in which Iowa's ROFR statute was passed was unconstitutional. The statute granted incumbent electric transmission owners, including ITC, a ROFR to construct, own and maintain certain electric transmission assets in the state. The District Court did not make any determination on the merits of the ROFR itself, but did issue a permanent injunction preventing ITC and others from taking further action to construct the MISO LRTP tranche 1 Iowa projects in reliance on the ROFR.

MISO's decision with respect to the assignment of the tranche 1 LRTP projects was finalized on July 25, 2022. MISO is the only entity charged with determining what projects are to be competitively bid pursuant to its tariff. In May 2024, MISO commenced a variance analysis process as a result of the inability to construct a portion of the tranche 1 LRTP projects in Iowa due to the injunction imposed by the District Court. In August 2024, MISO concluded the variance analysis, which reaffirmed the original allocation of projects to ITC and other incumbent transmission owners. Approximately US$800 million of capital expenditures associated with the first tranche of MISO's LRTP in Iowa is reflected in Fortis' 2025-2029 capital plan. While the results of MISO's variance analysis process allow ITC to move forward with the development of its portion of tranche 1 LRTP projects in Iowa, various legal proceedings with respect to this matter are ongoing for which the timing and outcome are unknown.

UNS Energy

Generic Regulatory Lag Docket: In December 2024, the ACC approved a formula rate plan policy statement which allows utilities to propose formula rates in future rate cases. A formula rate plan, if approved by the ACC, would adjust rates annually based on a predetermined formula. A formula rate plan is expected to improve rate stability for customers, while also reducing regulatory lag and the number of existing rate adjusters.

UNS Gas General Rate Application: In November 2024, UNS Gas filed a general rate application with the ACC requesting an increase in gas delivery rates effective February 1, 2026. The application includes a request to set its ROE at 10.25% and a 56% common equity component of capital structure. In January 2025, UNS Gas filed supplemental material proposing an annual rate adjustment mechanism as a result of the ACC's formula rate policy statement discussed above. The timing and outcome of this proceeding are unknown.

Central Hudson

2025 General Rate Application: In August 2024, Central Hudson filed a general rate application with the PSC requesting an increase in electric and gas delivery rates effective July 1, 2025. The application includes a request to set Central Hudson's allowed ROE at 10% and a 48% common equity component of capital structure. The timing and outcome of this proceeding are unknown.

Show Cause Order: In October 2024, the PSC issued a Show Cause Order which directed Central Hudson to explain why the PSC should not initiate an enforcement proceeding in connection with a gas-related explosion that occurred in November 2023. Central Hudson filed its response in November 2024. The timing and outcome of the Show Cause Order are unknown.

FortisBC Energy and FortisBC Electric

2025-2027 Rate Framework: In April 2024, FortisBC filed an application with the BCUC requesting approval of a rate framework for the period 2025 through 2027. The rate framework builds upon the current multi-year rate plan and includes, amongst other items, updates to depreciation and capitalized overhead rates, a revised level of operation and maintenance expense per customer indexed for inflation less a fixed productivity adjustment factor, a similar approach to growth capital, a forecast approach to sustaining and other capital, continued collection of an innovation fund recognizing the need to accelerate investment in clean energy innovation, and the continued sharing with customers of variances from the allowed ROE. The rate framework also proposes the continuation of deferral mechanisms currently in place. A decision from the BCUC is expected in mid-2025.

FortisAlberta

GCOC Decision: In October 2023, the AUC issued a decision on the 2024 GCOC proceeding. In November 2023, FortisAlberta sought permission to appeal the GCOC decision to the Court of Appeal on the basis that the AUC erred in its decision to not adjust FortisAlberta's ROE and common equity component of capital structure to address incremental business risk associated with competition from REAs located in FortisAlberta's service area, as well as heightened regulatory risk due to the non-recovery of costs attributable to REAs. In April 2024, the Court of Appeal granted FortisAlberta permission to appeal, and a decision is expected in the first quarter of 2025.

Third PBR Term Decision: In October 2023, the AUC issued a decision establishing the parameters for the third PBR term for the period of 2024 through 2028. In November 2023, FortisAlberta sought permission to appeal the decision to the Court of Appeal on the basis that the AUC erred in its decision to determine capital funding using 2018-2022 historical capital investments without consideration for funding of new capital programs included in the company's 2023 cost of service revenue requirement as approved by the AUC. FortisAlberta's application for permission to appeal the decision was heard by the Court of Appeal in December 2024 and a decision is expected in the first quarter of 2025.

FINANCIAL POSITION

Significant Changes between December 31, 2024 and 2023

Balance Sheet Account	**Variance**		
($ millions)	**FX**	**Other**	**Explanation**
Cash and cash equivalents	**44**	**(449)**	Reflects the timing of a debt issuance at ITC in 2023, with proceeds reinvested in operating and capital requirements in 2024.
Other assets	**87**	**268**	Due primarily to an increase in employee future benefit assets, driven by higher discount rates as well as investment returns on DBP and OPEB plans.
Regulatory assets (current and long-term)	**126**	**121**	Due to changes associated with various regulatory mechanisms, including an increase in deferred income taxes and deferred energy management costs.
Property, plant and equipment, net	**2,423**	**3,648**	Reflects capital investments, partially offset by depreciation.
Accounts payable & other current liabilities	**119**	**262**	Due to an increase in trade accounts payable related to the Corporation's capital program, and an increase in customer deposits for the Eagle Mountain Pipeline project.
Regulatory liabilities (current and long-term)	**214**	**119**	Due to changes associated with various regulatory mechanisms including employee future benefit and future cost of removal deferrals, partially offset by the normal operation of rate stabilization accounts.
Deferred income taxes	**238**	**383**	Primarily due to higher temporary differences associated with ongoing capital investments.
Long-term debt (including current portion)	**1,655**	**2,028**	Reflects debt issuances, partially offset by debt repayments, as well as higher borrowings under committed credit facilities, in support of the Corporation's capital plan.
Shareholders' equity	**1,405**	**898**	Due primarily to: (i) Common Equity Earnings for 2024, less dividends declared on common shares; and (ii) the issuance of common shares, largely under the DRIP.

LIQUIDITY AND CAPITAL RESOURCES

Cash Flow Requirements

At the subsidiary level, it is expected that operating expenses and interest costs will be paid from Operating Cash Flow, with varying levels of residual cash flow available for capital expenditures and/or dividend payments to Fortis. Remaining capital expenditures are expected to be financed primarily from borrowings under credit facilities, long-term debt offerings and equity injections from Fortis. Borrowings under credit facilities may be required periodically to support seasonal working capital requirements.

Cash required of Fortis to support subsidiary growth is generally derived from borrowings under the Corporation's credit facilities, the operation of the DRIP, as well as issuances of long-term debt, preference equity, and common shares including those issued through the ATM Program. The subsidiaries pay dividends to Fortis and receive equity injections from Fortis when required. Both Fortis and its subsidiaries initially borrow through their credit facilities and periodically replace these borrowings with long-term financing. Financing needs also arise to refinance maturing debt.

Credit facilities are syndicated primarily with large banks in Canada and the U.S., with no one bank holding more than approximately 20% of the Corporation's total revolving credit facilities. Approximately $5.8 billion of the total credit facilities are committed with maturities ranging from 2025 through 2029. Available credit facilities are summarized in the following table.

Credit Facilities

As at December 31 *($ millions)*	Regulated Utilities	Corporate and Other	**2024**	2023
Total credit facilities [(1)]	4,396	1,946	**6,342**	6,176
Credit facilities utilized:				
Short-term borrowings	(98)	—	**(98)**	(119)
Long-term debt (including current portion)	(1,335)	(881)	**(2,216)**	(1,572)
Letters of credit outstanding	(81)	(21)	**(102)**	(101)
Credit facilities unutilized	2,882	1,044	**3,926**	4,384

(1) *Additional information about the Corporation's credit facilities is provided in Note 14 in the 2024 Annual Financial Statements*

In April 2024, FortisBC Energy increased its operating credit facility from $700 million to $900 million and extended the maturity to July 2028. In May 2024, FortisBC Electric increased its operating credit facility from $150 million to $200 million and extended the maturity to April 2028.

In May 2024, the Corporation extended the maturity on its unsecured US$500 million non-revolving term credit facility to May 2025. Half of the term credit facility was repaid in the third quarter of 2024 and the remaining US$250 million has been fully utilized as at December 31, 2024. The facility is repayable at any time without penalty. In June 2024, the Corporation amended its $1.3 billion revolving term committed credit facility to extend the maturity to July 2029.

In August 2024, Newfoundland Power increased its operating credit facility from $100 million to $130 million and extended the maturity to August 2029.

The Corporation's ability to service debt and pay dividends is dependent on the financial results of, and the related cash payments from, its subsidiaries. Certain regulated subsidiaries are subject to restrictions that limit their ability to distribute cash to Fortis, including restrictions by certain regulators limiting annual dividends and restrictions by certain lenders limiting debt to total capitalization. There are also practical limitations on using the net assets of the regulated subsidiaries to pay dividends, based on management's intent to maintain the subsidiaries' regulator-approved capital structures. Fortis does not expect that maintaining such capital structures will impact its ability to pay dividends in the foreseeable future.

As at December 31, 2024, consolidated fixed-term debt maturities/repayments are expected to average $1,484 million annually over the next five years and approximately 76% of the Corporation's consolidated long-term debt, excluding credit facility borrowings, had maturities beyond five years.

In December 2024, Fortis filed a short-form base shelf prospectus with a 25-month life under which it may issue common or preference shares, subscription receipts, or debt securities in an aggregate principal amount of up to $2.0 billion. Fortis also reestablished the ATM Program pursuant to the short-form base shelf prospectus, which allows the Corporation to issue up to $500 million of common shares from treasury to the public from time to time, at the Corporation's discretion, effective until January 10, 2027. As at December 31, 2024, $500 million remained available under the ATM Program and $1.5 billion remained available under the short-form base shelf prospectus.

Fortis is well positioned with strong liquidity. This combination of available credit facilities and manageable annual debt maturities/repayments provides flexibility in the timing of access to capital markets. Given current credit ratings and capital structures, the Corporation and its subsidiaries currently expect to continue to have reasonable access to long-term capital in 2025.

Fortis and its subsidiaries were in compliance with debt covenants as at December 31, 2024 and are expected to remain compliant in 2025.

Cash Flow Summary

Summary of Cash Flows

Years ended December 31

($ millions)	**2024**	2023	Variance
Cash and cash equivalents, beginning of year	**625**	209	416
Cash from (used in):			
Operating activities	**3,882**	3,545	337
Investing activities	**(5,395)**	(3,742)	(1,653)
Financing activities	**1,064**	613	451
Effect of exchange rate changes on cash and cash equivalents	**44**	—	44
Cash and cash equivalents, end of year	**220**	625	(405)

Operating Activities

See "Performance at a Glance - Operating Cash Flow" on page 4.

Investing Activities

The increase in cash used in investing activities primarily reflects higher capital expenditures in 2024, as well as the proceeds received in 2023 related to the disposition of Aitken Creek. See "Capital Plan" on page 19. Lower customer contributions in aid of construction also contributed to the year over year variance.

Financing Activities

Cash flows related to financing activities will fluctuate largely as a result of changes in the subsidiaries' capital expenditures and the amount of Operating Cash Flow available to fund those capital expenditures, which together impact the amount of funding required from debt and common equity issuances. See "Cash Flow Requirements" on page 14. The year over year increase in cash from financing activities also reflects the repayment of credit facility borrowings in 2023 with the proceeds received from the sale of Aitken Creek.

Debt Financing

Significant Long-Term Debt Issuances

Year ended December 31, 2024	Month Issued	Interest Rate (%)	Maturity		Amount ($ millions)	Use of Proceeds
ITC						
Secured senior notes	January	5.98	2034	**US**	**85**	(1) (2) (3)
First mortgage bonds	January	5.11	2029	**US**	**75**	(1) (2) (3)
First mortgage bonds	January	5.38	2034	**US**	**75**	(1) (2) (3)
Unsecured senior notes	May	5.65	2034	**US**	**400**	(3) (4)
First mortgage bonds	December	4.88	2035	**US**	**125**	(1) (2) (3)
First mortgage bonds	December	5.25	2043	**US**	**125**	(1) (2) (3)
UNS Energy						
Unsecured senior notes	May	5.60	2036	**US**	**30**	(1) (3)
Unsecured senior notes	August	5.20	2034	**US**	**400**	(3) (4)
Central Hudson						
Senior notes	April	5.59	2031	**US**	**25**	(1) (3)
Senior notes	April	5.69	2034	**US**	**35**	(1) (3)
Senior notes	October	4.88	2029	**US**	**25**	(3) (4)
Senior notes	October	5.30	2034	**US**	**44**	(3) (4)
Senior notes	October	5.40	2036	**US**	**35**	(3) (4)
FortisBC Electric						
Unsecured debentures	August	4.92	2054		**100**	(1)
FortisAlberta						
Unsecured debentures	May	4.90	2054		**300**	(1) (2) (3) (4)
Caribbean Utilities						
Unsecured senior notes	May	6.17	2039	**US**	**40**	(1) (2) (3)
Unsecured senior notes	May	6.37	2049	**US**	**40**	(1) (2) (3)
FortisOntario						
Unsecured senior notes	August	5.05	2054		**55**	(1)
Fortis						
Unsecured senior notes	September	4.17	2031		**500**	(1) (3) (4)

(1) *Repay short-term and/or credit facility borrowings*
(2) *Fund capital expenditures*
(3) *General corporate purposes*
(4) *Repay maturing long-term debt*

Common Equity Financing

Common Equity Issuances and Dividends Paid

Years ended December 31 *($ millions, except as indicated)*	2024	2023	Variance
Common shares issued:			
Cash (1)	**46**	43	3
Non-cash (2)	**435**	409	26
Total common shares issued	**481**	452	29
Number of common shares issued *(# millions)*	**8.7**	8.4	0.3
Common share dividends paid:			
Cash	**(744)**	(701)	(43)
Non-cash (3)	**(434)**	(408)	(26)
Total common share dividends paid	**(1,178)**	(1,109)	(69)
Dividends paid per common share *($)*	**2.39**	2.29	0.10

(1) *Includes common shares issued under stock option and employee share purchase plans*
(2) *Common shares issued under the DRIP and stock option plan*
(3) *Common share dividends reinvested under the DRIP*

On December 4, 2024 and February 13, 2025, Fortis declared a dividend of $0.615 per common share payable on March 1, 2025 and June 1, 2025, respectively. The payment of dividends is at the discretion of the Board and depends on the Corporation's financial condition and other factors.

On March 1, 2024, the annual fixed dividend per share for the First Preference Shares, Series K was reset from $0.9823 to $1.3673 for the five-year period up to but excluding March 1, 2029.

On December 1, 2024, the annual fixed dividend per share for the First Preference Shares, Series M was reset from $0.9783 to $1.3733 for the five-year period up to but excluding December 1, 2029.

Contractual Obligations

Contractual Obligations

As at December 31, 2024

($ millions)	**Total**	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Long-term debt:							
Principal [(1)]	**33,405**	1,990	2,585	2,541	1,499	1,024	23,766
Interest	**19,630**	1,371	1,343	1,252	1,162	1,116	13,386
Finance leases [(2)]	**1,139**	37	37	37	37	37	954
Other obligations [(3)]	**464**	127	110	100	22	21	84
Other commitments: [(4)]							
Gas and fuel purchase obligations	**6,299**	763	571	520	465	393	3,587
Renewable power purchase agreements	**2,628**	139	166	182	182	173	1,786
Waneta Expansion capacity agreement	**2,362**	56	58	59	60	61	2,068
Power purchase obligations	**1,335**	302	217	131	124	122	439
ITC easement agreement	**370**	14	14	14	14	14	300
TEP EPC agreements	**308**	307	1	—	—	—	—
Debt collection agreement	**99**	3	3	3	3	3	84
Renewable energy credit purchase agreements	**58**	18	7	6	6	6	15
Other	**140**	32	11	11	12	10	64
	68,237	5,159	5,123	4,856	3,586	2,980	46,533

(1) *Amounts not reduced by unamortized deferred financing and discount costs of $191 million. Additional information is provided in Note 14 of the 2024 Annual Financial Statements*

(2) *Additional information is provided in Note 15 of the 2024 Annual Financial Statements*

(3) *Primarily includes commitments with respect to long-term compensation and employee future benefit arrangements*

(4) *Represents unrecorded commitments. Additional information is provided in Note 27 of the 2024 Annual Financial Statements*

Other Contractual Obligations

The Corporation's regulated utilities are obligated to provide service to customers within their respective service territories. Capital Expenditures are forecast to be approximately $5.2 billion for 2025 and approximately $26.0 billion for the five-year 2025-2029 capital plan. See "Capital Plan" on page 19.

Under a funding framework with the Governments of Ontario and Canada, Fortis will contribute a minimum of approximately $165 million of equity capital to Wataynikaneyap Power, based on Fortis' proportionate 39% ownership interest and the final regulatory-approved capital cost of the related project. Wataynikaneyap Power has construction financing loan agreements in place and it is expected that long-term operating financing will replace the construction financing. In the event a lender under the loan agreements realizes security on the loans, Fortis may be required to accelerate its equity capital contributions, which may be in excess of the amount otherwise required of Fortis under the funding framework, to a maximum total funding of $235 million. Equity of $137 million has been contributed as of December 31, 2024.

UNS Energy has joint generation performance guarantees with participants at Four Corners and Luna, with agreements expiring in 2041 and 2046 respectively, and at San Juan and Navajo through decommissioning. The participants have guaranteed that in the event of payment default, each non-defaulting participant will bear its proportionate share of expenses otherwise payable by the defaulting participant. In exchange, the non-defaulting participants are entitled to receive their proportionate share of the generation capacity of the defaulting participant. In the case of San Juan and Navajo, participants would seek financial recovery from the defaulting party. There is no maximum amount under these guarantees, except for a maximum of $360 million for Four Corners. As at December 31, 2024, there was no obligation under these guarantees.

Off-Balance Sheet Arrangements

With the exception of letters of credit outstanding of $102 million as at December 31, 2024 and the unrecorded commitments in the table above, the Corporation had no off-balance sheet arrangements.

Capital Structure and Credit Ratings

Fortis requires ongoing access to capital and, therefore, targets a consolidated long-term capital structure that will enable it to maintain investment-grade credit ratings. The regulated utilities maintain their own capital structures in line with those reflected in customer rates.

Consolidated Capital Structure	2024		2023	
As at December 31	*($ millions)*	*(%)*	*($ millions)*	*(%)*
Debt [1]	**33,435**	**56.4**	29,364	55.7
Preference shares	**1,623**	**2.7**	1,623	3.1
Common shareholders' equity and non-controlling interests [2]	**24,230**	**40.9**	21,709	41.2
	59,288	**100.0**	52,696	100.0

(1) *Includes long-term debt and finance leases, including current portion, and short-term borrowings, net of cash*
(2) *Includes shareholders' equity, excluding preference shares, and non-controlling interests. Non-controlling interests represented 3.4% as at December 31, 2024 (December 31, 2023 - 3.5%)*

Outstanding Share Data

As at February 13, 2025, the Corporation had issued and outstanding 499.3 million common shares and the following First Preference Shares: 5.0 million Series F; 9.2 million Series G; 7.7 million Series H; 2.3 million Series I; 8.0 million Series J; 10.0 million Series K; and 24.0 million Series M.

The common shares of the Corporation have voting rights. The Corporation's first preference shares do not have voting rights unless and until Fortis fails to pay eight quarterly dividends, whether or not consecutive or declared.

If all outstanding stock options were converted as at February 13, 2025, an additional 1.5 million common shares would be issued and outstanding.

Credit Ratings

The Corporation's credit ratings shown below reflect its low business risk profile, diversity of operations, the stand-alone nature and financial separation of each regulated subsidiary, and the level of holding company debt.

As at December 31, 2024	Rating	Type	Outlook
S&P	A-	Issuer	Negative
	BBB+	Unsecured debt	
Morningstar DBRS	A (low)	Issuer	Stable
	A (low)	Unsecured debt	Stable
Moody's	Baa3	Issuer	Stable
	Baa3	Unsecured debt	

Capital Plan

Capital investment in energy infrastructure is required to ensure the continued and enhanced performance, reliability and safety of the electricity and gas systems, to meet customer growth, and to deliver cleaner energy.

Capital Expenditures in 2024 were $5.2 billion, consistent with expectations and $0.9 billion higher than 2023. The increase compared to 2023 was primarily due to investments associated with the Eagle Mountain Pipeline project at FortisBC Energy, expenditures on various transmission reliability projects at ITC, and construction of the Roadrunner Reserve battery storage projects at UNS Energy.

2024 Capital Expenditures (1)(2)

	Regulated Utilities									
($ millions, except as indicated)	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Other Electric	**Total Regulated Utilities**	**Non-Regulated Corporate and Other**	**Total**
Total	1,456	1,151	431	1,035	554	132	483	**5,242**	**5**	**5,247**

Forecast 2025 Capital Expenditures (2)

	Regulated Utilities									
($ millions, except as indicated)	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Other Electric	**Total Regulated Utilities**	**Non-Regulated Corporate and Other**	**Total (3)**
Total	1,403	1,276	462	687	624	179	540	**5,171**	**7**	**5,178**

2025-2029 Capital Plan (2)

($ billions)	2025	2026	2027	2028	2029	**Total (3)**
Five-year capital plan	5.2	5.2	5.6	5.4	4.6	**26.0**

(1) *See "Non-U.S. GAAP Financial Measures" on page 10. Reflects a U.S. dollar-to-Canadian dollar exchange rate of 1.37 for 2024*
(2) *Excludes the non-cash equity component of AFUDC*
(3) *Reflects an assumed U.S. dollar-to-Canadian dollar exchange rate of 1.30. On average, Fortis estimates that a five-cent increase or decrease in the U.S. dollar relative to the Canadian dollar would increase or decrease Capital Expenditures by approximately $600 million over the five-year planning period*

The Corporation's 2025-2029 capital plan of $26.0 billion is $1.0 billion higher than the previous five-year plan. The increase is driven by projects associated with the MISO LRTP and resiliency investments at ITC, as well as distribution investments largely due to customer growth at FortisAlberta.

The five-year capital plan is low risk and highly executable, with nearly all investments being regulated and only 23% relating to Major Capital Projects. Geographically, 58% of planned expenditures are expected in the U.S., including 29% at ITC, with 38% in Canada and the remaining 4% in the Caribbean.

The five-year capital plan is expected to be funded primarily by cash from operations and regulated utility debt. Common equity proceeds are expected to be provided by the Corporation's DRIP, assuming current participation levels. The Corporation's $500 million ATM Program remains available and provides funding flexibility as required.

Planned capital expenditures are based on detailed forecasts of energy demand as well as labour and material costs, including inflation, supply chain availability, general economic conditions, foreign exchange rates and other factors. These factors, including potential new or revised tariffs, could change and cause actual expenditures to differ from forecast. Fortis remains focused on maintaining customer affordability by controlling costs, investing in cleaner energy resulting in fuel savings for customers, utilizing available tax credits, and implementing innovative practices, among other initiatives.

Midyear Rate Base [1]

($ billions)	2024[2]	2025[2]	2029[2]
ITC	**12.5**	12.8	16.5
UNS Energy	**7.6**	7.7	10.7
Central Hudson	**3.2**	3.4	4.3
FortisBC Energy	**5.8**	6.3	8.7
FortisAlberta	**4.4**	4.7	5.7
FortisBC Electric	**1.7**	1.8	2.1
Other Electric	**3.8**	4.0	5.0
Total	**39.0**	40.7	53.0

(1) *Simple average of Rate Base at beginning and end of the year*
(2) *Reflects a U.S. dollar-to-Canadian dollar average exchange rate of 1.37 for 2024. 2025 and 2029 reflect an assumed U.S. dollar-to-Canadian dollar exchange rate of 1.30 consistent with the Corporation's 2025-2029 capital plan. On average, Fortis estimates that a five-cent increase or decrease in the U.S. dollar relative to the Canadian dollar would increase or decrease Rate Base by approximately $1.1 billion over the five-year planning period*

Total midyear Rate Base is forecast to grow to $53.0 billion by 2029 underpinned by the five-year capital plan, translating to a CAGR of 6.5%.

Major Capital Projects

($ millions)	Pre-2024	Actual 2024	Plan 2025-2029	Expected Completion
ITC				
MISO LRTP	25	**64**	1,704	Post-2029
UNS Energy				
IRP Related Generation	—	**1**	1,620	Various
Roadrunner Reserve Battery Storage Project 1	137	**286**	51	2025
Roadrunner Reserve Battery Storage Project 2	1	**115**	325	2026
Vail-to-Tortolita Transmission Project	152	**47**	253	2027
FortisBC Energy				
Eagle Mountain Pipeline Project [1]	50	**386**	314	2027
Tilbury LNG Storage Expansion	29	**6**	585	2029
AMI Project	7	**30**	733	2028
Tilbury 1B Project	44	**5**	339	2029
Total		**940**	5,924	

(1) *Net of customer contributions*

MISO LRTP

Reflects investments associated with two tranches of the MISO LRTP. In 2022, the MISO board approved the first tranche of projects representing 18 transmission projects across the MISO Midwest subregion with total associated costs estimated at US$10 billion. Six of these projects run through ITC's MISO operating companies' service territories. ITC estimates transmission investments of US$1.4 billion to US$1.8 billion through 2030 associated with six of the 18 projects, with investments of approximately $1.6 billion (US$1.2 billion) included in the Corporation's 2025-2029 capital plan.

Investments of approximately $0.2 billion (US$0.1 billion) have been included in the Corporation's 2025-2029 capital plan associated with tranche 2.1. Significant additional investment opportunities remain for tranche 2.1 (see "Additional Investment Opportunities" on page 21).

IRP Related Generation

Includes capital expenditures supporting the energy transition as outlined in the 2023 IRPs for TEP and UNS Electric including renewable generation, energy storage systems and natural gas generation. Investments support approximately 950 MW of generation, subject to all-source requests for proposals.

Roadrunner Reserve Battery Storage Projects

Consists of two, 200 MW, battery energy storage systems which will facilitate the integration of renewable energy into the electric grid. Each system is capable of storing 800 MW hours of energy, enough to serve approximately 42,000 homes for four hours when deployed at full capacity. TEP will own and operate the systems.

Construction of Roadrunner Reserve 1 has commenced and is scheduled for completion in 2025. In October 2024, TEP filed an application with the ACC requesting approval to defer certain costs associated with owning and operating Roadrunner Reserve 1 for future recovery. TEP cannot predict the timing or outcome of this application.

In August 2024, TEP entered into an EPC agreement to develop Roadrunner Reserve 2, which is scheduled for completion in 2026.

Vail-to-Tortolita Transmission Project
Includes investment in one circuit of a new double circuit 230 kilovolt transmission line to tie infrastructure into the TEP system, improving service and reliability to customers. Construction commenced in late 2023, and is scheduled for completion in 2027.

Eagle Mountain Pipeline Project
The project consists of a 50-km pipeline expansion to a small-scale LNG facility owned by Woodfibre LNG near Squamish, British Columbia. FortisBC Energy commenced construction of the project in 2023 which is scheduled for completion in 2027.

Tilbury LNG Storage Expansion Project
This project replaces the original LNG storage tank at the Tilbury site and increases the available regasification capacity to provide backup gas supply for lower mainland customers. The regulatory process was adjourned in 2023 in order for FortisBC Energy to prepare further information in support of the CPCN application. In October 2024, FortisBC Energy filed the additional information requested. A decision from the BCUC is expected in late 2025.

AMI Project
The project includes replacement of residential, commercial and industrial meters with advanced gas meters to support the safety, resiliency, and efficient operation of FortisBC Energy's gas distribution system. The project will enable remote meter reading and remote shutoff of gas. The CPCN application was approved by the BCUC in 2023, and installation of the advanced meters is expected to commence in 2025 and be substantially complete in 2028.

Tilbury 1B Project
Construction of additional liquefaction and dispensing, including on-shore piping, in support of marine bunkering and to further optimize the Tilbury Phase 1A Expansion Project. This FortisBC Energy project received an Order in Council from the Government of British Columbia in 2017. An initial project scope has been filed with regulators to support the federal impact assessment and provincial environmental assessment required to further expand the Tilbury site.

Additional Investment Opportunities

Fortis is pursuing additional investment opportunities within existing service territories that are not yet included in the five-year capital plan.

ITC
The MISO LRTP is expected to consist of several tranches. The opportunity associated with the first tranche of projects is outlined above. In December 2024, the MISO board of directors approved a portfolio of tranche 2.1 LRTP projects with estimated transmission costs of approximately US$22 billion. ITC now estimates a range of US$3.7 billion to US$4.2 billion in capital expenditures for the MISO tranche 2.1 projects located in Michigan and Minnesota where ROFRs are in effect and for projects requiring system upgrades in Iowa which are not subject to a competitive bidding process. A majority of the tranche 2.1 investment is expected beyond 2029.

In October 2024, ITC in collaboration with another Midwest U.S. energy company, received MISO approval for the Big Cedar Load Expansion Project in Iowa. The project will consist of two phases and includes transmission upgrades to serve up to 1,600 MW of new data center load at the Big Cedar Industrial Center. The first phase of the project requires transmission upgrades to support 800 MW of new load with a targeted in-service date of 2027, and phase two requires an additional 800 MW with an expected in-service date of 2028. The project requires franchise approvals from the Iowa Utilities Commission prior to construction. The project has a potential investment of up to US$400 million.

UNS Energy
TEP is experiencing significant interest from potential new large retail customers in the manufacturing, data center, and mining sectors with energy demands that could create substantial new energy needs. TEP continues to work with the potential companies to assess capital requirements and associated timelines.

FortisBC Energy - LNG
During 2024, provincial and federal environmental assessment certificates were issued for the Tilbury Marine Jetty project. The construction of the jetty supports further expansion of FortisBC's Tilbury LNG facility, which is uniquely positioned to meet customer demand for LNG. The site is scalable, can accommodate additional storage and liquefaction equipment and is close to international shipping lanes. Once constructed, the jetty would utilize FortisBC Energy's assets at the Tilbury site, including the Tilbury Phase 1B Project yet to be constructed, to service marine bunkering.

Other Opportunities
Includes incremental transmission investment and grid modernization projects at ITC; projects related to the 2023 IRPs as well as transmission investments at UNS Energy; regional transmission in New York; further renewable gas and LNG infrastructure opportunities in British Columbia; grid resiliency and climate adaptation investments; and the acceleration of load growth and cleaner energy infrastructure investments across our jurisdictions.

GHG Emissions Reduction Targets

Fortis is primarily an energy delivery company with 93% of its assets related to transmission and distribution. This limits the impact of the Corporation's utilities on the environment when compared to more generation-intensive businesses. Fortis has a relatively small amount of fossil-fuel generation in its portfolio and plans to transition to more renewable sources of energy for its customers.

Fortis continues to lower its already low emissions profile, and has set a 2050 net-zero direct GHG emissions target. This goal is in addition to the Corporation's interim targets to reduce direct GHG emissions 50% by 2030 and 75% by 2035 from a 2019 base year. Fortis expects to achieve its targets primarily through TEP's plan to exit from coal, as well as clean energy initiatives across the Corporation's other utilities. The Corporation's ability to achieve the GHG targets may be impacted by federal, state and provincial energy policies, as well as external factors, including significant customer and load growth and the development of clean energy technology. Reliability and affordability will remain key priorities as Fortis works to meet its emissions reduction targets.

Through 2024, Fortis has made significant progress on its emissions reduction targets with the Corporation's Scope 1 emissions 34% lower compared to 2019 levels. The retirement of certain coal generating stations, the commencement of seasonal operations at other generating stations, and the introduction of renewable wind and solar energy in Arizona, have supported our carbon emissions reduction to date.

Climate-Related Disclosure Standards

In December 2024, the CSSB issued CSDS S1, *General Requirements for Disclosure of Sustainability-Related Financial Information*, and CSDS S2, *Climate-Related Disclosures*, which require an entity to disclose information about its sustainability-related and climate-related risks and opportunities, including the disclosure of material Scope 1, 2 and 3 GHG emissions. The CSSB standards are voluntary and must be adopted by the CSA to become mandatory for Canadian reporting issuers, including Fortis. The CSA continues to work towards a revised climate-related disclosure rule that will consider the CSSB standards and may include modifications considered appropriate for Canadian capital markets. The content and timing of the CSA's revised climate-related disclosure rule are unknown. Fortis will continue to monitor updates from the CSA to assess any potential impact on the Corporation's disclosures.

In March 2024, the SEC released Rule No. 33-11275, *The Enhancement and Standardization of Climate-Related Disclosures for Investors*, which outlines climate-related disclosure requirements. The rule requires disclosure of the financial effects of severe weather events and other natural conditions, as well as other climate-related financial information, in the notes to the financial statements. In addition, the rule requires disclosure of risk management, governance and oversight activities, the impact of material climate-related risks on a company's strategy, business model and outlook, and details of material climate-related targets or goals. Disclosure of material Scope 1 and 2 GHG emissions is also required for certain filers. The SEC subsequently voluntarily stayed the rule pending completion of judicial review by the Court of Appeals for the Eighth Circuit. While the rule does not apply to Fortis as a foreign private issuer filing in the U.S. using Form 40-F, management is reviewing the standard to assess the potential impact on the Corporation's disclosures.

BUSINESS RISKS

Fortis has an ERM program that identifies and evaluates the severity and probability of risks to its business. The Fortis Board, through its audit committee, oversees Fortis' ERM program ensuring that management has an effective risk management system to support strategic planning. The ERM program at the subsidiary level is overseen by each subsidiary's board of directors and any material risks identified form part of Fortis' ERM program. Materiality thresholds are reviewed annually. Systems of internal controls are used by management to monitor and manage identified risks. A summary of the Corporation's significant business risks follows.

Utility Regulation

Regulated utility assets represented virtually all of the Corporation's total assets as at December 31, 2024. Regulatory jurisdictions include five Canadian provinces, ten U.S. states and three Caribbean countries, as well FERC regulation for transmission assets in the U.S.

Regulators administer legislation covering material aspects of the utilities' business including: customer rates, allowed ROEs and deemed capital structures; capital expenditures; the terms and conditions for the provision of energy and capacity, ancillary services and affiliate services; securities issuances; and certain accounting matters. Regulatory or legislative changes and decisions, and delays in the recovery of costs in rates due to regulatory lag, could have a Material Adverse Effect. The risk of regulatory lag may be significant for UNS Energy given the past practice of its regulator to use historical test years in setting customer rates.

The ability to recover the actual cost of service and earn the approved ROE or ROA typically depends upon achieving the forecasts established in the rate-setting process. For those utilities subject to PBR mechanisms, rates reflect assumed inflation rates and productivity improvement factors, and variances therefrom could adversely affect rates of return. Failure to recover costs and/or earn a return could have a Material Adverse Effect.

For transmission operations, the underlying elements of FERC-established formula rates can be challenged by third parties which could result in rate reductions and customer refunds. These underlying elements include the ROE, ROE adders and deemed capital structure, as well as operating and capital expenditures.

In addition, the U.S. Congress periodically considers enacting energy legislation that could assign new responsibilities to FERC, modify provisions of the U.S. *Federal Power Act* or the *Natural Gas Act*, or provide FERC or another entity with increased authority to regulate U.S. federal energy matters.

While Fortis is well-positioned to maintain constructive regulatory relationships through local management teams and subsidiary boards of directors comprised mostly of independent local members, it cannot predict future legislative or regulatory changes, whether caused by economic, political or other factors. The Corporation and its utilities may experience challenges and compliance costs in responding to such regulatory changes in an effective and timely manner. Any such regulatory changes or operational impacts could have a Material Adverse Effect.

Physical Risks

The provision of electric and gas service is subject to physical risks, including impacts from severe weather and natural disasters, wars, terrorism, vandalism, critical equipment failure and other catastrophic events, including wildfires, within and outside the Corporation's service territories.

Electric utilities face risk of loss or damage from wildfires, floods, hurricanes, storm surges, washouts, landslides, earthquakes, avalanches, snow or ice storms, and other acts of nature. Further, certain utilities operate in remote or mountainous terrain that can be difficult to access for timely repairs and maintenance.

Gas utilities are exposed to operational risks associated with natural gas, including fires, explosions, pipeline corrosion and leaks, accidental damage to mains and service lines, equipment failure, damage and destruction from earthquakes, fires, floods and other natural disasters.

Accidents or natural disasters affecting any of the Corporation's electricity or gas utilities can lead to service disruption, spills and commensurate environmental or other liability.

In addition, the operation of electric and gas systems has the potential to cause fires, including wildfires as a result of equipment failure, falling trees, lightning strikes to lines or equipment, or otherwise. The risks associated with fire damage vary depending on weather, forestation, the proximity of habitation and third-party facilities to utility facilities, and other factors. Failure to adequately address the risk of fire and wildfires could result in civil actions and government enforcement proceedings and utilities may become liable for fire-suppression costs, regeneration and timber value costs, and third-party losses if their facilities are determined to have been responsible for, or contributed to, a fire or wildfire.

Generating equipment and facilities are subject to physical risks, including equipment breakdown or damage from fire, floods or other natural disasters, that may result in the uncontrolled release of water, interruption of fuel supply, lower-than-expected operational efficiency or performance, and service disruption.

Electricity and gas systems require ongoing maintenance, improvement and replacement. The utilities are responsible for operating and maintaining their assets in a safe manner, including the development and application of appropriate standards, system processes and/or procedures to ensure the safety of employees, contractors and the general public.

If service disruption, or damage arising from, or caused by, the failure to properly implement or complete approved maintenance and capital expenditures, severe weather or other physical risks, is not mitigated through insurance policies or the recovery of such costs in customer rates, such service disruption or damage could result in loss.

Any of the foregoing potential impacts of physical risk could have a Material Adverse Effect.

The foregoing physical risks can be exacerbated by the "Climate Change" risks discussed below.

Climate Change

Climate-Related Physical Risk

Climate change may negatively impact the ability to provide reliable and safe electric and gas service. A changing climate that leads to higher temperatures and more frequent and severe weather events may impact or disrupt the reliability of electric or gas systems. The physical risks associated with a changing climate requires the Corporation’s utilities to adapt and respond to continue delivering reliable service to customers.

Severe weather and events related to severe weather impact the Corporation's service territories, primarily in the form of thunderstorms, flooding, drought, extreme heat, wildfires, hurricanes, storm surges, atmospheric rivers and snow, or ice storms. Increased frequency of such events could increase the cost of providing service through increased repairs and use of contingency plans. Extreme weather conditions and changes in air temperature require system backup and can result in system stress, including service disruptions, and decreased efficiency of operating facilities over time. Changes in precipitation that impact soil moisture and water levels, or result in droughts, could increase the risk of wildfire caused by the Corporation's electricity assets or may cause water shortages that could adversely affect operations.

Longer-term climate change impacts, such as sustained higher temperatures, higher sea levels, larger storm surges and floods, could result in service disruption, shortened asset life, increased repair and replacement costs, and costs associated with strengthened design standards and systems. The impacts of climate change can intensify the "Physical Risks" (see "Physical Risks" on page 23).

The physical risks posed by the impacts of climate change and resultant damage to assets, service disruption repair and replacement costs, and liability for third party damages could have a Material Adverse Effect if not resolved in a timely and effective manner and/or mitigated through insurance policies or regulatory cost recovery. An increase in business risk associated with climate change can also impact credit ratings, which could affect credit risk spreads on new long-term debt and credit facilities, as well as their availability (see "Access to Capital" on page 28).

Climate-Related Transition Risk

A transition towards decarbonization and further renewable energy use elevates risks associated with policy, legal, technological and market changes which may have capital and financial implications for the Corporation and its utilities.

The transition to cleaner energy will require the Corporation's utilities to effectively manage, among other things, evolving regulatory and legislative requirements, new resiliency standards, the integration of new technologies and impacts on customer demand and rates. Failure to appropriately respond to climate change and decarbonize may disrupt the ability of the utilities to provide safe and cost-effective service, which could cause reputational harm and other impacts.

Fortis expects changes to government policy and regulation to continue in the coming years (see "Environmental Regulation" on page 25). Further, the emergence of initiatives designed to reduce GHG emissions, increase renewable energy use, and control or limit the effects of climate change has increased the incentive for the development of new technologies that produce renewable energy, enable more efficient storage of energy and reduce energy consumption. As new technologies become widely available, infrastructure design risks and time delays may emerge. Utility energy delivery systems will require technological changes and updates in order to effectively deliver increasing amounts of renewable energy to customers (see "Technology Developments and AI" on page 25).

The availability of regulatory mechanisms or the ability of the Corporation's utilities to pass related costs on to customers remains uncertain. Regulatory lag in relation to the adoption of climate change initiatives and/or the availability of regulatory recovery mechanisms in certain jurisdictions could contribute to financial harm to Fortis and its utilities (see "Utility Regulation" on page 22).

Technological advancements will be required in order for the Corporation to achieve its net-zero target while preserving system reliability and customer affordability. In addition to the development and implementation of relevant energy technologies, the Corporation's ability to achieve its GHG targets depends upon many factors, including the impact of federal, provincial and state energy policies, significant load and customer growth, the size of the Corporation's service territory, or the adoption of alternative energy products by the public, any of which could cause actual results and the ability to achieve such targets to materially differ from expectations. The ultimate impact of achieving or failing to achieve such targets could cause reputational damage which could result in a Material Adverse Effect.

Cybersecurity and Information and Operations Technology

As operators of critical energy infrastructure, the Corporation's utilities are at risk of cybercrime, including cyberattacks, data breaches, cyber extortion, and similar compromises. As with other businesses, our information systems and the information systems of our third-party vendors are targeted by malware, phishing efforts, and other cyberattacks. Certain of the information systems of the Corporation's utilities have been subjected to direct and/or third-party cybersecurity breaches, including unauthorized access, none of which have been material. We expect to be targeted by similar attacks in the future. The ability of the Corporation's utilities to operate effectively is dependent upon using and maintaining complex information systems and infrastructure that: (i) support the operation of generation, transmission and distribution facilities, including electric and gas facilities; (ii) provide customers with billing, consumption and load settlement information, where applicable; and (iii) support financial and general operations.

Information and operations technology systems, including those of the Corporation's third-party service providers, may be vulnerable to unauthorized access or disruption due to cyber and other attacks, including hacking, malware, acts of war or terrorism, and acts of vandalism, among others. Further, geopolitical conflicts and the advancement of AI and generative AI may further increase the scale, sophistication or frequency of cyberattacks from malicious actors, some of which actions may even be initiated by or connected with nation-state actors.

Any such event could result in the disruption of energy service and other business operations, including safety disruptions, disruption of internal control processes, property damage, reputational damage, corruption or unavailability of critical data, loss of assets, and the theft, loss, misappropriation and/or disclosure of sensitive, confidential and proprietary business information, intellectual property, or personal information of customers and/or employees. The Corporation's exposure to these risks increases as the Corporation continues to partner with third-party providers (see "Reliance on Supply Chain and Third Parties" on page 28).

A material cybersecurity breach of the Corporation's information security systems or those of a third-party service provider, or any delay or failure in assessing the materiality of such breach and related reporting/disclosure, could expose the Corporation to significant remediation costs and/or adversely affect the operations and financial performance of the Corporation, its reputation and standing with customers, regulators and financial markets, and expose it to claims for third-party damages or regulatory penalties. The resultant financial impacts may not be fully covered by insurance policies or, in the case of utilities, through regulatory cost recovery, and could have a Material Adverse Effect.

Growth

Fortis has a history of both growth through acquisitions and organic growth from capital investment in existing service territories. The Corporation's dividend growth guidance is significantly dependent upon achieving the Rate Base growth expected from the execution of the five-year capital plan as described under "Capital Plan" on page 19. Projects, particularly Major Capital Projects, are subject to risks of delay and cost overruns during construction caused by commodity price fluctuations, supply and labour costs, potential new or revised tariffs, supply chain constraints, supplier non-performance, weather, geologic conditions or other factors beyond the Corporation's control. There is no assurance that regulators will approve: (i) all of the planned projects or their amounts or timing; (ii) permits in a timely manner, or with reasonable terms and conditions; or (iii) the recovery of cost overruns in customer rates, which may have a Material Adverse Effect.

Health and Safety

The operations of the Corporation's utilities inherently involve risk to the health and safety of both employees and the public. Personal injury or loss of life could result from failure to implement or observe appropriate health and safety procedures and gives rise to operational, reputational or financial impacts, any of which could have a Material Adverse Effect. In addition, failure to comply with health and safety regulations could result in fines, penalties, reputational damage, litigation, increased capital and operating costs or adverse regulatory outcomes.

Political Environment

The political environment, at the local, national or global level, may impact energy laws, governmental energy policies or regulatory decisions. For example, political pressure or intervention to address energy prices and customer affordability concerns may impact regulatory decisions, as well as the period over which the Corporation’s utilities recover allowed costs.

The business is further exposed to risks associated with international relations and geopolitical events. Political, economic or social instability or events, trade disputes, new or revised tariffs, changes in laws or the imposition of onerous regulations applicable to existing operations, currency restrictions, and the impacts of changes in political leadership could lead to an increase in commodity prices, impact the availability and cost of energy or generally affect global economic conditions, any of which could have a Material Adverse Effect (see "Environmental Regulation" below and "General Economic Conditions" on page 27).

Technology Developments and AI

New technology developments in distributed generation, particularly solar, and energy efficiency products and services, as well as the implementation of renewable energy and energy efficiency standards, will continue to impact retail sales. Heightened awareness of energy costs and environmental concerns have increased demand for products that reduce energy consumption. The Corporation's utilities are also promoting demand-side management programs. New technologies available to customers include energy derived from renewable sources, customer-owned generation, energy-efficient appliances, battery storage and control systems. Advances in these or other technologies could have a significant impact on retail sales with a potential Material Adverse Effect. Additionally, advances in AI or generative AI could cause disruption to our business and, if we are unable to acquire, develop, implement or adopt new technology, we may suffer a competitive disadvantage, which could also have an adverse effect on our results of operations, financial condition and/or liquidity.

Further, the implementation of new information technology systems and emerging technologies, such as cloud computing, AI and generative AI into the business, including those impacting utility operations, customer billing systems and cybersecurity threat monitoring, carries risk that any such technology or system will not operate as expected. Failure to maintain, upgrade, replace or properly implement such new technology or systems could result in increased risk of a cybersecurity incident and have an adverse effect on operational efficiency, revenue or reputation (see "Cybersecurity and Information and Operations Technology" on page 24).

Environmental Regulation

The Corporation's businesses are subject to environmental laws and regulations, including those which concern emissions into the air, discharges into water or soil, use of water, hazardous waste disposal and containment, and the investigation and remediation of contamination, among others.

The risk of contamination of air, soil and water associated with electricity operations primarily relates to: (i) the transportation, handling, storage and combustion of fuel; (ii) the use of petroleum-based products, mainly transformer and lubricating oil; (iii) the management and disposal of coal combustion residuals and other wastes; and (iv) accidents resulting in hazardous release at or from coal mines that supply generating facilities. Contamination risks at gas operations primarily relate to leaks and other accidents involving gas systems. The key environmental risks for hydroelectric generation operations include dam failures and the creation of artificial water flows that may disrupt natural habitats.

Failure to comply with environmental laws and regulations, or to obtain or comply with any necessary environmental permits pursuant to such laws and regulations, could result in injunctions, fines or other penalties. Further, liabilities relating to contamination investigation and remediation, and related claims for personal injury or property damage, may arise at many locations, including formerly and currently owned/operated properties and waste treatment or disposal sites, regardless of whether such contamination was caused by the business at the time it owned the property, whether it resulted from non-compliance with applicable environmental laws and regulations, or whether it resulted from any act or omission of the business. These liabilities could result in substantial monetary judgments for clean-up costs, damages, fines and/or penalties. To the extent not fully covered by insurance or through regulatory mechanisms, these foregoing costs could have a Material Adverse Effect.

Environmental laws and regulations continue to develop and may result in significant additional expense. In particular, the management of GHG emissions and related decarbonization requirements is a concern due to new and emerging federal, state and provincial GHG laws, regulations and guidelines. Regulation and the pace of regulatory change to address reliability, resiliency, resource planning and safety is expected to increase. Future legislation could impact generation assets, operations, energy supply, operational costs, reporting obligations and other material aspects of the Corporation's business. Increased compliance costs or additional operating restrictions from revised or additional regulation could have a Material Adverse Effect (see "Climate Change" at page 23).

Natural Gas Competitiveness

Approximately 18% of the Corporation's revenue is derived from the delivery of natural gas. In British Columbia, which accounts for 79% of the Corporation's natural gas revenue, natural gas primarily competes with electricity for space and hot water heating load. Upfront capital costs for gas service continue to present competitive challenges for natural gas compared to electricity service. If gas becomes less competitive due to price or other factors, such as government policy or public perception of natural gas or its carbon intensity relative to other energy sources, the ability to add new customers could be impaired. Existing customers could also reduce their consumption or switch to electricity, placing further pressure on rates and, in the extreme, could ultimately lead to an inability to recover the utility's cost of service through customer rates.

Government policy could further impact the competitiveness of natural gas in British Columbia. As governments develop policies to address climate change, any resultant changes to energy policy may impact the competitiveness of natural gas relative to other energy sources.

Additionally, there are other competitive challenges that are impacting the penetration of natural gas into new housing stock such as the carbon intensity of the energy source and the type of housing stock being built. As part of their own climate change policy plans, local governments may use various tools at their disposal such as franchise agreements, permits, building codes and zoning bylaws to impose limitations on energy sources permitted in new and existing developments. Municipalities can also provide incentives, such as higher density allowance, to builders to adopt carbon free energy options for their developments. These actions and policies may hinder the Corporation's ability to attract new natural gas customers or retain existing customers.

A decrease in the competitiveness of natural gas due to pricing, government policy or other factors could have a Material Adverse Effect.

Weather Variability and Seasonality

Electricity consumption varies significantly in response to seasonal weather changes which have been and will continue to be impacted by climate change (see "Climate Change" on page 23). Cool summers may reduce the use of air conditioning and other cooling equipment, while warmer and less severe winters may reduce heating load. Alternatively, severe weather could unexpectedly increase heating and cooling loads, negatively impacting system reliability. Hydroelectric generation is sensitive to rainfall levels and unexpected variations in seasonal rainfall levels can negatively impact operations.

Weather and seasonality have a significant impact on gas distribution volumes as a major portion of natural gas is used for space heating by residential customers. The earnings of the Corporation's gas utilities are typically highest in the first and fourth quarters. Regulatory deferral and revenue decoupling mechanisms are in place at certain of the Corporation's utilities to minimize the volatility in earnings that would otherwise be caused by variations in weather conditions. The absence or the discontinuance of key regulatory mechanisms could result in significant and prolonged weather variations from seasonal norms having a Material Adverse Effect.

Required Approvals

The acquisition, ownership and operation of electric and gas businesses require numerous licences, permits, agreements, orders, certificates, consultations, and other approvals from various levels of government, regulators, government agencies and/or other third parties. There is no assurance that: (i) such approvals will be obtained, continuously maintained or renewed without delay; and (ii) the terms and conditions thereof will be fully complied with at all times and will not change in a material adverse manner. Significant failures in these regards could prevent the operation of the businesses and have a Material Adverse Effect.

Reliability Standards

The Energy Policy Act of 2005 provides for a regulatory framework which requires owners, operators and users of the bulk electric system in the U.S. to meet mandatory reliability standards developed by the North American Electric Reliability Corporation and its regional entities, which are approved and enforced by FERC. Many of these, or similar, standards have been adopted in certain Canadian provinces including British Columbia and Alberta. The failure to develop, implement and maintain appropriate operating practices/systems and capital plans to address reliability obligations could lead to compliance violations and a Material Adverse Effect, including as a result of the exclusion of related costs from customer rates and other potentially significant penalties.

Indigenous Peoples' Land Claims

In British Columbia, the Corporation's utilities provide service to customers on Indigenous Peoples' lands and maintain facilities on lands that are subject to Indigenous Peoples' land claims. Various treaty negotiation processes involving Indigenous Peoples and the Governments of British Columbia and Canada are underway, but the basis for potential settlements is unclear and not all Indigenous Peoples are participating in such processes. To date, the policy of the Government of British Columbia has been to structure settlements without prejudicing existing third-party rights; however, there is no assurance that the settlement processes will not have a Material Adverse Effect.

FortisAlberta has distribution assets on Indigenous Peoples' lands in Alberta with access permits held by a third party. Some of these permits require approvals from First Nations and Crown-Indigenous Relations and Northern Affairs Canada. FortisAlberta may be unable to obtain such approvals or negotiate land-use agreements with reasonable terms. Significant failures in these regards could have a Material Adverse Effect.

Certain jointly owned facilities and portions of TEP's transmission lines are located on tribal lands pursuant to leases, land easements and other rights-of-way that are effective for specified time periods. The inability to receive future approvals for continued access to the facilities and land could have a Material Adverse Effect.

Joint-Ownership Interests and Third-Party Operators

Certain generating facilities from which TEP receives power are jointly owned with, or are operated by, third parties. TEP may not have sole discretion or any ability to affect the management or operations of such facilities, including how to best address changing economic conditions or environmental requirements. A divergence in the interests of TEP and those of the joint owners or operators could have a Material Adverse Effect.

General Economic Conditions

Fluctuations in general economic conditions, inflation, energy prices, employment levels, personal disposable incomes, housing starts, industrial activity and other factors, including potential new or revised tariffs, may lower energy demand and sales and reduce capital spending, particularly to the extent that related customer and Rate Base growth are impacted. A severe and prolonged economic downturn could also impair customers' ability to pay their bills in a timely manner. Each of these factors could lead to the impairment of goodwill or other long-term assets, and could have a Material Adverse Effect. Further, the impact of macroeconomic factors, including, but not limited to, international relations and geopolitical events, could cause weaker economic conditions or increase the volatility of the equity capital markets, which could impact the business and financial condition of the Corporation or adversely impact the Corporation's share price.

Commodity Price Volatility

Purchased power and gas, and generation fuel costs are subject to commodity price volatility, which is managed through regulator-approved: (i) mechanisms that permit the flow through in customer rates of commodity price changes and/or that provide for rate-stabilization and other deferral accounts; and (ii) price-risk management strategies such as the use of derivative contracts that effectively fix costs (see "Financial Instruments - Derivatives" on page 33).

There is no assurance that current regulator-approved mechanisms or strategies will continue to exist in the future. Additionally, despite these mechanisms and strategies, severe and prolonged commodity price increases could result in rates that customers are unable to pay and/or could affect consumption and sales growth, which could have a Material Adverse Effect.

Purchased Power Supply

A significant portion of electricity and gas sold by the Corporation's utilities is purchased through the wholesale energy markets or pursuant to contracts with energy suppliers and is not being produced by the Corporation's utilities. A disruption in the wholesale energy markets, or a failure on the part of energy or fuel suppliers or operators of energy delivery systems that connect to the Corporation's utilities, could result in a loss and/or increase in the cost of purchased power and gas, which could have a Material Adverse Effect. The cost and availability of purchased power and gas may be adversely impacted by factors discussed under "Climate Change" on page 23, "Environmental Regulation" on page 25 and "Commodity Price Volatility" above.

Counterparty Credit Risk

ITC has a concentration of credit risk as approximately 70% of its revenue is derived from three customers. These customers have investment-grade credit ratings and credit risk is further managed by MISO by requiring a letter of credit or cash deposit equal to the credit exposure, which is determined by a credit-scoring model and other factors.

FortisAlberta has a concentration of credit risk as its distribution service billings are to a relatively small group of retailers. Credit risk is managed by obtaining from the retailers either a cash deposit, letter of credit, an investment-grade credit rating, or a financial guarantee from an entity with an investment-grade credit rating.

Central Hudson has seen an increase in accounts receivable since the suspension of collection efforts initially required in response to the COVID-19 pandemic. Central Hudson continues to contact customers regarding past-due balances and collection efforts continue to expand. Under its regulatory framework, Central Hudson can defer uncollectible write-offs above the amounts collected in customer rates for future recovery.

UNS Energy, Central Hudson, FortisBC Energy, and Fortis may be exposed to credit risk from non-performance by counterparties to derivative contracts. Credit risk is managed by net settling payments, when possible, and dealing only with counterparties that have investment-grade credit ratings. At UNS Energy, Central Hudson and FortisBC Energy, certain contractual arrangements require counterparties to post collateral.

There is no assurance that credit risk management strategies will continue to be effective. Significant counterparty defaults could have a Material Adverse Effect.

Reliance on Supply Chain and Third Parties

Domestic and global supply chain disruptions, as a result of either physical or cyberattacks or geopolitical issues, may delay the delivery or result in shortages of certain materials, equipment and other resources that are critical to the operation of the Corporation's utilities, or impact the services and performance of the operation of the Corporation's utilities. Failure to eliminate or manage constraints in, or performance of, the supply chain may impact the availability of items or service that are necessary to support operations as well as materials that are required for continued infrastructure growth and could have a Material Adverse Effect. Further, cybersecurity incidents in the Corporation's supply chain or cyberattacks originating from the Corporation's supply chain may further result in disruption of energy service and other business operations which could have a Material Adverse Effect.

Interest Rates

Generally, the market price of the Corporation's common shares is inversely correlated to interest rate changes. Additionally, allowed ROEs are exposed to changes in long-term interest rates, such that a decreasing interest rate environment can result in lower allowed ROEs over time. While a rising interest rate environment could result in higher allowed ROEs, such ROE changes tend to lag as a result of regulatory timelines. Borrowings under variable-rate credit facilities and long-term debt, as well as new debt issuances, are also exposed to interest rate changes. Although interest costs at the regulated utilities are generally recovered through customer rates, the discontinuance of regulatory mechanisms that permit the flow-through of actual interest costs, the impact of regulatory lag at UNS Energy, and higher finance costs on holding company debt could have a Material Adverse Effect.

Foreign Exchange Exposure

As at December 31, 2024, 69% of the Corporation's assets were located outside Canada and 62% of 2024 revenue was derived from foreign operations. The reporting currency of ITC, UNS Energy, Central Hudson, Caribbean Utilities, FortisTCI, Fortis Belize and Belize Electricity is, or is pegged to, the U.S. dollar. The earnings and cash flow from, and net investments in, these entities are exposed to fluctuations in the U.S. dollar-to-Canadian dollar exchange rate. The Corporation’s $26.0 billion five-year capital plan for 2025 through 2029 also includes exposure to foreign exchange.

Fortis has reduced its U.S. dollar currency exposure through hedging. The Corporation has issued and designated U.S. dollar-denominated long-term debt as an effective hedge of foreign net investments. Fortis has also entered into foreign exchange contracts and cross-currency swaps to manage a portion of its exposure to foreign currency risk.

Given only partial hedging, earnings and cash flow continue to be impacted by exchange rate fluctuations. In addition, there is no assurance that existing hedging strategies will continue to be effective, and therefore a significant, prolonged decrease in the U.S dollar-to-Canadian dollar exchange rate could have a Material Adverse Effect.

Access to Capital

The Corporation and certain of its subsidiaries have incurred material amounts of indebtedness. Ongoing access to cost-effective capital is required to fund, among other things, capital expenditures and the repayment of maturing debt.

Operating Cash Flow may not be sufficient to fund the repayment of all outstanding liabilities when due or fund anticipated capital expenditures.

The ability to meet long-term debt repayments is dependent upon obtaining sufficient and cost-effective financing to replace maturing indebtedness. The ability to arrange financing is subject to numerous factors, including the results of operations and financial condition of Fortis and its subsidiaries, the regulatory environments including decisions regarding capital structure and allowed ROEs, capital market conditions, general economic conditions, credit ratings, and the environmental, social and governance profile of Fortis and its subsidiaries. Changes in credit ratings could affect credit risk spreads on new long-term debt and credit facilities, as well as their availability.

Fortis is a holding company and, as such, has no revenue-generating operations of its own. The Corporation's subsidiaries are separate legal entities and have no independent obligation to pay dividends to Fortis. Prior to paying dividends to the Corporation, the subsidiaries have financial obligations that must be satisfied, including, among others, their operating expenses and obligations to creditors. Furthermore, the Corporation's utilities are required by regulation to maintain a minimum equity-to-total capital ratio that may restrict their ability to pay dividends to the Corporation or may require the Corporation to contribute capital to such subsidiaries. The future enactment of laws or regulations may prohibit or further restrict the ability of the Corporation's subsidiaries to pay dividends or to repay intercorporate indebtedness. In addition, in the event of a subsidiary's liquidation or reorganization, the Corporation's right to participate in a distribution of assets is subject to the prior claims of the subsidiary's creditors. As a result, the Corporation's ability to generate cash flow to service its debt obligations and pay dividends is reliant on the ability of its subsidiaries to generate sustained earnings and cash flows and to pay dividends and repay loans.

There is no assurance that sufficient capital will continue to be available on acceptable terms. For further information see "Liquidity and Capital Resources" on page 14.

Taxation

Earnings at Fortis and its subsidiaries could be impacted by changes in income tax rates and other tax legislation in Canada, the U.S. and other international jurisdictions. The nature, timing or impact of changes in tax laws cannot be predicted and could have a Material Adverse Effect. Although income taxes at the regulated utilities are generally recovered in customer rates, tax-related regulatory lag can result in recovery delays or non-recovery for certain periods. At the non-regulated level, changes in income tax rates and other tax legislation could materially affect the after-tax cost of existing and future debt which is not recoverable in customer rates.

Insurance

Insurance is maintained with reputable industry insurers for property damage, potential liabilities and business interruption for coverage considered appropriate and in accordance with industry practice.

A significant portion of transmission and distribution assets is uninsured, as is customary in North America, as the cost to insure such assets is prohibitive. Insurance is subject to coverage limits and deductibles, as well as time-sensitive claims discovery and reporting provisions. There is no assurance that: (i) the amounts and types of losses from actual damage, liabilities or business interruption will be fully covered by insurance; (ii) regulatory relief would be obtained for coverage shortfalls; (iii) adequate insurance at reasonable rates will continue to be available; or (iv) insurers will fulfill their obligations. Significant actual shortfalls in insurance coverage or claims payment could have a Material Adverse Effect. The availability and cost of certain types of insurance may be adversely impacted by the risks described under "Climate Change" on page 23.

Pandemics and Public Health Crises

The Corporation could be negatively impacted by widespread outbreaks of communicable diseases or other public health crises that cause economic and/or other disruptions. Outbreaks of communicable diseases, as well as efforts to reduce the health impacts and control disease spread, can lead to restrictions on business operations, including business closures and the potential impacts of reduced labour availability and productivity, supply chain disruptions, project construction delays, disruptions to capital markets, governmental and regulatory action, and a prolonged reduction in economic activity. An extended economic slowdown could reduce energy sales and adversely impact the ability of customers, contractors and suppliers to fulfill their obligations and could disrupt operations and capital expenditure programs or cause impairment of goodwill (see "General Economic Conditions" on page 27).

The Corporation's utilities provide essential services and must be operational and maintained throughout any pandemic or other public health crisis, though such events can challenge operations and increase operating costs. The duration and severity of a pandemic or other public health crisis could have a Material Adverse Effect.

Talent Management

The delivery of safe, reliable and cost-effective service depends on the attraction, development and retention of a skilled workforce as well as filling strategic positions. Like its peers, Fortis faces demographic challenges and competitive markets relating to trades, technical and professional staff, particularly considering its significant capital plan. ITC relies heavily on agreements with third parties to provide services for the construction, maintenance and operation of certain aspects of its business. Significant failures in attracting or retaining a skilled workforce or filling strategic positions within the Corporation or its utilities could have a Material Adverse Effect.

Labour Relations

Most of the Corporation's utilities employ members of labour unions or associations under collective bargaining agreements. Fortis considers its labour relationships to be satisfactory, but there is no assurance that this will continue or that existing collective bargaining agreements will be renewed on reasonable terms without work disruption or other job action. Significant failures in these regards could cause service interruptions and/or labour cost increases for which regulators may not allow full recovery in customer rates, and could have a Material Adverse Effect.

Post-Retirement Obligations

Fortis and most of its subsidiaries maintain a combination of DBP and/or OPEB plans for certain employees and retirees. The most significant cost drivers for these plans are investment performance and interest rates, which are affected by global financial markets. Regulatory deferral mechanisms are in place at many of the Corporation's utilities that permit the flow through in customer rates of certain impacts associated with market fluctuations. Severe and prolonged market disruptions, significant declines in the market values of investments held to meet plan obligations, discount rate changes, participant demographics, changes in laws and regulations, as well as changes in existing regulatory treatment of post-retirement benefit costs, may increase plan expenses or require additional plan funding and could have a Material Adverse Effect.

Reputation, Relationships and Stakeholder Activism

There can be no assurance that internal processes, controls or audits, including those related to the preparation and presentation of financial statements, will ensure compliance with the Corporation's internal policies, including its Code of Conduct, or anti-bribery and anti-corruption laws. Employees, affiliates, independent contractors or agents may violate such policies and laws, which may potentially lead to reputational damage, in addition to potential fines, penalties or litigation, any of which could have a Material Adverse Effect.

The Corporation's operations and growth prospects require strong relationships with key stakeholders, including regulators, governments and agencies, Indigenous communities, landowners, and environmental organizations. Inadequately managing expectations and issues important to stakeholders, including those arising during construction of Major Capital Projects, could affect the Corporation's reputation as well as have a significant impact on its operations and infrastructure development. See "Required Approvals" and "Indigenous Peoples' Land Claims" on page 27.

External stakeholders have been challenging companies regarding climate change, sustainability, diversity, returns (including ROEs and ROAs), executive compensation, and other matters. Public opposition to larger infrastructure projects is becoming increasingly common, which can challenge capital plans and resultant organic growth. While the Corporation actively monitors such activism and is committed to developing stronger relationships with its external stakeholders, failure to effectively manage or respond to stakeholder activism could have a Material Adverse Effect.

Legal, Administrative and Other Proceedings

Legal, administrative and other proceedings arise in the ordinary course of business and may include environmental claims, employment-related claims, securities-based litigation, contractual disputes, personal injury or property damage claims, actions by regulatory or tax authorities, and other matters. Unfavourable outcomes such as judgments or settlements for monetary or other damages, injunctions, denial or revocation of permits, reputational harm, and other results could have a Material Adverse Effect.

ACCOUNTING MATTERS

New Accounting Policies

Segment Reporting: The Corporation adopted ASU No. 2023-07, *Improvements to Reportable Segment Disclosures*, for the year ended December 31, 2024 and will adopt it for interim periods beginning in 2025. This update requires disclosure of incremental segment information, including significant segment expenses and other items that are included in segment profit or loss. This adoption of this standard did not materially impact Fortis' disclosures.

Future Accounting Pronouncements

Income Taxes: ASU No. 2023-09, *Improvements to Income Tax Disclosures*, is effective for Fortis on January 1, 2025 on a prospective basis, with retrospective application and early adoption permitted. The ASU requires additional disclosure of income tax information by jurisdiction to reflect an entity's exposure to potential changes in tax legislation, and associated risks and opportunities. Fortis does not expect the ASU to materially impact its disclosures.

Expense Disaggregation: ASU No. 2024-03, *Disaggregation of Income Statement Expenses*, is effective for Fortis on January 1, 2027 for annual periods and on January 1, 2028 for interim periods, on a prospective basis, with retrospective application and early adoption permitted. The ASU requires detailed disclosure of certain expense categories included on the consolidated statements of earnings, including energy supply costs, operating expenses, and depreciation and amortization expense. Fortis is assessing the impact on its disclosures.

Critical Accounting Estimates

General

The preparation of the 2024 Annual Financial Statements required management to make estimates and judgments that affect the reported amounts of, and disclosures related to, assets, liabilities, revenues, expenses, gains, losses and contingencies. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time they are made, with any adjustments recognized in the period they become known. Actual results may differ significantly from these estimates.

Regulatory Assets and Liabilities

As at December 31, 2024, Fortis recognized regulatory assets of $4.6 billion (2023 - $4.4 billion) and regulatory liabilities of $4.3 billion (2023 - $4.0 billion).

Regulatory assets represent future revenues and/or receivables associated with certain costs incurred that will be, or are expected to be, recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent: (i) future reductions or limitations of increases in revenue associated with amounts that will be, or are expected to be, refunded to customers through the rate-setting process; or (ii) obligations to provide future service that customers have paid for in advance.

The recognition of regulatory assets and liabilities and the period(s) of settlement are often estimates based on past, existing or expected regulatory orders in relation to the nature of the underlying amounts, and are subject to regulatory approval. There is no assurance that actual settlement amounts and the related settlement periods will not be materially different from those estimated. Differences arising from the regulator's orders would be recognized in accordance with those orders, whereby any amounts disallowed would be immediately recognized in earnings with the remainder recognized in earnings in accordance with their inclusion in customer rates.

Employee Future Benefits

Key Estimates and Assumptions

Years ended December 31	DBP Plans		OPEB Plans	
($ millions, except as indicated)	**2024**	2023	**2024**	2023
Funded status: [1]				
Benefit obligation [2]	**(3,440)**	(3,347)	**(603)**	(596)
Plan assets	**3,613**	3,313	**506**	430
	173	(34)	**(97)**	(166)
Net benefit cost [2]	**11**	21	**12**	15
Key assumptions: *(weighted average %)*				
Discount rate as at December 31 [3]	**5.25**	4.84	**5.43**	4.94
Expected long-term rate of return on plan assets [4]	**6.51**	6.58	**6.05**	5.92
Rate of compensation increase	**3.52**	3.37	**—**	—
Health care cost trend increase rate [5]	**—**	—	**4.53**	4.52

(1) *Periodic actuarial valuations determine funding contributions for the DBP plans and U.S. OPEB plans, while Canadian OPEB plans are unfunded*

(2) *Actuarially determined using the projected benefits method prorated on service and management's best estimate of expected plan investment performance, salary escalation, average remaining service life of employees, mortality rates and, for OPEB plans, expected health care costs*

(3) *Reflects market interest rates on high-quality bonds with cash flows that match the timing and amount of expected pension payments. The discount rate used during the year for DBP plans is 4.84% (2023 - 5.36%) and 4.96% (2023 - 5.39%) for OPEB plans*

(4) *Developed using best estimates of expected returns, volatilities and correlations for each class of asset. Estimates are based on historical performance, future expectations and periodic portfolio rebalancing among the diversified asset classes*

(5) *Actuarially determined, the projected 2025 rate is 6.51% and is assumed to decrease over the next 10 years to the ultimate rate of 4.53% in 2034 and thereafter*

Sensitivity Analysis	**Rate of Return**		**Discount Rate**		**Health Care Costs Trend Rate**	
Year ended December 31, 2024	**1% change**		**1% change**		**1% change**	
($ millions)	**Increase**	**Decrease**	**Increase**	**Decrease**	**Increase**	**Decrease**
DBP plans:						
Net benefit cost	**(33)**	**29**	**(24)**	**41**	**n/a**	**n/a**
Projected benefit obligation	**(2)**	**(66)**	**(378)**	**453**	**n/a**	**n/a**
OPEB plans:						
Net benefit cost	**(4)**	**4**	**(9)**	**11**	**14**	**(11)**
Accumulated benefit obligation	**—**	**—**	**(68)**	**84**	**62**	**(52)**

At the regulated utilities, changes in net benefit cost are generally expected to be reflected in customer rates, subject to regulatory lag and forecast risk at certain utilities.

ITC, Central Hudson, FortisBC Energy, FortisBC Electric and Newfoundland Power have regulator-approved mechanisms to defer variations between actual net pension cost and that forecast and reflected in customer rates. There is no assurance that these deferral mechanisms will continue in the future.

Depreciation and Amortization
As at December 31, 2024, Fortis recognized property, plant and equipment and intangible assets of $51.1 billion (2023 - $44.9 billion) representing 70% of total assets (2023 - 68%). Depreciation and amortization of these assets totalled $1.8 billion for 2024 (2023 - $1.7 billion).

Depreciation and amortization reflect the estimated useful lives of the underlying assets, which considers historical experience, manufacturers' ratings and specifications, the past and expected future pattern and nature of usage, and other factors.

At the regulated utilities, depreciation rates require regulatory approval and include a provision for estimated future removal costs, not identified as a legal obligation. Estimates primarily reflect historical experience and expected cost trends. The provision is recognized as a long-term regulatory liability against which actual removal costs are netted when incurred. As at December 31, 2024, this regulatory liability was $1.7 billion (2023 - $1.5 billion).

Depreciation rates at the regulated utilities are typically determined through periodic depreciation studies performed by external experts. Where actual experience differs from previous estimates, resultant differences are generally reflected in future depreciation rates and thereby recovered or refunded through customer rates in the manner prescribed by the regulator.

Goodwill Impairment
As at December 31, 2024, Fortis recognized goodwill of $13.1 billion (2023 - $12.2 billion), representing 18% of total assets (2023 - 18%). The increase in goodwill was due to a higher U.S. dollar-to-Canadian dollar exchange rate at December 31, 2024 in comparison to December 31, 2023, and the associated impact on the translation of U.S. dollar-denominated goodwill.

Goodwill at each of the Corporation's reporting units is tested for impairment annually and whenever an event or change in circumstances indicates that fair value may be below carrying value. If so determined, goodwill is written down to estimated fair value and an impairment loss is recognized.

The Corporation performs a qualitative assessment on each reporting unit and if it is determined that it is not likely that fair value is less than carrying value, then a quantitative estimate of fair value is not required. When a quantitative assessment is performed, the primary method for estimating fair value of the reporting units is the income approach, whereby net cash flow projections are discounted. Underlying estimates and assumptions, with varying degrees of uncertainty, include the amount and timing of expected future cash flows, growth rates, and discount rates. A secondary valuation, the market approach along with a reconciliation of the total estimated fair value of all the reporting units to the Corporation's market capitalization, is also performed and evaluated.

The recognition of impairment losses could have a Material Adverse Effect. Such losses are not recoverable in regulated utility rates. To the extent impairment losses signal lower expected future cash flows to support interest payments on unregulated holding company debt and dividends on common shares, they could adversely affect the future cost of such capital, expressed as higher interest rates on such debt, which is not recoverable in regulated utility rates, and lower common share market prices.

Income Tax
As at December 31, 2024, deferred income tax liabilities, income tax receivable, deferred income taxes included in regulatory assets, income tax payable, and deferred income taxes included in regulatory liabilities totalled $5.0 billion, $nil, $2.2 billion, $33 million and $1.3 billion, respectively (2023 - $4.4 billion, $78 million, $2.1 billion, $nil, and $1.3 billion, respectively). Income tax expense was $346 million in 2024 (2023 - $360 million).

Current income taxes reflect the estimated taxes payable/receivable in the current year based on enacted tax rates and laws, and the estimated proportion of taxable earnings/loss attributable to various jurisdictions.

Deferred income tax assets and liabilities reflect temporary differences between the tax and accounting basis of assets and liabilities. A deferred income tax asset or liability is determined for each temporary difference based on enacted income tax rates and laws in effect when the temporary differences are expected to be recovered or settled. A valuation allowance is recognized in earnings to the extent that future tax recovery is not assessed as "more likely than not".

At the regulated utilities, differences between the income tax expense or recovery recognized under U.S. GAAP and reflected in customer rates, which is expected to be recovered from, or refunded to, customers in future rates, are recognized as regulatory assets or liabilities. These are subsequently amortized to earnings in accordance with their inclusion in customer rates pursuant to the regulator's orders. Otherwise, changes in expectations and resultant estimates arising from changes in tax rates, tax laws, jurisdictional earnings allocations and other factors are recognized in earnings upon occurrence.

The Corporation and certain of its subsidiaries are subject to taxation in Canada, the United States and other foreign jurisdictions. The material jurisdictions in which the Corporation is subject to potential income tax compliance examinations include the United States (Federal, Arizona, Kansas, Iowa, Michigan, Minnesota and New York) and Canada (Federal, British Columbia and Alberta). The Corporation's 2020 to 2024 taxation years are still open for audit in Canadian jurisdictions, and its 2020 to 2024 taxation years are still open for audit in U.S. jurisdictions. The impact of such income tax compliance examinations could be material to the Corporation (see "Business Risks - Taxation" on page 29).

In June 2024, the Government of Canada enacted legislation with respect to interest deductibility limitations and global minimum tax, both of which were applicable to Fortis as of January 1, 2024. There was no material impact to Fortis in 2024 and the Corporation does not expect a material impact on its financial results, Operating Cash Flow or credit metrics over the five-year planning period.

Derivatives
The fair values of derivatives are based on estimates that cannot be determined with precision as they involve uncertainties and matters of judgment and, therefore, may not be relevant in predicting future earnings or cash flows.

Contingencies
The Corporation and its subsidiaries are subject to various legal proceedings and claims arising in the ordinary course of business, including those generally described under "Business Risks - Legal, Administrative and Other Proceedings" on page 30, for which no amounts have been accrued because the outcomes currently cannot be reasonably determined. Further information is provided in Note 27 in the 2024 Annual Financial Statements.

FINANCIAL INSTRUMENTS

Long-Term Debt and Other

As at December 31, 2024, the carrying value of long-term debt, including the current portion, was $33.4 billion (2023 - $29.7 billion) compared to an estimated fair value of $31.3 billion (2023 - $27.9 billion).

The consolidated carrying value of the remaining financial instruments, other than derivatives, approximates fair value, reflecting their short-term maturity, normal trade credit terms and/or nature.

Derivatives

The Corporation generally limits the use of derivatives to those that qualify as accounting, economic or cash flow hedges, or those that are approved for regulatory recovery. Derivatives are recorded at fair value, with certain exceptions, including those derivatives that qualify for the normal purchase and normal sale exception.

Energy contracts subject to regulatory deferral
UNS Energy holds electricity power purchase contracts, customer supply contracts and gas swap contracts to reduce its exposure to energy price risk. Fair values are measured primarily under the market approach using independent third-party information, where possible. When published prices are not available, adjustments are applied based on historical price curve relationships, transmission costs and line losses.

Central Hudson holds swap contracts for electricity and natural gas to minimize price volatility by fixing the effective purchase price. Fair values are measured using forward pricing provided by independent third-party information.

FortisBC Energy holds gas supply contracts to fix the effective purchase price of natural gas. Fair values reflect the present value of future cash flows based on published market prices and forward natural gas curves.

Unrealized gains or losses associated with changes in the fair value of these energy contracts are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulators. As at December 31, 2024, unrealized losses of $175 million (2023 - $197 million) were recognized as regulatory assets and unrealized gains of $41 million (2023 - $37 million) were recognized as regulatory liabilities.

Energy contracts not subject to regulatory deferral

UNS Energy holds wholesale trading contracts to fix power prices and realize potential margin, of which 10% of any realized gains is shared with customers through rate stabilization accounts. Fair values are measured using a market approach incorporating, where possible, independent third-party information.

Aitken Creek, which was sold on November 1, 2023, held gas swap contracts to manage exposure to changes in natural gas prices, capture natural gas price spreads, and manage the financial risk posed by physical transactions. Fair values were measured using forward pricing from published market sources.

Gains or losses associated with changes in the fair value of these energy contracts are recognized in revenue. In 2024, gains of $48 million (2023 - losses of $28 million) were recognized in revenue.

Total return swaps

The Corporation holds total return swaps to manage the cash flow risk associated with forecast future cash and/or share settlements of certain stock-based compensation obligations. The swaps have a combined notional amount of $134 million and terms up to three years expiring at varying dates through January 2027. Fair value is measured using an income valuation approach based on forward pricing curves. Unrealized gains and losses associated with changes in fair value are recognized in other income, net. In 2024, unrealized gains of $12 million (2023 - $nil) were recognized in other income, net.

Foreign exchange contracts

The Corporation holds U.S. dollar-denominated foreign exchange contracts to help mitigate exposure to foreign exchange rate volatility. The contracts expire at varying dates through September 2026 and have a combined notional amount of $608 million. Fair value was measured using independent third-party information. Unrealized gains and losses associated with changes in fair value are recognized in other income, net. In 2024, unrealized losses of $17 million (2023 - unrealized gains of $10 million) were recognized in other income, net.

Interest rate contracts

During 2024, ITC entered into and settled interest rate locks with a combined notional value of US$300 million. These contracts were used to manage interest rate risk associated with the issuance of US$400 million unsecured senior notes in May 2024. Realized losses of US$3 million were recognized in other comprehensive income, which will be reclassified to earnings as a component of interest expense over five years.

ITC also entered into five-year interest rate swap contracts in 2024 with a combined notional value of US$135 million. The swaps will be used to manage interest rate risk associated with forecasted debt issuances. Fair value was measured using a discounted cash flow method based on SOFR. Unrealized gains and losses associated with the changes in fair value are recognized in other comprehensive income, and will be reclassified to earnings as a component of interest expense over the life of the debt. Unrealized gains of US$4 million were recorded in 2024.

In 2025, ITC entered into five-year interest rate swap contracts with a notional value of US$95 million to manage interest rate risk associated with forecasted debt issuances, increasing the total notional amount of interest rate swaps outstanding to US$230 million.

During 2024, the Corporation entered into and settled interest rate locks with a combined notional value of $250 million. These contract were used to manage interest rate risk associated with the issuance of $500 million unsecured senior notes in September 2024. Realized losses of $2 million were recognized in other comprehensive income, which will be reclassified to earnings as a component of interest expense over seven years.

Cross-Currency interest rate swaps

The Corporation holds cross-currency interest rate swaps, maturing in 2029, to effectively convert its $500 million, 4.43% unsecured senior notes to US$391 million, 4.34% debt. The Corporation has designated this notional U.S. debt as an effective hedge of its foreign net investments and unrealized gains and losses associated with exchange rate fluctuations on the notional U.S. debt are recognized in other comprehensive income, consistent with the translation adjustment related to the foreign net investments. Other changes in the fair value of the swaps are also recognized in other comprehensive income but are excluded from the assessment of hedge effectiveness. Fair value is measured using a discounted cash flow method based on SOFR. In 2024, unrealized losses of $29 million (2023 - unrealized gains of $15 million) were recorded in other comprehensive income.

Derivative Fair Values

The following table presents derivative assets and liabilities that are accounted for at fair value on a recurring basis.

($ millions)	Level 1 [(1)]	Level 2 [(1)]	Level 3 [(1)]	Total
As at December 31, 2024				
Assets [(2)]				
Energy contracts subject to regulatory deferral	**—**	**63**	**—**	**63**
Energy contracts not subject to regulatory deferral	**—**	**7**	**—**	**7**
Total return swaps and interest rate contracts	**—**	**16**	**—**	**16**
Other investments	**150**	**—**	**—**	**150**
	150	**86**	**—**	**236**
Liabilities [(3)]				
Energy contracts subject to regulatory deferral	**—**	**(197)**	**—**	**(197)**
Energy contracts not subject to regulatory deferral	**—**	**(2)**	**—**	**(2)**
Foreign exchange contracts and cross-currency interest rate swaps	**—**	**(45)**	**—**	**(45)**
	—	**(244)**	**—**	**(244)**
As at December 31, 2023				
Assets [(2)]				
Energy contracts subject to regulatory deferral	—	49	—	49
Energy contracts not subject to regulatory deferral	—	6	—	6
Foreign exchange contracts	—	5	—	5
Other investments	145	—	—	145
	145	60	—	205
Liabilities [(3)]				
Energy contracts subject to regulatory deferral	—	(209)	—	(209)
Energy contracts not subject to regulatory deferral	—	(3)	—	(3)
Total return and cross-currency interest rate swaps	—	(6)	—	(6)
	—	(218)	—	(218)

(1) *Under the hierarchy, fair value is determined using: (i) Level 1 - unadjusted quoted prices in active markets; (ii) Level 2 - other pricing inputs directly or indirectly observable in the marketplace; and (iii) Level 3 - unobservable inputs, used when observable inputs are not available. Classifications reflect the lowest level of input that is significant to the fair value measurement.*

(2) *Included in cash and cash equivalents, accounts receivable and other current assets, or other assets*

(3) *Included in accounts payable and other current liabilities or other liabilities*

Derivative Volumes

As at December 31	2024	2023
Energy contracts subject to regulatory deferral [(1)]		
Electricity swap contracts *(GWh)*	**774**	628
Electricity power purchase contracts *(GWh)*	**430**	588
Gas swap contracts *(PJ)*	**236**	228
Gas supply contracts *(PJ)*	**105**	134
Energy contracts not subject to regulatory deferral [(1)]		
Wholesale trading contracts *(GWh)*	**1,499**	1,310
Gas swap contracts *(PJ)*	**3**	3

(1) *Energy contracts settle on various dates through 2029*

SELECTED ANNUAL FINANCIAL INFORMATION

Years ended December 31 *($ millions, except as indicated)*	**2024**	2023	2022
Revenue	**11,508**	11,517	11,043
Net earnings	**1,828**	1,710	1,514
Common Equity Earnings	**1,606**	1,506	1,330
EPS: *($)*			
Basic	**3.24**	3.10	2.78
Diluted	**3.24**	3.10	2.78
Total assets	**73,486**	65,920	64,252
Long-term debt (excluding current portion)	**31,224**	27,235	25,931
Dividends declared: *($)*			
Per common share	**2.41**	2.31	2.20
Per first preference share:			
Series F	**1.2250**	1.2250	1.2250
Series G (1)	**1.5308**	1.3145	1.0983
Series H	**0.4588**	0.4588	0.4588
Series I (2)	**1.4902**	1.5619	0.9157
Series J	**1.1875**	1.1875	1.1875
Series K (3)	**1.3673**	0.9823	0.9823
Series M (4)	**1.0770**	0.9783	0.9783

(1) *The annual dividend per share was reset to $1.5308 for the five-year period from September 1, 2023 up to but excluding September 1, 2028*
(2) *Floating quarterly dividend rate is reset every quarter based on the then current three-month Government of Canada Treasury Bill rate plus the applicable reset dividend yield*
(3) *The annual dividend per share was reset from $0.9823 to $1.3673 for the five-year period from March 1, 2024 up to but excluding March 1, 2029*
(4) *The annual dividend per share was reset from $0.9783 to $1.3733 for the five-year period from December 1, 2024 up to but excluding December 1, 2029*

2024/2023

For a discussion of the changes in revenue, Common Equity Earnings, EPS, total assets and long-term debt see "Performance at a Glance" on page 2, "Operating Results" on page 6, and "Financial Position" on page 13.

2023/2022

The increase in revenue was due primarily to: (i) a higher U.S. dollar-to-Canadian dollar exchange rate; (ii) Rate Base growth; (iii) higher retail revenue at UNS Energy driven by new customer rates effective September 1, 2023, customer additions, and warmer weather; and (iv) the recognition of a regulatory deferral at FortisBC associated with the new cost of capital parameters approved by the BCUC effective January 1, 2023. The increase was partially offset by the flow-through of lower commodity costs in customer rates.

Common Equity Earnings increased by $176 million in comparison to 2022. The increase was primarily driven by Rate Base growth across our utilities and the new cost of capital parameters approved for FortisBC effective January 1, 2023. Higher earnings in Arizona also contributed to earnings growth, reflecting higher retail electricity sales, new customer rates at TEP effective September 1, 2023, and lower depreciation expense associated with retirement of the San Juan generating station in 2022. An increase in the market value of certain investments that support retirement benefits, and the higher U.S. dollar-to-Canadian dollar exchange rate, also favourably impacted earnings year over year. The increase was partially offset by higher corporate finance costs and lower earnings from Aitken Creek.

In addition to the above-noted items impacting earnings, the change in EPS also reflected an increase in the weighted average number of common shares outstanding, largely associated with the Corporation's DRIP.

The increase in total assets was primarily due to capital expenditures in 2023 and an increase in regulatory assets, largely due to an increase in deferred income taxes and unrealized losses on energy derivatives. The increase was partially offset by the translation of U.S. dollar-denominated assets at a lower U.S. dollar-to-Canadian dollar exchange rate.

FOURTH QUARTER RESULTS

Sales

(GWh, except as indicated)	2024	2023	Variance
Regulated Utilities			
UNS Energy			
Retail Electricity	**2,348**	2,302	46
Wholesale Electricity	**1,295**	1,349	(54)
Gas *(PJ)*	**5**	5	—
Central Hudson			
Electricity	**1,187**	1,196	(9)
Gas *(PJ)*	**6**	6	—
FortisBC Energy *(PJ)*	**67**	66	1
FortisAlberta	**4,428**	4,273	155
FortisBC Electric	**916**	901	15
Other Electric	**2,533**	2,525	8
Non-Regulated			
Corporate and Other	**80**	58	22

Electricity sales for the fourth quarter were largely consistent with the comparable period in 2023 for most of Fortis' utilities. The increase in retail sales at UNS Energy was due primarily to customer additions, while the decrease in wholesale sales was related to lower long-term wholesale sales due to the expiration of certain contracts. As well, the increase in sales at FortisAlberta was due to customer additions and higher average consumption from industrial and residential customers.

Gas sales for the fourth quarter were consistent with the comparable period in 2023.

Revenue and Common Equity Earnings

	Revenue			Earnings		
($ millions, except as indicated)	**2024**	2023	Variance	**2024**	2023	Variance
Regulated Utilities						
ITC	**567**	527	40	**127**	136	(9)
UNS Energy	**659**	706	(47)	**52**	62	(10)
Central Hudson	**356**	311	45	**66**	36	30
FortisBC Energy	**522**	544	(22)	**120**	105	15
FortisAlberta	**207**	188	19	**42**	36	6
FortisBC Electric	**149**	145	4	**18**	15	3
Other Electric	**479**	457	22	**52**	35	17
Non-regulated						
Corporate and Other	**10**	7	3	**(81)**	(44)	(37)
Total	**2,949**	2,885	64	**396**	381	15
Weighted average number of common shares outstanding *(# millions)*				**498.2**	489.4	8.8
Basic EPS *($)*				**0.79**	0.78	0.01

The increase in revenue was due primarily to Rate Base growth, a higher U.S. dollar-to-Canadian dollar exchange rate, and new customer rates at Central Hudson effective July 1, 2024. The implementation of Central Hudson's new customer rates has shifted the timing of quarterly rate recovery in comparison to related costs, resulting in higher revenue and earnings in the fourth quarter of 2024. The increase was partially offset by: (i) lower flow-through costs at UNS Energy and FortisBC Energy; and (ii) the recognition of a refund liability at ITC in 2024, largely reflecting the prior period impact of the reduction in the MISO base ROE approved by FERC (see "Regulatory Highlights - Significant Regulatory Matters" on page 12).

The increase in Common Equity Earnings was driven by Rate Base growth as well as higher earnings at Central Hudson due to new customer rates and a higher allowed ROE effective July 1, 2024. The increase was partially offset by the refund liability recognized at ITC, discussed above, and lower earnings in Arizona, largely reflecting higher operating expenses. Unrealized losses on derivative contracts and the $10 million gain on disposition of Aitken Creek recognized in 2023 also unfavourably impacted fourth quarter earnings in comparison to the prior year.

The favourable earnings impact resulting from the translation of U.S. dollar denominated earnings at the higher average U.S. dollar-to-Canadian dollar exchange rate was largely offset by foreign exchange losses associated with the revaluation of U.S. dollar denominated liabilities at a rate of US$1.00=CA$1.44 at December 31, 2024.

The increase in basic EPS reflects higher Common Equity Earnings, as discussed above, partially offset by an increase in the weighted average number of common shares outstanding, largely associated with the Corporation's DRIP.

Cash Flows

($ millions)	2024	2023	Variance
Cash and cash equivalents, beginning of period	**896**	765	131
Cash from (used in):			
Operating activities	**962**	746	216
Investing activities	**(1,796)**	(748)	(1,048)
Financing activities	**125**	(134)	259
Effect of exchange rate changes on cash and cash equivalents	**33**	(13)	46
Change in cash associated with assets held for sale	**—**	9	(9)
Cash and cash equivalents, end of period	**220**	625	(405)

Operating Activities

The increase in Operating Cash Flow was largely driven by FortisBC Energy reflecting higher deposits received, net of expenditures incurred, associated with the Eagle Mountain Pipeline project, as well as other changes in working capital balances. The increase was partially offset by the timing of flow-through transmission amounts at FortisAlberta as well as higher interest payments.

Investing Activities

The increase in cash used in investing activities primarily reflects higher capital expenditures in 2024, as well as the proceeds received in 2023 related to the disposition of Aitken Creek. Lower customer contributions in aid of construction also contributed to the variance.

Financing Activities

The increase in cash from financing activities reflects changes in the subsidiaries' capital expenditures and the amount of Operating Cash Flow available to fund those capital expenditures, as well as the repayment of credit facility borrowings in the fourth quarter of 2023 associated with the proceeds received from the sale of Aitken Creek. See "Cash Flow Summary" on page 15.

SUMMARY OF QUARTERLY RESULTS

Quarter ended	Revenue ($ millions)	Common Equity Earnings ($ millions)	Basic EPS ($)	Diluted EPS ($)
December 31, 2024	**2,949**	**396**	**0.79**	**0.79**
September 30, 2024	**2,771**	**420**	**0.85**	**0.85**
June 30, 2024	**2,670**	**331**	**0.67**	**0.67**
March 31, 2024	**3,118**	**459**	**0.93**	**0.93**
December 31, 2023	2,885	381	0.78	0.78
September 30, 2023	2,719	394	0.81	0.81
June 30, 2023	2,594	294	0.61	0.61
March 31, 2023	3,319	437	0.90	0.90

Generally, within each calendar year, quarterly results fluctuate in accordance with seasonality. Given the diversified nature of the Corporation's subsidiaries, seasonality varies. Earnings of the gas utilities tend to be highest in the first and fourth quarters due to space-heating requirements. Earnings of the electric distribution utilities in the U.S. tend to be highest in the second and third quarters due to the use of air conditioning and other cooling equipment.

Generally, from one calendar year to the next, quarterly results reflect: (i) continued organic growth driven by the Corporation's capital plan; (ii) any significant temperature fluctuations from seasonal norms; (iii) the impact of market conditions, particularly with respect to long-term wholesale sales at UNS Energy; (iv) the timing and significance of any regulatory decisions; (v) changes in the U.S. dollar-to-Canadian dollar exchange rate; (vi) for revenue, the flow through in customer rates of commodity costs; and (vii) for EPS, increases in the weighted average number of common shares outstanding.

December 2024/December 2023

See "Fourth Quarter Results" on page 37.

September 2024/September 2023

Common Equity Earnings increased by $26 million and basic EPS increased by $0.04 in comparison to the third quarter of 2023. The increase was driven by: (i) Rate Base growth; and (ii) strong earnings in Arizona, reflecting new customer rates at TEP effective September 1, 2023, an increase in the market value of investments that support retirement benefits and higher production tax credits. Unrealized gains on derivative contracts recognized in the third quarter of 2024, and an unfavourable deferred income tax adjustment recognized by ITC in the third quarter of 2023, also contributed to the growth in earnings. The increase was partially offset by the timing of recognition of new cost of capital parameters approved for FortisBC in 2023, which included $26 million associated with the retroactive impact to January 1, 2023, as well as higher holding company finance costs. The change in basic EPS also reflected an increase in the weighted average number of common shares outstanding, largely associated with the Corporation's DRIP.

June 2024/June 2023

Common Equity Earnings increased by $37 million and basic EPS increased by $0.06 in comparison to the second quarter of 2023. The increase was driven by strong earnings in Arizona, reflecting new customer rates at TEP effective September 1, 2023 and higher retail electricity sales associated with warmer weather. Rate Base growth across our utilities and the timing of recognition of new cost of capital parameters approved for FortisBC in 2023 also contributed to earnings growth. The increase was partially offset by lower earnings for Central Hudson and the Other Electric segment, largely reflecting higher operating costs. The change in basic EPS also reflected an increase in the weighted average number of common shares outstanding, largely associated with the Corporation's DRIP.

March 2024/March 2023

Common Equity Earnings increased by $22 million and basic EPS increased by $0.03 in comparison to the first quarter of 2023. The increase was due to the timing of recognition of new cost of capital parameters approved for FortisBC in 2023 and Rate Base growth across our utilities. The increase was partially offset by higher holding company costs, including finance charges and unrealized losses on derivative contracts, and the November 1, 2023 disposition of Aitken Creek. In addition, the change in EPS reflected an increase in the weighted average number of common shares outstanding, largely associated with the Corporation's DRIP.

RELATED-PARTY AND INTER-COMPANY TRANSACTIONS

Related-party transactions are in the normal course of operations and are measured at the amount of consideration agreed to by the related parties. There were no material related-party transactions in 2024 or 2023.

As of December 31, 2024, accounts receivable included $18 million due from Belize Electricity (December 31, 2023 - $8 million).

Fortis periodically provides short-term financing to subsidiaries to support capital expenditures and seasonal working capital requirements, the impacts of which are eliminated on consolidation. As at December 31, 2024 and 2023, there were no inter-segment loans outstanding. Interest charged on inter-segment loans was not material in 2024 and 2023.

MANAGEMENT'S EVALUATION OF CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

DCP are designed to provide reasonable assurance that information required to be disclosed in reports filed with, or submitted to, securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under Canadian and U.S. securities laws. As of December 31, 2024, an evaluation was carried out under the supervision of, and with the participation of, the Corporation's management, including the CEO and CFO, of the effectiveness of the Corporation's DCP, as defined in the applicable Canadian and U.S. securities laws. Based on that evaluation, the CEO and CFO concluded that such DCP are effective as of December 31, 2024.

Internal Control over Financial Reporting

ICFR is designed by, or under the supervision of, the Corporation's CEO and CFO and effected by the Corporation's Board, 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 U.S. GAAP. Because of its inherent limitations, ICFR may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The Corporation's management, including the Corporation's CEO and CFO, assessed the effectiveness of the Corporation's ICFR as of December 31, 2024, based on the criteria set forth in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management concluded that, as of December 31, 2024, the Corporation's ICFR was effective.

During the year ended December 31, 2024, there have been no changes in the Corporation's ICFR that have materially affected, or are reasonably likely to materially affect, the Corporation's ICFR.

OUTLOOK

Fortis continues to enhance shareholder value through the execution of its capital plan, the balance and strength of its diversified portfolio of regulated utility businesses, and growth opportunities within and proximate to its service territories. The Corporation's $26.0 billion five-year capital plan is expected to increase midyear Rate Base from $39.0 billion in 2024 to $53.0 billion by 2029, translating into a five-year CAGR of 6.5%.

Beyond the five-year capital plan, opportunities to expand and extend growth include: further expansion of the electric transmission grid in the U.S. to support load growth and facilitate the interconnection of cleaner energy; transmission investments associated with the MISO LRTP tranches 1, 2.1, and 2.2 as well as regional transmission in New York; grid resiliency and climate adaptation investments; renewable gas solutions and LNG infrastructure in British Columbia; and the acceleration of load growth and cleaner energy infrastructure investments across our jurisdictions.

Fortis expects its long-term growth in Rate Base will drive earnings that support dividend growth guidance of 4-6% annually through 2029, and is premised on the assumptions and material factors listed under "Forward-Looking Information".

Fortis has reduced its corporate-wide direct GHG emissions by 34% from a 2019 base year, and has targets to further reduce such GHG emissions by 50% by 2030 and 75% by 2035. The Corporation's additional 2050 net-zero direct GHG emissions target reinforces Fortis' commitment to further decarbonize over the long-term, while continuing our focus on reliability and affordability. The Corporation's ability to achieve the GHG targets may be impacted by federal, state and provincial energy policies, as well as external factors, including significant customer and load growth and the development of clean energy technology.

FORWARD-LOOKING INFORMATION

Fortis includes forward-looking information in the MD&A within the meaning of applicable Canadian securities laws and forward-looking statements within the meaning of the U.S. Private Securities Litigation Reform Act of 1995, (collectively referred to as "forward-looking information"). Forward-looking information reflects expectations of Fortis management regarding future growth, results of operations, performance, business prospects and opportunities. Wherever possible, words such as anticipates, believes, budgets, could, estimates, expects, forecasts, intends, may, might, plans, projects, schedule, should, target, will, would, and the negative of these terms, and other similar terminology or expressions, have been used to identify the forward-looking information, which includes, without limitation: the expectation that Fortis is well-positioned for future investment opportunities; annual dividend growth guidance through 2029; forecast Capital Expenditures for 2025 through 2029; the expected sources of funding for the capital plan, including the source of common equity proceeds; forecast midyear Rate Base for 2029 and projected Rate Base growth from 2024 through to 2029; the expected nature, timing and benefits of additional opportunities beyond the capital plan, including further expansion of the electric transmission grid in the U.S. to support load growth and facilitate the interconnection of cleaner energy, transmission investments associated with the MISO LRTP tranches 1, 2.1 and 2.2 as well as regional transmission in New York, grid resiliency and climate adaptation investments, renewable gas solutions and LNG infrastructure in British Columbia, and the acceleration of load growth and cleaner energy infrastructure investments; expected implications of utility industry trends on the utility sector and on the Corporation's capital investments; the expected timing, outcome and impact of legal and regulatory proceedings and decisions; the expected or potential funding sources for operating expenses, interest costs and capital expenditures; the expectation that maintaining the targeted capital structure of the regulated operating subsidiaries will not have an impact on the Corporation's ability to pay dividends in the foreseeable future; the expected consolidated fixed-term debt maturities and repayments over the next five years; the expectation that the Corporation and its subsidiaries will continue to have reasonable access to long-term capital and will remain compliant with debt covenants in 2025; the expected uses of proceeds from debt financings; the performance of contractual obligations to provide equity capital to Wataynikaneyap Power; the potential impact of new or revised tariffs on forecast and actual capital expenditures; forecast midyear Rate Base for 2025 and 2029 by segment; the nature, timing, benefits and expected costs of certain capital projects, including ITC's transmission projects associated with the MISO LRTP, IRP Related Generation, the Roadrunner Reserve Battery Storage Projects 1 and 2, the Vail-to-Tortolita Transmission Project, the Eagle Mountain Pipeline Project, the Tilbury LNG Storage Expansion, the AMI Project, and the Tilbury 1B Project, and additional investment opportunities; the 2050 net-zero direct GHG emissions target; the 2030 and 2035 direct GHG emissions reduction targets; how the Corporation's GHG emissions targets are expected to be achieved, including TEP's plan to exit coal; the potential impact of federal, state and provincial energy policies and other factors, including significant customer and load growth and the development of clean energy technology, on the Corporation's ability to achieve its GHG emissions reduction targets; the expected impacts of future accounting pronouncements on the Corporation's disclosures; the potential impact of the recognition of goodwill impairment losses; the potential and expected impacts of income tax compliance examinations and legislation with respect to interest deductibility limitations and global minimum tax; and the expectation that long-term growth in Rate Base will drive earnings that support dividend growth guidance of 4-6% annually through 2029.

Forward-looking information involves significant risks, uncertainties and assumptions. Certain material factors or assumptions have been applied in drawing the conclusions contained in the forward-looking information including, without limitation: reasonable legal and regulatory decisions and the expectation of regulatory stability; the successful execution of the capital plan; no material capital project or financing cost overrun; sufficient human resources to deliver service and execute the capital plan; the realization of additional opportunities beyond the capital plan; no significant variability in interest rates; no material changes in the assumed U.S. dollar- to- Canadian dollar exchange rate; the continuation of current participation levels in the Corporation's DRIP; the Board exercising its discretion to declare dividends, taking into account the financial performance and condition of the Corporation; no significant operational disruptions or environmental liability or upset; the continued ability to maintain the performance of the electricity and gas systems; no severe and prolonged economic downturn; sufficient liquidity and capital resources; the ability to hedge exposures to fluctuations in foreign exchange rates, natural gas prices and electricity prices; the continued availability of natural gas, fuel, coal and electricity supply; continuation of power supply and capacity purchase contracts; no significant changes in government energy plans, environmental laws and regulations that could have a material negative impact; maintenance of adequate insurance coverage; the ability to obtain and maintain licences and permits; retention of existing service areas; no significant changes in tax laws and the continued tax deferred treatment of earnings from the Corporation's foreign operations; continued maintenance of information technology infrastructure and no material breach of cybersecurity; continued favourable relations with Indigenous Peoples; and favourable labour relations.

Fortis cautions readers that a number of factors could cause actual results, performance or achievements to differ materially from those discussed or implied in the forward-looking information. These factors should be considered carefully and undue reliance should not be placed on the forward-looking information. Risk factors which could cause results or events to differ from current expectations are detailed under the heading "Business Risks" in this MD&A and in other continuous disclosure materials filed from time to time with Canadian securities regulatory authorities and the Securities and Exchange Commission. Key risk factors for 2025 include, but are not limited to: uncertainty regarding changes in utility regulation, including the outcome of regulatory proceedings at the Corporation's utilities; the physical risks associated with the provision of electric and gas service, which can be exacerbated by the impacts of climate change; risks related to environmental laws and regulations; risks associated with capital projects and the impact on the Corporation's continued growth; risks associated with cybersecurity and information and operations technology; the impact of weather variability and seasonality on heating and cooling loads, gas distribution volumes and hydroelectric generation; risks associated with commodity price volatility and supply of purchased power; and risks related to general economic conditions, including inflation, interest rate and foreign exchange risks.

All forward-looking information herein is given as of February 13, 2025. Fortis disclaims any intention or obligation to update or revise any forward-looking information, whether as a result of new information, future events or otherwise.

GLOSSARY

2024 Annual Financial Statements: the Corporation's audited consolidated financial statements and notes thereto for the year ended December 31, 2024

Actual Payout Ratio: dividends paid per common share divided by basic EPS

Adjusted Basic EPS: Adjusted Common Equity Earnings divided by the basic weighted average number of common shares outstanding

Adjusted Common Equity Earnings: net earnings attributable to common equity shareholders adjusted as shown under "Non-U.S. GAAP Financial Measures" on page 10

Adjusted Payout Ratio: dividends paid per common share divided by Adjusted Basic EPS as shown under "Non-U.S. GAAP Financial Measures" on page 10

AFUDC: allowance for funds used during construction

AI: artificial intelligence

Aitken Creek: Aitken Creek Gas Storage ULC, a 93.8%-owned subsidiary of FortisBC Holdings Inc., sold on November 1, 2023

AMI: advanced metering infrastructure

ATM Program: at-the-market equity program

ACC: Arizona Corporation Commission

ASU: accounting standards update

AUC: Alberta Utilities Commission

BCUC: British Columbia Utilities Commission

Belize Electricity: Belize Electricity Limited, in which Fortis indirectly holds a 33% equity interest

Board: Board of Directors of the Corporation

CAGR(s): compound annual growth rate of a particular item. CAGR = $(EV/BV)^{(1/n)}-1$, where: (i) EV is the ending value of the item; (ii) BV is the beginning value of the item; and (iii) n is the number of periods. Calculated on a constant U.S. dollar-to-Canadian dollar exchange rate

Capital Expenditures: cash outlay for additions to property, plant and equipment and intangible assets as shown in the Annual Financial Statements, as well as Fortis' 39% share of capital spending for the Wataynikaneyap Transmission Power project. See "Non-U.S. GAAP Financial Measures" on page 10

Caribbean Utilities: Caribbean Utilities Company, Ltd., an indirect approximately 60%-owned (as at December 31, 2024) subsidiary of Fortis, together with its subsidiary

Central Hudson: CH Energy Group, Inc., an indirect wholly-owned subsidiary of Fortis, together with its subsidiaries, including Central Hudson Gas & Electric Corporation

CEO: Chief Executive Officer of Fortis

CFO: Chief Financial Officer of Fortis

Common Equity Earnings: net earnings attributable to common equity shareholders

Corporation: Fortis Inc.

COS: cost of service

Court of Appeal: Court of Appeal of Alberta

CPCN: Certificate of Public Convenience and Necessity

CSA: Canadian Securities Administrators

CSDS: Canadian Sustainability Disclosure Standard

CSSB: Canadian Sustainability Standards Board

DBP: defined benefit pension

D.C. Circuit Court: U.S. Court of Appeals for the District of Columbia Circuit

DCP: disclosure controls and procedures

DRIP: dividend reinvestment plan

EPC: engineering, procurement and construction

EPRI: Electric Power Research Institute

EPS: earnings per common share

ERM: enterprise risk management

FERC: Federal Energy Regulatory Commission

Fortis: Fortis Inc.

FortisAlberta: FortisAlberta Inc., an indirect wholly-owned subsidiary of Fortis

FortisBC: FortisBC Energy and FortisBC Electric

FortisBC Electric: FortisBC Inc., an indirect wholly-owned subsidiary of Fortis, together with its subsidiaries

FortisBC Energy: FortisBC Energy Inc., an indirect wholly-owned subsidiary of Fortis, together with its subsidiaries

FortisOntario: FortisOntario Inc., a direct wholly-owned subsidiary of Fortis, together with its subsidiaries

FortisTCI: FortisTCI Limited, an indirect wholly-owned subsidiary of Fortis, together with its subsidiary

Fortis Belize: Fortis Belize Limited, an indirect wholly-owned subsidiary of Fortis

Four Corners: Four Corners Generating Station, Units 4 and 5

FX: foreign exchange associated with the translation of U.S. dollar-denominated amounts. Foreign exchange is calculated by applying the change in the U.S. dollar-to-Canadian dollar FX rates to the prior period U.S. dollar balance

GCOC: generic cost of capital

GHG: greenhouse gas

GWh: gigawatt hour(s)

ICFR: internal control over financial reporting

IRP: integrated resource plan

ITC: ITC Investment Holdings Inc., an indirect 80.1%-owned subsidiary of Fortis, together with its subsidiaries, including International Transmission Company, Michigan Electric Transmission Company, LLC, ITC Midwest LLC, and ITC Great Plains, LLC

LNG: liquefied natural gas

LRTP: long range transmission plan

Luna: Luna Energy Facility

Major Capital Projects: projects, other than ongoing maintenance projects, individually costing $200 million or more in the forecast/planning period

Maritime Electric: Maritime Electric Company, Limited, an indirect wholly-owned subsidiary of Fortis

Material Adverse Effect: a material adverse effect on the Corporation's business, results of operations, financial position or liquidity, on a consolidated basis

MD&A: the Corporation's management discussion and analysis for the year ended December 31, 2024

MISO: Midcontinent Independent System Operator, Inc.

Moody's: Moody's Investor Services, Inc.

Morningstar DBRS: DBRS Limited

MW: megawatt(s)

Navajo: Navajo Generating Station

Newfoundland Power: Newfoundland Power Inc., a direct wholly-owned subsidiary of Fortis

Non-U.S. GAAP Financial Measures: financial measures that do not have a standardized meaning prescribed by U.S. GAAP

NOPR: notice of proposed rulemaking

NYSE: New York Stock Exchange

OPEB: other post-employment benefits

Operating Cash Flow: cash from operating activities

PBR: performance-based rate-setting

PJ: petajoule(s)

PPFAC: purchased power and fuel adjustment clause

PSC: New York State Public Service Commission

Rate Base: the stated value of property on which a regulated utility is permitted to earn a specified return in accordance with its regulatory construct

REA: Rural Electrification Association

RNG: renewable natural gas

ROA: rate of return on Rate Base

ROE: rate of return on common equity

ROFR: right of first refusal

RTO: regional transmission organization

S&P: Standard & Poor's Financial Services LLC

San Juan: San Juan Generating Station Unit 1

SEC: U.S. Securities and Exchange Commission

SEDAR+: Canadian System for Electronic Document Analysis and Retrieval

SOFR: secured overnight financing rates

TEP: Tucson Electric Power Company

TSR: total shareholder return, which is a measure of the return to common equity shareholders in the form of share price appreciation and dividends (assuming reinvestment) over a specified time period in relation to the share price at the beginning of the period.

TSX: Toronto Stock Exchange

UNS Electric: UNS Electric, Inc.

UNS Energy: UNS Energy Corporation, an indirect wholly-owned subsidiary of Fortis, together with its subsidiaries, including TEP, UNS Electric and UNS Gas

UNS Gas: UNS Gas, Inc.

U.S.: United States of America

U.S. GAAP: accounting principles generally accepted in the U.S.

Waneta Expansion: Waneta Expansion hydroelectric generation facility

Wataynikaneyap Power: Wataynikaneyap Power Limited Partnership, in which Fortis indirectly holds a 39% equity interest

FORTIS INC.

Audited Consolidated Financial Statements
As at and for the years ended December 31, 2024 and 2023

Table of Contents

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Fortis Inc. and its subsidiaries (the "Corporation") is responsible for establishing and maintaining adequate internal control over financial reporting ("ICFR"). The Corporation's ICFR is designed by, or under the supervision of, the Corporation's President and Chief Executive Officer ("CEO") and Executive Vice President, Chief Financial Officer ("CFO") and effected by the Corporation's 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 accounting principles generally accepted in the United States of America. Because of its inherent limitations, ICFR may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The Corporation's management, including its CEO and CFO, assessed the effectiveness of the Corporation's ICFR as of December 31, 2024, based on the criteria set forth in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management concluded that, as of December 31, 2024, the Corporation's ICFR was effective.

The Corporation's ICFR as of December 31, 2024 has been audited by Deloitte LLP, an Independent Registered Public Accounting Firm, which also audited the Corporation's consolidated financial statements for the year ended December 31, 2024. Deloitte LLP issued an unqualified opinion for both audits.

February 13, 2025

/s/ David G. Hutchens

David G. Hutchens

President and Chief Executive Officer, Fortis Inc.
St. John's, Canada

/s/ Jocelyn H. Perry

Jocelyn H. Perry

Executive Vice President, Chief Financial Officer, Fortis Inc.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of Fortis Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Fortis Inc. and subsidiaries (the "Corporation") as of December 31, 2024 and 2023, the related consolidated statements of earnings, comprehensive income, cash flows, and changes in equity, for each of the two years in the period ended December 31, 2024, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Corporation as of December 31, 2024 and 2023, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2024, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Corporation's internal control over financial reporting as of December 31, 2024, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 13, 2025, expressed an unqualified opinion on the Corporation's internal control over financial reporting.

Basis for Opinion

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

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

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current-period audit of the financial statements that were communicated or required to be communicated to the audit committee and that (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Assessment for Impairment of Goodwill - Refer to Notes 3 and 12 to the financial statements

Critical Audit Matter Description

The Corporation assesses goodwill for impairment annually as well as whenever any event or other change indicates that the fair value of a reporting unit may be below its carrying value. Management has determined that there is no impairment based on its current annual assessment.

Management's assessment primarily utilizes the income approach which is based on underlying estimates and assumptions with varying degrees of uncertainty. Those with the highest degree of subjectivity and impact are the assumed terminal growth rates and discount rates. Auditing these estimates and assumptions required a high degree of audit judgment and effort, including the involvement of a fair value specialist.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the terminal growth rate and discount rate used by management to estimate the fair value of more recently acquired reporting units included the following, among others:

- Evaluating the effectiveness of controls over the estimated fair value of the reporting units, including the review and approval of the terminal growth rate and discount rate selected by management.
- Evaluating management's ability to accurately forecast the terminal growth rate by:
  - Assessing the methodology used in management's determination of the terminal growth rate; and
  - Comparing management's assumptions to historical data and available market projection data.
- With the assistance of a fair value specialist, evaluating the reasonableness of the discount rate by:
  - Testing the source information underlying the determination of the discount rate; and
  - Developing a range of independent estimates and comparing those to the discount rate selected by management.

Impact of Rate Regulation on the financial statements - Refer to Notes 2, 3 and 8 to the financial statements

Critical Audit Matter Description

The Corporation's regulated utilities are subject to rate regulation and annual earnings oversight by various federal, state and provincial regulatory authorities who have jurisdiction in the United States and Canada. Rates and resultant earnings of the Corporation's regulated utilities are determined under cost of service regulation, with some using performance-based rate-setting mechanisms. The regulation of rates is premised on the full recovery of prudently incurred costs and a reasonable rate of return on asset value ("ROA") or common shareholders' equity ("ROE"). Regulatory decisions can have an impact on the timely recovery of costs and the regulator-approved ROE and/or ROA. Accounting for the economics of rate regulation impacts multiple financial statement line items and disclosures, such as property, plant, and equipment; regulatory assets and liabilities; operating revenues and expenses; income taxes; and depreciation expense.

We identified the impact of rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about impacted account balances and disclosures and the high degree of subjectivity involved in assessing the potential impact of future regulatory orders on the financial statements. Management judgments include assessing the likelihood of recovery of costs incurred or a refund to customers through the rate-setting process. While the Corporation's regulated utilities have indicated they expect to recover costs from customers through regulated rates, there is a risk that the respective regulatory authority will not approve full recovery of the costs incurred and a reasonable ROE and/or ROA. Auditing these matters required especially subjective judgment and specialized knowledge of accounting for rate regulation due to its inherent complexities across different jurisdictions.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the likelihood of recovery of costs incurred or a refund to customers through the rate-setting process, included the following, among others:

- Evaluating the effectiveness of controls over the monitoring and evaluation of regulatory developments that may affect the likelihood of recovering costs in future rates or of a future reduction in rates.
- Assessing relevant regulatory orders, regulatory statutes and interpretations as well as procedural memorandums, utility and intervener filings, and other publicly available information to evaluate the likelihood of recovery in future rates or of a future reduction in rates and the ability to earn a reasonable ROA or ROE.
- For regulatory matters in progress, inspecting the regulated utilities' filings for any evidence that might contradict management's assertions. We obtained an analysis from management and letters from internal and external legal counsel, as appropriate, regarding cost recoveries or a future reduction in rates.
- Evaluating the Corporation's disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments.

/s/ Deloitte LLP

Chartered Professional Accountants

St. John's, Canada
February 13, 2025

We have served as the Corporation's auditor since 2017.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of Fortis Inc.

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Fortis Inc. and subsidiaries (the "Corporation") as of December 31, 2024, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2024, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2024, of the Corporation and our report dated February 13, 2025, expressed an unqualified opinion on those financial statements.

Basis for Opinion

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

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

Definition and Limitations of Internal Control over Financial Reporting

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

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

/s/ Deloitte LLP

Chartered Professional Accountants

St. John's, Canada
February 13, 2025

CONSOLIDATED BALANCE SHEETS

FORTIS INC.

As at December 31 (in millions of Canadian dollars)	**2024**	2023
ASSETS		
Current assets		
Cash and cash equivalents	**$ 220**	$ 625
Accounts receivable and other current assets (Note 6)	**1,886**	1,818
Prepaid expenses	**182**	150
Inventories (Note 7)	**685**	566
Regulatory assets (Note 8)	**823**	866
Total current assets	**3,796**	4,025
Other assets (Note 9)	**1,653**	1,298
Regulatory assets (Note 8)	**3,808**	3,518
Property, plant and equipment, net (Note 10)	**49,456**	43,385
Intangible assets, net (Note 11)	**1,661**	1,510
Goodwill (Note 12)	**13,112**	12,184
Total assets	**$ 73,486**	$ 65,920
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings (Note 14)	**$ 98**	$ 119
Accounts payable and other current liabilities (Note 13)	**3,353**	2,972
Regulatory liabilities (Note 8)	**595**	577
Current installments of long-term debt (Note 14)	**1,990**	2,296
Total current liabilities	**6,036**	5,964
Regulatory liabilities (Note 8)	**3,696**	3,381
Deferred income taxes (Note 23)	**5,020**	4,399
Long-term debt (Note 14)	**31,224**	27,235
Finance leases (Note 15)	**343**	339
Other liabilities (Note 16)	**1,314**	1,270
Total liabilities	**47,633**	42,588
Commitments and contingencies (Note 27)		
Equity		
Common shares [(1)]	**15,589**	15,108
Preference shares (Note 18)	**1,623**	1,623
Additional paid-in capital	**8**	9
Accumulated other comprehensive income (Note 19)	**2,067**	653
Retained earnings	**4,521**	4,112
Shareholders' equity	**23,808**	21,505
Non-controlling interests	**2,045**	1,827
Total equity	**25,853**	23,332
Total liabilities and equity	**$ 73,486**	$ 65,920

[(1)] No par value. Unlimited authorized shares. 499.3 million and 490.6 million issued and outstanding as at December 31, 2024 and 2023, respectively

Approved on Behalf of the Board

/s/ Jo Mark Zurel
Jo Mark Zurel,
Director

/s/ Maura J. Clark
Maura J. Clark,
Director

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF EARNINGS

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars, except per share amounts)		**2024**		2023
Revenue (Note 5)	**$**	**11,508**	$	11,517
Expenses				
Energy supply costs		**3,249**		3,771
Operating expenses		**3,040**		2,889
Depreciation and amortization		**1,927**		1,773
Total expenses		**8,216**		8,433
Operating income		**3,292**		3,084
Other income, net (Note 22)		**288**		291
Finance charges		**1,406**		1,305
Earnings before income tax expense		**2,174**		2,070
Income tax expense (Note 23)		**346**		360
Net earnings	**$**	**1,828**	$	1,710
Net earnings attributable to:				
Non-controlling interests	**$**	**148**	$	137
Preference equity shareholders (Note 18)		**74**		67
Common equity shareholders		**1,606**		1,506
	$	**1,828**	$	1,710
Earnings per common share (Note 17)				
Basic	**$**	**3.24**	$	3.10
Diluted	**$**	**3.24**	$	3.10

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

For the years ended December 31 (in millions of Canadian dollars)		**2024**		2023
Net earnings	**$**	**1,828**	$	1,710
Other comprehensive income (loss)				
Unrealized foreign currency translation gains (losses), net of hedging activities and income tax recovery (expense) of $14 million and $(3) million, respectively		**1,561**		(402)
Other, net of income tax expense of $3 million and $4 million, respectively		**9**		6
		1,570		(396)
Comprehensive income	**$**	**3,398**	$	1,314
Comprehensive income attributable to:				
Non-controlling interests	**$**	**304**	$	96
Preference equity shareholders		**74**		67
Common equity shareholders		**3,020**		1,151
	$	**3,398**	$	1,314

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars)	**2024**	2023
Operating activities		
Net earnings	**$ 1,828**	$ 1,710
Adjustments to reconcile net earnings to net cash provided by operating activities:		
Depreciation - property, plant and equipment	**1,695**	1,542
Amortization - intangible assets	**153**	150
Amortization - other	**79**	81
Deferred income tax expense (Note 23)	**154**	272
Equity component, allowance for funds used during construction (Note 22)	**(139)**	(101)
Other	**43**	72
Change in long-term regulatory assets and liabilities	**(99)**	(100)
Change in working capital (Note 25)	**168**	(81)
Cash from operating activities	**3,882**	3,545
Investing activities		
Additions to property, plant and equipment	**(5,012)**	(3,986)
Additions to intangible assets	**(206)**	(183)
Contributions in aid of construction	**106**	216
Proceeds on disposition, net (Note 21)	**—**	454
Contributions to equity-accounted investees	**—**	(24)
Other	**(283)**	(219)
Cash used in investing activities	**(5,395)**	(3,742)
Financing activities		
Proceeds from long-term debt, net of issuance costs (Note 14)	**3,124**	2,810
Repayments of long-term debt and finance leases	**(1,718)**	(1,210)
Borrowings under committed credit facilities	**8,618**	7,217
Repayments under committed credit facilities	**(8,055)**	(7,276)
Net change in short-term borrowings	**(25)**	(126)
Issue of common shares, net of costs, and dividends reinvested	**46**	43
Dividends		
Common shares, net of dividends reinvested	**(744)**	(701)
Preference shares	**(74)**	(67)
Subsidiary dividends paid to non-controlling interests	**(110)**	(83)
Other	**2**	6
Cash from financing activities	**1,064**	613
Effect of exchange rate changes on cash and cash equivalents	**44**	—
Change in cash and cash equivalents	**(405)**	416
Cash and cash equivalents, beginning of year	**625**	209
Cash and cash equivalents, end of year	**$ 220**	$ 625

Supplementary Cash Flow Information (Note 25)

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars, except share numbers)	**Common Shares** *(# millions)*	**Common Shares**	**Preference Shares** (Note 18)	**Additional Paid-In Capital**	**Accumulated Other Comprehensive Income (Loss)** (Note 19)	**Retained Earnings**	**Non-Controlling Interests**	**Total Equity**
As at December 31, 2023	**490.6**	**$ 15,108**	**$ 1,623**	**$ 9**	**$ 653**	**$ 4,112**	**$ 1,827**	**$ 23,332**
Net earnings	**—**	**—**	**—**	**—**	**—**	**1,680**	**148**	**1,828**
Other comprehensive income	**—**	**—**	**—**	**—**	**1,414**	**—**	**156**	**1,570**
Common shares issued	**8.7**	**481**	**—**	**—**	**—**	**—**	**—**	**481**
Advances from non-controlling interests	**—**	**—**	**—**	**—**	**—**	**—**	**21**	**21**
Subsidiary dividends paid to non-controlling interests	**—**	**—**	**—**	**—**	**—**	**—**	**(110)**	**(110)**
Dividends declared on common shares ($2.41 per share)	**—**	**—**	**—**	**—**	**—**	**(1,197)**	**—**	**(1,197)**
Dividends on preference shares	**—**	**—**	**—**	**—**	**—**	**(74)**	**—**	**(74)**
Other	**—**	**—**	**—**	**(1)**	**—**	**—**	**3**	**2**
As at December 31, 2024	**499.3**	**$ 15,589**	**$ 1,623**	**$ 8**	**$ 2,067**	**$ 4,521**	**$ 2,045**	**$ 25,853**
As at December 31, 2022	482.2	$ 14,656	$ 1,623	$ 10	$ 1,008	$ 3,733	$ 1,812	$ 22,842
Net earnings	—	—	—	—	—	1,573	137	1,710
Other comprehensive loss	—	—	—	—	(355)	—	(41)	(396)
Common shares issued	8.4	452	—	—	—	—	—	452
Subsidiary dividends paid to non-controlling interests	—	—	—	—	—	—	(83)	(83)
Dividends declared on common shares ($2.31 per share)	—	—	—	—	—	(1,127)	—	(1,127)
Dividends on preference shares	—	—	—	—	—	(67)	—	(67)
Other	—	—	—	(1)	—	—	2	1
As at December 31, 2023	490.6	$ 15,108	$ 1,623	$ 9	$ 653	$ 4,112	$ 1,827	$ 23,332

See accompanying Notes to Consolidated Financial Statements

1. DESCRIPTION OF BUSINESS

Fortis Inc. ("Fortis" or the "Corporation") is a well-diversified North American regulated electric and gas utility holding company. Entities within the reporting segments that follow operate with substantial autonomy.

Regulated Utilities

ITC: ITC Investment Holdings Inc., ITC Holdings Corp. and the electric transmission operations of its regulated operating subsidiaries, which include International Transmission Company ("ITCTransmission"), Michigan Electric Transmission Company, LLC ("METC"), ITC Midwest LLC ("ITC Midwest"), and ITC Great Plains, LLC. Fortis owns 80.1% of ITC and an affiliate of GIC Private Limited owns a 19.9% minority interest.

ITC owns and operates high-voltage transmission lines in Michigan's lower peninsula and portions of Iowa, Minnesota, Illinois, Missouri, Kansas, Oklahoma and Wisconsin.

UNS Energy: UNS Energy Corporation, which primarily includes Tucson Electric Power Company ("TEP"), UNS Electric, Inc. ("UNS Electric") and UNS Gas, Inc. ("UNS Gas").

UNS Energy's largest operating subsidiary, TEP, and UNS Electric are vertically integrated regulated electric utilities. They generate, transmit and distribute electricity to retail customers in southeastern Arizona, including the greater Tucson metropolitan area. TEP also sells wholesale electricity to other entities in the western United States. Together they own generating capacity of 3,442 megawatts ("MW"), including 68 MW of solar capacity and 250 MW of wind capacity. Several generating assets in which they have an interest are jointly owned.

UNS Gas is a regulated gas distribution utility serving retail customers in northern and southern Arizona.

Central Hudson: CH Energy Group, Inc., which primarily includes Central Hudson Gas & Electric Corporation. Central Hudson is a regulated electric and gas transmission and distribution utility that serves portions of New York State's Mid-Hudson River Valley and owns gas-fired and hydroelectric generating capacity totalling 43 MW.

FortisBC Energy: FortisBC Energy Inc., which is the largest regulated distributor of natural gas in British Columbia, providing transmission and distribution services. FortisBC Energy sources natural gas supplies primarily from northeastern British Columbia and Alberta on behalf of most customers.

FortisAlberta: FortisAlberta Inc. is a regulated electricity distribution utility operating in a substantial portion of southern and central Alberta. FortisAlberta is not involved in the direct sale of electricity.

FortisBC Electric: FortisBC Inc. is an integrated regulated electric utility operating in the southern interior of British Columbia. It owns four hydroelectric generating facilities with a combined capacity of 225 MW. It also provides operating, maintenance and management services relating to five hydroelectric generating facilities in British Columbia that are owned by third parties.

Other Electric: Eastern Canadian and Caribbean utilities, as follows: Newfoundland Power Inc. ("Newfoundland Power"); Maritime Electric Company, Limited ("Maritime Electric"); FortisOntario Inc. ("FortisOntario"); a 39% equity investment in Wataynikaneyap Power Limited Partnership ("Wataynikaneyap Power"); an approximate 60% controlling interest in Caribbean Utilities Company, Ltd. ("Caribbean Utilities"); FortisTCI Limited and Turks and Caicos Utilities Limited (collectively, "FortisTCI"); and a 33% equity investment in Belize Electricity Limited ("Belize Electricity").

Newfoundland Power is an integrated regulated electric utility and the principal distributor of electricity on the island portion of Newfoundland and Labrador with a generating capacity of 145 MW, of which 98 MW is hydroelectric. Maritime Electric is an integrated regulated electric utility and the principal distributor of electricity on Prince Edward Island ("PEI") with on-Island generating capacity of 90 MW. FortisOntario consists of three regulated electric utilities that provide service to customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario with a generating capacity of 3 MW. Wataynikaneyap Power is a transmission company majority-owned by 24 First Nations in which Fortis owns a 39% interest. The 1,800 kilometer Wataynikaneyap Power Transmission Line will connect 17 remote First Nations to the Ontario power grid.

Caribbean Utilities is an integrated regulated electric utility and the sole electricity provider on Grand Cayman with a diesel-powered generating capacity of 166 MW. FortisTCI consists of two integrated regulated electric utilities that provide electricity to certain Turks and Caicos Islands and has a generating capacity of 99 MW, including 95 MW of diesel-powered generating capacity and 4 MW of solar capacity. Belize Electricity is an integrated electric utility and the principal distributor of electricity in Belize.

Non-Regulated

Corporate and Other: Captures expenses and revenues not specifically related to any reportable segment and those business operations that are below the required threshold for segmented reporting. Consists of non-regulated holding company expenses, as well as non-regulated long-term contracted generation assets in Belize. The generation assets include three hydroelectric generating facilities with a combined generating capacity of 51 MW, held through the Corporation's indirectly wholly owned subsidiary Fortis Belize Limited, the output of which is sold to Belize Electricity under 50-year power purchase agreements ("PPAs"). Also includes results for the Aitken Creek natural gas storage facility ("Aitken Creek") until the November 1, 2023 date of disposition (Note 21).

2. REGULATION

General

The earnings of the Corporation's regulated utilities are determined under cost of service ("COS") regulation, with some using performance-based rate setting ("PBR") mechanisms.

Under COS regulation, the regulator sets customer rates to permit a reasonable opportunity for the timely recovery of the estimated costs of providing service, including a fair rate of return on a deemed or targeted capital structure applied to an approved regulatory asset value ("rate base"). PBR mechanisms generally apply a formula that incorporates inflation and assumed productivity improvements for a set term.

The ability to recover prudently incurred costs of providing service and earn the regulator-approved rate of return on common shareholders' equity ("ROE") and/or rate of return on rate base assets ("ROA") may depend on achieving the forecasts established in the rate-setting process. As well, the Corporation's regulated utilities, where applicable, are permitted by their respective regulators to flow through to customers, without markup, the cost of natural gas, fuel and/or purchased power through base customer rates and/or the use of rate stabilization and other mechanisms (Note 8). There can be varying degrees of regulatory lag between when costs are incurred and when they are reflected in customer rates.

Nature of Regulation		Allowed Common Equity	Allowed ROE [1] (%)		
Regulated Utility	Regulatory Authority	(%)	2024	2023	Significant Features
ITC	Federal Energy Regulatory Commission ("FERC")	60.0	**10.73** [2]	10.77 [2]	Cost-based formula rates, with annual true-up mechanism [3] Incentive adders
TEP	Arizona Corporation Commission ("ACC")	54.3	**9.55**	9.55 [4]	COS regulation Historical test year
	FERC	[5]	**9.79**	9.79	Formula transmission rates
UNS Electric	ACC	53.7	**9.75** [6]	9.50	
UNS Gas	ACC	50.8	**9.75** [7]	9.75	
Central Hudson	New York State Public Service Commission ("PSC")	48.0	**9.50** [8]	9.00	COS regulation Future test year
FortisBC Energy	British Columbia Utilities Commission ("BCUC")	45.0	**9.65**	9.65	COS regulation with formula components and incentives
FortisBC Electric	BCUC	41.0	**9.65**	9.65	Future test year
FortisAlberta	Alberta Utilities Commission ("AUC")	37.0	**9.28**	8.50	PBR, with formula to calculate ROE on an annual basis [9]
Newfoundland Power	Newfoundland and Labrador Board of Commissioners of Public Utilities	45.0	**8.50**	8.50	COS regulation Future test year
Maritime Electric	Island Regulatory and Appeals Commission	40.0	**9.35**	9.35	COS regulation Future test year
FortisOntario [10]	Ontario Energy Board	40.0	**8.52-9.30**	8.52-9.30	COS regulation with incentive mechanisms
Caribbean Utilities [11]	Utility Regulation and Competition Office	N/A	**8.25-10.25**	7.50-9.50	COS regulation Rate-cap adjustment mechanism
FortisTCI [12]	Government of the Turks and Caicos Islands	N/A	**15.00-17.50**	15.00-17.50	COS regulation Historical test year

(1) ROA for Caribbean Utilities and FortisTCI
(2) Reflects the allowed common equity and ROE for ITCTransmission, METC, and ITC Midwest. The ROE above is inclusive of the base ROE as well as incentive adders totalling 0.75%. FERC issued an order in October 2024 retroactively revising the base ROE to certain prior periods including 2023. See "Significant Regulatory Matters" below
(3) Annual true-up collected or refunded in rates within a two-year period
(4) Allowed common equity of 54.3% and ROE of 9.55% effective September 1, 2023
(5) The allowed common equity component for FERC transmission rates is formulaic, and is updated annually based on TEP's actual equity ratio
(6) Allowed common equity of 53.7% and ROE of 9.75% effective February 1, 2024
(7) A general rate application requesting new customer rates is ongoing. See "Significant Regulatory Matters" below
(8) ROE of 9.5% effective July 1, 2024. A general rate application requesting new customer rates effective July 1, 2025 is ongoing. See "Significant Regulatory Matters" below
(9) In 2023, FortisAlberta was subject to a COS revenue requirement. The ROE for 2025 has been set at 8.97%
(10) Two of FortisOntario's utilities follow COS regulation with incentive mechanisms, while the remaining utility is subject to a 35-year franchise agreement expiring in 2033
(11) Operates under licences from the Government of the Cayman Islands. Its exclusive transmission and distribution licence is for an initial 20-year period, expiring in April 2028, with a provision for automatic renewal. Its non-exclusive generation licence is for a 25-year term, expiring in November 2039
(12) Operates under 25 and 50 year licences from the Government of the Turks and Caicos Islands, which expire in 2036 and 2037, respectively

2. REGULATION (cont'd)

Significant Regulatory Matters

ITC

MISO Base ROE: In 2022, the U.S. Court of Appeals for the District of Columbia Circuit issued a decision vacating certain FERC orders that had established the methodology for setting the base ROE for transmission owners operating in the Midcontinent Independent System Operator, Inc. ("MISO") region, including ITC, and remanded the matter to FERC for further process. This matter dates back to complaints filed at FERC in 2013 and 2015 challenging the MISO base ROE then in effect.

In October 2024, FERC issued an order that removed the use of the risk premium model from the calculation of the base ROE, while maintaining other modifications to the methodology. The updated methodology revised the base ROE from 10.02% to 9.98%, with a maximum ROE inclusive of incentives not to exceed 12.58%. The order also directed the payment of certain refunds, with interest, by December 2025, for the 15-month period from November 2013 through February 2015, and prospectively from September 2016. A regulatory liability of $39 million (US$27 million) associated with the refunds has been recognized by ITC as of December 31, 2024.

Certain MISO transmission owners, including ITC, filed a request for rehearing with FERC in November 2024, and filed an appeal of the order with the D.C. Circuit Court in January 2025. The requests for rehearing and appeal primarily focus on the refund period and the related interest. The timing and outcome of these filings are unknown.

Transmission Incentives: In 2021, FERC issued a supplemental notice of proposed rulemaking ("NOPR") on transmission incentives modifying the proposal in the initial NOPR released by FERC in 2020. The supplemental NOPR proposes to eliminate the 50-basis point regional transmission organization ("RTO") ROE incentive adder for RTO members that have been members for longer than three years. The timing and outcome of this proceeding remain unknown.

Transmission Right of First Refusal ("ROFR"): In December 2023, the Iowa District Court ruled that the manner in which Iowa's ROFR statute was passed was unconstitutional. The statute granted incumbent electric transmission owners, including ITC, a ROFR to construct, own and maintain certain electric transmission assets in the state. The District Court did not make any determination on the merits of the ROFR itself, but did issue a permanent injunction preventing ITC and others from taking further action to construct the MISO long-range transmission plan ("LRTP") tranche 1 Iowa projects in reliance on the ROFR.

In May 2024, MISO commenced a variance analysis process as a result of the inability to construct a portion of the tranche 1 LRTP projects in Iowa due to the injunction imposed by the District Court. In August 2024, MISO concluded the variance analysis, which reaffirmed the original allocation of projects to ITC and other incumbent transmission owners. While the results of MISO's variance analysis process allow ITC to move forward with the development of its portion of tranche 1 LRTP projects in Iowa, various legal proceedings with respect to this matter are ongoing for which the timing and outcome are unknown.

UNS Energy

Generic Regulatory Lag Docket: In December 2024, the ACC approved a formula rate plan policy statement which allows utilities to propose formula rates in future rate cases. A formula rate plan, if approved by the ACC, would adjust rates annually based on a predetermined formula. A formula rate plan is expected to improve rate stability for customers, while also reducing regulatory lag and the number of existing rate adjusters.

UNS Gas General Rate Application: In November 2024, UNS Gas filed a general rate application with the ACC requesting an increase in gas delivery rates effective February 1, 2026. The application includes a request to set its ROE at 10.25% and a 56% common equity component of capital structure. In January 2025, UNS Gas filed supplemental material proposing an annual rate adjustment mechanism as a result of the ACC's formula rate policy statement discussed above. The timing and outcome of this proceeding are unknown.

Central Hudson

2025 General Rate Application: In August 2024, Central Hudson filed a general rate application with the PSC requesting an increase in electric and gas delivery rates effective July 1, 2025. The application includes a request to set Central Hudson's allowed ROE at 10% and a 48% common equity component of capital structure. The timing and outcome of this proceeding are unknown.

Show Cause Order: In October 2024, the PSC issued a Show Cause Order which directed Central Hudson to explain why the PSC should not initiate an enforcement proceeding in connection with a gas-related explosion that occurred in November 2023. Central Hudson filed its response in November 2024. The timing and outcome of the Show Cause Order are unknown.

FortisBC Energy and FortisBC Electric

2025-2027 Rate Framework: In April 2024, FortisBC filed an application with the BCUC requesting approval of a rate framework for the period 2025 through 2027. The rate framework builds upon the current multi-year rate plan and includes, amongst other items, updates to depreciation and capitalized overhead rates, a revised level of operation and maintenance expense per customer indexed for inflation less a fixed productivity adjustment factor, a similar approach to growth capital, a forecast approach to sustaining and other capital, continued collection of an innovation fund recognizing the need to accelerate investment in clean energy innovation, and the continued sharing with customers of variances from the allowed ROE. The rate framework also proposes the continuation of deferral mechanisms currently in place. A decision from the BCUC is expected in mid-2025.

2. REGULATION (cont'd)

FortisAlberta

Generic Cost of Capital ("GCOC") Decision: In October 2023, the AUC issued a decision on the 2024 GCOC proceeding. In November 2023, FortisAlberta sought permission to appeal the GCOC decision to the Court of Appeal of Alberta ("Court of Appeal") on the basis that the AUC erred in its decision to not adjust FortisAlberta's ROE and common equity component of capital structure to address incremental business risk associated with competition from Rural Electrification Associations ("REAs") located in FortisAlberta's service area, as well as heightened regulatory risk due to the non-recovery of costs attributable to REAs. In April 2024, the Court of Appeal granted FortisAlberta permission to appeal, and a decision is expected in the first quarter of 2025.

Third PBR Term Decision: In October 2023, the AUC issued a decision establishing the parameters for the third PBR setting term for the period of 2024 through 2028. In November 2023, FortisAlberta sought permission to appeal the decision to the Court of Appeal on the basis that the AUC erred in its decision to determine capital funding using 2018-2022 historical capital investments without consideration for funding of new capital programs included in the company's 2023 cost of service revenue requirement as approved by the AUC. FortisAlberta's application for permission to appeal the decision was heard by the Court of Appeal in December 2024 and a decision is expected in the first quarter of 2025.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

These consolidated financial statements have been prepared and presented in accordance with accounting principles generally accepted in the United States of America ("U.S. GAAP") for rate-regulated entities, and are in Canadian dollars unless otherwise indicated.

These consolidated financial statements include the accounts of the Corporation and its subsidiaries. They reflect the equity method of accounting for entities in which Fortis has significant influence, but not control, and proportionate consolidation for assets that are jointly owned with non-affiliated entities.

Cash and Cash Equivalents

Cash and cash equivalents include cash, cash held in margin accounts, and short-term deposits with initial maturities of three months or less from the date of deposit.

Allowance for Credit Losses

Fortis and its subsidiaries recognize an allowance for credit losses to reduce accounts receivable for amounts estimated to be uncollectible. The allowance for credit losses is estimated based on historical collection patterns, sales, and current and forecast economic and other conditions. Accounts receivable are written off in the period in which they are deemed uncollectible.

Inventories

Inventories, consisting of materials and supplies, gas, fuel and coal in storage, are measured at the lower of weighted average cost and net realizable value.

Regulatory Assets and Liabilities

Regulatory assets and liabilities arise as a result of the utility rate-setting process and are subject to regulatory approval. Regulatory assets represent future revenues and/or receivables associated with certain costs incurred that will be, or are expected to be, recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent: (i) future reductions or limitations of increases in revenue associated with amounts that will be, or are expected to be, refunded to customers through the rate-setting process; or (ii) obligations to provide future service that customers have paid for in advance.

Certain remaining recovery and settlement periods are those expected by management and the actual periods could differ based on regulatory approval.

Investments

Investments are reviewed annually for potential impairment in value. Impairments are recognized when identified.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

Property, Plant and Equipment

Property, plant and equipment ("PPE") are recognized at cost less accumulated depreciation. Contributions in aid of construction by customers and governments are recognized as a reduction in the cost of, and are amortized in a manner consistent with, the related PPE.

Depreciation rates of the Corporation's regulated utilities include a provision for estimated future removal costs not identified as a legal obligation. The provision is recognized as a long-term regulatory liability (Note 8) against which actual removal costs are netted when incurred.

The Corporation's regulated utilities derecognize PPE on disposal or when no future economic benefits are expected from their use. Upon derecognition, any difference between cost and accumulated depreciation, net of salvage proceeds, is charged to accumulated depreciation. No gain or loss is recognized.

Through methodologies established by their respective regulators, the Corporation's regulated utilities capitalize: (i) overhead costs that are not directly attributable to specific PPE but relate to the overall capital expenditure plan; and (ii) an allowance for funds used during construction ("AFUDC"). The debt component of AFUDC for 2024 totalled $74 million (2023 - $56 million) and is reported as a reduction of finance charges and the equity component is reported as other income (Note 22). Both components are recorded to earnings through depreciation expense over the estimated service lives of the applicable PPE.

Excluding UNS Energy and Central Hudson, PPE includes inventory held for the development, construction and betterment of other assets. As required by its regulators, UNS Energy and Central Hudson recognize such items as inventory until used and reclassifies them to PPE once put into service.

Repairs and maintenance costs are charged to earnings in the period incurred. Replacements and betterments that extend the useful lives of PPE are capitalized.

PPE is depreciated using the straight-line method based on the estimated service lives of the assets. Depreciation rates for regulated PPE are approved by the respective regulators and ranged from 0.5% to 33.0% for 2024 (2023 - 0.5% to 35.0%). The weighted average composite rate of depreciation, before reduction for amortization of contributions in aid of construction, was 2.7% for 2024 (2023 – 2.6%).

The service life ranges and weighted average remaining service life of PPE as at December 31 were as follows.

	2024		2023	
(years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Distribution				
Electric	**5-80**	**32**	5-80	31
Gas	**18-83**	**37**	18-95	38
Transmission				
Electric	**20-85**	**42**	20-90	41
Gas	**10-80**	**35**	10-85	36
Generation	**2-95**	**22**	2-95	23
Other	**3-80**	**13**	3-80	10

Intangible Assets

Intangible assets are recorded at cost less accumulated amortization. Their useful lives are assessed to be either indefinite or finite.

Intangible assets with indefinite useful lives are not amortized and are tested for impairment annually, either individually or, where the particular entity also has goodwill, at the reporting unit level in conjunction with goodwill impairment testing. An annual review is completed to determine whether the indefinite life assessment continues to be supportable. If not, the resultant changes are made prospectively.

Intangible assets with finite lives are amortized using the straight-line method based on the estimated service lives of the assets. Amortization rates for regulated intangible assets are approved by the respective regulators and ranged from 1.0% to 33.0% for 2024 (2023 – 1.0% to 33.0%).

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

The service life ranges and weighted average remaining service life of finite-life intangible assets as at December 31 were as follows.

	2024		2023	
(years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Computer software	**3-18**	**5**	3-18	5
Land, transmission and water rights	**30-85**	**52**	30-90	52
Other	**10-100**	**16**	10-100	14

The Corporation's regulated utilities derecognize intangible assets on disposal or when no future economic benefits are expected from their use. Upon derecognition any difference between the cost and accumulated amortization of the asset, net of salvage proceeds, is charged to accumulated amortization. No gain or loss is recognized.

Impairment of Long-Lived Assets

The Corporation reviews the valuation of PPE, intangible assets with finite lives, and other long-term assets when events or changes in circumstances indicate that the total undiscounted cash flows expected to be generated by the asset may be below carrying value. If that is determined to be the case, the asset is written down to estimated fair value and an impairment loss is recognized.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of the identifiable net assets related to business acquisitions.

Goodwill at each of the Corporation's reporting units is tested for impairment annually and whenever an event or change in circumstances indicates that fair value may be below carrying value. If so determined, goodwill is written down to estimated fair value and an impairment loss is recognized.

The Corporation performs a qualitative assessment on each reporting unit, and if it is determined that it is not likely that fair value is less than carrying value, then a quantitative estimate of fair value is not required. When a quantitative assessment is performed, the primary method for estimating fair value of the reporting units is the income approach, whereby net cash flow projections are discounted. Underlying estimates and assumptions, with varying degrees of uncertainty, include the amount and timing of expected future cash flows, growth rates, and discount rates. A secondary valuation, the market approach along with a reconciliation of the total estimated fair value of all the reporting units to the Corporation's market capitalization, is also performed and evaluated.

Deferred Financing Costs

Issue costs, discounts and premiums are recognized against, and amortized over the life of, the related long-term debt.

Employee Future Benefits

Fortis and each subsidiary maintain one or a combination of defined benefit pension ("DBP") and defined contribution pension plans, as well as other post-employment benefit ("OPEB") plans, including certain health and dental coverage and life insurance benefits, for qualifying members. The costs of defined contribution pension plans are expensed as incurred.

For DBP and OPEB plans, the projected or accumulated benefit obligation and net benefit costs are actuarially determined using the projected benefits method prorated on service and management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and, for OPEB plans, expected health care costs. Discount rates reflect market interest rates on high-quality bonds with cash flows that match the timing and amount of expected pension or OPEB payments.

DBP and OPEB plan assets are recognized at fair value. For the purpose of determining defined benefit pension cost, FortisBC Energy and Newfoundland Power use the market-related value whereby investment returns in excess of, or below, expected returns are recognized in the asset value over a period of three years.

The excess of any cumulative net actuarial gain or loss over 10% of the greater of: (i) the projected or accumulated benefit obligation; and (ii) the fair value or market-related value, as applicable, of plan assets at the beginning of the fiscal year, along with unamortized past service costs, are deferred and amortized over the average remaining service period of active employees.

The net funded or unfunded status of DBP and OPEB plans, measured as the difference between the fair value of the plan assets and the projected or accumulated benefit obligation, is recognized on the Corporation's consolidated balance sheets.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

For most of the Corporation's regulated utilities, any difference between DBP or OPEB plan costs ordinarily recognized under U.S. GAAP and those recovered from customers in current rates is subject to deferral account treatment and is expected to be recovered from, or refunded to, customers in future rates. In addition, any unamortized balances related to net actuarial gains and losses, past service costs and transitional obligations associated with DBP or OPEB plans, as applicable, which would otherwise be recognized in accumulated other comprehensive income, are subject to deferral account treatment (Note 8).

Leases

A right-of-use asset and lease liability is recognized for leases with a lease term greater than 12 months. The right-of-use asset and liability are both measured at the present value of future lease payments, excluding variable payments that are based on usage or performance. Future lease payments include both lease components (e.g., rent, real estate taxes and insurance costs) and non-lease components (e.g., common area maintenance costs), which Fortis accounts for as a single lease component. The present value is calculated using the rate implicit in the lease or a lease-specific secured interest rate based on the remaining lease term. Renewal options are included in the lease term when it is reasonably certain that the option will be exercised.

Finance leases are depreciated over the lease term, except where: (i) ownership of the asset is transferred at the end of the lease term, in which case depreciation is over the estimated service life of the underlying asset; and (ii) the regulator has approved a different recovery methodology for rate-setting purposes, in which case the timing of the expense recognition will conform to the regulator's requirements.

Revenue Recognition

Most revenue is derived from energy sales and the provision of transmission services to customers based on regulator-approved tariff rates. Most contracts have a single performance obligation, being the delivery of energy or the provision of transmission services. No component of the transaction price is allocated to unsatisfied performance obligations. Energy sales are generally measured in kilowatt hours, gigajoules or transmission load delivered. The billing of energy sales is based on customer meter readings, which occur systematically throughout each month. The billing of transmission services at ITC is based on peak monthly load.

FortisAlberta is a distribution company and is required by its regulator to arrange and pay for transmission services with the Alberta Electric System Operator ("AESO"). This includes the collection of transmission revenue from its customers, which occurs through the transmission component of its regulator-approved rates. FortisAlberta reports transmission revenue and expenses on a net basis.

Electricity, gas and transmission service revenue includes an estimate for unbilled energy consumed or service provided since the last meter reading that has not been billed at the end of the reporting period. Sales estimates generally reflect an analysis of historical consumption in relation to key inputs, such as current energy prices, population growth, economic activity, weather conditions and system losses. Unbilled revenue accruals are adjusted in the periods actual consumption becomes known.

Generation revenue from non-regulated operations is recognized on delivery at contracted fixed or market rates.

Variable consideration is estimated at the most likely amount and reassessed at each reporting date until the amount is known. Variable consideration, including amounts subject to a future regulatory decision, is recognized as a refund liability until entitlement is probable.

Revenue excludes sales and municipal taxes collected from customers.

The Corporation has elected not to assess or account for any significant financing components associated with revenue billed in accordance with equal payment plans as the period between the transfer of energy to customers and the customers' payment is less than one year.

Stock-Based Compensation

Fortis recognizes liabilities associated with directors' deferred share units ("DSUs"), performance share units ("PSUs") and restricted share units ("RSUs"). DSUs represent cash-settled awards whereas PSUs and RSUs represent cash or share-settled awards. The fair value of these liabilities is based on the five-day volume weighted average price ("VWAP") of the Corporation's common shares at the end of each reporting period. The fair value of the PSU liability is also based on the expected payout probability, based on historical performance in accordance with the defined metrics of each grant and management's best estimate.

Compensation expense is recognized on a straight-line basis over the vesting period, which for PSUs and RSUs is over the lesser of three years or the period to retirement eligibility and for DSUs is at the time of grant. Forfeitures are accounted for as they occur.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

Foreign Currency Translation

Assets and liabilities of the Corporation's foreign operations, all of which have a U.S. dollar functional currency, are translated at the exchange rate in effect at the balance sheet date and the resultant unrealized translation gains and losses are recognized in accumulated other comprehensive income. The exchange rate as at December 31, 2024 was US$1.00=CA$1.44 (2023 – US$1.00=CA$1.32).

Revenue and expenses of the Corporation's foreign operations are translated at the average exchange rate for the reporting period, which was US$1.00=CA$1.37 for 2024 (2023 - US$1.00=CA$1.35).

Monetary assets and liabilities denominated in foreign currencies are translated at the exchange rate prevailing at the balance sheet date. Revenue and expenses denominated in foreign currencies are translated at the exchange rate prevailing at the transaction date. Translation gains and losses are recognized in earnings.

Translation gains and losses on foreign currency-denominated debt that is designated as an effective hedge of foreign net investments are recognized in other comprehensive income.

Derivatives and Hedging

Derivatives Not Designated as Hedges

Derivatives not designated as hedges are used by: (i) Fortis, to manage cash flow risk associated with forecast U.S. dollar cash inflows and forecast future cash settlements of DSU, PSU and RSU obligations; and (ii) UNS Energy, to meet forecast load and reserve requirements. Aitken Creek, to its date of disposition, utilized derivatives to manage commodity price risk, capture natural gas price spreads, and manage the financial risk of physical transactions (Note 21). Derivatives are measured at fair value with changes thereto recognized in earnings.

Derivatives not designated as hedges are also used by UNS Energy, Central Hudson and FortisBC Energy to reduce energy price risk associated with purchased power and gas requirements. The settled amounts of these derivatives are generally included in regulated rates, as permitted by the respective regulators. These derivatives are measured at fair value with changes recognized as regulatory assets or liabilities for recovery from, or refund to, customers in future rates (Note 8).

Derivatives that meet the normal purchase or normal sale scope exception are not measured at fair value and settled amounts are recognized in earnings as energy supply costs.

Derivatives Designated as Hedges

Fortis, ITC and Central Hudson use cash flow hedges, from time to time, to manage interest rate risk. Unrealized gains and losses are initially recognized in accumulated other comprehensive income and reclassified to earnings when the underlying hedged transaction affects earnings.

The Corporation's earnings from, and net investments in, foreign subsidiaries and certain equity-accounted investments are exposed to fluctuations in the U.S. dollar-to-Canadian dollar exchange rate. The Corporation has hedged a portion of this exposure through U.S. dollar-denominated debt at the corporate level. Exchange rate fluctuations associated with the translation of this debt and the foreign net investments are recognized in accumulated other comprehensive income.

Presentation of Derivatives

The fair value of derivatives is recognized as current or long-term assets and liabilities depending on the timing of settlements and resulting cash flows. Derivatives under master netting agreements and collateral positions are presented on a gross basis. Cash flows associated with the settlement of all derivatives are presented in operating activities in the consolidated statements of cash flows.

Income Taxes

The Corporation and its taxable subsidiaries follow the asset and liability method of accounting for income taxes. Current income tax expense or recovery is recognized for the estimated income taxes payable or receivable in the current year.

Deferred income tax assets and liabilities are recognized for temporary differences between the tax and accounting basis of assets and liabilities, as well as for the benefit of losses available to be carried forward to future years for tax purposes that are "more likely than not" to be realized. They are measured using enacted income tax rates and laws in effect when the temporary differences are expected to be recovered or settled. The effect of a change in income tax rates on deferred income tax assets and liabilities is recognized in earnings in the period when the change occurs. Valuation allowances are recognized when it is "more likely than not" that all of, or a portion of, a deferred income tax asset will not be realized.

Customer rates at ITC, UNS Energy, Central Hudson and Maritime Electric reflect current and deferred income tax. Customer rates at FortisAlberta reflect current income tax. Customer rates at FortisBC Energy, FortisBC Electric, Newfoundland Power and FortisOntario reflect current income tax and, for certain regulatory balances, deferred income tax. Caribbean Utilities, FortisTCI and Fortis Belize are not subject to income tax.

Differences between the income tax expense or recovery recognized under U.S. GAAP and reflected in current customer rates, which is expected to be recovered from, or refunded to, customers in future rates, are recognized as regulatory assets or liabilities (Note 8).

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

Income Taxes (cont'd)

Fortis does not recognize deferred income taxes on temporary differences related to investments in foreign subsidiaries where it intends to indefinitely reinvest earnings. The difference between the carrying values of these foreign investments and their tax bases, resulting from unrepatriated earnings and currency translation adjustments, is approximately $8.1 billion as at December 31, 2024 (2023 - $6.3 billion). If such earnings are repatriated, the Corporation may be subject to income taxes and foreign withholding taxes. The determination of the amount of unrecognized deferred income tax liabilities on such amounts is impractical.

Tax benefits associated with actual or expected income tax positions are recognized when the "more likely than not" recognition threshold is met. The tax benefits are measured at the largest amount of benefit that is greater than 50% likely to be realized upon settlement.

Income tax interest and penalties are recognized as income tax expense when incurred.

Asset Retirement Obligations

The Corporation's subsidiaries have asset retirement obligations ("AROs") associated with certain generation, transmission, distribution and interconnection assets, including land and environmental remediation and/or asset removal. These assets and related licences, permits, rights-of-way and agreements are reasonably expected to effectively exist and operate in perpetuity due to their nature. Consequently, where the final date and cost of remediation and/or removal of the noted assets cannot be reasonably determined, AROs have not been recognized.

Otherwise, AROs are recognized at fair value in the period incurred as an increase in PPE and long-term other liabilities (Note 16) if a reasonable estimate of fair value can be determined. Fair value is estimated as the present value of expected future cash outlays, discounted at a credit-adjusted risk-free interest rate. The increase in the liability due to the passage of time is recognized through accretion and the capitalized cost is depreciated over the useful life of the asset. Accretion and depreciation expense are deferred as a regulatory asset or liability based on regulatory recovery of these costs. Actual settlement costs are recognized as a reduction in the accrued liability.

Contingencies

Fortis and its subsidiaries are subject to various legal proceedings and claims that arise in the normal course of business. Management makes judgments regarding the future outcome of contingent events and recognizes a loss based on its best estimate when it is determined that such loss, or range of loss, is probable and can be reasonably estimated. Legal fees are expensed as incurred. When a loss is recoverable in future rates, a regulatory asset is also recognized.

Management regularly reviews current information to determine whether recognized provisions should be adjusted and new provisions are required. However, estimating probable losses requires considerable judgment about potential actions by third parties and matters are often resolved over long periods of time. Actual outcomes may differ materially from the amounts recognized.

Use of Accounting Estimates

The preparation of these consolidated financial statements in accordance with U.S. GAAP requires management to make estimates and judgments, including those arising from matters dependent upon the finalization of regulatory proceedings, that affect the reported amounts of assets, liabilities, revenues, expenses, gains and losses. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time they are made, with any adjustments being recognized in the period they become known. Actual results may differ significantly from these estimates.

New Accounting Policies

Segment Reporting: The Corporation adopted ASU No. 2023-07, *Improvements to Reportable Segment Disclosures*, for the year ended December 31, 2024 and will adopt it for interim periods beginning in 2025. This update requires disclosure of incremental segment information, including significant segment expenses and other items that are included in segment profit or loss. This adoption of this standard did not materially impact Fortis' disclosures.

Future Accounting Pronouncements

The Corporation considers the applicability and impact of all Accounting Standards Updates ("ASUs") issued by the Financial Accounting Standards Board. Any ASUs not included in these consolidated financial statements were assessed and determined to be either not applicable to the Corporation or are not expected to have a material impact on the consolidated financial statements.

Income Taxes: ASU No. 2023-09, *Improvements to Income Tax Disclosures,* is effective for Fortis on January 1, 2025 on a prospective basis, with retrospective application and early adoption permitted. The ASU requires additional disclosure of income tax information by jurisdiction to reflect an entity's exposure to potential changes in tax legislation, and associated risks and opportunities. Fortis does not expect the ASU to materially impact its disclosures.

Expense Disaggregation: ASU No. 2024-03, *Disaggregation of Income Statement Expenses*, is effective for Fortis on January 1, 2027 for annual periods and on January 1, 2028 for interim periods, on a prospective basis, with retrospective application and early adoption permitted. The ASU requires detailed disclosure of certain expense categories included on the consolidated statements of earnings, including energy supply costs, operating expenses, and depreciation and amortization expense. Fortis is assessing the impact on its disclosures.

4. SEGMENTED INFORMATION

Fortis' CEO is considered the chief operating decision maker ("CODM") for purposes of reviewing segment performance. Fortis segments its business based on regulatory jurisdiction and service territory, as well as the information used by the CODM in deciding how to allocate resources. Segment performance is evaluated principally on net earnings attributable to common equity shareholders, and this measure is used consistently in the evaluation of actual segment performance as well as in the Corporation's business plan and forecasting processes.

Related-Party and Inter-Company Transactions

Related-party transactions are in the normal course of operations and are measured at the amount of consideration agreed to by the related parties. There were no material related-party transactions in 2024 or 2023.

As of December 31, 2024, accounts receivable included $18 million due from Belize Electricity (December 31, 2023 - $8 million).

Fortis periodically provides short-term financing to subsidiaries to support capital expenditures and seasonal working capital requirements, the impacts of which are eliminated on consolidation. As at December 31, 2024 and 2023, there were no inter-segment loans outstanding. Interest charged on inter-segment loans was not material in 2024 and 2023.

	Regulated								Non-Regulated	Inter-	
($ millions)	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Other Electric	Sub-total	Corporate and Other	segment eliminations	Total
Year ended December 31, 2024											
Revenue	2,229	3,007	1,372	1,665	817	545	1,838	**11,473**	**35**	**—**	**11,508**
Energy supply costs	—	1,183	393	423	—	155	1,095	**3,249**	**—**	**—**	**3,249**
Operating expenses	530	798	659	418	195	141	250	**2,991**	**49**	**—**	**3,040**
Depreciation and amortization	448	404	134	337	291	88	218	**1,920**	**7**	**—**	**1,927**
Operating income	1,251	622	186	487	331	161	275	**3,313**	**(21)**	**—**	**3,292**
Other income, net	96	51	58	45	11	6	29	**296**	**(8)**	**—**	**288**
Finance charges	483	155	79	155	135	81	93	**1,181**	**225**	**—**	**1,406**
Income tax expense	200	70	37	83	26	14	23	**453**	**(107)**	**—**	**346**
Net earnings	664	448	128	294	181	72	188	**1,975**	**(147)**	**—**	**1,828**
Non-controlling interests	122	—	—	1	—	—	25	**148**	**—**	**—**	**148**
Preference share dividends	—	—	—	—	—	—	—	**—**	**74**	**—**	**74**
Net earnings attributable to common equity shareholders	542	448	128	293	181	72	163	**1,827**	**(221)**	**—**	**1,606**
Additions to property, plant and equipment and intangible assets	1,456	1,151	431	1,035	554	132	454	**5,213**	**5**	**—**	**5,218**
As at December 31, 2024											
Goodwill	8,828	1,987	649	913	231	235	269	**13,112**	**—**	**—**	**13,112**
Total assets	27,202	14,690	6,278	10,156	6,181	2,807	5,810	**73,124**	**374**	**(12)**	**73,486**
Year ended December 31, 2023											
Revenue	2,085	3,006	1,360	1,955	738	528	1,761	11,433	84	—	11,517
Energy supply costs	—	1,290	499	760	—	153	1,069	3,771	—	—	3,771
Operating expenses	494	776	601	408	180	127	231	2,817	72	—	2,889
Depreciation and amortization	416	361	113	309	265	96	204	1,764	9	—	1,773
Operating income	1,175	579	147	478	293	152	257	3,081	3	—	3,084
Other income, net	82	49	54	34	6	4	23	252	39	—	291
Finance charges	427	145	67	163	125	79	86	1,092	213	—	1,305
Income tax expense	208	83	29	74	12	9	26	441	(81)	—	360
Net earnings	622	400	105	275	162	68	168	1,800	(90)	—	1,710
Non-controlling interests	114	—	—	1	—	—	22	137	—	—	137
Preference share dividends	—	—	—	—	—	—	—	—	67	—	67
Net earnings attributable to common equity shareholders	508	400	105	274	162	68	146	1,663	(157)	—	1,506
Additions to property, plant and equipment and intangible assets	1,103	916	341	593	608	126	466	4,153	16	—	4,169
As at December 31, 2023											
Goodwill	8,127	1,830	597	913	228	235	254	12,184	—	—	12,184
Total assets	24,269	12,784	5,371	9,225	5,962	2,715	5,227	65,553	401	(34)	65,920

5. REVENUE

The following table presents the disaggregation of the Corporation's revenue on the consolidated statements of earnings by geography and substantially autonomous utility operations.

($ millions)	**2024**	2023
Electric and gas revenue		
United States		
ITC	**2,205**	2,098
UNS Energy	**2,731**	2,707
Central Hudson	**1,366**	1,329
Canada		
FortisBC Energy	**1,538**	1,766
FortisAlberta	**770**	699
FortisBC Electric	**481**	460
Newfoundland Power	**770**	759
Maritime Electric	**277**	258
FortisOntario	**235**	217
Caribbean		
Caribbean Utilities	**402**	388
FortisTCI	**118**	108
Total electric and gas revenue	**10,893**	10,789
Other services revenue	**350**	374
Revenue from contracts with customers	**11,243**	11,163
Alternative revenue	**169**	150
Other revenue	**96**	204
Total revenue	**11,508**	11,517

Revenue from Contracts with Customers

Electric and gas revenue includes revenue from the sale and/or delivery of electricity and gas, transmission revenue, and wholesale electric revenue, all based on regulator-approved tariff rates including the flow through of commodity costs.

Other services revenue includes management fees at UNS Energy for the operation of Springerville Units 3 and 4 and revenue from other services that reflect the ordinary business activities of Fortis' utilities. Other services revenue for 2023 also includes revenue from storage optimization activities at Aitken Creek through the date of disposition (Note 21).

Alternative Revenue

Alternative revenue programs allow utilities to adjust future rates in response to past activities or completed events if certain criteria are met. Alternative revenue is recognized on an accrual basis with a corresponding regulatory asset or liability until the revenue is settled. Upon settlement, revenue is not recognized as revenue from contracts with customers but rather as settlement of the regulatory asset or liability. The significant alternative revenue programs of Fortis' utilities are summarized as follows.

ITC's formula rates include an annual true-up mechanism that compares actual revenue requirements to billed revenue, and any under- or over-collections are accrued as a regulatory asset or liability and reflected in future rates within a two year period (Note 8). The formula rates do not require annual regulatory approvals, although inputs remain subject to legal challenge.

UNS Energy's lost fixed-cost recovery mechanism ("LFCR") surcharge recovers lost fixed costs, as measured by a reduction in non-fuel revenue, associated with energy efficiency savings and distributed generation. To recover the LFCR regulatory asset, UNS Energy is required to file an annual LFCR adjustment request with the ACC for the LFCR revenue recognized in the prior year. The recovery is subject to a year-over-year cap of 2% of total retail revenue.

FortisBC Energy and FortisBC Electric have an earnings sharing mechanism that provides for a 50/50 sharing of variances from the allowed ROE. Additionally, variances between forecast and actual customer-use rates and industrial and other customer revenue are captured in a revenue stabilization account and a flow-through deferral account, respectively, to be refunded to, or received from, customers in rates within two years.

Other Revenue

Other revenue primarily includes gains or losses on energy contract derivatives, as well as regulatory deferrals at FortisBC Energy and FortisBC Electric including cost recovery variances from forecast.

6. ACCOUNTS RECEIVABLE AND OTHER CURRENT ASSETS

($ millions)	**2024**	2023
Trade accounts receivable	**1,009**	890
Unbilled accounts receivable	**738**	727
Allowance for credit losses	**(78)**	(68)
	1,669	1,549
Income tax receivable	**—**	78
Other [1]	**217**	191
	1,886	1,818

[1] *Consists mainly of customer billings for non-core services, gas mitigation costs and collateral deposits for gas purchases, and the fair value of derivative instruments (Note 26)*

Allowance for Credit Losses

The allowance for credit losses changed as follows.

($ millions)	**2024**	2023
Balance, beginning of year	**(68)**	(58)
Credit loss expensed	**(30)**	(33)
Credit loss deferral	**(31)**	(13)
Write-offs, net of recoveries	**55**	35
Foreign exchange	**(4)**	1
Balance, end of year	**(78)**	(68)

See Note 26 for disclosure on the Corporation's credit risk.

7. INVENTORIES

($ millions)	**2024**	2023
Materials and supplies	**548**	431
Gas and fuel in storage	**65**	96
Coal inventory	**72**	39
	685	566

8. REGULATORY ASSETS AND LIABILITIES

($ millions)	**2024**	2023
Regulatory assets		
Deferred income taxes (Note 3)	**2,248**	2,058
Deferred energy management costs [1]	**591**	521
Rate stabilization and related accounts [2]	**453**	521
Employee future benefits (Notes 3 and 24)	**235**	254
Derivatives (Notes 3 and 26)	**175**	197
Deferred lease costs [3]	**142**	137
Deferred restoration costs [4]	**133**	115
Manufactured gas plant site remediation deferral (Note 16)	**82**	81
Generation early retirement costs [5]	**66**	64
Renewable natural gas account [6]	**58**	47
Other regulatory assets [7]	**448**	389
Total regulatory assets	**4,631**	4,384
Less: Current portion	**(823)**	(866)
Long-term regulatory assets	**3,808**	3,518

8. REGULATORY ASSETS AND LIABILITIES (cont'd)

($ millions)	2024	2023
Regulatory liabilities		
Future cost of removal (Note 3)	**1,728**	1,547
Deferred income taxes (Note 3)	**1,329**	1,280
Employee future benefits (Notes 3 and 24)	**459**	294
Rate stabilization and related accounts (2)	**208**	292
Renewable energy surcharge (8)	**155**	129
Energy efficiency liability (9)	**88**	78
Electric and gas moderator account (10)	**61**	50
AESO charges deferral (11)	**58**	121
Other regulatory liabilities (7)	**205**	167
Total regulatory liabilities	**4,291**	3,958
Less: Current portion	**(595)**	(577)
Long-term regulatory liabilities	**3,696**	3,381

(1) ***Deferred Energy Management Costs:*** Certain regulated subsidiaries provide energy management services to facilitate customer energy efficiency programs where the related expenditures have been deferred as a regulatory asset and are being amortized, and recovered from customers through rates, on a straight-line basis over periods ranging from one to 10 years.

(2) ***Rate Stabilization and Related Accounts:*** Rate stabilization accounts mitigate the earnings volatility otherwise caused by variability in the cost of fuel, purchased power and natural gas above or below a forecast or predetermined level, and by weather-driven volume variability. At certain utilities, revenue decoupling mechanisms minimize the earnings impact of reduced energy consumption as energy efficiency programs are implemented. Resultant deferrals are recovered from, or refunded to, customers in future rates as approved by the respective regulators.

Related accounts include the annual true-up mechanism at ITC (Note 5).

(3) ***Deferred Lease Costs:*** Deferred lease costs at FortisBC Electric primarily relate to the Brilliant Power Purchase Agreement ("BPPA") (Note 15). The depreciation of the asset under finance lease and interest expense on the finance lease obligation are not being fully recovered in current customer rates since these rates only reflect the cash payments required under the BPPA. The annual differences are being deferred as a regulatory asset, which is expected to be recovered from customers in future rates over the term of the lease, which expires in 2056.

(4) ***Deferred Restoration Costs:*** Incremental costs incurred at Central Hudson and Maritime Electric associated with restoration activities due to significant weather events. Incremental costs incurred in excess of that collected in customer rates at Central Hudson are recovered through rate stabilization accounts. The form and recovery period for Maritime Electric will be determined by the regulator.

(5) ***Generation Early Retirement Costs:*** Includes costs at TEP associated with the retirement of the Navajo Generating Station ("Navajo"), Sundt Generating Facility Units 1 and 2, and the San Juan Generating Station ("San Juan"), as approved for recovery by its regulator.

(6) ***Renewable Natural Gas Account:*** Reflects the variance between costs incurred to procure consumable biomethane gas and the related revenue recovered in customer rates. The difference is generally refunded or recovered from customers within one year.

(7) ***Other Regulatory Assets and Liabilities:*** Comprised of regulatory assets and liabilities individually less than $50 million.

(8) ***Renewable Energy Surcharge:*** Under the ACC's Renewable Energy Standard ("RES"), UNS Energy is required to increase its use of renewable energy each year until it represents at least 15% of its total annual retail energy requirements by 2025. The cost of carrying out the plan is recovered from retail customers through a RES surcharge. Any RES surcharge collections above or below the costs incurred to implement the plans are deferred as a regulatory liability or asset.

The ACC measures RES compliance through Renewable Energy Credits ("RECs"). Each REC represents one kilowatt hour generated from renewable resources. When UNS Energy purchases renewable energy, the premium paid above the market cost of conventional power equals the REC recoverable through the RES surcharge. When RECs are purchased, UNS Energy records their cost as long-term other assets (Note 9) with a corresponding regulatory liability to reflect the obligation to use the RECs for future RES compliance. When RECs are utilized for RES compliance, energy supply costs and revenue are recognized in an equal amount.

(9) ***Energy Efficiency Liability:*** The energy efficiency liability primarily relates to Central Hudson's Energy Efficiency Program, established to fund environmental policies associated with energy conservation programs as approved by its regulator.

(10) ***Electric and Gas Moderator Account:*** As part of Central Hudson's general rate applications, certain regulatory assets and liabilities were offset and included in the electric and gas moderator account, which will be used for future customer rate moderation.

(11) ***AESO Charges Deferral:*** Relates to differences in revenue collected and amounts incurred for transmission-related items at FortisAlberta that are expected to be collected or refunded in customer rates.

8. REGULATORY ASSETS AND LIABILITIES (cont'd)

Regulatory assets not earning a return: (i) totalled $1,908 million and $1,995 million as at December 31, 2024 and 2023, respectively; (ii) are primarily related to deferred income taxes and employee future benefits; and (iii) generally do not represent a past cash outlay as they are offset by related liabilities that, likewise, do not incur a carrying cost for rate-making purposes. Recovery periods vary or are yet to be determined by the respective regulators.

9. OTHER ASSETS

($ millions)	**2024**	2023
Employee future benefits (Note 24)	**551**	355
Equity investments [1]	**259**	237
Other investments	**225**	180
RECs (Note 8)	**176**	155
Supplemental Executive Retirement Plan ("SERP")	**127**	117
Operating leases (Note 15)	**64**	51
Derivatives	**48**	43
Deferred compensation plan	**29**	22
Other	**174**	138
	1,653	1,298

[1] *Includes investments in Belize Electricity and Wataynikaneyap Power*

ITC, UNS Energy and Central Hudson provide additional post-employment benefits through SERPs and deferred compensation plans for directors and officers. The assets held to support these plans are reported separately from the related liabilities (Note 16). Most plan assets are held in trust and funded mainly through life insurance policies and mutual funds. Assets in mutual and money market funds are recorded at fair value on a recurring basis (Note 26).

10. PROPERTY, PLANT AND EQUIPMENT

($ millions)	**Cost**	**Accumulated Depreciation**	**Net Book Value**
2024			
Distribution			
Electric	**15,771**	**(4,078)**	**11,693**
Gas	**7,148**	**(1,866)**	**5,282**
Transmission			
Electric	**23,084**	**(4,865)**	**18,219**
Gas	**2,937**	**(894)**	**2,043**
Generation	**8,056**	**(3,110)**	**4,946**
Other	**5,014**	**(1,809)**	**3,205**
Assets under construction	**3,578**	**—**	**3,578**
Land	**490**	**—**	**490**
	66,078	**(16,622)**	**49,456**
2023			
Distribution			
Electric	14,352	(3,708)	10,644
Gas	6,682	(1,736)	4,946
Transmission			
Electric	19,886	(4,267)	15,619
Gas	2,751	(843)	1,908
Generation	7,192	(2,739)	4,453
Other	4,444	(1,645)	2,799
Assets under construction	2,581	—	2,581
Land	435	—	435
	58,323	(14,938)	43,385

10. PROPERTY, PLANT AND EQUIPMENT (cont'd)

Electric distribution assets are those used to distribute electricity at lower voltages (generally below 69 kilovolts ("kV")). These assets include poles, towers and fixtures, low-voltage wires, transformers, overhead and underground conductors, street lighting, meters, metering equipment and other related equipment. Gas distribution assets are those used to transport natural gas at low pressures (generally below 2,070 kilopascals ("kPa")). These assets include distribution stations, telemetry, distribution pipe for mains and services, meter sets and other related equipment.

Electric transmission assets are those used to transmit electricity at higher voltages (generally at 69 kV and higher). These assets include poles, wires, switching equipment, transformers, support structures and other related equipment. Gas transmission assets are those used to transport natural gas at higher pressures (generally at 2,070 kPa and higher). These assets include transmission stations, telemetry, transmission pipe and other related equipment.

Generation assets are those used to generate electricity. These assets include hydroelectric and thermal generation stations, gas and combustion turbines, coal-fired generating stations, dams, reservoirs, photovoltaic systems, wind resources and other related equipment.

Other assets include buildings, equipment, vehicles, inventory, and information technology assets.

As at December 31, 2024, assets under construction largely reflect ongoing transmission projects at ITC and UNS Energy, as well as the Roadrunner Reserve battery storage projects at UNS Energy and the Eagle Mountain Pipeline project at FortisBC Energy.

The cost of PPE under finance lease as at December 31, 2024 was $324 million (2023 - $318 million) and related accumulated depreciation was $119 million (2023 - $113 million) (Note 15).

Jointly Owned Facilities

UNS Energy and ITC hold undivided interests in jointly owned generating facilities and transmission systems, are entitled to their pro rata share of the PPE, and are proportionately liable for the associated operating costs and liabilities. As at December 31, 2024, interests in jointly owned facilities consisted of the following.

($ millions, except as indicated)	**Ownership** *(%)*	**Cost**	**Accumulated Depreciation**	**Net Book Value**
Transmission Facilities	Various	**1,704**	**(489)**	**1,215**
Springerville Common Facilities	86.0	**580**	**(344)**	**236**
Springerville Coal Handling Facilities	83.0	**299**	**(154)**	**145**
Four Corners Units 4 and 5 ("Four Corners")	7.0	**311**	**(155)**	**156**
Gila River Common Facilities	50.0	**131**	**(52)**	**79**
Luna Energy Facility ("Luna")	33.3	**101**	**3**	**104**
		3,126	**(1,191)**	**1,935**

11. INTANGIBLE ASSETS

($ millions)	**Cost**	**Accumulated Amortization**	**Net Book Value**
2024			
Computer software	**1,035**	**(493)**	**542**
Land, transmission and water rights	**1,188**	**(210)**	**978**
Other	**143**	**(95)**	**48**
Assets under construction	**93**	**—**	**93**
	2,459	**(798)**	**1,661**
2023			
Computer software	1,040	(528)	512
Land, transmission and water rights	1,071	(182)	889
Other	132	(81)	51
Assets under construction	58	—	58
	2,301	(791)	1,510

Included in the cost of land, transmission and water rights as at December 31, 2024 was $123 million (2023 - $113 million) not subject to amortization. Amortization expense was $153 million for 2024 (2023 - $150 million). Amortization is estimated to average approximately $97 million for each of the next five years.

12. GOODWILL

($ millions)	2024	2023
Balance, beginning of year	**12,184**	12,464
Disposition of Aitken Creek (Note 21)	**—**	(27)
Foreign currency translation impacts [1]	**928**	(253)
Balance, end of year	**13,112**	12,184

[1] *Relates to the translation of goodwill associated with the acquisitions of ITC, UNS Energy, Central Hudson, Caribbean Utilities and FortisTCI, whose functional currency is the U.S. dollar*

No goodwill impairment was recognized by the Corporation in 2024 or 2023.

13. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

($ millions)	2024	2023
Trade accounts payable	**1,121**	990
Customer and other deposits	**360**	263
Dividends payable	**314**	295
Interest payable	**305**	274
Accrued taxes other than income taxes	**304**	268
Employee compensation and benefits payable	**303**	275
Gas and fuel cost payable	**221**	232
Derivatives (Note 26)	**169**	170
Income tax payable	**33**	—
Employee future benefits (Note 24)	**29**	28
Other	**194**	177
	3,353	2,972

14. LONG-TERM DEBT

($ millions)	Maturity Date	**2024**	2023
ITC			
Secured U.S. First Mortgage Bonds -			
4.34% weighted average fixed rate (2023 - 4.22%)	2027-2055	**3,944**	3,268
Secured U.S. Senior Notes -			
4.16% weighted average fixed rate (2023 - 4.00%)	2028-2055	**1,511**	1,278
Unsecured U.S. Senior Notes -			
4.37% weighted average fixed rate (2023 - 4.16%)	2026-2043	**5,610**	5,165
Unsecured U.S. Shareholder Note -			
6.00% fixed rate (2023 - 6.00%)	2028	**286**	263
UNS Energy			
Unsecured U.S. Fixed Rate Notes -			
4.09% weighted average fixed rate (2023 - 3.80%)	2026-2053	**4,172**	3,668
Central Hudson			
Unsecured U.S. Promissory Notes - 4.38% weighted			
average fixed and variable rate (2023 - 4.27%)	2025-2060	**1,974**	1,687
FortisBC Energy			
Unsecured Debentures -			
4.61% weighted average fixed rate (2023 - 4.61%)	2026-2052	**3,295**	3,295
FortisAlberta			
Unsecured Debentures -			
4.63% weighted average fixed rate (2023 - 4.52%)	2034-2054	**2,835**	2,685
FortisBC Electric			
Unsecured Debentures -			
4.72% weighted average fixed rate (2023 - 4.70%)	2035-2054	**960**	860
Other Electric			
Secured First Mortgage Sinking Fund Bonds -			
5.24% weighted average fixed rate (2023 - 5.24%)	2026-2060	**739**	748
Secured First Mortgage Bonds -			
5.29% weighted average fixed rate (2023 - 5.29%)	2025-2061	**320**	320
Unsecured Senior Notes -			
4.61% weighted average fixed rate (2023 - 4.45%)	2041-2054	**207**	152
Unsecured U.S. Senior Loan Notes and Bonds -			
5.03% weighted average fixed and variable rate (2023 - 4.89%)	2025-2052	**876**	702
Corporate and Other			
Unsecured U.S. Senior Notes and Promissory Notes -			
3.79% weighted average fixed rate (2023 - 3.82%)	2026-2044	**2,172**	2,251
Unsecured Debentures -			
6.51% fixed rate (2023 - 6.51%)	2039	**200**	200
Unsecured Senior Notes -			
4.11% weighted average fixed rate (2023 - 4.10%)	2028-2033	**2,000**	1,500
Long-term classification of credit facility borrowings		**2,216**	1,572
Fair value adjustment - ITC acquisition		**88**	89
Total long-term debt (Note 26)		**33,405**	29,703
Less: Deferred financing costs and debt discounts		**(191)**	(172)
Less: Current installments of long-term debt		**(1,990)**	(2,296)
		31,224	27,235

Most long-term debt at the Corporation's regulated utilities is redeemable at the option of the respective utility at the greater of par or a specified price, together with accrued and unpaid interest. Security, if provided, is typically through a fixed or floating first charge on specific assets of the utility.

14. LONG-TERM DEBT (cont'd)

The Corporation's unsecured debentures and senior notes are redeemable at the option of Fortis at the greater of par or a specified price together with accrued and unpaid interest.

Certain long-term debt agreements have covenants that provide that the Corporation shall not declare, pay or make any restricted payments, including special or extraordinary dividends, if immediately thereafter its consolidated debt to consolidated capitalization ratio would exceed 65%.

Significant Long-Term Debt Issuances in 2024	Month Issued	Interest Rate (%)	Maturity		Amount ($ millions)	Use of Proceeds
ITC						
Secured senior notes	January	5.98	2034	US	85	(1) (2) (3)
First mortgage bonds	January	5.11	2029	US	75	(1) (2) (3)
First mortgage bonds	January	5.38	2034	US	75	(1) (2) (3)
Unsecured senior notes	May	5.65	2034	US	400	(3) (4)
First mortgage bonds	December	4.88	2035	US	125	(1) (2) (3)
First mortgage bonds	December	5.25	2043	US	125	(1) (2) (3)
UNS Energy						
Unsecured senior notes	May	5.60	2036	US	30	(1) (3)
Unsecured senior notes	August	5.20	2034	US	400	(3) (4)
Central Hudson						
Senior notes	April	5.59	2031	US	25	(1) (3)
Senior notes	April	5.69	2034	US	35	(1) (3)
Senior notes	October	4.88	2029	US	25	(3) (4)
Senior notes	October	5.30	2034	US	44	(3) (4)
Senior notes	October	5.40	2036	US	35	(3) (4)
FortisBC Electric						
Unsecured debentures	August	4.92	2054		100	(1)
FortisAlberta						
Unsecured debentures	May	4.90	2054		300	(1) (2) (3) (4)
Caribbean Utilities						
Unsecured senior notes	May	6.17	2039	US	40	(1) (2) (3)
Unsecured senior notes	May	6.37	2049	US	40	(1) (2) (3)
FortisOntario						
Unsecured senior notes	August	5.05	2054		55	(1)
Fortis						
Unsecured senior notes	September	4.17	2031		500	(1) (3) (4)

(1) *Repay short-term and/or credit facility borrowings*
(2) *Fund capital expenditures*
(3) *General corporate purposes*
(4) *Repay maturing long-term debt*

14. LONG-TERM DEBT (cont'd)

Long-Term Debt Repayments

The consolidated requirements to meet principal repayments and maturities in each of the next five years and thereafter are as follows.

($ millions)	**Total**
2025	1,990
2026	2,585
2027	2,541
2028	1,499
2029	1,024
Thereafter	23,766
	33,405

In December 2024, Fortis filed a short-form base shelf prospectus with a 25-month life under which it may issue common or preference shares, subscription receipts, or debt securities in an aggregate principal amount of up to $2.0 billion. Fortis also reestablished the at-the-market equity program ("ATM Program") pursuant to the short-form base shelf prospectus, which allows the Corporation to issue up to $500 million of common shares from treasury to the public from time to time, at the Corporation's discretion, effective until January 10, 2027. As at December 31, 2024, $500 million remained available under the ATM Program and $1.5 billion remained available under the short-form base shelf prospectus.

Credit Facilities

($ millions)	Regulated Utilities	Corporate and Other	**2024**	2023
Total credit facilities	4,396	1,946	**6,342**	6,176
Credit facilities utilized:				
Short-term borrowings [(1)]	(98)	—	**(98)**	(119)
Long-term debt (including current portion) [(2)]	(1,335)	(881)	**(2,216)**	(1,572)
Letters of credit outstanding	(81)	(21)	**(102)**	(101)
Credit facilities unutilized	2,882	1,044	**3,926**	4,384

[(1)] *The weighted average interest rate was approximately 6.1% (2023 - 6.9%).*
[(2)] *The weighted average interest rate was approximately 4.6% (2023 - 6.2%). The current portion was $1,860 million (2023 - $1,160 million).*

Credit facilities are syndicated primarily with large banks in Canada and the U.S., with no one bank holding more than approximately 20% of the Corporation's total revolving credit facilities. Approximately $5.8 billion of the total credit facilities are committed with maturities ranging from 2025 through 2029.

In April 2024, FortisBC Energy increased its operating credit facility from $700 million to $900 million and extended the maturity to July 2028. In May 2024, FortisBC Electric increased its operating credit facility from $150 million to $200 million and extended the maturity to April 2028.

In May 2024, the Corporation extended the maturity on its unsecured US$500 million non-revolving term credit facility to May 2025. Half of the term credit facility was repaid in the third quarter of 2024 and the remaining US$250 million has been fully utilized as at December 31, 2024. The facility is repayable at any time without penalty. In June 2024, the Corporation amended its $1.3 billion revolving term committed credit facility to extend the maturity to July 2029.

In August 2024, Newfoundland Power increased its operating credit facility from $100 million to $130 million and extended the maturity to August 2029.

14. LONG-TERM DEBT (cont'd)

Consolidated credit facilities of approximately $6.3 billion as at December 31, 2024 are itemized below.

($ millions)		Amount	Maturity
Unsecured committed revolving credit facilities			
Regulated utilities			
ITC [1]	**US**	**1,000**	2028
UNS Energy	**US**	**375**	2027
Central Hudson	**US**	**250**	2029
FortisBC Energy		**900**	2028
FortisAlberta		**250**	2029
FortisBC Electric		**200**	2028
Other Electric		**285**	[2]
Other Electric	**US**	**83**	2025
Corporate and Other		**1,350**	[3]
Other facilities			
Regulated utilities			
Central Hudson - uncommitted credit facility	**US**	**60**	n/a
FortisBC Energy - uncommitted credit facility		**55**	2025
FortisBC Electric - unsecured demand overdraft facility		**10**	n/a
Other Electric - unsecured demand facilities		**20**	n/a
Other Electric - unsecured demand facility and emergency standby loan	**US**	**93**	2025
Corporate and Other			
Unsecured non-revolving facility	**US**	**250**	2025
Unsecured revolving facility	**US**	**150**	2025
Unsecured non-revolving facility		**21**	n/a

(1) *ITC also has a US$400 million commercial paper program, under which $nil was outstanding as at December 31, 2024 and 2023*
(2) *$90 million in 2027, $65 million in 2027, and $130 million in 2029*
(3) *$50 million in 2026 and $1.3 billion in 2029*

15. LEASES

The Corporation and its subsidiaries lease office facilities, utility equipment, land, and communication tower space with remaining terms of up to 23 years, with optional renewal terms. Certain lease agreements include rental payments adjusted periodically for inflation or require the payment of real estate taxes, insurance, maintenance, or other operating expenses associated with the leased premises.

The Corporation's subsidiaries also have finance leases related to generating facilities with remaining terms of up to 31 years.

Leases were presented on the consolidated balance sheets as follows.

($ millions)	2024	2023
Operating leases		
Other assets	**64**	51
Accounts payable and other current liabilities	**(17)**	(12)
Other liabilities	**(47)**	(39)
Finance leases [1]		
Regulatory assets	**142**	137
PPE, net	**205**	205
Accounts payable and other current liabilities	**(4)**	(3)
Finance leases	**(343)**	(339)

(1) *FortisBC Electric has a finance lease for the BPPA (Note 8), which relates to the sale of the output of the Brilliant hydroelectric plant, and for the Brilliant Terminal Station ("BTS"), which relates to the use of the station. Both agreements expire in 2056. In exchange for the specified take-or-pay amounts of power, the BPPA requires semi-annual payments based on a return on capital, which includes the original and ongoing capital cost, and related variable power purchase costs. The BTS requires semi-annual payments based on a charge related to the recovery of the capital cost of the BTS, and related variable operating costs.*

15. LEASES (cont'd)

The components of lease expense were as follows.

($ millions)	2024	2023
Operating lease cost	19	12
Finance lease cost:		
Amortization	2	3
Interest	33	33
Variable lease cost	21	23
Total lease cost	75	71

As at December 31, 2024, the present value of minimum lease payments was as follows.

($ millions)	Operating Leases	Finance Leases	Total
2025	18	37	55
2026	15	37	52
2027	12	37	49
2028	6	37	43
2029	4	37	41
Thereafter	19	954	973
	74	1,139	1,213
Less: Imputed interest	(10)	(792)	(802)
Total lease obligations	64	347	411
Less: Current installments	(17)	(4)	(21)
	47	343	390

Supplemental lease information follows.

($ millions, except as indicated)	2024	2023
Weighted average remaining lease term *(years)*		
Operating leases	7	7
Finance leases	31	32
Weighted average discount rate *(%)*		
Operating leases	4.6	4.5
Finance leases	5.0	5.0

16. OTHER LIABILITIES

($ millions)	2024	2023
Employee future benefits (Note 24)	446	527
AROs (Note 3)	249	163
Customer and other deposits	128	168
Stock-based compensation plans (Note 20)	113	82
Manufactured gas plant site remediation (1)	101	94
Derivatives (Note 26)	66	48
Deferred compensation plan (Note 9)	63	54
Operating leases (Note 15)	47	39
Mine reclamation obligations (2)	40	30
Retail energy contract (3)	20	27
Other	41	38
	1,314	1,270

16. OTHER LIABILITIES (Cont'd)

(1) Environmental regulations require Central Hudson to investigate sites at which it or its predecessors once owned and/or operated manufactured gas plants and, if necessary, remediate those sites. Costs are accrued based on the amounts that can be reasonably estimated. Central Hudson has notified its insurers that it intends to seek reimbursement where insurance coverage exists. Differences between actual costs and the associated rate allowances are deferred as a regulatory asset for future recovery (Note 8).

(2) TEP pays ongoing reclamation costs related to two coal mines that supply generating facilities in which it has an ownership interest but does not operate. Costs are deferred as a regulatory asset and recovered from customers as permitted by the regulator. TEP's share of the reclamation costs is estimated to be $49 million. The present value of the estimated future liability in included in other liabilities.

(3) FortisAlberta has an agreement with a retail energy provider to act as its default retailer to eligible customers under the regulated retail option. As part of this agreement FortisAlberta received an upfront payment which is being amortized to revenue over the eight year agreement.

17. EARNINGS PER COMMON SHARE

Diluted earnings per share ("EPS") was calculated using the treasury stock method for stock options.

	2024			2023		
	Net Earnings to Common Shareholders *($ millions)*	**Weighted Average Shares** *(# millions)*	**EPS** *($)*	Net Earnings to Common Shareholders *($ millions)*	Weighted Average Shares *(# millions)*	EPS *($)*
Basic EPS	**1,606**	**495.0**	**3.24**	1,506	486.3	3.10
Potential dilutive effect of stock options (Note 20)	**—**	**0.2**	**—**	—	0.2	—
Diluted EPS	**1,606**	**495.2**	**3.24**	1,506	486.5	3.10

18. PREFERENCE SHARES

Authorized

An unlimited number of first preference shares and second preference shares, without nominal or par value.

Issued and Outstanding First Preference Shares	**2024**		2023	
	Number of Shares *(thousands)*	**Amount** *($ millions)*	Number of Shares *(thousands)*	Amount *($ millions)*
Series F	**5,000**	**122**	5,000	122
Series G	**9,200**	**225**	9,200	225
Series H	**7,665**	**188**	7,665	188
Series I	**2,335**	**57**	2,335	57
Series J	**8,000**	**196**	8,000	196
Series K	**10,000**	**244**	10,000	244
Series M	**24,000**	**591**	24,000	591
	66,200	**1,623**	66,200	1,623

18. PREFERENCE SHARES (Cont'd)

Characteristics of the first preference shares are as follows:

First Preference Shares [1][2]	Dividend Rate (%)	Annual Dividend ($)	Reset Dividend Yield (%)	Redemption and/or Conversion Option Date	Redemption Value ($)	Right to Convert on a One-For-One Basis
Perpetual fixed rate						
Series F	4.90	1.2250	—	Currently Redeemable	25.00	—
Series J	4.75	1.1875	—	Currently Redeemable	25.00	—
Fixed rate reset [3][4]						
Series G	6.12	1.5308	2.13	September 1, 2028	25.00	—
Series H	1.84	0.4588	1.45	June 1, 2025	25.00	Series I
Series K	5.47	1.3673	2.05	March 1, 2029	25.00	Series L
Series M	5.49	1.3733	2.48	December 1, 2029	25.00	Series N
Floating rate reset [4][5]						
Series I	[5]	—	1.45	June 1, 2025	25.00	Series H
Series L	—	—	—	—	—	Series K
Series N	—	—	—	—	—	Series M

(1) Holders are entitled to receive a fixed or floating cumulative quarterly cash dividend as and when declared by the Board of Directors of the Corporation, payable in equal installments on the first day of each quarter.

(2) On or after the specified redemption dates, the Corporation has the option to redeem for cash the outstanding first preference shares, in whole or in part, at the specified per share redemption value plus all accrued and unpaid dividends up to but excluding the dates fixed for redemption, and in the case of the first preference shares that reset, on every fifth anniversary date thereafter.

(3) On the redemption and/or conversion option date, and on each five-year anniversary thereafter, the reset annual dividend per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date, plus the applicable reset dividend yield.

(4) On each conversion option date, the holders have the option, subject to certain conditions, to convert any or all of their shares into an equal number of Cumulative Redeemable first preference shares of a specified series.

(5) The floating quarterly dividend rate will be reset every quarter based on the then current three-month Government of Canada Treasury Bill rate plus the applicable reset dividend yield.

On the liquidation, dissolution or winding-up of Fortis, holders of common shares are entitled to participate ratably in any distribution of assets of Fortis, subject to the rights of holders of first and second preference shares, and any other class of shares of the Corporation entitled to receive the assets of the Corporation on such a distribution, in priority to or ratably with the holders of the common shares.

19. ACCUMULATED OTHER COMPREHENSIVE INCOME

($ millions)	Opening Balance	Net Change	Ending Balance
2024			
Unrealized foreign currency translation gains (losses)			
Net investments in foreign operations	**1,059**	**1,653**	**2,712**
Hedges of net investments in foreign operations	**(452)**	**(262)**	**(714)**
Income tax recovery	**4**	**14**	**18**
	611	**1,405**	**2,016**
Other			
Interest rate hedges (Note 26)	**62**	**10**	**72**
Unrealized employee future benefits (losses) gains (Note 24)	**(9)**	**2**	**(7)**
Income tax expense	**(11)**	**(3)**	**(14)**
	42	**9**	**51**
Accumulated other comprehensive income	**653**	**1,414**	**2,067**
2023			
Unrealized foreign currency translation gains (losses)			
Net investments in foreign operations	1,495	(436)	1,059
Hedges of net investments in foreign operations	(530)	78	(452)
Income tax recovery (expense)	7	(3)	4
	972	(361)	611
Other			
Interest rate hedges (Note 26)	49	13	62
Unrealized employee future benefits losses (Note 24)	(6)	(3)	(9)
Income tax expense	(7)	(4)	(11)
	36	6	42
Accumulated other comprehensive income	1,008	(355)	653

20. STOCK-BASED COMPENSATION PLANS

Stock Options

Beginning January 1, 2022, the Corporation no longer grants stock options. Existing options to purchase common shares of the Corporation are exercisable for a period of 10 years from the grant date, expire no later than three years after the death or retirement of the optionee, and vest evenly over a four year period on each anniversary of the grant date. Compensation expense related to stock options was measured at the grant date using the Black-Scholes fair value option-pricing model with each grant amortized to compensation expense evenly over the four year vesting period, with the offsetting entry to additional paid-in capital. Fortis satisfies stock option exercises by issuing common shares from treasury. Upon exercise, proceeds are credited to capital stock at the option prices and the fair value of the options, as previously recognized, is reclassified from additional paid-in capital to capital stock.

As at December 31, 2024, the Corporation had 1.5 million stock options outstanding (2023 - 1.9 million) with a weighted average exercise price of $48.96 (2023 - $48.12). There were 1.4 million options vested as of December 31, 2024 (2023 – 1.6 million) with a weighted average exercise price of $48.87 (2023 - $47.19).

In 2024, 0.4 million stock options were exercised (2023 - 0.3 million) for cash proceeds of $15 million (2023 - $13 million) and an intrinsic value realized by option holders of $5 million (2023 - $6 million).

DSUs

Directors of the Corporation who are not officers are eligible for grants of DSUs representing the equity portion of their annual compensation. Directors can also elect to receive credit for their quarterly cash retainer in a notional account of DSUs in lieu of cash. The Corporation may also determine that special circumstances justify the grant of additional DSUs to a director.

Beginning in 2024, in any year in which a director satisfies their share ownership target, the director may elect to receive a portion of their equity compensation in cash or common shares, with the remaining portion to be granted as DSUs. Common share elections are satisfied quarterly through purchases on the Toronto Stock Exchange or the New York Stock Exchange.

Each DSU vests at the grant date, has an underlying value equivalent to that of one common share of the Corporation, is entitled to commensurate notional common share dividends, and is settled in cash.

20. STOCK-BASED COMPENSATION PLANS (cont'd)

DSUs (cont'd)

The following table summarizes information related to DSUs.

	2024	2023
Number of units *(thousands)*		
Beginning of year	**241**	224
Granted	**29**	40
Notional dividends reinvested	**10**	10
Paid out	**(39)**	(33)
End of year	**241**	241

The accrued liability has been recognized at the respective December 31st VWAP and included in other liabilities (Note 16). The accrued liability, compensation expense and cash payout were not material for 2024 or 2023.

PSUs

Senior management of the Corporation and its subsidiaries, and all ITC employees, are eligible for grants of PSUs representing a component of their long-term compensation.

Each PSU vests over a three year period, has an underlying value equivalent to that of one common share of the Corporation, and is entitled to commensurate notional common share dividends. PSUs are generally settled in cash with cash payouts calculated at the end of the three year vesting period as the product of: (i) the number of units vested; (ii) the VWAP of the Corporation's common shares for the five trading days prior to the vesting date; and (iii) a payout percentage that may range from 0% to 200%. Effective with the 2024 grant, PSUs granted under the Corporation's Omnibus Equity Plan can be settled in cash or common shares of the Corporation. PSUs settled through common shares will be satisfied by issuing common shares from treasury.

The payout percentage is based on the Corporation's performance over the three year vesting period, mainly determined by: (i) the Corporation's total shareholder return as compared to a predefined peer group of companies; (ii) the Corporation's cumulative EPS, or for subsidiaries the company's cumulative net income, as compared to the target established at the time of the grant; and (iii) beginning with the 2022 PSU grant, the Corporation's Scope 1 carbon reduction performance as compared to target established at the time of the grant. In addition, the 2023 PSU grant included a payout modifier based on the achievement of diversity, equity and inclusion goals.

The following table summarizes information related to PSUs.

	2024	2023
Number of units *(thousands)*		
Beginning of year	**1,942**	1,790
Granted	**788**	722
Notional dividends reinvested	**78**	66
Paid out	**(609)**	(606)
Cancelled/forfeited	**(28)**	(30)
End of year	**2,171**	1,942
Additional information *($ millions)*		
Compensation expense recognized	**53**	45
Compensation expense unrecognized [(1)]	**34**	28
Cash payout	**44**	46
Accrued liability as at December 31 [(2)]	**105**	90
Aggregate intrinsic value as at December 31 [(3)]	**139**	118

(1) Relates to unvested PSUs and is expected to be recognized over a weighted average period of two years
(2) Recognized at the respective December 31st VWAP and included in accounts payable and other current liabilities and in other liabilities (Notes 13 and 16)
(3) Relates to outstanding PSUs and reflects a weighted average contractual life of one year

20. STOCK-BASED COMPENSATION PLANS (cont'd)

RSUs

Senior management of the Corporation and its subsidiaries, and all ITC employees, are eligible for grants of RSUs representing a component of their long-term compensation.

Each RSU vests over a three year period, has an underlying value equivalent to that of one common share of the Corporation, is entitled to commensurate notional common share dividends, and is settled in cash or common shares of the Corporation. Beginning with the 2024 grant, RSUs settled through common shares will be satisfied by issuing common shares from treasury.

The following table summarizes information related to RSUs.

	2024	2023
Number of units *(thousands)*		
Beginning of year	**1,079**	977
Granted	**464**	416
Notional dividends reinvested	**38**	35
Paid out	**(357)**	(323)
Cancelled/forfeited	**(23)**	(26)
End of year	**1,201**	1,079
Additional information *($ millions)*		
Compensation expense recognized	**29**	21
Compensation expense unrecognized (1)	**21**	17
Cash payout	**19**	17
Accrued liability as at December 31 (2)	**54**	42
Aggregate intrinsic value as at December 31 (3)	**75**	59

(1) *Relates to unvested RSUs and is expected to be recognized over a weighted average period of two years*
(2) *Recognized at the respective December 31st VWAP and included in accounts payable and other current liabilities and in long-term other liabilities (Notes 13 and 16)*
(3) *Relates to outstanding RSUs and reflects a weighted average contractual life of one year*

Share-settlements were not material for 2024 and 2023.

21. DISPOSITION

On November 1, 2023, FortisBC Holdings Inc. ("FHI") completed the sale of its Aitken Creek business to a subsidiary of Enbridge Inc. for approximately $470 million including working capital and closing adjustments, following the satisfaction of all regulatory requirements. The transaction reflected a March 31, 2023 effective date. A gain on disposition of $23 million ($10 million after tax), net of transaction costs, was recognized in the Corporate and Other segment.

For the seven-month period between the March 31, 2023 effective date and the November 1, 2023 disposition date, Aitken Creek recognized net earnings, excluding the gain as noted above, of $5 million.

From January 1, 2023 through to the November 1, 2023 disposition date, excluding the gain, Aitken Creek recognized net earnings of $20 million.

22. OTHER INCOME, NET

($ millions)	**2024**	2023
Equity component of AFUDC	**139**	101
Non-service component of net periodic benefit cost	**73**	62
Interest income [(1)]	**64**	76
Equity income	**14**	14
Gain on disposal of Aitken Creek, pre-tax (Note 21)	**—**	23
Gain on derivatives, net	**—**	9
Net foreign exchange (loss) gain	**(10)**	4
Other	**8**	2
	288	291

[(1)] *Includes interest on short-term deposits, as well as interest on regulatory deferrals, including the PPFAC at TEP and UNS Electric*

23. INCOME TAXES

Deferred Income Tax Assets and Liabilities

The significant components of deferred income tax assets and liabilities consisted of the following.

($ millions)	**2024**	2023
Gross deferred income tax assets		
Regulatory liabilities	**659**	636
Tax loss and credit carryforwards	**629**	600
Employee future benefits	**123**	136
Other	**216**	144
	1,627	1,516
Valuation allowance	**(50)**	(23)
Net deferred income tax asset	**1,577**	1,493
Gross deferred income tax liabilities		
PPE	**(5,993)**	(5,355)
Regulatory assets	**(432)**	(372)
Intangible assets	**(172)**	(165)
	(6,597)	(5,892)
Net deferred income tax liability	**(5,020)**	(4,399)

Income Tax Expense

($ millions)	**2024**	2023
Canadian		
Earnings before income tax expense	**518**	526
Current income tax	**154**	71
Deferred income tax	**(87)**	17
Total Canadian	**67**	88
Foreign		
Earnings before income tax expense	**1,656**	1,544
Current income tax	**38**	17
Deferred income tax	**241**	255
Total Foreign	**279**	272
Income tax expense	**346**	360

Income tax expense differs from the amount that would be expected to be generated by applying the enacted combined Canadian federal and provincial statutory income tax rate to earnings before income tax expense.

23. INCOME TAXES (cont'd)

The following is a reconciliation of consolidated statutory taxes to consolidated effective taxes.

($ millions, except as indicated)	**2024**	2023
Earnings before income tax expense	**2,174**	2,070
Combined Canadian federal and provincial statutory income tax rate *(%)*	**30.0**	30.0
Expected federal and provincial taxes at statutory rate	**652**	621
(Decrease)/Increase resulting from:		
Foreign and other statutory rate differentials	**(169)**	(166)
Effects of rate-regulated accounting	**(97)**	(98)
Tax credits	**(36)**	(14)
Enactment of new tax laws, change in tax rate	**2**	12
Other	**(6)**	5
Income tax expense	**346**	360
Effective tax rate *(%)*	**15.9**	17.4

Income Tax Carryforwards[1]

($ millions)	Expiring Year	**2024**
Canadian		
Non-capital loss	2028-2044	**155**
Other tax credits and restricted interest and financing expenses[2]	2026-2044	**77**
		232
Foreign		
Federal and state net operating loss[3]	2029-2044	**315**
Other tax credits	2027-2044	**82**
		397
Total income tax carryforwards recognized		**629**

(1) *Income tax carryforwards presented on an after-tax basis*
(2) *Indefinite carryforward for restricted interest and financing expenses*
(3) *Indefinite carryforward for Federal net operating losses, and for states that have adopted the Federal provisions, effective for tax years beginning after December 31, 2017*

The Corporation and certain of its subsidiaries are subject to taxation in Canada, the United States and other foreign jurisdictions. The material jurisdictions in which the Corporation is subject to potential income tax compliance examinations include the United States (Federal, Arizona, Kansas, Iowa, Michigan, Minnesota and New York) and Canada (Federal, British Columbia and Alberta). The Corporation's 2020 to 2024 taxation years are still open for audit in Canadian jurisdictions, and its 2020 to 2024 taxation years are still open for audit in United States jurisdictions.

24. EMPLOYEE FUTURE BENEFITS

For DBP and OPEB plans, the benefit obligation and fair value of plan assets are measured as at December 31.

For the Corporation's Canadian and Caribbean subsidiaries, actuarial valuations to determine funding contributions for pension plans are required at least every three years. The most recent valuations were as of December 31, 2021 for certain FortisBC Energy and FortisBC Electric plans; December 31, 2022 for the remaining FortisBC Energy and FortisBC Electric plans, Newfoundland Power, FortisAlberta and FortisOntario; December 31, 2023 for the Corporation; and December 31, 2024 for Caribbean Utilities.

ITC, UNS Energy and Central Hudson perform annual actuarial valuations as their funding requirements are based on maintaining minimum annual targets, all of which have been met.

The Corporation's investment policy is to ensure that the DBP and OPEB plan assets, together with expected contributions, are invested in a prudent and cost-effective manner to optimally meet the liabilities of the plans. The investment objective is to maximize returns in order to manage the funded status of the plans and minimize the Corporation's cost over the long term, as measured by both cash contributions and recognized expense.

24. EMPLOYEE FUTURE BENEFITS (cont'd)

Allocation of Plan Assets *(weighted average %)*	**2024 Target Allocation**	**2024**	2023
Equities	**46**	**47**	46
Fixed income	**46**	**45**	45
Real estate	**7**	**7**	8
Cash and other	**1**	**1**	1
	100	**100**	100

Fair Value of Plan Assets

($ millions)	**Level 1** [1]	**Level 2** [1]	**Level 3** [1]	**Total**
2024				
Equities	**773**	**1,168**	**—**	**1,941**
Fixed income	**268**	**1,561**	**—**	**1,829**
Real estate	**—**	**—**	**300**	**300**
Cash and other	**23**	**26**	**—**	**49**
	1,064	**2,755**	**300**	**4,119**
2023				
Equities	666	1,059	—	1,725
Fixed income	232	1,447	—	1,679
Real estate	—	—	291	291
Cash and other	34	14	—	48
	932	2,520	291	3,743

[1] *See Note 26 for a description of the fair value hierarchy.*

The following table reconciles the changes in the fair value of plan assets that have been measured using Level 3 inputs.

($ millions)	**2024**	2023
Balance, beginning of year	**291**	282
Return on plan assets	**5**	(9)
Foreign currency translation	**3**	(1)
Purchases, sales and settlements	**1**	19
Balance, end of year	**300**	291

24. EMPLOYEE FUTURE BENEFITS (cont'd)

Funded Status

($ millions)	DBP Plans 2024	DBP Plans 2023	OPEB Plans 2024	OPEB Plans 2023
Change in benefit obligation [1]				
Balance, beginning of year	**3,347**	3,063	**596**	582
Service costs	**74**	62	**25**	22
Employee contributions	**17**	17	**4**	3
Interest costs	**161**	159	**29**	30
Benefits paid	**(181)**	(169)	**(35)**	(31)
Actuarial (gains) losses	**(115)**	255	**(49)**	(1)
Past service credits/plan amendments	**(3)**	—	**—**	—
Foreign currency translation	**140**	(40)	**33**	(9)
Balance, end of year [2]	**3,440**	3,347	**603**	596
Change in value of plan assets				
Balance, beginning of year	**3,313**	3,079	**430**	389
Actual return on plan assets	**249**	373	**50**	61
Benefits paid	**(174)**	(162)	**(31)**	(26)
Employee contributions	**17**	17	**4**	3
Employer contributions	**57**	46	**14**	13
Foreign currency translation	**151**	(40)	**39**	(10)
Balance, end of year	**3,613**	3,313	**506**	430
Funded status	**173**	(34)	**(97)**	(166)
Balance sheet presentation				
Other assets (Note 9)	**395**	236	**156**	119
Other current liabilities (Note 13)	**(16)**	(15)	**(13)**	(13)
Other liabilities (Note 16)	**(206)**	(255)	**(240)**	(272)
	173	(34)	**(97)**	(166)

[1] *Amounts reflect projected benefit obligation for DBP plans and accumulated benefit obligation for OPEB plans.*
[2] *The accumulated benefit obligation, which excludes assumptions about future salary levels, for DBP plans was $3,144 million as at December 31, 2024 (2023 - $2,983 million).*

For those DBP plans for which the projected benefit obligation exceeded the fair value of plan assets as at December 31, 2024, the obligation was $1,668 million compared to plan assets of $1,460 million (2023 - $1,940 million and $1,681 million, respectively).

For those DBP plans for which the accumulated benefit obligation exceeded the fair value of plan assets as at December 31, 2024, the obligation was $195 million compared to plan assets of $62 million (2023 - $268 million and $130 million, respectively).

For those OPEB plans for which the accumulated benefit obligation exceeded the fair value of plan assets as at December 31, 2024, the obligation was $296 million compared to plan assets of $44 million (2023 - $320 million and $36 million, respectively).

Net Benefit Cost [1]

($ millions)	DBP Plans 2024	DBP Plans 2023	OPEB Plans 2024	OPEB Plans 2023
Service costs	**74**	62	**25**	22
Interest costs	**161**	159	**29**	30
Expected return on plan assets	**(221)**	(202)	**(26)**	(22)
Amortization of actuarial gains	**(1)**	(9)	**(17)**	(19)
Amortization of past service credits/plan amendments	**(1)**	(1)	**(1)**	(1)
Regulatory adjustments	**(1)**	12	**2**	5
	11	21	**12**	15

[1] *The non-service benefit cost components of net periodic benefit cost are included in other income, net in the consolidated statements of earnings.*

24. EMPLOYEE FUTURE BENEFITS (cont'd)

The following table summarizes the accumulated amounts of net benefit cost that have not yet been recognized in earnings or comprehensive income and shows their classification on the consolidated balance sheets.

	DBP Plans		OPEB Plans	
($ millions)	**2024**	2023	**2024**	2023
Unamortized net actuarial losses (gains)	**11**	12	**(11)**	(10)
Unamortized past service costs	**1**	1	**6**	6
Income tax (recovery) expense	**(3)**	(3)	**1**	1
Accumulated other comprehensive income	**9**	10	**(4)**	(3)
Net actuarial losses (gains)	**46**	189	**(283)**	(215)
Past service credits	**(1)**	(2)	**(2)**	(3)
Other regulatory deferrals	**12**	(11)	**4**	2
	57	176	**(281)**	(216)
Regulatory assets (Note 8)	**235**	254	**—**	—
Regulatory liabilities (Note 8)	**(178)**	(78)	**(281)**	(216)
Net regulatory assets (liabilities)	**57**	176	**(281)**	(216)

The following table summarizes the components of net benefit cost recognized in comprehensive income or as regulatory (liabilities) assets.

	DBP Plans		OPEB Plans	
($ millions)	**2024**	2023	**2024**	2023
Current year net actuarial (gains) losses	**(1)**	4	**(1)**	1
Past service credits/plan amendments	**—**	—	**—**	(1)
Foreign currency translation	**—**	(1)	**—**	—
Income tax recovery	**—**	(1)	**—**	—
Total recognized in comprehensive income	**(1)**	2	**(1)**	—
Current year net actuarial (gains) losses	**(142)**	78	**(72)**	(40)
Amortization of actuarial gains	**1**	9	**16**	18
Amortization of past service credits	**1**	2	**1**	1
Foreign currency translation	**(2)**	(1)	**(12)**	2
Regulatory adjustments	**23**	(5)	**2**	(5)
Total recognized in regulatory (liabilities) assets	**(119)**	83	**(65)**	(24)

Significant Assumptions

	DBP Plans		OPEB Plans	
(weighted average %)	**2024**	2023	**2024**	2023
Discount rate as at December 31 [(1)]	**5.25**	4.84	**5.43**	4.94
Expected long-term rate of return on plan assets [(2)]	**6.51**	6.58	**6.05**	5.92
Rate of compensation increase	**3.52**	3.37	**—**	—
Health care cost trend increase as at December 31 [(3)]	**—**	—	**4.53**	4.52

(1) *The discount rate used during the year was 4.84% for DBP plans (2023 - 5.36%) and 4.96% for OPEB plans (2023 - 5.39%). ITC and UNS Energy use the split discount rate methodology for determining current service and interest costs. All other subsidiaries use the single discount rate approach.*

(2) *Developed by management using best estimates of expected returns, volatilities and correlations for each class of asset. Best estimates are based on historical performance, future expectations and periodic portfolio rebalancing among the diversified asset classes.*

(3) *The projected 2025 health care cost trend rate is 6.51% and is assumed to decrease over the next 10 years to the ultimate health care cost trend rate of 4.53% in 2034 and thereafter.*

24. EMPLOYEE FUTURE BENEFITS (cont'd)

Expected Benefit Payments

($ millions)	DBP Plans	OPEB Plans
2025	$ 196	$ 33
2026	201	34
2027	206	34
2028	210	35
2029	218	36
2030-2034	1,155	203

During 2025, the Corporation expects to contribute $49 million for DBP plans and $12 million for OPEB plans.

In 2024, the Corporation expensed $58 million (2023 - $53 million) related to defined contribution pension plans.

25. SUPPLEMENTARY CASH FLOW INFORMATION

($ millions)	**2024**	2023
Years ended December 31		
Cash paid (received) for		
Interest	**1,361**	1,255
Income taxes	**(17)**	129
Change in working capital		
Accounts receivable and other current assets	**(2)**	142
Prepaid expenses	**(21)**	(7)
Inventories	**(73)**	(1)
Regulatory assets - current portion	**93**	104
Accounts payable and other current liabilities	**115**	(390)
Regulatory liabilities - current portion	**56**	71
	168	(81)
Non-cash financing activity		
Common share dividends reinvested	**434**	408
As at December 31		
Non-cash investing and financing activities		
Accrued capital expenditures	**722**	516
Contributions in aid of construction	**14**	15

26. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Derivatives

The Corporation generally limits the use of derivatives to those that qualify as accounting, economic or cash flow hedges, or those that are approved for regulatory recovery.

Derivatives are recorded at fair value, with certain exceptions, including those derivatives that qualify for the normal purchase and normal sale exception. Fair values reflect estimates based on current market information about the derivatives as at the balance sheet dates. The estimates cannot be determined with precision as they involve uncertainties and matters of judgment and, therefore, may not be relevant in predicting the Corporation's future consolidated earnings or cash flow.

26. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (cont'd)

Energy Contracts Subject to Regulatory Deferral

UNS Energy holds electricity power purchase contracts, customer supply contracts and gas swap contracts to reduce its exposure to energy price risk. Fair values are measured primarily under the market approach using independent third-party information, where possible. When published prices are not available, adjustments are applied based on historical price curve relationships, transmission costs and line losses.

Central Hudson holds swap contracts for electricity and natural gas to minimize price volatility by fixing the effective purchase price. Fair values are measured using forward pricing provided by independent third-party information.

FortisBC Energy holds gas supply contracts to fix the effective purchase price of natural gas. Fair values reflect the present value of future cash flows based on published market prices and forward natural gas curves.

Unrealized gains or losses associated with changes in the fair value of these energy contracts are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulators. As at December 31, 2024, unrealized losses of $175 million (2023 - $197 million) were recognized as regulatory assets and unrealized gains of $41 million (2023 - $37 million) were recognized as regulatory liabilities.

Energy Contracts Not Subject to Regulatory Deferral

UNS Energy holds wholesale trading contracts to fix power prices and realize potential margin, of which 10% of any realized gains is shared with customers through rate stabilization accounts. Fair values are measured using a market approach incorporating, where possible, independent third-party information.

Aitken Creek, which was sold on November 1, 2023 (Note 21), held gas swap contracts to manage exposure to changes in natural gas prices, capture natural gas price spreads, and manage the financial risk posed by physical transactions. Fair values were measured using forward pricing from published market sources.

Gains or losses associated with changes in the fair value of these energy contracts are recognized in revenue. In 2024, gains of $48 million (2023 - losses of $28 million) were recognized in revenue.

Total Return Swaps

The Corporation holds total return swaps to manage the cash flow risk associated with forecast future cash and/or share settlements of certain stock-based compensation obligations. The swaps have a combined notional amount of $134 million and terms up to three years expiring at varying dates through January 2027. Fair value is measured using an income valuation approach based on forward pricing curves. Unrealized gains and losses associated with changes in fair value are recognized in other income, net. In 2024, unrealized gains of $12 million (2023 - $nil) were recognized in other income, net.

Foreign Exchange Contracts

The Corporation holds U.S. dollar-denominated foreign exchange contracts to help mitigate exposure to foreign exchange rate volatility. The contracts expire at varying dates through September 2026 and have a combined notional amount of $608 million. Fair value was measured using independent third-party information. Unrealized gains and losses associated with changes in fair value are recognized in other income, net. In 2024, unrealized losses of $17 million (2023 - unrealized gains of $10 million) were recognized in other income, net.

Interest Rate Contracts

During 2024, ITC entered into and settled interest rate locks with a combined notional value of US$300 million. These contracts were used to manage interest rate risk associated with the issuance of US$400 million unsecured senior notes in May 2024. Realized losses of US$3 million were recognized in other comprehensive income, which will be reclassified to earnings as a component of interest expense over five years.

ITC also entered into 5-year interest rate swap contracts in 2024 with a combined notional value of US$135 million. The swaps will be used to manage interest rate risk associated with forecasted debt issuances. Fair value was measured using a discounted cash flow method based on secured overnight financing rates ("SOFR"). Unrealized gains and losses associated with the changes in fair value are recognized in other comprehensive income, and will be reclassified to earnings as a component of interest expense over the life of the debt. Unrealized gains of US$4 million were recorded in 2024.

In 2025, ITC entered into 5-year interest rate swap contracts with a notional value of US$95 million to manage interest rate risk associated with forecasted debt issuances, increasing the total notional amount of interest rate swaps outstanding to US$230 million.

During 2024, the Corporation entered into and settled interest rate locks with a combined notional value of $250 million. These contract were used to manage interest rate risk associated with the issuance of $500 million unsecured senior notes in September 2024. Realized losses of $2 million were recognized in other comprehensive income, which will be reclassified to earnings as a component of interest expense over seven years.

Cross-Currency Interest Rate Swaps

The Corporation holds cross-currency interest rate swaps, maturing in 2029, to effectively convert its $500 million, 4.43% unsecured senior notes to US$391 million, 4.34% debt. The Corporation has designated this notional U.S. debt as an effective hedge of its foreign net investments and unrealized gains and losses associated with exchange rate fluctuations on the notional U.S. debt are recognized in other comprehensive income, consistent with the translation adjustment related to the foreign net investments. Other changes in the fair value of the swaps are also recognized in other comprehensive income but are excluded from the assessment of hedge effectiveness. Fair value is measured using a discounted cash flow method based on SOFR. In 2024, unrealized losses of $29 million (2023 - unrealized gains of $15 million) were recorded in other comprehensive income.

26. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (cont'd)

Recurring Fair Value Measures

The following table presents derivative assets and liabilities that are accounted for at fair value on a recurring basis.

($ millions)	Level 1 [(1)]	Level 2 [(1)]	Level 3 [(1)]	Total
As at December 31, 2024				
Assets				
Energy contracts subject to regulatory deferral [(2) (3)]	**—**	**63**	**—**	**63**
Energy contracts not subject to regulatory deferral [(2)]	**—**	**7**	**—**	**7**
Total return swaps and interest rate contracts [(2)]	**—**	**16**	**—**	**16**
Other investments [(4)]	**150**	**—**	**—**	**150**
	150	**86**	**—**	**236**
Liabilities				
Energy contracts subject to regulatory deferral [(3) (5)]	**—**	**(197)**	**—**	**(197)**
Energy contracts not subject to regulatory deferral [(5)]	**—**	**(2)**	**—**	**(2)**
Foreign exchange contracts and cross-currency interest rate swaps [(5)]	**—**	**(45)**	**—**	**(45)**
	—	**(244)**	**—**	**(244)**
As at December 31, 2023				
Assets				
Energy contracts subject to regulatory deferral [(2) (3)]	—	49	—	49
Energy contracts not subject to regulatory deferral [(2)]	—	6	—	6
Foreign exchange contracts [(2)]	—	5	—	5
Other investments [(4)]	145	—	—	145
	145	60	—	205
Liabilities				
Energy contracts subject to regulatory deferral [(3) (5)]	—	(209)	—	(209)
Energy contracts not subject to regulatory deferral [(5)]	—	(3)	—	(3)
Total return and cross-currency interest rate swaps [(5)]	—	(6)	—	(6)
	—	(218)	—	(218)

(1) *Under the hierarchy, fair value is determined using: (i) Level 1- unadjusted quoted prices in active markets; (ii) Level 2 - other pricing inputs directly or indirectly observable in the marketplace; and (iii) Level 3 - unobservable inputs, used when observable inputs are not available. Classifications reflect the lowest level of input that is significant to the fair value measurement.*
(2) *Included in accounts receivable and other current assets or other assets*
(3) *Unrealized gains and losses arising from changes in fair value of these contracts are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates as permitted by the regulators, with the exception of long-term wholesale trading contracts and certain gas swap contracts.*
(4) *UNS Energy holds investments in money market accounts, and ITC and Central Hudson hold investments in trust associated with supplemental retirement benefit plans for select employees, which include mutual funds and money market accounts. The fair value of these investments is included in cash and cash equivalents and other assets, with gains and losses recognized in other income, net*
(5) *Included in accounts payable and other current liabilities or other liabilities*

Energy Contracts

The Corporation has elected gross presentation for its derivative contracts under master netting agreements and collateral positions, which apply only to its energy contracts. The following table presents the potential offset of counterparty netting.

($ millions)	Gross Amount Recognized In Balance Sheet	Counterparty Netting of Energy Contracts	Cash Collateral Posted/(Received)	Net Amount
As at December 31, 2024				
Derivative assets	**70**	**(30)**	**15**	**55**
Derivative liabilities	**(199)**	**30**	**—**	**(169)**
As at December 31, 2023				
Derivative assets	55	(24)	28	59
Derivative liabilities	(212)	24	(1)	(189)

26. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (cont'd)

Volume of Derivative Activity

As at December 31, 2024, the Corporation had various energy contracts that will settle on various dates through 2029. The volumes related to electricity and natural gas derivatives are outlined below.

	2024	2023
Energy contracts subject to regulatory deferral [(1)]		
Electricity swap contracts *(GWh)*	**774**	628
Electricity power purchase contracts *(GWh)*	**430**	588
Gas swap contracts *(PJ)*	**236**	228
Gas supply contracts *(PJ)*	**105**	134
Energy contracts not subject to regulatory deferral [(1)]		
Wholesale trading contracts *(GWh)*	**1,499**	1,310
Gas swap contracts *(PJ)*	**3**	3

(1) *GWh means gigawatt hours and PJ means petajoules*

Credit Risk

For cash equivalents, accounts receivable and other current assets, and long-term other receivables, credit risk is generally limited to the carrying value on the consolidated balance sheets. The Corporation's subsidiaries generally have a large and diversified customer base, which minimizes the concentration of credit risk. Policies in place to minimize credit risk include requiring customer deposits, prepayments and/or credit checks for certain customers, performing disconnections and/or using third-party collection agencies for overdue accounts.

ITC has a concentration of credit risk as approximately 70% of its revenue is derived from three customers. These customers have investment-grade credit ratings and credit risk is further managed by MISO by requiring a letter of credit or cash deposit equal to the credit exposure, which is determined by a credit-scoring model and other factors.

FortisAlberta has a concentration of credit risk as its distribution service billings are to a relatively small group of retailers. Credit risk is managed by obtaining from the retailers either a cash deposit, letter of credit, an investment-grade credit rating, or a financial guarantee from an entity with an investment-grade credit rating.

Central Hudson has seen an increase in accounts receivable since the suspension of collection efforts initially required in response to the COVID-19 pandemic. Central Hudson continues to contact customers regarding past-due balances and collection efforts continue to expand. Under its regulatory framework, Central Hudson can defer uncollectible write-offs above the amounts collected in customer rates for future recovery.

UNS Energy, Central Hudson, FortisBC Energy, and Fortis may be exposed to credit risk from non-performance by counterparties to derivative contracts. Credit risk is managed by net settling payments, when possible, and dealing only with counterparties that have investment-grade credit ratings. At UNS Energy, Central Hudson and FortisBC Energy, certain contractual arrangements require counterparties to post collateral.

The value of derivatives in net liability positions under contracts with credit risk-related contingent features that, if triggered, could require the posting of a like amount of collateral was $117 million as at December 31, 2024 (2023 - $117 million).

Hedge of Foreign Net Investments

The reporting currency of ITC, UNS Energy, Central Hudson, Caribbean Utilities, FortisTCI, Fortis Belize Limited and Belize Electricity is, or is pegged to, the U.S. dollar. The earnings and cash flow from, and net investments in, these entities are exposed to fluctuations in the U.S. dollar-to-Canadian dollar exchange rate. The Corporation has reduced this exposure through hedging.

As at December 31, 2024, US$2.2 billion (2023 - US$2.6 billion) of corporately issued U.S. dollar-denominated long-term debt has been designated as an effective hedge of net investments, leaving approximately US$12.6 billion (2023 - US$11.5 billion) unhedged. Exchange rate fluctuations associated with the hedged net investment in foreign subsidiaries and the debt serving as the hedge are recognized in accumulated other comprehensive income.

Financial Instruments Not Carried at Fair Value

Excluding long-term debt, the consolidated carrying value of the Corporation's remaining financial instruments approximates fair value, reflecting their short-term maturity, normal trade credit terms and/or nature.

As at December 31, 2024, the carrying value of long-term debt, including the current portion, was $33.4 billion (2023 - $29.7 billion) compared to an estimated fair value of $31.3 billion (2023 - $27.9 billion).

27. COMMITMENTS AND CONTINGENCIES

As at December 31, 2024, unconditional minimum purchase obligations were as follows.

($ millions)	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Gas and fuel purchase obligations (1)	**6,299**	763	571	520	465	393	3,587
Renewable PPAs (2)	**2,628**	139	166	182	182	173	1,786
Waneta Expansion capacity agreement (3)	**2,362**	56	58	59	60	61	2,068
Power purchase obligations (4)	**1,335**	302	217	131	124	122	439
ITC easement agreement (5)	**370**	14	14	14	14	14	300
TEP EPC agreements (6)	**308**	307	1	—	—	—	—
Debt collection agreement (7)	**99**	3	3	3	3	3	84
Renewable energy credit purchase agreements (8)	**58**	18	7	6	6	6	15
Other (9)	**140**	32	11	11	12	10	64
	13,599	**1,634**	**1,048**	**926**	**866**	**782**	**8,343**

(1) *FortisBC Energy ($5,014 million):* includes contracts of $2,792 million for the purchase of renewable natural gas expiring in 2045 and contracts of $2,222 million for the purchase of gas, renewable gas, gas transportation and storage services, expiring in 2062. FortisBC Energy's gas purchase obligations are based on gas commodity indices that vary with market prices and the obligations are based on index prices as at December 31, 2024. The renewable gas supply obligations disclosed reflect the contracted price per gigajoule between the Corporation and the suppliers.

UNS Energy ($1,160 million): includes long-term contracts for the purchase and delivery of coal to fuel generating facilities, the purchase of gas transportation services to meet load requirements, the purchase of transmission services for purchased power, as well as natural gas commodity agreements based on projected market prices as of December 31, 2024. Amounts paid for coal depend on actual quantities purchased and delivered. Certain contracts have price adjustment clauses that will affect future costs. These contracts have various expiry dates through 2048.

(2) *TEP and UNS Electric* are party to renewable PPAs, with expiry dates from 2027 through 2051, that require TEP and UNS Electric to purchase 100% of the output of certain renewable energy generating facilities and RECs associated with the output delivered once commercial operation is achieved. The agreements include purchase commitments that are contingent upon the developers obtaining commercial operation of the generating facilities, which are expected to be placed in service in 2026 and 2027. Amounts are the estimated future payments.

(3) *FortisBC Electric* is a party to an agreement to purchase capacity from the Waneta Expansion hydroelectric generating facility for forty-years, beginning April 2015.

(4) *Maritime Electric ($563 million):* includes an energy purchase agreement and transmission capacity contract for 30 MW of capacity to PEI with New Brunswick Power, expiring December 2026 and November 2032, respectively. The agreements entitle Maritime Electric to approximately 4.55% of the output of New Brunswick Power's Point Lepreau nuclear generating station and require Maritime Electric to pay its share of the station's capital operating costs for the life of the unit.

FortisOntario ($374 million): an agreement with Hydro-Québec for the supply of up to 145 MW of capacity and a minimum of 537 GWh of associated energy annually through December 2030.

FortisBC Electric ($301 million): an agreement with BC Hydro to purchase up to 200 MW of capacity and 1,752 GWh of associated energy annually for a 20-year term beginning October 1, 2013.

(5) ITC is party to an agreement with Consumers Energy, the primary customer of METC, which provides METC with an easement for transmission purposes and rights-of-way, leasehold interests, fee interests and licenses associated with the land over which its transmission lines cross. The agreement expires in December 2050, subject to 10 potential 50-year renewals thereafter unless METC gives notice of non-renewal at least one year in advance.

(6) TEP has entered into two engineering, procurement and construction ("EPC") agreements associated with the development of energy storage projects. Roadrunner Reserve 1 is expected to be placed in service in 2025, with Roadrunner Reserve 2 to follow in 2026.

(7) Maritime Electric is party to a debt collection agreement with PEI Energy Corporation for the initial capital cost of the submarine cables and associated parts of the New Brunswick transmission system interconnection. Payments under the agreement, which expires in February 2056, are collected in customer rates.

(8) UNS Energy and Central Hudson are party to REC purchase agreements, mainly for the purchase of environmental attributions from retail customers with solar installations or other renewable generation. Payments are primarily made at contractually agreed-upon intervals based on metered energy production.

(9) Includes AROs and joint-use asset and shared service agreements.

27. COMMITMENTS AND CONTINGENCIES (cont'd)

Other Commitments

Under a funding framework with the Governments of Ontario and Canada, Fortis will contribute a minimum of approximately $165 million of equity capital to Wataynikaneyap Power, based on Fortis' proportionate 39% ownership interest and the final regulatory-approved capital cost of the related project. Wataynikaneyap Power has construction financing loan agreements in place and it is expected that long-term operating financing will replace the construction financing. In the event a lender under the loan agreements realizes security on the loans, Fortis may be required to accelerate its equity capital contributions, which may be in excess of the amount otherwise required of Fortis under the funding framework, to a maximum total funding of $235 million. Equity of $137 million has been contributed as of December 31, 2024.

UNS Energy has joint generation performance guarantees with participants at Four Corners and Luna, with agreements expiring in 2041 and 2046 respectively, and at San Juan and Navajo through decommissioning. The participants have guaranteed that in the event of payment default, each non-defaulting participant will bear its proportionate share of expenses otherwise payable by the defaulting participant. In exchange, the non-defaulting participants are entitled to receive their proportionate share of the generation capacity of the defaulting participant. In the case of San Juan and Navajo, participants would seek financial recovery from the defaulting party. There is no maximum amount under these guarantees, except for a maximum of $360 million for Four Corners. As at December 31, 2024, there was no obligation under these guarantees.

Contingency

In 2013, FHI and Fortis were named as defendants in an action in the British Columbia Supreme Court by the Coldwater Indian Band ("Band") regarding interests in a pipeline across reserve lands. The Band seeks cancellation of the right-of-way and damages for wrongful interference with the Band's use and enjoyment of reserve lands. In 2016, the Federal Court dismissed the Band's application for judicial review of the ministerial consent. In 2017, the Federal Court of Appeal set aside the minister's consent and returned the matter to the minister for redetermination. No amount has been accrued as the outcome cannot yet be reasonably determined.