FORTIS INC.

St. John's, NL - February 12, 2026

FORTIS INC. REPORTS FOURTH QUARTER & ANNUAL 2025 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 diversified leader in the North American regulated electric and gas utility industry, released its 2025 fourth quarter and annual financial results.[1]

Highlights

- Annual net earnings of $1.7 billion, or $3.40 per common share for 2025
- Annual adjusted net earnings per common share[2] of $3.53, up from $3.28 for 2024
- Capital expenditures[2] of $5.6 billion, yielding 7% annual rate base growth[3]
- 4.1% increase in fourth quarter common share dividend achieving 52 consecutive years of common share dividend increases
- 2026 Climate Resiliency Report released

"2025 was another year of strong financial and operational performance for Fortis, reflecting the dedication of our people, the growth of our regulated utilities, and our commitment to long-term value creation," said David Hutchens, President and Chief Executive Officer, Fortis Inc. "Our focus on reliability and affordability, and the disciplined execution of our capital plan delivered solid results again this year."

"Looking ahead, we recently announced our largest five-year capital plan of $28.8 billion, which will drive long-term rate base growth of 7% and support annual dividend growth of 4-6% through 2030," added Mr. Hutchens. "Our strategy remains clear: deliver safe, reliable and affordable energy today while investing responsibly to support the evolving needs of our customers and communities."

Net Earnings

The Corporation reported net earnings attributable to common shareholders ("Net Earnings") of $1.7 billion, or $3.40 per common share, for 2025 compared to $1.6 billion, or $3.24 per common share, for 2024. Earnings growth in 2025 was impacted by $63 million of losses associated with the dispositions of FortisTCI, Fortis Belize and Belize Electricity, approximately half of which related to income taxes. In addition, results for 2024 were unfavourably impacted by $20 million associated with the retroactive impact of a reduction in the Midcontinent Independent System Operator ("MISO") base rate of return on common equity ("ROE") at ITC.

Excluding the above-noted items, Net Earnings increased by $151 million, or $0.25 per common share, compared to 2024. The increase was primarily due to rate base growth across our utilities, including growth associated with major capital projects. The rebasing of costs effective July 1, 2024 at Central Hudson, unrealized gains on derivative contracts, and the favourable impact of foreign exchange also contributed to earnings growth. The increase was partially offset by lower earnings at UNS Energy due to higher costs associated with Rate Base growth not yet reflected in customer rates, lower retail electricity sales due to milder weather, and lower margins on wholesale electricity sales. The expiration of a regulatory incentive at FortisAlberta, higher non-recoverable stock-based compensation and holding company finance costs, as well as lower earnings from FortisTCI and Fortis Belize also unfavourably impacted results. Net Earnings per common share were also impacted by an increase in the weighted average number of common shares outstanding, largely associated with the Corporation's dividend reinvestment plan.

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

2 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. 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.

For the fourth quarter of 2025, Net Earnings were $422 million, or $0.83 per common share, compared to $396 million, or $0.79 per common share for the same period in 2024. Excluding the $31 million loss on the disposition of the Corporation's investments in Belize in 2025, and the unfavourable $20 million retroactive impact of the reduction in the MISO base ROE in 2024, Net Earnings increased by $37 million, or $0.07 per common share, compared to the fourth quarter of 2024. The increase was primarily due to the same factors discussed for the year as well as the timing of operating costs at FortisAlberta.

Adjusted Net Earnings[2]

Adjusted net earnings attributable to common equity shareholders ("Adjusted Net Earnings") reflect the removal of items that management excludes in its key decision-making processes and evaluation of operating results. Net Earnings were favourably adjusted by $31 million related to the disposition of Fortis' investments in Belize in the fourth quarter of 2025, and by $63 million related to the dispositions of FortisTCI and the investments in Belize for the year ended December 31, 2025. For the fourth quarter and year ended December 31, 2024, Net Earnings were favourably adjusted for the $20 million retroactive impact of the reduction in the MISO base ROE.

Capital Expenditures[2]

Capital expenditures totalled $5.6 billion in 2025, and reflected progress on several of the Corporation's major capital projects, including projects within the first tranche of the Midcontinent Independent System Operator long-range transmission plan ("MISO LRTP") and the Big Cedar Load Expansion project at ITC, as well as the Vail-to-Tortolita and Black Mountain Gas Generation projects at UNS Energy. Capital expenditures increased midyear rate base to $42.4 billion, representing 7% growth over 2024.[3]

The Corporation's 2026-2030 capital plan of $28.8 billion is $2.8 billion higher than the previous five-year plan. The increase is primarily driven by higher transmission investments associated with new interconnections, the MISO LRTP and baseline reliability projects at ITC. It also includes incremental capital at UNS Energy, reflecting an increase in transmission and distribution investments to serve load growth, increase reliability, and provide a path for connecting future generation resources. Planned generation investments in Arizona have also been updated to reflect the Springerville Natural Gas Conversion project. Customer growth and reliability investments across our utilities, as well as a higher assumed U.S. dollar-to-Canadian dollar exchange rate also contributed to the increase. The plan is low-risk and highly executable, with only 21% relating to major capital projects.

The capital plan is expected to be funded primarily by cash from operations and regulated utility debt. Common equity is expected to be provided by the Corporation's dividend reinvestment plan, assuming current participation levels. The $500 million at-the-market common equity program has not been utilized to date and remains available for funding flexibility as required.

Regulatory Updates

In December 2025, the Arizona Corporation Commission ("ACC") approved an Energy Supply Agreement for approximately 300 megawatts associated with a planned data center located in Tucson Electric Power's ("TEP") service territory. The agreement remains subject to other contractual contingencies. The initial phase of the data center is expected to be operational as early as 2027. TEP currently expects to serve this customer from its existing and planned capacity, including solar and battery storage projects currently in development.

In January 2026, an ACC Administrative Law Judge issued a Recommended Opinion and Order on the UNS Gas General Rate Application, recommending an allowed ROE of 9.57% and a 56% common equity component of capital structure. While the order also recommended an annual formulaic rate adjustment mechanism, it reflected certain exceptions to the formula including the exclusion of post-test year adjustments. Should the annual formula not be approved, the order recommended the use of adjustor mechanisms for the timely recovery of infrastructure investments and income tax changes. UNS Gas filed its response on February 9, 2026. The rate application remains subject to ACC approval which is anticipated later this month.

2026 Climate Resiliency Report

Fortis released its 2026 Climate Resiliency Report today, building on previous reports and consolidating climate risk and vulnerability assessments completed across our utilities. Informed by climate scenario analysis, the report provides new detail on key climate hazards, the potential impact on assets, and the adaptation and resiliency measures underway across the Fortis group of companies. The Corporation remains focused on ensuring our energy delivery networks are designed to operate safely and reliably today, and to withstand potential future climate conditions.

The Corporation has made consistent progress to decarbonize its energy mix and deliver cleaner energy to customers, achieving an approximate 38% reduction in scope 1 greenhouse gas emissions through 2025 compared to 2019 levels. In 2026, Fortis will be reviewing its decarbonization strategy, including potentially establishing new interim emission targets to replace its former targets. This work will be informed by resource planning across the Corporation's utilities, including a new integrated resource plan expected to be filed by TEP in 2026. Fortis remains committed to having a coal-free generation mix in 2032 and advancing toward net-zero emissions by 2050.

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 $28.8 billion five-year capital plan is expected to increase midyear rate base from $42.4 billion in 2025 to $57.9 billion by 2030, translating into a five-year compound annual growth rate of 7%.[3] Fortis expects its long-term growth in rate base will drive earnings that support dividend growth guidance of 4-6% annually through 2030.

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 new energy resources; transmission investments associated with the MISO LRTP as well as regional transmission in New York; grid resiliency and climate adaptation investments; investments in renewable gas and liquefied natural gas infrastructure in British Columbia; and energy infrastructure investments to support the acceleration of load growth across our jurisdictions.

Non-U.S. GAAP Reconciliation

Periods ended December 31	Quarter			Annual		
($ millions, except as indicated)	**2025**	2024	Variance	**2025**	2024	Variance
Adjusted Net Earnings						
Net Earnings	**422**	396	26	**1,714**	1,606	108
Adjusting items:						
Dispositions[4]	**31**	—	31	**63**	—	63
October 2024 MISO base ROE decision[5]	**—**	20	(20)	**—**	20	(20)
Adjusted Net Earnings	**453**	416	37	**1,777**	1,626	151
Adjusted Basic EPS *($)*	**0.90**	0.83	0.07	**3.53**	3.28	0.25
Capital Expenditures						
Additions to property, plant and equipment	**1,618**	1,629	(11)	**5,942**	5,012	930
Additions to intangible assets	**76**	64	12	**292**	206	86
Adjusting items:						
Eagle Mountain Pipeline Project[6]	**(251)**	—	(251)	**(620)**	—	(620)
Wataynikaneyap Transmission Power Project[7]	**—**	—	—	**—**	29	(29)
Capital Expenditures	**1,443**	1,693	(250)	**5,614**	5,247	367

About Fortis

Fortis is a diversified leader in the North American regulated electric and gas utility industry with 2025 revenue of $12 billion and total assets of $75 billion as at December 31, 2025. The Corporation's 9,900 employees serve utility customers in five Canadian provinces, ten U.S. states and the Caribbean.

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4 Fortis sold its utility in Turks and Caicos in September 2025, and its investments in Belize, including the non-regulated hydroelectric generation facilities, in October 2025. For the fourth quarter of 2025, the adjustment represents the loss on the disposition of the investments in Belize, inclusive of income tax expense of $5 million. For the year ended December 31, 2025, the adjustment represents the total loss on each of the dispositions, inclusive of income tax expense of $31 million.

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

6 Represents contributions in aid of construction received for the Eagle Mountain Pipeline project.

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

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, 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 2026 through 2030; expected sources of funding for the five-year capital plan, including the source of common equity; expected timing, outcomes and impacts of legal and regulatory proceedings and decisions; expected review of the Corporation's decarbonization strategy; potential establishment of new interim emissions targets; expected timing and contents of TEP's new integrated resource plan; the expectation that the Corporation will have a coal-free generation mix in 2032; the Corporation's 2050 net-zero GHG emissions target; forecast midyear rate base for 2030 and forecast five-year compound annual growth rate; the expectation that long-term growth in rate base will drive earnings that support dividend growth guidance of 4-6% annually through 2030; and expected nature, timing and benefits of additional opportunities to expand and extend growth 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 new energy resources, transmission investments associated with the MISO LRTP as well as regional transmission in New York, grid resiliency and climate adaptation investments, investments in renewable gas and liquefied natural gas infrastructure in British Columbia, and energy infrastructure investments to support the acceleration of load growth.

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: 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; reasonable outcomes for legal and regulatory proceedings and the expectation of regulatory stability; 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 2025 Annual Results

A teleconference and webcast will be held on February 12, 2026 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 2025 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 1.833.821.0229. Individuals in other international locations can participate by calling 1.647.846.2371. 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 12, 2026. Please call 1.855.669.9658 or 1.412.317.0088 and enter access code 2215707#.

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.

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Management Discussion and Analysis

Contents

Dated February 11, 2026

This MD&A has been prepared in accordance with National Instrument 51-102 - *Continuous Disclosure Obligations*. It should be read in conjunction with the 2025 Annual Financial Statements and is subject to the cautionary statement and disclaimer provided under "Forward-Looking Information" on page 39. 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 1.40 and 1.37 for the years ended December 31, 2025 and 2024, respectively; (ii) 1.37 and 1.44 as at December 31, 2025 and 2024, respectively; (iii) average of 1.39 and 1.40 for the quarters ended December 31, 2025 and 2024, respectively; and (iv) 1.35 for all forecast periods. Certain terms used in this MD&A are defined in the "Glossary" on page 40.

ABOUT FORTIS

Fortis (TSX/NYSE: FTS) is a diversified leader in the North American regulated electric and gas utility industry, with revenue of $12 billion in 2025 and total assets of $75 billion as at December 31, 2025. The Corporation's 9,900 employees serve 3.5 million utility customers in five Canadian provinces, ten U.S. states and the Caribbean. As at December 31, 2025, 65% of the Corporation's assets were located in the U.S., 33% in Canada and the remaining 2% in the Caribbean. Operations in the U.S. accounted for 58% of the Corporation's 2025 revenue, with the remaining 38% in Canada, and 4% in the Caribbean.

Fortis is principally an energy delivery company, with approximately 95% 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); and Caribbean Utilities (integrated electric - Grand Cayman). The Corporation also owns a 39% equity investment in Wataynikaneyap Power (electric transmission - Ontario). Fortis sold FortisTCI (integrated electric - Turks and Caicos Islands) on September 2, 2025 and its 33% equity investment in Belize Electricity (integrated electric - Belize) on October 31, 2025.

The Corporation's only non-regulated business was Fortis Belize (three hydroelectric generation facilities - Belize), which was also sold on October 31, 2025.

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. 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 2025 Annual Financial Statements.

PERFORMANCE AT A GLANCE

Key Financial Metrics

($ millions, except as indicated)	**2025**	2024	Variance
Common Equity Earnings			
Actual	**1,714**	1,606	108
Adjusted [(1)]	**1,777**	1,626	151
Basic EPS *($)*			
Actual	**3.40**	3.24	0.16
Adjusted [(1)]	**3.53**	3.28	0.25
Dividends			
Paid per common share *($)*	**2.49**	2.39	0.10
Actual Payout Ratio *(%)*	**73.1**	73.6	(0.5)
Adjusted Payout Ratio *(%)* [(1)]	**70.4**	72.7	(2.3)
Weighted average number of common shares outstanding *(# millions)*	**503.5**	495.0	8.5
Operating Cash Flow	**4,062**	3,882	180
Capital Expenditures [(1)]	**5,614**	5,247	367

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

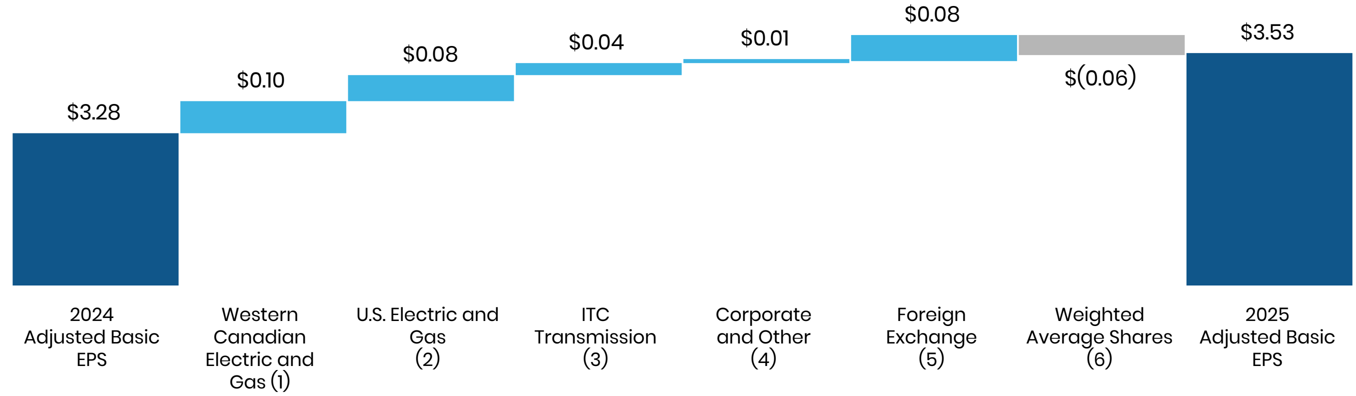
Earnings and EPS

Common Equity Earnings increased by $108 million, or $0.16 per common share, compared to 2024. Earnings growth in 2025 was impacted by $63 million of losses associated with the dispositions of FortisTCI, Fortis Belize and Belize Electricity, approximately half of which related to income taxes. In addition, results for 2024 were unfavourably impacted by $20 million associated with the retroactive impact of a reduction in the MISO base ROE at ITC as approved by FERC.

Excluding the above-noted items, Common Equity Earnings increased by $151 million, or $0.25 per common share, compared to 2024. The increase was primarily due to Rate Base growth across the utilities, including AFUDC associated with Major Capital Projects. Growth in earnings was also due to the rebasing of costs effective July 1, 2024 at Central Hudson, unrealized gains on derivative contracts, and the favourable impact of changes in the U.S. dollar-to-Canadian dollar exchange rate. The increase was partially offset by: (i) higher costs associated with Rate Base growth not yet reflected in customer rates, lower retail electricity sales due to milder weather, and lower margins on wholesale electricity sales at UNS Energy; (ii) the expiration of a regulatory incentive at FortisAlberta; and (iii) higher stock-based compensation and holding company finance costs. Lower earnings from FortisTCI and Fortis Belize, net of finance cost savings associated with the proceeds received on the dispositions, also unfavourably impacted results. 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, which exclude the losses associated with dispositions in 2025 and the retroactive ROE adjustment at ITC in 2024, as discussed previously, increased by $151 million and $0.25, 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 FortisBC Energy, FortisAlberta and FortisBC Electric. Reflects Rate Base growth, including AFUDC associated with FortisBC Energy's investment in the Eagle Mountain Pipeline project, partially offset by the expiration of the PBR efficiency carry-over mechanism at the end of 2024 at FortisAlberta.*

(2) *Includes UNS Energy and Central Hudson. Reflects higher earnings at Central Hudson primarily due to Rate Base growth, the rebasing of costs effective July 1, 2024, and a change in a regulatory deferral for uncollectible accounts as approved in the order on the 2025 general rate application. Also reflects lower earnings at UNS Energy due to higher costs associated with Rate Base growth not yet reflected in customer rates, lower retail electricity sales due to milder weather, and lower margin on wholesale sales, partially offset by higher transmission revenue and AFUDC*

(3) *Reflects Rate Base growth, partially offset by higher non-recoverable stock-based compensation and holding company finance costs*

(4) *Reflects unrealized gains on foreign exchange contracts and total return swaps, partially offset by higher holding company finance and stock-based compensation costs*

(5) *Reflects average foreign exchange rate of 1.40 in 2025 compared to 1.37 in 2024, and the revaluation of U.S. dollar denominated short-term liabilities*

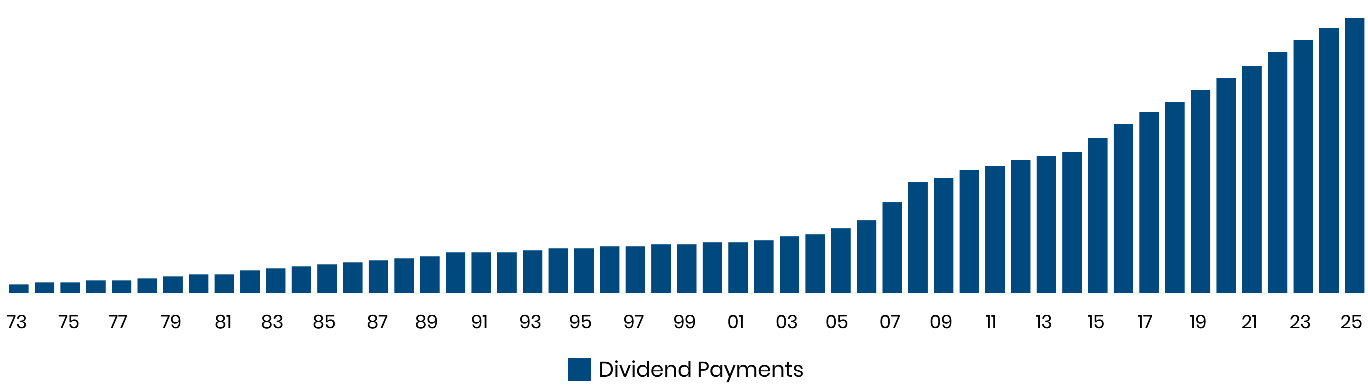
(6) *Weighted average shares of 503.5 million in 2025 compared to 495.0 million in 2024*

Dividends

Fortis paid a dividend of $0.64 per common share in the fourth quarter of 2025, up 4.1% from 0.615 paid in each of the previous four quarters. This marked the Corporation's 52nd consecutive year of increases in dividends paid. The Adjusted Payout Ratio was 70% in 2025 and the Actual Payout Ratio averaged 73% over the three-year period of 2023 through 2025.

Fortis is targeting annual dividend growth of approximately 4-6% through 2030. See "Outlook" on page 38.

52 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	**23.9**	**10.7**	**10.8**	**9.5**

(1) *Annualized TSR per Bloomberg, as at December 31, 2025*

Operating Cash Flow

The $180 million increase in Operating Cash Flow was due to higher cash earnings, reflecting Rate Base growth, new customer delivery rates at Central Hudson as approved by the PSC, and the sale of investment tax credits at UNS Energy. The timing of transmission charges at FortisAlberta and the higher U.S. dollar-to-Canadian dollar exchange rate also contributed to growth in Operating Cash Flow. The increase was partially offset by: (i) the timing of flow-through costs at UNS Energy associated with higher PPFAC collections in 2024, and at FortisBC Energy related to the consumer carbon tax which was effectively repealed in 2025; (ii) the receipt of a tax refund at FortisBC Energy in 2024; and (iii) higher interest payments.

Capital Expenditures

Capital Expenditures in 2025 were $5.6 billion, consistent with expectations and $0.4 billion higher than 2024. The increase compared to 2024 was largely related to: (i) investments in Major Capital Projects, including projects within the first tranche of the MISO LRTP and the Big Cedar Load Expansion project at ITC, as well as the Vail-to-Tortolita and Black Mountain Gas Generation projects at UNS Energy; (ii) incremental transmission and distribution investments across the Corporation's utilities; and (iii) the impact of the higher U.S. dollar-to-Canadian dollar exchange rate. The increase was partially offset by FortisBC Energy's investment in the Eagle Mountain Pipeline project in 2024. Construction of the project in 2025 was largely funded by CIACs rather than investments by FortisBC Energy.

Capital Expenditures is a Non-U.S. GAAP Financial Measure. Refer to "Non-U.S. GAAP Financial Measures" on page 10 and in the "Glossary" on page 40.

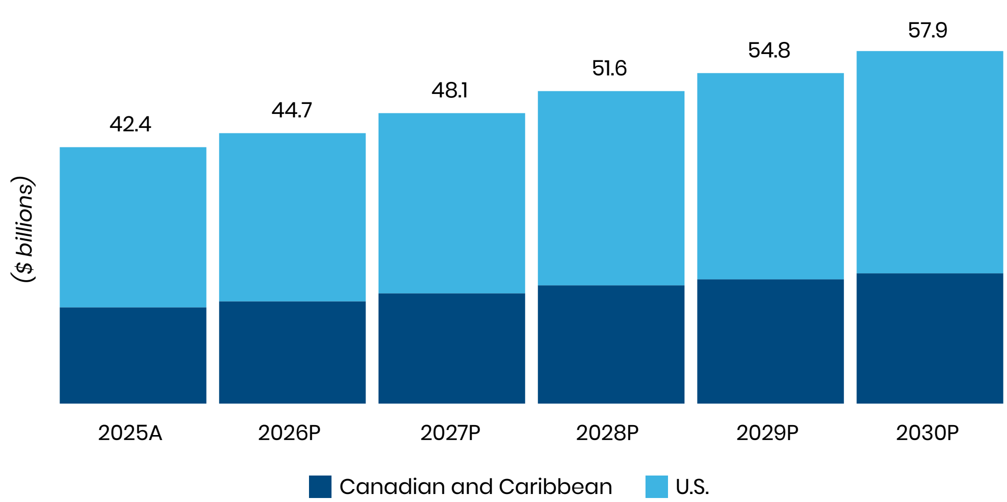
New Five-Year Capital Plan

The Corporation's 2026-2030 Capital Plan of $28.8 billion is the largest in the Corporation's history and is $2.8 billion higher than the previous five-year plan. The increase is primarily driven by higher FERC regulated transmission investments associated with new interconnections, the MISO LRTP and baseline reliability projects at ITC. It also includes incremental capital at UNS Energy, reflecting an increase in transmission and distribution investments to serve load growth, increase reliability, and provide a path for connecting future generation resources. Planned generation investments in Arizona have also been updated to reflect the Springerville Natural Gas Conversion project. Customer growth and reliability investments across our utilities, as well as a higher assumed U.S. dollar-to-Canadian dollar exchange rate also contributed to the increase in the five-year plan. For a detailed discussion of the Corporation's capital expenditure program, see "Capital Plan" on page 18.

The Capital Plan is expected to be funded primarily by cash from operations and regulated utility debt. Common equity is expected to be provided by the Corporation's DRIP, assuming current participation levels. The Corporation's $500 million ATM Program has not been utilized to date and remains available for funding flexibility as required.

The five-year Capital Plan is expected to increase midyear Rate Base from $42.4 billion in 2025 to $57.9 billion by 2030, translating into a five-year CAGR of 7.0%.

PROJECTED RATE BASE (1)



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 new energy resources; transmission investments associated with the MISO LRTP as well as regional transmission in New York; grid resiliency and climate adaptation investments; investments in renewable gas and LNG infrastructure in British Columbia; and energy infrastructure investments to support the acceleration of load growth across our jurisdictions.

THE INDUSTRY

The North American utility industry is undergoing significant transformation, driven by energy security and climate adaptation priorities, as well as projected growth in load driven by data centers, manufacturing and electrification. Together, these factors are creating substantial investment opportunities across the sector.

Policy makers and regulators at the federal, state, and provincial levels are increasingly prioritizing matters of energy security. The convergence of policy directives and forecasted load growth has resulted in opportunities to invest in renewable and natural gas generation, energy storage systems and transmission infrastructure. Continued electrification of heating and transportation represents another opportunity to expand the output and efficiency of the grid.

Grid resilience remains a focus with increased frequency and intensity of weather events such as extreme temperatures, 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 weather 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 necessary to meet growing energy needs. Natural gas investments, as well as energy storage solutions, will enable the adoption of additional renewable energy.

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. Energy delivery systems are becoming more intelligent, with advanced meters, remote sensing, and grid automation. Energy management capabilities are expanding through emerging storage, demand response, and distributed energy management systems. More capable operational technology provides utilities with detailed usage data, advanced system control, enhanced inspection techniques, and predictive capabilities. In addition, investments in AI look to unlock potential in the data collected by the Corporation's utilities. With increased digitization and an ever-changing threat landscape, investments in cyber and physical security continue to be high priorities. These technological advancements and challenges offer strategic investment opportunities for Fortis' utilities.

A focus on customer experience is important for utilities as customer expectations evolve. 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 real-time, digital communication. At the same time, customer affordability is critical and remains a priority across Fortis' utilities. In response, our utilities are enhancing customer information systems, adopting digital technologies including AI, and advancing new and modern approaches to customer experience.

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

OPERATING RESULTS

			Variance	
($ millions)	**2025**	2024	FX	Other
Revenue	**12,170**	11,508	142	520
Energy supply costs	**3,371**	3,249	36	86
Operating expenses	**3,250**	3,040	40	170
Depreciation and amortization	**2,057**	1,927	21	109
Other income, net	**340**	288	13	39
Finance charges	**1,478**	1,406	17	55
Income tax expense	**393**	346	2	45
Net earnings	**1,961**	1,828	39	94
Net earnings attributable to:				
Non-controlling interests	**162**	148	2	12
Preference equity shareholders	**85**	74	—	11
Common equity shareholders	**1,714**	1,606	37	71
Net earnings	**1,961**	1,828	39	94

Revenue

The increase in revenue, net of foreign exchange, was due to: (i) Rate Base growth; (ii) higher flow-through costs in customer rates; and (iii) the implementation of new customer delivery rates at Central Hudson as approved by the PSC. The increase was also due to the retroactive impact of a reduction in the MISO base ROE at ITC in 2024 as approved by FERC. The increase was partially offset by lower retail electricity sales due to milder weather, and lower wholesale sales revenue due to a reduction in short-term wholesale sales and lower pricing driven by market conditions at UNS Energy.

Energy Supply Costs

The increase in energy supply costs, net of foreign exchange, was primarily due to the flow through of higher commodity costs at FortisBC Energy and Central Hudson, partially offset by lower sales and the flow through of lower commodity costs at UNS Energy.

Operating Expenses

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

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.

Other Income, Net

The increase in other income, net of foreign exchange, was due to higher AFUDC at UNS Energy and FortisBC Energy as well as unrealized gains on foreign exchange contracts and total return swaps. The increase was partially offset by the pre-tax loss on the disposition of Fortis Belize and Belize Electricity, as well as a reduction in interest income due to lower interest on short-term deposits and regulatory deferrals.

Finance Charges

The increase in finance charges, net of foreign exchange, was primarily due to higher debt levels to support the Corporation's Capital Plan.

Income Tax Expense

The increase in income tax expense, net of foreign exchange, was driven by income tax associated with the repatriation of proceeds on the dispositions of FortisTCI, Fortis Belize, and Belize Electricity, as well as higher earnings before income taxes.

Net Earnings

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

BUSINESS UNIT PERFORMANCE

Common Equity Earnings

			Variance	
($ millions)	**2025**	2024	FX [1]	Other
Regulated Utilities				
ITC	**592**	542	11	39
UNS Energy	**437**	448	8	(19)
Central Hudson	**191**	128	3	60
FortisBC Energy	**336**	293	—	43
FortisAlberta	**182**	181	—	1
FortisBC Electric	**75**	72	—	3
Other Electric [2]	**167**	163	1	3
	1,980	1,827	23	130
Non-Regulated				
Corporate and Other [3]	**(266)**	(221)	14	(59)
Common Equity Earnings	**1,714**	1,606	37	71

(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; and Caribbean Utilities. Also includes FortisTCI up to the September 2, 2025 date of disposition and Belize Electricity up to the October 31, 2025 date of disposition*

(3) *Consists of non-regulated holding company expenses, earnings from non-regulated long-term contracted generation assets in Belize up to the October 31, 2025 date of disposition, and losses on the dispositions of FortisTCI, Fortis Belize and Belize Electricity in 2025*

ITC

($ millions)	2025	2024	Variance FX	Variance Other
Revenue [(1)]	**2,495**	2,229	44	222
Earnings [(1)]	**592**	542	11	39

[(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 primarily due to Rate Base growth and higher flow-through costs in customer rates. The increase was also due to the recognition of a refund liability in 2024 associated with 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.

Earnings

The increase in earnings, net of foreign exchange, was primarily due to Rate Base growth. Growth in earnings was also due to FERC's approval of a reduction in the MISO base ROE in 2024, as discussed above, which resulted in a $20 million unfavourable impact to earnings in that year associated with the retroactive impact to prior periods. The increase in earnings was partially offset by higher non-recoverable stock-based compensation and holding company finance costs.

UNS Energy

($ millions, except as indicated)	2025	2024	Variance FX	Variance Other
Retail electricity sales *(GWh)*	**10,734**	10,870	—	(136)
Wholesale electricity sales *(GWh)* [(1)]	**5,034**	5,810	—	(776)
Gas sales *(PJ)*	**16**	17	—	(1)
Revenue	**2,913**	3,007	58	(152)
Earnings	**437**	448	8	(19)

[(1)] *Primarily short-term wholesale sales*

Sales

The decrease in retail electricity sales was primarily due to lower average use associated with milder temperatures in comparison to 2024.

The decrease in wholesale electricity sales was driven by lower short-term wholesale sales reflecting unfavourable market conditions as well as outages at certain of the company's generation facilities, resulting in lower generation levels. 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 relatively consistent with 2024.

Revenue

The decrease in revenue, net of foreign exchange, was primarily due to: (i) the recovery of overall lower fuel and non-fuel costs through the normal operation of regulatory mechanisms; (ii) lower electricity sales, discussed above; and (iii) lower pricing on wholesale sales. The decrease was partially offset by higher transmission revenue.

Earnings

The decrease in earnings, net of foreign exchange, was primarily due to: (i) higher costs associated with Rate Base growth not yet reflected in customer rates; (ii) lower retail electricity sales due to milder weather; and (iii) lower margin on wholesale sales, reflecting less favourable market conditions. The decrease was partially offset by higher transmission revenue and AFUDC.

Central Hudson

($ millions, except as indicated)	2025	2024	Variance FX	Variance Other
Electricity sales *(GWh)*	**5,092**	5,060	—	32
Gas sales *(PJ)*	**30**	25	—	5
Revenue	**1,620**	1,372	29	219
Earnings	**191**	128	3	60

Sales

The increase in electricity sales was due to higher average consumption by residential customers due to colder weather.

The increase in gas sales was due to higher average consumption by industrial customers.

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 increase in revenue, net of foreign exchange, was due to the flow-through of higher energy supply costs, Rate Base growth, and higher customer delivery rates as approved by the PSC.

Earnings

The increase in earnings, net of foreign exchange, was primarily due to: (i) Rate Base growth; (ii) the rebasing of customer rates effective July 1, 2024, which reflected a higher allowed ROE and improved recovery of costs; and (iii) a change in the timing of recognition of a regulatory deferral for uncollectible accounts, as approved in the order on the 2025 general rate application. This increase was partially offset by higher contributions made to a customer benefit fund in 2025.

FortisBC Energy

($ millions, except as indicated)	2025	2024	Variance
Gas sales *(PJ)*	**217**	220	(3)
Revenue	**1,874**	1,665	209
Earnings	**336**	293	43

Sales

The decrease in gas sales was due to lower average consumption by transportation and residential customers, partially offset by higher average consumption by industrial customers. Lower average consumption by residential customers was primarily due to milder weather in the fourth quarter of 2025.

Revenue

The increase in revenue was primarily due to: (i) the normal operation of regulatory mechanisms; (ii) Rate Base growth; and (iii) a higher cost of natural gas recovered from customers.

Earnings

The increase in earnings was primarily due to Rate Base growth, including higher AFUDC associated with FortisBC Energy's investment in the Eagle Mountain Pipeline project.

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)	2025	2024	Variance
Electricity deliveries *(GWh)*	**17,561**	17,324	237
Revenue	**829**	817	12
Earnings	**182**	181	1

Deliveries

The increase in electricity deliveries was primarily due to higher average consumption by industrial customers, largely reflecting activity in the energy sector. Customer additions, as well as higher average consumption by residential customers due to warmer weather in the second quarter of 2025, also contributed to the increase.

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 and Earnings

The increase in revenue and earnings was due to Rate Base growth and customer additions, partially offset by: (i) the expiration of the PBR efficiency carry-over mechanism, as this regulatory incentive was only available through 2024; (ii) favourable non-recurring true-ups recorded in 2024 associated with the finalization of prior period Rate Base balances; and (iii) a reduction in the allowed ROE from 9.28% to 8.97% effective January 1, 2025, due to the automatic adjustment mechanism.

FortisBC Electric

($ millions, except as indicated)	**2025**	2024	Variance
Electricity sales *(GWh)*	**3,619**	3,513	106
Revenue	**557**	545	12
Earnings	**75**	72	3

Sales

The increase in electricity sales was due to higher average consumption by industrial and commercial customers, partially offset by lower average consumption by residential customers due to milder weather in the second half of 2025.

Revenue

The increase in revenue was primarily due to higher electricity sales, higher energy supply costs recovered from customers and Rate Base growth.

Earnings

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

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

Other Electric

			Variance	
($ millions, except as indicated)	**2025**	2024	FX	Other
Electricity sales *(GWh)*	**9,918**	9,879	—	39
Revenue	**1,851**	1,838	10	3
Earnings	**167**	163	1	3

Sales

The increase in electricity sales was due to higher average consumption by residential and commercial customers, as well as customer additions. Higher average consumption by residential customers was largely due to the conversion of home heating systems from oil to electric in Eastern Canada. The increase was partially offset by the impact of the September 2025 disposition of FortisTCI.

Revenue

The increase in revenue, net of foreign exchange, was primarily due to Rate Base growth and higher electricity sales, as well as the July 1, 2025 electricity rate change at Newfoundland Power. The increase was partially offset by the disposition of FortisTCI, the flow-through of lower energy supply costs recovered from customers and the operation of regulatory deferral mechanisms at Newfoundland Power.

Earnings

The increase in earnings, net of foreign exchange, was primarily due to Rate Base growth and higher electricity sales, partially offset by the September 2025 disposition of FortisTCI.

Corporate and Other

($ millions)	2025	2024	Variance FX	Variance Other
Electricity sales *(GWh)* (1)	**167**	215	—	(48)
Revenue (1)	**31**	35	1	(5)
Net loss (2)	**(266)**	(221)	14	(59)

(1) *Reflects Fortis Belize up to the October 31, 2025 date of disposition*

(2) *Includes non-regulated holding company expenses, earnings for Fortis Belize up to the October 31, 2025 date of disposition, and losses on the dispositions of FortisTCI, Fortis Belize and Belize Electricity in 2025*

Sales and Revenue

The decrease in electricity sales and revenue was due to the impact of the October 2025 disposition of Fortis Belize.

Net Loss

The increase in net loss was driven by $63 million of losses associated with the dispositions of FortisTCI, Fortis Belize and Belize Electricity, approximately half of which related to income taxes.

Excluding the impact of the dispositions, the net loss decreased by $4 million due to unrealized gains on foreign exchange contracts in 2025, as compared to unrealized losses in 2024, as well as higher unrealized gains on total return swaps, partially offset by higher finance and stock-based compensation costs. Lower earnings contribution from Fortis Belize due to the October 2025 disposition also unfavourably impacted the net loss.

The favourable foreign exchange impact was primarily due to foreign exchange gains in 2025, as compared to losses in 2024, associated with the revaluation of U.S. dollar denominated short-term liabilities.

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.

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, less CIACs received by FortisBC Energy associated with the Eagle Mountain Pipeline project. The CIACs received for this Major Capital Project are significant and presentation of Capital Expenditures net of CIACs better aligns with the Rate Base growth associated with this project. Capital Expenditures for 2024 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)	2025	2024	Variance
Adjusted Common Equity Earnings, Adjusted Basic EPS and Adjusted Payout Ratio			
Common Equity Earnings	**1,714**	1,606	108
Adjusting items:			
Dispositions [1]	**63**	—	63
October 2024 MISO base ROE decision [2]	**—**	20	(20)
Adjusted Common Equity Earnings	**1,777**	1,626	151
Adjusted Basic EPS [3] ($)	**3.53**	3.28	0.25
Adjusted Payout Ratio [4] (%)	**70.4**	72.7	(2.3)
Capital Expenditures			
Additions to property, plant and equipment	**5,942**	5,012	930
Additions to intangible assets	**292**	206	86
Adjusting items:			
Eagle Mountain Pipeline Project [5]	**(620)**	—	(620)
Wataynikaneyap Transmission Power Project [6]	**—**	29	(29)
Capital Expenditures	**5,614**	5,247	367

(1) Represents losses on the dispositions of FortisTCI, Fortis Belize and the Corporation's 33% ownership in Belize Electricity, inclusive of income tax expense of $31 million, included in the Corporate and Other segment

(2) Represents the prior period impact of FERC's October 2024 MISO base ROE decision, net of income tax recovery of $7 million, included in the ITC segment

(3) Calculated using Adjusted Common Equity Earnings divided by weighted average common shares of 503.5 million in 2025 (2024 - 495.0 million)

(4) Calculated using dividends paid per common share of $2.49 in 2025 (2024 - $2.39) divided by Adjusted Basic EPS

(5) Represents CIACs received for the Eagle Mountain Pipeline project, included in the FortisBC Energy segment

(6) 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 Cayman Islands are regulated by the country's regulatory authority.

Additional information about regulation and the regulatory matters discussed below is provided in Note 2 in the 2025 Annual Financial Statements. Also refer to "Business Risks - Utility Regulation" on page 22.

Significant Regulatory Matters

ITC

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 are unknown, every 10-basis point change in ROE at ITC impacts Fortis' annual EPS by approximately $0.01.

UNS Energy

TEP General Rate Application: In June 2025, TEP filed a general rate application with the ACC requesting new rates effective September 1, 2026 using a December 31, 2024 test year, with post-test year adjustments through June 30, 2025. The application includes a proposal to phase-out or eliminate certain adjustor mechanisms, and requests an annual formulaic rate adjustment mechanism consistent with the ACC's approval of a formula rate policy statement in 2024.

The Residential Utility Consumer Office has challenged the ACC's authority to implement a formula rate framework through a policy statement, and in November 2025, the Arizona Court of Appeals ruled that the Residential Utility Consumer Office may proceed with its challenge. The timing and outcome of these regulatory and legal proceedings are unknown. The ACC has previously approved adjustor mechanisms, including formula-based mechanisms, in rate cases.

UNS Gas General Rate Application: In January 2026, an ACC Administrative Law Judge issued a Recommended Opinion and Order recommending an allowed ROE of 9.57% and a 56% common equity component of capital structure. The order also recommended an annual formulaic rate adjustment mechanism including a range of +/- 40 basis points around the allowed return, a 5% efficiency credit to incremental revenue requirement, and the exclusion of post-test year adjustments. Should the annual formulaic mechanism not be approved, the order recommended the use of adjustor mechanisms for the timely recovery of infrastructure investments and income tax changes. The Recommended Opinion and Order proposes implementation of new rates by March 1, 2026. The rate application remains subject to ACC approval which is anticipated in February 2026.

FortisAlberta

Third PBR Term Decision: In 2023, the AUC issued a decision establishing the parameters for the third PBR term for the period of 2024 through 2028. 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 COS revenue requirement as approved by the AUC. In March 2025, the Court of Appeal granted FortisAlberta permission to appeal, which was heard in January 2026. A decision is expected in the third quarter of 2026.

FINANCIAL POSITION

Significant Changes between December 31, 2025 and 2024

Balance Sheet Account *($ millions)*	**Variance** FX	Other	**Explanation**
Cash and cash equivalents	**(19)**	**166**	Primarily due to the timing of capital and operating requirements at UNS Energy, and unused proceeds from the disposition of Fortis Belize and Belize Electricity. Balances on hand have been invested in interest-bearing accounts and will be utilized in 2026.
Accounts receivable and other current assets	**(53)**	**(138)**	Primarily reflects a decrease in accounts receivable associated with collection efforts at Central Hudson, as well as a shift in long-term receivables associated with deferred payment agreements to other assets.
Other assets	**(60)**	**189**	Primarily due to an increase in employee future benefits assets, driven by investment returns on DBP and OPEB plans, and an increase in long-term receivables associated with deferred payment agreements at Central Hudson.
Regulatory assets (current and long-term)	**(62)**	**453**	Due to changes associated with various regulatory mechanisms including an increase in deferred income taxes, deferred energy management costs, and the normal operation of rate stabilization accounts.
Property, plant and equipment, net	**(1,516)**	**2,946**	Due to capital expenditures, partially offset by depreciation expense and CIACs, as well as the dispositions of FortisTCI and Fortis Belize.
Intangible assets, net	**(56)**	**118**	Largely reflects investments in computer software across the utilities.
Short-term borrowings	**(4)**	**318**	Reflects the issuance of commercial paper at ITC to finance working capital requirements.
Accounts payable & other current liabilities	**(73)**	**223**	Primarily due to an increase in deposits associated with the construction of the Eagle Mountain Pipeline project at FortisBC Energy.
Deferred income taxes	**(152)**	**424**	Primarily due to higher temporary differences associated with ongoing capital investments.
Long-term debt (including current portion)	**(985)**	**1,640**	Due to debt issuances in support of the Corporation's Capital Plan, partially offset by debt and credit facility repayments and the disposition of FortisTCI.
Shareholders' equity	**(943)**	**945**	Due primarily to: (i) Common Equity Earnings for 2025, 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 any 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 $5.4 billion of the total credit facilities are committed with maturities ranging from 2027 through 2030. Available credit facilities are summarized in the following table.

Credit Facilities

As at December 31 *($ millions)*	Regulated Utilities	Corporate and Other	**2025**	2024
Total credit facilities [1]	4,196	1,577	**5,773**	6,342
Credit facilities utilized:				
Short-term borrowings	(412)	—	**(412)**	(98)
Long-term debt (including current portion)	(1,515)	—	**(1,515)**	(2,216)
Letters of credit outstanding	(83)	(22)	**(105)**	(102)
Credit facilities unutilized	2,186	1,555	**3,741**	3,926

[1] *Additional information about the Corporation's credit facilities is provided in Note 14 in the 2025 Annual Financial Statements*

In April 2025, FortisAlberta increased its operating credit facility from $250 million to $300 million and extended the maturity to April 2030.

In May 2025, the Corporation amended its $1.3 billion revolving term committed credit facility to extend the maturity to July 2030.

In September 2025, FortisUS Inc., a holding company subsidiary of Fortis, extended the maturity on its unsecured US$150 million revolving term credit facility to October 2027. Also in September 2025, the Corporation fully repaid its unsecured US$250 million non-revolving term credit facility.

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, 2025, consolidated fixed-term debt maturities/repayments are expected to average $1.7 billion annually over the next five years, with a maximum of $2.4 billion due in any one year. Approximately 74% 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, 2025, $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.

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

Cash Flow Summary

Summary of Cash Flows

Years ended December 31 *($ millions)*	**2025**	2024	Variance
Cash and cash equivalents, beginning of year	**220**	625	(405)
Cash from (used in):			
Operating activities	**4,062**	3,882	180
Investing activities	**(5,357)**	(5,395)	38
Financing activities	**1,461**	1,064	397
Effect of exchange rate changes on cash and cash equivalents	**(19)**	44	(63)
Cash and cash equivalents, end of year	**367**	220	147

Operating Activities

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

Investing Activities

Cash used in investing activities was $38 million lower than 2024 primarily due to proceeds received on the dispositions of FortisTCI, Fortis Belize and Belize Electricity, partially offset by: (i) higher Capital Expenditures, net of CIACs; (ii) higher demand side management expenditures at FortisBC; and (iii) the higher U.S. dollar-to-Canadian dollar exchange rate.

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 13. The increase in cash from financing activities in 2025 primarily reflected an increase in borrowings to support capital investments.

Debt Financing

Significant Long-Term Debt Issuances

Year ended December 31, 2025	Month Issued	Interest Rate *(%)*	Maturity	**Amount** *($ millions)*	Use of Proceeds
UNS Energy					
Unsecured senior notes	February	5.90	2055	**US $300**	(1) (2) 3)
Unsecured senior notes	October	5.38	2035	**US $50**	(1) (3)
Central Hudson					
Unsecured senior notes	April	(4)	(4)	**US $70**	(1) (3)
Unsecured senior notes	November	(5)	(5)	**US $80**	(3)
FortisBC Energy					
Unsecured debentures	October	3.38	2030	**200**	(1)
FortisAlberta					
Unsecured senior debentures	July	4.76	2055	**200**	(1) (2) (3)
Newfoundland Power					
First mortgage bonds	August	4.91	2055	**120**	(1) (2) (3)
Maritime Electric					
First mortgage bonds	July	4.94	2055	**120**	(1) (2)
Fortis					
Unsecured senior notes	March	4.09	2032	**600**	(1) (3)
Unsecured subordinated notes	September	5.10	2055	**750**	(1) (3)

(1) *Repay credit facility borrowings*
(2) *Fund capital expenditures*
(3) *General corporate purposes*
(4) *Comprised of US$20 million at 5.61% due in 2035, US$30 million at 5.81% due in 2040 and US$20 million at 6.01% due in 2045*
(5) *Comprised of US$15 million at 5.25% due in 2035 and US$65 million at 5.90% due in 2045*

As shown in the table above, Fortis issued fixed-to-fixed rate unsecured hybrid subordinated notes in 2025. The interest rate will be reset on December 4, 2030, and every five years thereafter, equal to the then five-year Government of Canada bond yield plus 2.09% provided that the interest rate will not be below the initial interest rate of 5.10%. The subordinated notes receive 50% equity treatment from credit rating agencies.

In January 2026, ITC issued US$250 million of secured senior notes consisting of US$125 million 10-year, 5.08% notes and US$125 million 20-year, 5.71% notes. Proceeds were used to repay credit facility borrowings, fund capital expenditures and for general corporate purposes.

Common Equity Financing

Common Equity Issuances and Dividends Paid

Years ended December 31

($ millions, except as indicated)	**2025**	2024	Variance
Common shares issued:			
Cash [(1)]	**60**	46	14
Non-cash [(2)]	**463**	435	28
Total common shares issued	**523**	481	42
Number of common shares issued *(# millions)*	**8.0**	8.7	(0.7)
Common share dividends paid:			
Cash	**(788)**	(744)	(44)
Non-cash [(3)]	**(461)**	(434)	(27)
Total common share dividends paid	**(1,249)**	(1,178)	(71)
Dividends paid per common share *($)*	**2.49**	2.39	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, 2025 and February 11, 2026, Fortis declared a dividend of $0.64 per common share payable on March 1, 2026 and June 1, 2026, respectively. The payment of dividends is at the discretion of the Board and depends on the Corporation's financial condition and other factors.

On June 1, 2025, the annual fixed dividend per share for the First Preference Shares, Series H reset from $0.4588 to $1.0458 for the five-year period up to but excluding June 1, 2030. Also on June 1, 2025, 11,298 First Preference Shares, Series H were converted on a one-for-one basis into First Preference Shares, Series I and 248,830 First Preference Shares, Series I were converted on a one-for-one basis into First Preference Shares, Series H.

Contractual Obligations

As at December 31, 2025

($ millions)	**Total**	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Long-term debt:							
Principal [(1)]	**34,057**	3,146	2,389	1,880	943	1,714	23,985
Interest	**20,627**	1,423	1,338	1,253	1,213	1,168	14,232
Finance leases [(2)]	**1,125**	38	37	38	38	38	936
Other obligations [(3)]	**562**	188	123	128	23	23	77
Other commitments: [(4)]							
Gas and fuel purchase obligations	**6,592**	908	689	586	491	416	3,502
Renewable power purchase agreements	**2,374**	158	174	173	165	173	1,531
Waneta Expansion capacity agreement	**2,307**	58	59	60	61	63	2,006
Power purchase obligations	**1,135**	251	156	129	127	124	348
ITC easement agreement	**342**	14	14	14	14	14	272
UNS Energy EPC agreement	**269**	110	143	16	—	—	—
Debt collection agreement	**96**	3	3	3	3	3	81
Renewable energy credit purchase agreements	**50**	18	6	6	5	5	10
Other	**122**	27	12	9	9	2	63
	69,658	6,342	5,143	4,295	3,092	3,743	47,043

[(1)] *Amounts not reduced by unamortized deferred financing and discount costs of $188 million. Additional information is provided in Note 14 of the 2025 Annual Financial Statements*
[(2)] *Additional information is provided in Note 15 of the 2025 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 2025 Annual Financial Statements*

Other Commitments

The Corporation's utilities are obligated to provide service to customers within their respective service territories. Capital Expenditures are forecast to be approximately $5.6 billion for 2026 and approximately $28.8 billion for the five-year 2026-2030 Capital Plan. See "Capital Plan" on page 18.

Under a funding framework with the Governments of Ontario and Canada, Fortis has met the minimum equity capital contribution requirement of approximately $165 million 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 make additional 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.

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 $343 million for Four Corners. As at December 31, 2025, there was no obligation under these guarantees.

TEP has entered into an energy supply agreement to serve a customer expected to be located in TEP's service territory. The agreement, requiring potential power demand of approximately 300 MW, was approved by the ACC in December 2025 but remains subject to other contractual contingencies. The energy supply agreement provides additional consumer protections such as establishing minimum monthly payment obligations that apply irrespective of customer energy use, termination fees supported by financial assurance mechanisms, and imposing credit standards designed to mitigate the risk of default. The initial phase of the data center campus is expected to be operational as early as 2027, with a ramp schedule through 2029. TEP currently expects to serve the customer from its existing and planned capacity, including solar and battery storage projects currently in development.

TEP and UNS Electric have entered into long-term gas transportation precedent agreements to secure reliable access to natural gas. The agreements support the development of a new pipeline to be owned and operated by a third-party. Subject to the receipt of required regulatory approvals and other conditions, the pipeline is expected to be in service in 2029. Once the pipeline enters commercial operation, TEP and UNS Electric will enter into gas transportation service agreements with estimated purchase commitments of US$1.9 billion over 25 years.

Off-Balance Sheet Arrangements

With the exception of letters of credit outstanding of $105 million as at December 31, 2025, the unrecorded commitments in the table above and the "Other Commitments" discussed 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

As at December 31	**2025** ($ millions)	**2025** (%)	2024 ($ millions)	2024 (%)
Debt [1]	**34,262**	**57.0**	33,435	56.4
Preference shares	**1,623**	**2.7**	1,623	2.7
Common shareholders' equity and non-controlling interests [2]	**24,246**	**40.3**	24,230	40.9
	60,131	**100.0**	59,288	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, 2025 (December 31, 2024 - 3.4%)*

Outstanding Share Data

As at February 11, 2026, the Corporation had issued and outstanding 507.4 million common shares and the following First Preference Shares: 5.0 million Series F; 9.2 million Series G; 7.9 million Series H; 2.1 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 11, 2026, an additional 0.9 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, 2025	**Rating**	Type	Outlook
S&P	A-	Issuer	Stable
	BBB+	Unsecured debt	
Fitch	BBB+	Issuer	Stable
	BBB+	Unsecured debt	
Morningstar DBRS	A (low)	Issuer	Stable
	A (low)	Unsecured debt	Stable

In May 2025, Fitch assigned first time issuer and senior unsecured debt ratings of BBB+ to the Corporation with a stable outlook.

In November 2025, S&P confirmed the Corporation's A- issuer and BBB+ senior unsecured debt credit ratings and revised the outlook for the Corporation and certain of its subsidiaries from negative to stable. S&P noted that the change in outlook reflects improvement in the Corporation's FFO to debt ratio and developments at the subsidiaries to mitigate physical risks, namely wildfires.

In January 2026, Moody's Investor Services, Inc. withdrew its ratings for Fortis at the Corporation's request. The withdrawal does not impact the subsidiary credit ratings.

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 facilitate the interconnection of new energy resources.

Capital Expenditures in 2025 were $5.6 billion, consistent with expectations and $0.4 billion higher than 2024. The increase compared to 2024 was largely related to: (i) investments in Major Capital Projects, including projects within the first tranche of the MISO LRTP and the Big Cedar Load Expansion project at ITC, as well as the Vail-to-Tortolita and Black Mountain Gas Generation projects at UNS Energy; (ii) incremental transmission and distribution investments across the Corporation's utilities; and (iii) the impact of the higher U.S. dollar-to-Canadian dollar exchange rate. The increase was partially offset by FortisBC Energy's investment in the Eagle Mountain Pipeline project in 2024. Construction of the project in 2025 was largely funded by CIACs rather than investments by FortisBC Energy.

2025 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	1,840	1,365	481	650	598	186	491	**5,611**	**3**	**5,614**

Forecast 2026 Capital Expenditures [2][3]

	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	1,874	1,281	466	712	614	207	462	**5,616**	**—**	**5,616**

2026-2030 Capital Plan [2][3]

($ billions)	2026	2027	2028	2029	2030	**Total**
Five-year Capital Plan	5.6	5.9	5.6	6.2	5.5	**28.8**

(1) *See "Non-U.S. GAAP Financial Measures" on page 10. Reflects a U.S. dollar-to-Canadian dollar exchange rate of 1.40 for 2025*
(2) *Excludes the non-cash equity component of AFUDC*
(3) *Reflects an assumed U.S. dollar-to-Canadian dollar exchange rate of 1.35. On average, a five-cent increase or decrease in the U.S. dollar relative to the Canadian dollar would increase or decrease the 2026-2030 Capital Plan by approximately $0.7 billion over the five-year planning period*

The 2026-2030 Capital Plan is $2.8 billion higher than the previous five-year plan. The increase is primarily driven by higher FERC regulated transmission investments associated with new interconnections, the MISO LRTP and baseline reliability projects at ITC. It also includes incremental capital at UNS Energy, reflecting an increase in transmission and distribution investments to serve load growth, increase reliability, and provide a path for connecting future generation resources. Planned generation investments in Arizona have also been updated to reflect the Springerville Natural Gas Conversion project. Customer growth and reliability investments across our utilities also contributed to the increase, and the higher assumed U.S. dollar-to-Canadian dollar exchange rate of 1.35 resulted in approximately $0.6 billion of additional capital as compared to the previous plan.

Investments in the 2026-2030 Capital Plan are categorized as: (i) 46% transmission; (ii) 31% distribution; (iii) 7% generation; (iv) 5% renewable gas and LNG; and (v) 11% other, largely related to information technology and facility investments. The five-year Capital Plan is low risk and highly executable, with only 21% relating to Major Capital Projects. Geographically, 63% of planned expenditures are expected in the U.S., including 34% at ITC, with 35% in Canada and the remaining 2% in the Caribbean.

The Capital Plan is expected to be funded primarily by cash from operations and regulated utility debt. Common equity is expected to be provided by the Corporation's DRIP, assuming current participation levels. The Corporation's $500 million ATM Program has not been utilized to date and remains available for 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, new or revised tariffs and other factors. The Corporation continues to monitor government policy on foreign trade, including the imposition of tariffs and the potential impacts on the supply chain, commodity prices, the cost of energy and general economic conditions. These factors could change and cause actual expenditures to differ from forecast.

Midyear Rate Base [1]

($ billions)	**2025[2]**	2026[2]	2030[2]
ITC	**13.9**	14.6	19.8
UNS Energy	**8.4**	8.9	11.5
Central Hudson	**3.7**	4.0	5.0
FortisBC Energy	**6.5**	6.8	8.8
FortisAlberta	**4.7**	4.8	5.9
FortisBC Electric	**1.8**	1.9	2.3
Other Electric	**3.4**	3.7	4.6
Total	**42.4**	44.7	57.9

(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 1.40 for 2025. 2026 and 2030 reflect an assumed U.S. dollar-to-Canadian dollar exchange rate of 1.35 consistent with the Corporation's 2026-2030 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 $1.4 billion over the five-year planning period*

Total midyear Rate Base is forecast to grow to $57.9 billion by 2030 underpinned by the five-year Capital Plan, translating to a CAGR of 7.0%.

Major Capital Projects

($ millions)	Pre-2025	**Actual 2025**	Plan 2026-2030	Expected Completion
ITC				
MISO LRTP Tranche 1	89	**173**	1,812	2030
MISO LRTP Tranche 2.1	—	**8**	529	Post-2030
Big Cedar Load Expansion	5	**172**	394	2028
UNS Energy				
TEP Transmission Project	—	**—**	608	2029
Springerville Natural Gas Conversion	—	**—**	238	2030
Black Mountain Gas Generation	1	**58**	339	2028
Vail-to-Tortolita Transmission Project	199	**144**	147	2027
Roadrunner Reserve Battery Storage Project	116	**345**	3	2026
FortisBC Energy				
Tilbury LNG Storage Expansion	35	**5**	627	Post-2030
AMI Project	37	**136**	570	2028
Tilbury 1B Project	49	**12**	342	2030
Eagle Mountain Pipeline Project [1]	436	**14**	274	2027
Total		**1,067**	5,883	

(1) *Net of customer contributions*

MISO LRTP - Tranches 1 and 2.1
Six projects included in the first tranche of the MISO LRTP portfolio run through ITC's MISO operating companies' service territories. A majority of ITC's planned investment associated with these projects has been reflected in the 2026-2030 Capital Plan.

ITC has reflected investments of approximately $0.5 billion (US$0.4 billion) in the Corporation's 2026-2030 Capital Plan associated with MISO LRTP 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. Significant additional investment opportunities remain for tranche 2.1 (see "Additional Investment Opportunities" on page 21).

In July 2025, certain state regulatory commissions in the MISO region filed a complaint at FERC challenging the manner in which MISO developed the tranche 2.1 portfolio. The timing and outcome of this filing, and any potential impact on the Capital Plan, are unknown.

Big Cedar Load Expansion
The project consists 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.

TEP Transmission Project
Reflects a transmission project with expected completion in 2029 to serve load demand growth, increase reliability, and provide a path for connecting future generation investments.

Springerville Natural Gas Conversion
The project reflects the conversion of 793 MW of coal-fired generation at TEP's existing Springerville Generating Station to natural gas-fired generation with similar capacity by 2030. The conversion will support customer affordability, local communities, and reliability, and satisfies the need for replacement capacity included in TEP's 2023 IRP.

Black Mountain Gas Generation
Reflects the expansion of the existing Black Mountain Generation Station owned and operated by UNS Electric to support rising capacity demands in the service territory. The expansion will include four gas turbines, each with a nominal capacity of 48 MW, a 230 kV substation, and a 230 kV interconnection substation. The project is scheduled for completion in 2028.

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

Roadrunner Reserve Battery Storage Project
Reflects the second 200 MW Roadrunner Reserve battery project at TEP, following the completion of the first Roadrunner Reserve project in July 2025. The project consists of a battery energy storage system that will facilitate the integration of renewable energy into the electric grid. The 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 system. The project is scheduled for completion in 2026.

Tilbury LNG Storage Expansion Project
In October 2025, the CPCN application for this project was approved by the BCUC. Consistent with the expansion options outlined in the CPCN, the approval will allow FortisBC Energy to replace the original LNG storage tank at the Tilbury site with a new, expanded LNG storage tank, as well as increased regasification capacity, to ensure FortisBC Energy can continue to provide reliable and resilient energy services. The project remains subject to an environmental assessment process.

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 installation of the advanced meters commenced in 2025 and is expected to be substantially complete in 2028.

Tilbury 1B Project
Construction of additional liquefaction and dispensing facilities, including on-shore piping, in support of marine bunkering and to further optimize the Tilbury Phase 1A Expansion Project. This FortisBC Energy project has received an Order in Council from the Government of British Columbia. 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.

Eagle Mountain Pipeline Project
The project consists of a 50-km pipeline expansion to a 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.

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 board has approved tranche 2.1 LRTP projects with estimated transmission costs of approximately US$22 billion. ITC estimates a total 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. The majority of the tranche 2.1 investments are expected beyond 2030.

Any additional tranche 2.1 projects awarded to ITC as part of a competitive bidding process would be incremental to the estimated range of tranche 2.1 investments discussed above. ITC is evaluating projects within the portfolio and preparing to bid as deemed appropriate.

UNS Energy

In addition to the energy supply agreement signed in July 2025 (see "Contractual Obligations" on page 16), further negotiations are ongoing with the customer for additional capacity to support a full build at the initial site for a total of 600 MW. The customer has also indicated that additional capacity may be required for 500 MW to 700 MW at a second site. Should discussions progress and an agreement be negotiated, additional generation and transmission investments would be required for these subsequent phases.

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

TEP and UNS Electric are expecting to file new IRPs with the ACC in 2026, which will support increasing energy needs while taking into account reliable and affordable energy solutions.

FortisBC Energy

As indicated above, the BCUC approved the Tilbury LNG Storage Expansion project in October 2025. Based on the expansion option approved by the BCUC, the project has potential upside of $300 million as the five-year Capital Plan assumed the tank replacement would be a similar size and configuration to the existing tank. The incremental opportunity may extend beyond 2030 depending on the timing of environmental assessment approvals.

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.

Other Opportunities

Other opportunities include incremental transmission investments across our FERC regulated jurisdictions to support customer connections and grid modernization; further renewable gas and LNG infrastructure opportunities in British Columbia; grid resiliency and climate adaptation investments; and energy infrastructure investments to support the acceleration of load growth across our jurisdictions.

GHG Emissions Reduction Targets

Fortis is primarily an energy delivery company with approximately 95% 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. The Corporation has made consistent progress to decarbonize its energy mix and deliver cleaner energy to customers, achieving an approximate 38% reduction in scope 1 GHG emissions through 2025 compared to 2019 levels. The decrease in emissions in 2025 was primarily driven by outages at certain TEP fossil fuel generating units during the year.

In 2026, Fortis will be reviewing its decarbonization strategy, including potentially establishing new interim emission targets to replace its former targets. This work will be informed by resource planning across the Corporation's utilities, including the new IRPs to be filed in 2026 by TEP and UNS Electric, as discussed above. Fortis remains committed to having a coal-free generation mix in 2032 and advancing toward net-zero emissions by 2050.

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 assets as at December 31, 2025. Regulatory jurisdictions include five Canadian provinces, ten U.S. states and the Cayman Islands, as well as 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, or changes in the interpretation or application of laws and regulations, whether caused by economic, political (see "Political Environment" on page 24) 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.

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 18. Capital investments, including Major Capital Projects and opportunities to expand and extend the Capital Plan, are subject to risks of delay and cost overruns during construction caused by commodity price fluctuations, supply and labour costs, 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.

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 cyberattack or breach 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 27).

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.

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 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.

The Corporation has identified strong winds, extreme heat, wildfire risk and flooding as its most significant climate hazards. The Corporation's service territories may also experience other severe weather and events such as thunderstorms, drought, hurricanes, storm surges 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.

Longer-term climate change impacts 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 22). Failure to appropriately respond to climate change may disrupt the ability of the utilities to provide safe and cost-effective service, which could cause reputational harm and other impacts.

The physical risks posed by the potential 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 27).

Climate-Related Transition Risk
A transition towards decarbonization 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. Risks associated with policy, legal, technological and market changes may have capital and financial implications for the Corporation and its utilities.

Fortis expects changes to government policy and regulation to continue in the coming years (see "Environmental Regulation" below). Changes in policies and technologies, as well as the ability of the Corporation's utilities to pass related costs on to customers remain 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 net-zero emissions while preserving system reliability and customer affordability. In addition to the development and implementation of relevant energy technologies, the Corporation's ability to achieve net-zero emissions, and any GHG targets adopted by the Corporation, depends upon many factors including significant load growth, federal, state and provincial energy policies, 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 any such targets could cause reputational damage which could result in 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, regulatory independence 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. In addition, the Corporation could be adversely affected if certain of its utilities become subject to municipalization or other related government actions.

The business is further exposed to risks associated with geopolitical uncertainty. Global fragmentation, and political and economic uncertainty, including changing trade and energy policy, 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 26).

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 23).

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 changing 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 20% of the Corporation's revenue is derived from the delivery of natural gas. In British Columbia, which accounts for approximately 80% 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.

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 may 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 can increase heating and cooling loads, negatively impacting system reliability.

Weather and seasonality also have a significant impact on gas distribution volumes as a major portion of natural gas is used for space heating by residential customers. 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 certain utility assets are located on Indigenous lands and other lands pursuant to rights of way or other land tenure agreements or rights. Various treaty negotiation processes and court proceedings involving Indigenous Peoples and related land tenure are underway, but the potential basis for settlement and final decisions are unclear and not all Indigenous Peoples are participating in such processes or proceedings. The inability to maintain land agreements or rights, to renew such land rights, or to obtain replacement land rights, could have a Material Adverse Effect.

Certain of FortisAlberta's distribution assets are located on Indigenous Peoples' lands. The locating of these assets on such land is subject to a permitting process and requires approvals from the applicable Indigenous Peoples' band council and Indigenous Service Canada. The inability to obtain such approvals or access permits 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 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 or social disruptions could restrict or disrupt business operations, 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. Such factors may include, but are not limited to, international relations and geopolitical uncertainty and conflicts or the emergence of a pandemic or other health crisis.

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 32).

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 24 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 work with 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.

ITC, 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, 2025, 67% of the Corporation's assets were located outside Canada and 62% of 2025 revenue was derived from foreign operations. The reporting currency of ITC, UNS Energy, Central Hudson, and Caribbean Utilities is 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 $28.8 billion five-year Capital Plan for 2026 through 2030 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, financial condition and credit ratings of Fortis and its subsidiaries, the regulatory environments including decisions regarding capital structure and allowed ROEs, capital market conditions and general economic conditions. 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, and the inability to access cost-effective capital could have a Material Adverse Effect. For further information see "Liquidity and Capital Resources" on page 13.

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. At the holding company level, changes in income tax rates and other tax legislation could materially affect the after-tax cost of existing and future debt. 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.

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.

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" on page 25 and "Indigenous Peoples' Land Claims" on page 26.

External stakeholders have been challenging companies regarding strategy, governance, 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

Income Taxes: The Corporation adopted ASU No. 2023-09, *Improvements to Income Tax Disclosures*, effective January 1, 2025. This update 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. The ASU has been applied retrospectively and the updated disclosure is included in the 2025 Annual Financial Statements.

Future Accounting Pronouncements

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.

Internal-Use Software: ASU No. 2025-06, *Targeted Improvements to the Accounting for Internal-Use Software*, is effective for Fortis on January 1, 2028. The ASU may be adopted prospectively, retrospectively, or using a modified transition approach, and early adoption is permitted. The ASU removes references to development stages and requires capitalization of software costs once funding is authorized and project completion is probable, including assessment of whether significant development uncertainty exists. The guidance also clarifies that all capitalized internal-use software costs must follow the disclosure requirements in Subtopic 360-10, *Property, Plant and Equipment*. Fortis is assessing the impact on its consolidated financial statements and disclosures.

Critical Accounting Estimates

General

The preparation of the 2025 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, 2025, Fortis recognized regulatory assets of \$5.0 billion (2024 - \$4.6 billion) and regulatory liabilities of \$4.3 billion (2024 - \$4.3 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)	**2025**	2024	**2025**	2024
Funded status: [(1)]				
Benefit obligation [(2)]	**(3,495)**	(3,440)	**(589)**	(603)
Plan assets	**3,744**	3,613	**531**	506
	249	173	**(58)**	(97)
Net benefit cost [(2)]	**11**	11	**(1)**	12
Key assumptions: *(weighted average %)*				
Discount rate as at December 31 [(3)]	**5.24**	5.25	**5.36**	5.43
Expected long-term rate of return on plan assets [(4)]	**6.29**	6.51	**5.80**	6.05
Rate of compensation increase	**3.39**	3.52	**—**	—
Health care cost trend increase rate [(5)]	**—**	—	**4.40**	4.53

(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 5.25% (2024 - 4.84%) and 5.43% (2024 - 4.96%) 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 2026 rate is 6.60% and is assumed to decrease over the next 10 years to the ultimate rate of 4.40% in 2035 and thereafter

Sensitivity Analysis	**Rate of Return**		**Discount Rate**		**Health Care Costs Trend Rate**	
Year ended December 31, 2025	**1% change**		**1% change**		**1% change**	
($ millions)	**Increase**	**Decrease**	**Increase**	**Decrease**	**Increase**	**Decrease**
DBP plans:						
Net benefit cost	**(35)**	**29**	**(26)**	**45**	**n/a**	**n/a**
Projected benefit obligation	**4**	**(77)**	**(378)**	**468**	**n/a**	**n/a**
OPEB plans:						
Net benefit cost	**(5)**	**5**	**(7)**	**9**	**13**	**(11)**
Accumulated benefit obligation	**—**	**—**	**(67)**	**83**	**62**	**(51)**

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, 2025, Fortis recognized property, plant and equipment and intangible assets of $52.6 billion (2024 - $51.1 billion) representing 70% of total assets (2024 - 70%). Depreciation and amortization of these assets totalled $2.0 billion for 2025 (2024 - $1.8 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, 2025, this regulatory liability was $1.9 billion (2024 - $1.7 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, 2025, Fortis recognized goodwill of $12.5 billion (2024 - $13.1 billion), representing 17% of total assets (2024 - 18%). The decrease in goodwill was due to a lower U.S. dollar-to-Canadian dollar exchange rate at December 31, 2025 in comparison to December 31, 2024, and the associated impact on the translation of U.S. dollar-denominated goodwill. Goodwill was also reduced by $50 million in 2025 due to the disposition of FortisTCI.

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 more likely than not that fair value is less than carrying value, then a quantitative assessment is performed. Under the quantitative test, 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, is also performed and includes the comparison of each reporting unit's estimated fair value multiple to those of comparable utilities.

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 trigger non-compliance with debt covenants, or 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.

Income Taxes

As at December 31, 2025, deferred income tax liabilities, deferred income taxes included in regulatory assets, income tax payable, and deferred income taxes included in regulatory liabilities totalled $5.3 billion, $2.4 billion, $24 million and $1.3 billion, respectively (2024 - $5.0 billion, $2.2 billion, $33 million, and $1.3 billion, respectively). Income tax expense was $393 million in 2025 (2024 - $346 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 are recognized for 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 that 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. 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 2025 taxation years are still open for audit in Canadian jurisdictions, and its 2021 to 2025 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 28).

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 reliable in predicting future earnings or cash flows.

Contingencies

The Corporation and its subsidiaries are subject to various legal proceedings and claims that arise in the normal course of business, including those generally described under "Business Risks - Legal, Administrative and Other Proceedings" on page 29, for which no amounts have been accrued because the outcomes currently cannot be reasonably determined.

FINANCIAL INSTRUMENTS

Long-Term Debt and Other

As at December 31, 2025, the carrying value of long-term debt, including the current portion, was $34.1 billion (2024 - $33.4 billion) compared to an estimated fair value of $32.3 billion (2024 - $31.3 billion).

The consolidated carrying value of the remaining financial instruments 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, 2025, unrealized losses of $135 million (2024 - $175 million) were recognized as regulatory assets and unrealized gains of $37 million (2024 - $41 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. Gains or losses associated with changes in the fair value of these energy contracts are recognized in revenue. In 2025, gains of $39 million (2024 - $48 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 $136 million and terms up to three years expiring at varying dates through January 2028. 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 2025, unrealized gains of $24 million (2024 - $12 million) 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 2027 and have a combined notional amount of US$448 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 2025, unrealized gains of $17 million (2024 - unrealized losses of $17 million) were recognized in other income, net.

Interest rate contracts
ITC has entered into five-year interest rate swap contracts with a combined notional value of US$755 million which 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. In 2025, unrealized losses of US$5 million (2024 - unrealized gains of US$4 million) were recorded in other comprehensive income.

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 2025, unrealized gains of $9 million (2024 - unrealized losses of $29 million) were recorded in other comprehensive income.

Fair Value Measures

The following table presents 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, 2025				
Assets [(2)]				
Energy contracts subject to regulatory deferral	**—**	**51**	**—**	**51**
Energy contracts not subject to regulatory deferral	**—**	**4**	**—**	**4**
Total return swaps and foreign exchange contracts	**—**	**37**	**—**	**37**
Other investments	**190**	**—**	**—**	**190**
	190	**92**	**—**	**282**
Liabilities [(3)]				
Energy contracts subject to regulatory deferral	**—**	**(149)**	**—**	**(149)**
Energy contracts not subject to regulatory deferral	**—**	**(2)**	**—**	**(2)**
Interest rate contracts and cross-currency interest rate swaps	**—**	**(23)**	**—**	**(23)**
	—	**(174)**	**—**	**(174)**
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)

(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	**2025**	2024
Energy contracts subject to regulatory deferral [(1)]		
Electricity swap contracts *(GWh)*	**890**	774
Electricity power purchase contracts *(GWh)*	**395**	430
Gas swap contracts *(PJ)*	**183**	236
Gas supply contracts *(PJ)*	**147**	105
Energy contracts not subject to regulatory deferral [(1)]		
Wholesale trading contracts *(GWh)*	**1,430**	1,499
Gas swap contracts *(PJ)*	**2**	3

(1) *Energy contracts settle on various dates through 2030*

SELECTED ANNUAL FINANCIAL INFORMATION

Years ended December 31 *($ millions, except as indicated)*	**2025**	2024	2023
Revenue	**12,170**	11,508	11,517
Net earnings	**1,961**	1,828	1,710
Common Equity Earnings	**1,714**	1,606	1,506
EPS: *($)*			
Basic	**3.40**	3.24	3.10
Diluted	**3.40**	3.24	3.10
Total assets	**74,830**	73,486	65,920
Long-term debt (excluding current portion)	**30,723**	31,224	27,235
Dividends declared: *($)*			
Per common share	**2.51**	2.41	2.31
Per first preference share:			
Series F	**1.2250**	1.2250	1.2250
Series G (1)	**1.5308**	1.5308	1.3145
Series H (2)	**0.8990**	0.4588	0.4588
Series I (3)	**1.0277**	1.4902	1.5619
Series J	**1.1875**	1.1875	1.1875
Series K (4)	**1.3673**	1.3673	0.9823
Series M (5)	**1.3733**	1.0770	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) *The annual dividend per share was reset to $1.0458 for the five-year period from June 1, 2025 up to but excluding June 1, 2030*
(3) *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*
(4) *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*
(5) *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*

2025/2024

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 5, and "Financial Position" on page 13.

2024/2023

The decrease in revenue 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, 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, as well as a higher U.S. dollar-to-Canadian dollar exchange rate.

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 including 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.

The increase in total assets was primarily due to: (i) Capital Expenditures in 2024; (ii) the translation of U.S. dollar-denominated assets at a higher U.S. dollar-to-Canadian dollar exchange rate; and (iii) an increase in other assets, largely due to increase in employee future benefit assets, driven by higher discount rates on plan liabilities as well as investment returns on DBP and OPEB plans. The increase was partially offset by a reduction in cash and cash equivalents associated with the timing of a debt issuance at ITC in 2023.

FOURTH QUARTER RESULTS

Sales

(GWh, except as indicated)	**2025**	2024	Variance
Regulated Utilities			
UNS Energy			
Retail Electricity	**2,278**	2,348	(70)
Wholesale Electricity	**1,521**	1,295	226
Gas *(PJ)*	**4**	5	(1)
Central Hudson			
Electricity	**1,218**	1,187	31
Gas *(PJ)*	**9**	6	3
FortisBC Energy *(PJ)*	**65**	67	(2)
FortisAlberta	**4,507**	4,428	79
FortisBC Electric	**914**	916	(2)
Other Electric	**2,515**	2,533	(18)
Non-Regulated			
Corporate and Other	**13**	80	(67)

Utilities with notable increases in fourth quarter electricity sales include: (i) UNS Energy, due to higher short-term wholesale sales reflecting favourable market conditions, partially offset by lower retail electricity sales due to milder weather; (ii) FortisAlberta, reflecting higher average consumption by industrial customers due to increased activity in the energy sector; and (iii) Central Hudson, due to higher average consumption by residential customers due to colder weather. Lower sales in the Other Electric and Corporate and Other segments reflect the impacts of the dispositions of FortisTCI and Fortis Belize.

Gas sales by utility for the fourth quarter were largely consistent with the fourth quarter of 2024.

Revenue and Common Equity Earnings

	Revenue			**Earnings**		
($ millions, except as indicated)	**2025**	2024	Variance	**2025**	2024	Variance
Regulated Utilities						
ITC	**625**	567	58	**150**	127	23
UNS Energy	**646**	659	(13)	**43**	52	(9)
Central Hudson	**412**	356	56	**70**	66	4
FortisBC Energy	**576**	522	54	**134**	120	14
FortisAlberta	**208**	207	1	**50**	42	8
FortisBC Electric	**145**	149	(4)	**18**	18	—
Other Electric	**465**	479	(14)	**38**	52	(14)
Non-regulated						
Corporate and Other	**2**	10	(8)	**(81)**	(81)	—
Total	**3,079**	2,949	130	**422**	396	26
Weighted average number of common shares outstanding *(# millions)*				**506.4**	498.2	8.2
Basic EPS *($)*				**0.83**	0.79	0.04

The increase in revenue was primarily due to: (i) Rate Base growth, (ii) higher flow-through costs in customer rates; and (iii) the retroactive impact of a reduction in the MISO base ROE at ITC as approved by FERC in 2024, as discussed below. The increase was partially offset by the dispositions of FortisTCI and Fortis Belize.

Common Equity Earnings increased by $26 million compared to the fourth quarter of 2024. Common Equity Earnings in the fourth quarter of 2025 were unfavourably impacted by a $31 million loss on the disposition of Fortis Belize and Belize Electricity in October 2025. In addition, Common Equity Earnings in the fourth quarter of 2024 were unfavourably impacted by $20 million at ITC associated with the retroactive impact of a reduction in the MISO base ROE as approved by FERC.

Excluding the above-noted items, Common Equity Earnings increased by $37 million compared to the fourth quarter of 2024. The increase in Common Equity Earnings was primarily due to Rate Base growth across the utilities, including AFUDC associated with Major Capital Projects. Growth in earnings was also due to: (i) unrealized gains on derivative contracts; (ii) the timing of operating costs at FortisAlberta; and (iii) the favourable impact of foreign exchange, as discussed below. The increase was partially offset by higher costs associated with Rate Base growth not yet reflected in customer rates and lower retail electricity sales due to milder weather at UNS Energy, as well as higher stock-based compensation and holding company finance costs. Lower earnings contribution from FortisTCI and Belize due to the dispositions, net of finance cost savings associated with proceeds, also unfavourably impacted fourth quarter results.

The favourable change in earnings associated with foreign exchange largely reflected foreign exchange losses recorded in the fourth quarter of 2024 due to the significant appreciation of the U.S. dollar relative to the Canadian dollar during that quarter and the associated revaluation of U.S. dollar denominated short-term liabilities.

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)	**2025**	2024	Variance
Cash and cash equivalents, beginning of period	**389**	896	(507)
Cash from (used in):			
Operating activities	**1,018**	962	56
Investing activities	**(1,341)**	(1,796)	455
Financing activities	**305**	125	180
Effect of exchange rate changes on cash and cash equivalents	**(4)**	33	(37)
Cash and cash equivalents, end of period	**367**	220	147

Operating Activities

The increase in Operating Cash Flow was due to higher cash earnings, reflecting Rate Base growth as well as the sale of investment tax credits at UNS Energy. The timing of transmission charges at FortisAlberta also contributed to growth in Operating Cash Flow. The increase was partially offset by: (i) the timing of flow-through costs at UNS Energy associated with higher PPFAC collections in 2024, and at FortisBC Energy related to the collection of consumer carbon tax in 2024; and (ii) lower deposits received, net of expenditures incurred, associated with the Eagle Mountain Pipeline project at FortisBC Energy.

Investing Activities

Cash used in investing activities for the fourth quarter of 2025 was $455 million lower than the same period in 2024 due to proceeds received on the disposition of Fortis Belize and Belize Electricity in October 2025 and higher CIACs largely associated with the Eagle Mountain Pipeline project.

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 13.

Cash provided by financing activities for the fourth quarter of 2025 increased by $180 million as compared to the fourth quarter of 2024. The increase primarily reflected an increase in borrowings to support capital investments.

SUMMARY OF QUARTERLY RESULTS

Quarter ended	Revenue ($ millions)	Common Equity Earnings ($ millions)	Basic EPS ($)	Diluted EPS ($)
December 31, 2025	**3,079**	**422**	**0.83**	**0.83**
September 30, 2025	**2,938**	**409**	**0.81**	**0.81**
June 30, 2025	**2,815**	**384**	**0.76**	**0.76**
March 31, 2025	**3,338**	**499**	**1.00**	**1.00**
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

Generally, within each calendar year, quarterly results fluctuate in accordance with seasonality. Given the diversified nature of the Corporation's subsidiaries, seasonality varies. Earnings for the utilities in Canada and New York tend to be highest in the first and fourth quarters due to space heating requirements. Earnings for UNS Energy 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 2025/December 2024

See "Fourth Quarter Results" on page 35.

September 2025/September 2024

Common Equity Earnings decreased by $11 million and basic EPS decreased by $0.04 in comparison to the third quarter of 2024. The decrease was due to income taxes and closing costs totalling $32 million associated with the disposition of FortisTCI in September 2025. Excluding the impact of the disposition, Common Equity Earnings increased by $21 million compared to the third quarter of 2024. The increase was primarily due to Rate Base growth across the utilities, including AFUDC associated with Major Capital Projects. The higher U.S. dollar-to-Canadian dollar exchange rate also contributed to the increase in earnings. The increase was partially offset by higher costs associated with Rate Base growth not yet reflected in customer rates at UNS Energy, the expiration of a regulatory incentive and a lower allowed ROE at FortisAlberta, and 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 2025/June 2024

Common Equity Earnings increased by $53 million and basic EPS increased by $0.09 compared to the second quarter of 2024. The increase was due to Rate Base growth across the utilities, including AFUDC associated with FortisBC Energy's investment in the Eagle Mountain Pipeline project, as well as higher earnings at Central Hudson due to the rebasing of costs and a higher allowed ROE effective July 1, 2024 and the timing of operating costs in 2025. The higher U.S. dollar-to-Canadian dollar exchange rate also favourably impacted earnings year over year. The increase was partially offset by: (i) the timing of operating costs, the expiration of a regulatory incentive at the end of 2024 and a lower allowed ROE effective January 1, 2025 at FortisAlberta; and (ii) 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.

March 2025/March 2024

Common Equity Earnings increased by $40 million and basic EPS increased by $0.07 compared to the first quarter of 2024. The increase was due to Rate Base growth across the utilities, and higher earnings at Central Hudson due to the rebasing of costs and a higher allowed ROE, as well as a shift in quarterly revenue effective July 1, 2024. The higher U.S. dollar-to-Canadian dollar exchange rate also favourably impacted earnings. The increase was partially offset by: (i) lower earnings at UNS Energy due to lower margin on wholesale sales and higher costs associated with Rate Base growth not yet reflected in customer rates; (ii) lower earnings at FortisAlberta due to the timing of operating costs, the expiration of a regulatory incentive at the end of 2024 and a lower allowed ROE effective January 1, 2025; and (iii) 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.

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 2025 or 2024.

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, 2025 and 2024, there were no inter-segment loans outstanding. Interest charged on inter-segment loans was not material in 2025 and 2024.

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, 2025, 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, 2025.

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, 2025, 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, 2025, the Corporation's ICFR was effective.

During the year ended December 31, 2025, 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 $28.8 billion five-year Capital Plan is expected to increase midyear Rate Base from $42.4 billion in 2025 to $57.9 billion by 2030, translating into a five-year CAGR of 7.0%. Fortis expects its long-term growth in Rate Base will drive earnings that support dividend growth guidance of 4-6% annually through 2030.

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 new energy resources; transmission investments associated with the MISO LRTP as well as regional transmission in New York; grid resiliency and climate adaptation investments; investments in renewable gas and LNG infrastructure in British Columbia; and energy infrastructure investments to support the acceleration of load growth across our jurisdictions.

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 2030; forecast Capital Expenditures for 2026 through 2030; expected sources of funding for the Capital Plan, including sources of common equity; forecast midyear Rate Base for 2030 and forecast five-year Rate Base CAGR through 2030; expected implications of industry trends on the utility sector and on the Corporation's capital investments; the expectation that Fortis is well-positioned to support energy security, climate adaptation, and load growth across the Corporation's footprint; expected timing, outcome and impact of legal and regulatory proceedings and decisions; 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; 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; expected use of proceeds from debt financings; the potential requirement to accelerate equity capital contributions to Wataynikaneyap Power; expectations related to UNS Energy's joint generation performance guarantees, potential obligations arising from participant defaults, and associated recovery mechanisms; expected nature, timing, benefits and costs associated with TEP's energy supply agreement with a customer to support a planned data center in TEP's service territory; expected in-service date for a new pipeline in UNS Energy's service territory and the expectation that TEP and UNS Electric will enter into gas transportation service agreements and estimated purchase commitments associated therewith; the potential impact of new or revised tariffs on forecasted capital expenditures; forecast midyear Rate Base for 2026 and 2030 by business segment; the nature, timing, benefits and costs of certain Major Capital Projects, including the MISO LRTP, Big Cedar Load Expansion, TEP Transmission Project, Springerville Natural Gas Conversion, Black Mountain Gas Generation, Vail-to-Tortolita Transmission Project, Roadrunner Reserve Battery Storage Project, Tilbury LNG Storage Expansion, AMI Project, Tilbury 1B Project, and Eagle Mountain Pipeline Project; the nature, timing, benefits and costs of additional investment opportunities, including ITC's investments associated with MISO LRTP tranche 2.1, TEP's investments associated with additional energy demands from new large retail customers, and FortisBC Energy's investments associated with the Tilbury LNG Storage Expansion project and Tilbury Marine Jetty project; expected nature, timing and benefits of additional opportunities to expand and extend growth 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 new energy resources, transmission investments associated with the MISO LRTP as well as regional transmission in New York, grid resiliency and climate adaptation investments, investments in renewable gas and LNG infrastructure in British Columbia, and energy infrastructure investments to support the acceleration of load growth; the expectation that the Corporation will be reviewing its decarbonization strategy in 2026; the potential establishment of new interim emissions targets; expected timing and contents of TEP's and UNS Electric's new IRPs; the expectation that the Corporation will have a coal-free generation mix in 2032; the Corporation's 2050 net-zero GHG emissions target; the potential and expected impacts of new accounting policies and 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.

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 2026 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 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 related to environmental laws and regulation; 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 11, 2026. 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

2025 Annual Financial Statements: the Corporation's audited consolidated financial statements and notes thereto for the year ended December 31, 2025

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 held a 33% equity interest which was sold on October 31, 2025

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, less CIACs received by FortisBC Energy associated with the Eagle Mountain Pipeline project. Also includes Fortis' 39% share of capital spending for the Wataynikaneyap Transmission Power project in 2024. See "Non-U.S. GAAP Financial Measures" on page 10

Capital Plan: forecast Capital Expenditures. Represents a non-U.S. GAAP financial measure calculated in the same manner as Capital Expenditures

Caribbean Utilities: Caribbean Utilities Company, Ltd., an indirect approximately 60%-owned (as at December 31, 2025) 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

CIACs: contributions in aid of construction

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

DBP: defined benefit pension

DCP: disclosure controls and procedures

DRIP: dividend reinvestment plan

EPC: engineering, procurement and construction

EPS: earnings per common share

ERM: enterprise risk management

FERC: Federal Energy Regulatory Commission

FFO: funds from operations

Fitch: Fitch Ratings, Inc.

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, sold on September 2, 2025

Fortis Belize: Fortis Belize Limited, an indirect wholly-owned subsidiary of Fortis, sold on October 31, 2025

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

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

kV: kilovolt(s)

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, 2025

MISO: Midcontinent Independent System Operator, 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

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

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.

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, 2025 and 2024

Consolidated Financial Statements

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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, 2025, 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, 2025, the Corporation's ICFR was effective.

The Corporation's ICFR as of December 31, 2025 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, 2025. Deloitte LLP issued an unqualified opinion for both audits.

February 11, 2026

/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, 2025 and 2024, 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, 2025, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the results of operations of the Corporation as of December 31, 2025 and 2024, and its financial performance and its cash flows for each of the two years in the period ended December 31, 2025, 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, 2025, 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 11, 2026, 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 Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the 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 matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

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 11, 2026

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, 2025, 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, 2025, 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, 2025, of the Corporation and our report dated February 11, 2026, 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 11, 2026

CONSOLIDATED BALANCE SHEETS

FORTIS INC.

As at December 31 (in millions of Canadian dollars)	**2025**	2024
ASSETS		
Current assets		
Cash and cash equivalents	**$ 367**	$ 220
Accounts receivable and other current assets (Note 6)	**1,695**	1,886
Prepaid expenses	**179**	182
Inventories (Note 7)	**649**	685
Regulatory assets (Note 8)	**915**	823
Total current assets	**3,805**	3,796
Other assets (Note 9)	**1,782**	1,653
Regulatory assets (Note 8)	**4,107**	3,808
Property, plant and equipment, net (Note 10)	**50,886**	49,456
Intangible assets, net (Note 11)	**1,723**	1,661
Goodwill (Note 12)	**12,527**	13,112
Total assets	**$ 74,830**	$ 73,486
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings (Note 14)	**$ 412**	$ 98
Accounts payable and other current liabilities (Note 13)	**3,503**	3,353
Regulatory liabilities (Note 8)	**452**	595
Current installments of long-term debt (Note 14)	**3,146**	1,990
Total current liabilities	**7,513**	6,036
Regulatory liabilities (Note 8)	**3,810**	3,696
Deferred income taxes (Note 23)	**5,292**	5,020
Long-term debt (Note 14)	**30,723**	31,224
Finance leases (Note 15)	**348**	343
Other liabilities (Note 16)	**1,275**	1,314
Total liabilities	**48,961**	47,633
Commitments and contingencies (Note 27)		
Equity		
Common shares [(1)]	**16,112**	15,589
Preference shares (Note 18)	**1,623**	1,623
Additional paid-in capital	**5**	8
Accumulated other comprehensive income (Note 19)	**1,101**	2,067
Retained earnings	**4,969**	4,521
Shareholders' equity	**23,810**	23,808
Non-controlling interests	**2,059**	2,045
Total equity	**25,869**	25,853
Total liabilities and equity	**$ 74,830**	$ 73,486

[(1)] No par value. Unlimited authorized shares. 507.3 million and 499.3 million issued and outstanding as at December 31, 2025 and 2024, respectively

Approved on Behalf of the Board

/s/ Jo Mark Zurel	/s/ Margarita K. Dilley
Jo Mark Zurel,	**Margarita K. Dilley**
Director	**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)	**2025**	2024
Revenue (Note 5)	**$ 12,170**	$ 11,508
Expenses		
Energy supply costs	**3,371**	3,249
Operating expenses	**3,250**	3,040
Depreciation and amortization	**2,057**	1,927
Total expenses	**8,678**	8,216
Operating income	**3,492**	3,292
Other income, net (Note 22)	**340**	288
Finance charges	**1,478**	1,406
Earnings before income tax expense	**2,354**	2,174
Income tax expense (Note 23)	**393**	346
Net earnings	**$ 1,961**	$ 1,828
Net earnings attributable to:		
Non-controlling interests	**$ 162**	$ 148
Preference equity shareholders (Note 18)	**85**	74
Common equity shareholders	**1,714**	1,606
	$ 1,961	$ 1,828
Earnings per common share (Note 17)		
Basic	**$ 3.40**	$ 3.24
Diluted	**$ 3.40**	$ 3.24

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

For the years ended December 31 (in millions of Canadian dollars)	**2025**	2024
Net earnings	**$ 1,961**	$ 1,828
Other comprehensive (loss) income		
Unrealized foreign currency translation (losses) gains, net of hedging activities and income tax (expense) recovery of $(7) million and $14 million, respectively	**(950)**	1,561
Other, net of income tax recovery (expense) of $9 million and $(3) million, respectively	**(26)**	9
	(976)	1,570
Derecognition of foreign currency translation amount on dispositions (Note 19)	**(86)**	—
	(1,062)	1,570
Comprehensive income	**$ 899**	$ 3,398
Comprehensive income attributable to:		
Non-controlling interests	**$ 66**	$ 304
Preference equity shareholders	**85**	74
Common equity shareholders	**748**	3,020
	$ 899	$ 3,398

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)	**2025**	2024
Operating activities		
Net earnings	**$ 1,961**	$ 1,828
Adjustments to reconcile net earnings to net cash provided by operating activities:		
Depreciation - property, plant and equipment	**1,810**	1,695
Amortization - intangible assets	**160**	153
Amortization - other	**87**	79
Deferred income tax expense (Note 23)	**252**	154
Equity component, allowance for funds used during construction (Note 22)	**(174)**	(139)
Sale of investment tax credits	**63**	—
Other	**106**	43
Change in long-term regulatory assets and liabilities	**(85)**	(99)
Change in working capital (Note 25)	**(118)**	168
Cash from operating activities	**4,062**	3,882
Investing activities		
Additions to property, plant and equipment	**(5,942)**	(5,012)
Additions to intangible assets	**(292)**	(206)
Contributions in aid of construction	**775**	106
Proceeds on dispositions, net (Note 21)	**479**	—
Contributions to equity-accounted investees	**(27)**	—
Other	**(350)**	(283)
Cash used in investing activities	**(5,357)**	(5,395)
Financing activities		
Proceeds from long-term debt, net of issuance costs (Note 14)	**2,687**	3,124
Repayments of long-term debt and finance leases	**(108)**	(1,718)
Borrowings under committed credit facilities	**10,405**	8,618
Repayments under committed credit facilities	**(11,056)**	(8,055)
Net change in short-term borrowings	**385**	(25)
Issue of common shares, net of costs and dividends reinvested	**60**	46
Dividends		
Common shares, net of dividends reinvested	**(788)**	(744)
Preference shares	**(85)**	(74)
Subsidiary dividends paid to non-controlling interests	**(54)**	(110)
Other	**15**	2
Cash from financing activities	**1,461**	1,064
Effect of exchange rate changes on cash and cash equivalents	**(19)**	44
Change in cash and cash equivalents	**147**	(405)
Cash and cash equivalents, beginning of year	**220**	625
Cash and cash equivalents, end of year	**$ 367**	$ 220

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, 2024	**499.3**	**$ 15,589**	**$ 1,623**	**$ 8**	**$ 2,067**	**$ 4,521**	**$ 2,045**	**$ 25,853**
Net earnings	**—**	**—**	**—**	**—**	**—**	**1,799**	**162**	**1,961**
Other comprehensive loss	**—**	**—**	**—**	**—**	**(880)**	**—**	**(96)**	**(976)**
Derecognition of foreign currency translation amount on dispositions	**—**	**—**	**—**	**—**	**(86)**	**—**	**—**	**(86)**
Common shares issued	**8.0**	**523**	**—**	**(2)**	**—**	**—**	**—**	**521**
Subsidiary dividends paid to non-controlling interests	**—**	**—**	**—**	**—**	**—**	**—**	**(54)**	**(54)**
Dividends declared on common shares ($2.51 per share)	**—**	**—**	**—**	**—**	**—**	**(1,266)**	**—**	**(1,266)**
Dividends on preference shares	**—**	**—**	**—**	**—**	**—**	**(85)**	**—**	**(85)**
Other	**—**	**—**	**—**	**(1)**	**—**	**—**	**2**	**1**
As at December 31, 2025	**507.3**	**$ 16,112**	**$ 1,623**	**$ 5**	**$ 1,101**	**$ 4,969**	**$ 2,059**	**$ 25,869**
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 to 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

See accompanying Notes to Consolidated Financial Statements

1. DESCRIPTION OF BUSINESS

Fortis Inc. ("Fortis" or the "Corporation") is a 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 3,443 megawatts ("MW"), including 69 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"); and an approximate 60% controlling interest in Caribbean Utilities Company, Ltd. ("Caribbean Utilities"). Also includes FortisTCI Limited and Turks and Caicos Utilities Limited (collectively, "FortisTCI") until the September 2, 2025 date of disposition and the 33% equity investment in Belize Electricity Limited ("Belize Electricity") until the October 31, 2025 date of disposition (Note 21).

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 connects 17 remote First Nations to the Ontario power grid. Caribbean Utilities is an integrated regulated electric utility and the sole electricity distributor on Grand Cayman with a diesel-powered generating capacity of 166 MW.

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 until the October 31, 2025 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**	(%)	**2025**		**2024**	**Significant Features**
ITC	Federal Energy Regulatory Commission ("FERC")	60.0	**10.73**	[2]	10.73	Cost-based formula rates, with annual true-up mechanism [3] Incentive adders
TEP	Arizona Corporation Commission ("ACC")	54.3	**9.55**	[4]	9.55	COS regulation Historical test year
	FERC	[5]	**9.79**		9.79	Formula transmission rates
UNS Electric	ACC	53.7	**9.75**		9.75	
UNS Gas	ACC	50.8	**9.75**	[4]	9.75	
Central Hudson	New York State Public Service Commission ("PSC")	48.0	**9.50**	[6]	9.50	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	**8.97**		9.28	PBR, with formula to calculate ROE on an annual basis [7]
Newfoundland Power	Newfoundland and Labrador Board of Commissioners of Public Utilities	45.0	**8.60**		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 [8]	Ontario Energy Board	40.0	**8.66-9.30**		8.52-9.30	COS regulation with incentive mechanisms
Caribbean Utilities [9]	Utility Regulation and Competition Office	N/A	**8.50-10.50**		8.25-10.25	COS regulation Rate-cap adjustment mechanism

(1) ROA for Caribbean Utilities
(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%
(3) Annual true-up collected or refunded in rates within a two-year period
(4) A general rate application is ongoing. See "Significant Regulatory Matters" below
(5) The allowed common equity component for FERC transmission rates is formulaic, and is updated annually based on TEP's actual equity ratio
(6) The PSC approved a three-year rate plan effective July 1, 2025, with the continuation of a 9.5% allowed ROE and 48% common equity component
(7) The ROE for 2026 has been set at 9.02%
(8) 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
(9) 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

2. REGULATION (cont'd)

Significant Regulatory Matters

ITC

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 are unknown.

UNS Energy

TEP General Rate Application: In June 2025, TEP filed a general rate application with the ACC requesting new rates effective September 1, 2026 using a December 31, 2024 test year, with post-test year adjustments through June 30, 2025. The application includes a proposal to phase-out or eliminate certain adjustor mechanisms, and requests an annual formulaic rate adjustment mechanism consistent with the ACC's approval of a formula rate policy statement in 2024.

The Residential Utility Consumer Office has challenged the ACC's authority to implement a formula rate framework through a policy statement, and in November 2025, the Arizona Court of Appeals ruled that the Residential Utility Consumer Office may proceed with its challenge. The timing and outcome of these regulatory and legal proceedings are unknown.

UNS Gas General Rate Application: In January 2026, an ACC Administrative Law Judge issued a Recommended Opinion and Order recommending an allowed ROE of 9.57% and a 56% common equity component of capital structure. The order also recommended an annual formulaic rate adjustment mechanism including a range of +/- 40 basis points around the allowed return, a 5% efficiency credit to incremental revenue requirement, and the exclusion of post-test year adjustments. Should the annual formulaic mechanism not be approved, the order recommended the use of adjustor mechanisms for the timely recovery of infrastructure investments and income tax changes. The Recommended Opinion and Order proposes implementation of new rates by March 1, 2026. The rate application remains subject to ACC approval which is anticipated in February 2026.

FortisAlberta

Third PBR Term Decision: In 2023, the AUC issued a decision establishing the parameters for the third PBR term for the period of 2024 through 2028. FortisAlberta sought permission to appeal the decision to the Court of Appeal of Alberta ("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. In March 2025, the Court of Appeal granted FortisAlberta permission to appeal, which was heard in January 2026. A decision is expected in the third quarter of 2026.

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.

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

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 regulatory assets do not earn a return as they do not represent a past cash outlay and are offset by related liabilities that, likewise, do not incur a carrying cost for rate-making purposes. These regulatory assets are primarily related to deferred income taxes and employee future benefits.

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.

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 2025 totalled $96 million (2024 - $74 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, these companies 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 2025 (2024 - 0.5% to 33.0%). The weighted average composite rate of depreciation, before reduction for amortization of contributions in aid of construction, was 2.7% for 2025 (2024 – 2.7%).

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

	2025		2024	
(years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Distribution				
Electric	**7-80**	**32**	5-80	32
Gas	**18-83**	**40**	18-83	37
Transmission				
Electric	**20-85**	**42**	20-85	42
Gas	**10-80**	**34**	10-80	35
Generation	**6-95**	**22**	2-95	22
Other	**3-80**	**13**	3-80	13

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

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 2025 (2024 – 1.0% to 33.0%).

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

	2025		2024	
(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	**10-85**	**55**	30-85	52
Other	**10-100**	**19**	10-100	16

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 more likely than not that fair value is less than carrying value, then a quantitative assessment is performed. Under the quantitative test, 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, is also performed and includes the comparison of each reporting unit's estimated fair value multiple to those of comparable utilities.

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.

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

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.

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.

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, 2025 was US$1.00=CA$1.37 (2024 – US$1.00=CA$1.44).

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$1.40 for 2025 (2024 - US$1.00=CA$1.37).

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. 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 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 is not subject to income tax.

Differences between the income tax expense or recovery recognized under U.S. GAAP and that 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)

Fortis does not recognize deferred income taxes on temporary differences related to investments in foreign subsidiaries where it intends to indefinitely reinvest earnings. 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

Income Taxes: The Corporation adopted Accounting Standard Update ("ASU") No. 2023-09, *Improvements to Income Tax Disclosures*, effective January 1, 2025. This update 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. The ASU has been applied retrospectively and the updated disclosure is included in Notes 23 and 25.

Future Accounting Pronouncements

The Corporation considers the applicability and impact of all 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.

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.

Internal-Use Software: ASU No. 2025-06, *Targeted Improvements to the Accounting for Internal-Use Software*, is effective for Fortis on January 1, 2028. The ASU may be adopted prospectively, retrospectively, or using a modified transition approach, and early adoption is permitted. The ASU removes references to development stages and requires capitalization of software costs once funding is authorized and project completion is probable, including assessment of whether significant development uncertainty exists. The guidance also clarifies that all capitalized internal-use software costs must follow the disclosure requirements in Subtopic 360-10, *Property, Plant and Equipment*. Fortis is assessing the impact on its consolidated financial statements and 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 2025 or 2024. 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, 2025 and 2024, there were no inter-segment loans outstanding. Interest charged on inter-segment loans was not material in 2025 and 2024.

	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, 2025											
Revenue	2,495	2,913	1,620	1,874	829	557	1,851	**12,139**	**31**	**—**	**12,170**
Energy supply costs	—	1,064	507	548	—	165	1,087	**3,371**	**—**	**—**	**3,371**
Operating expenses	628	824	688	450	199	147	253	**3,189**	**61**	**—**	**3,250**
Depreciation and amortization	487	427	158	367	300	83	228	**2,050**	**7**	**—**	**2,057**
Operating income	1,380	598	267	509	330	162	283	**3,529**	**(37)**	**—**	**3,492**
Other income, net	79	73	72	54	8	5	26	**317**	**23**	**—**	**340**
Finance charges	515	167	94	152	135	81	89	**1,233**	**245**	**—**	**1,478**
Income tax expense	218	67	54	74	21	11	26	**471**	**(78)**	**—**	**393**
Net earnings	726	437	191	337	182	75	194	**2,142**	**(181)**	**—**	**1,961**
Non-controlling interests	134	—	—	1	—	—	27	**162**	**—**	**—**	**162**
Preference share dividends	—	—	—	—	—	—	—	**—**	**85**	**—**	**85**
Net earnings attributable to common equity shareholders	592	437	191	336	182	75	167	**1,980**	**(266)**	**—**	**1,714**
Additions to property, plant and equipment and intangible assets	1,840	1,365	481	1,270	598	186	491	**6,231**	**3**	**—**	**6,234**
As at December 31, 2025											
Goodwill	8,423	1,896	619	913	231	235	210	**12,527**	**—**	**—**	**12,527**
Total assets	27,474	15,006	6,463	10,842	6,508	2,960	5,247	**74,500**	**341**	**(11)**	**74,830**
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

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)	**2025**	2024
Electric and gas revenue		
United States		
ITC	**2,470**	2,205
UNS Energy	**2,646**	2,731
Central Hudson	**1,588**	1,366
Canada		
FortisBC Energy	**1,766**	1,538
FortisAlberta	**793**	770
FortisBC Electric	**504**	481
Newfoundland Power	**795**	770
Maritime Electric	**296**	277
FortisOntario	**245**	235
Caribbean		
Caribbean Utilities	**396**	402
FortisTCI (Note 21)	**85**	118
Total electric and gas revenue	**11,584**	10,893
Other services revenue	**316**	350
Revenue from contracts with customers	**11,900**	11,243
Alternative revenue	**151**	169
Other revenue	**119**	96
Total revenue	**12,170**	11,508

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.

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)	2025	2024
Trade accounts receivable	813	1,009
Unbilled accounts receivable	760	738
Allowance for credit losses	(80)	(78)
	1,493	1,669
Other [(1)]	202	217
	1,695	1,886

[(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)*

Central Hudson has established deferred payment agreements with certain customers for the collection of trade accounts receivable. The non-current portion of these agreements has been reflected in other assets (Note 9).

Allowance for Credit Losses

The allowance for credit losses changed as follows.

($ millions)	2025	2024
Balance, beginning of year	(78)	(68)
Credit loss expensed	(38)	(30)
Credit loss deferral	(44)	(31)
Write-offs, net of recoveries	72	55
Dispositions (Note 21)	6	—
Foreign exchange	2	(4)
Balance, end of year	(80)	(78)

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

7. INVENTORIES

($ millions)	2025	2024
Materials and supplies	516	548
Gas and fuel in storage	58	65
Coal inventory	75	72
	649	685

8. REGULATORY ASSETS AND LIABILITIES

($ millions)	2025	2024
Regulatory assets		
Deferred income taxes (Note 3)	2,424	2,248
Deferred energy management costs [(1)]	701	591
Rate stabilization and related accounts [(2)]	552	453
Employee future benefits (Notes 3 and 24)	192	235
Deferred lease costs [(3)]	145	142
Derivatives (Notes 3 and 26)	135	175
Deferred restoration costs [(4)]	109	133
Manufactured gas plant site remediation deferral (Note 16)	84	82
Business development deposit tax [(5)]	58	18
Generation early retirement costs [(6)]	49	66
Meter cost recovery [(7)]	37	—
Renewable natural gas account [(8)]	28	58
Other regulatory assets [(9)]	508	430
Total regulatory assets	5,022	4,631
Less: Current portion	(915)	(823)
Long-term regulatory assets	4,107	3,808

8. REGULATORY ASSETS AND LIABILITIES (cont'd)

($ millions)	**2025**	2024
Regulatory liabilities		
Future cost of removal (Note 3)	**1,853**	1,728
Deferred income taxes (Note 3)	**1,349**	1,329
Employee future benefits (Notes 3 and 24)	**467**	459
Rate stabilization and related accounts [(2)]	**183**	208
Renewable energy surcharge [(10)]	**164**	155
Energy efficiency liability [(11)]	**68**	88
Electric and gas moderator account [(12)]	**36**	61
AESO charges deferral [(13)]	**5**	58
Other regulatory liabilities [(9)]	**137**	205
Total regulatory liabilities	**4,262**	4,291
Less: Current portion	**(452)**	(595)
Long-term regulatory liabilities	**3,810**	3,696

[(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)] ***Business Development Deposit Tax:*** Relates to the recognition of temporary tax impacts associated with deposits received from Woodfibre LNG related to future capital expenditures for the Eagle Mountain Pipeline project. As capital expenditures related to the deposits are incurred, the corresponding deferred tax amounts will reverse.

[(6)] ***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.

[(7)] ***Meter Cost Recovery:*** The meter cost recovery deferral primarily captures the net book value of FortisBC Energy's meters that have been removed from service as they are replaced by advanced metering infrastructure meters. The balance is to be recovered from customers over five years.

[(8)] ***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.

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

[(10)] ***Renewable Energy Surcharge:*** Under the ACC's Renewable Energy Standard ("RES"), UNS Energy was required to increase its use of renewable energy each year until it represented at least 15% of its total annual retail energy requirements. 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.

[(11)] ***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.

[(12)] ***Electric and Gas Moderator Account:*** As part of past general rate applications at Central Hudson, 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.

[(13)] ***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.

9. OTHER ASSETS

($ millions)	**2025**	2024
Employee future benefits (Note 24)	**648**	551
Other investments	**246**	225
Equity investments [(1)]	**215**	259
RECs (Note 8)	**169**	176
Supplemental Executive Retirement Plan ("SERP")	**123**	127
Deferred payment agreements (Note 6)	**80**	—
Operating leases (Note 15)	**60**	64
Derivatives	**32**	48
Deferred compensation plan	**29**	29
Other	**180**	174
	1,782	1,653

(1) *Includes investments in Belize Electricity until the October 31, 2025 date of disposition 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**
2025			
Distribution			
Electric	**16,283**	**(4,233)**	**12,050**
Gas	**7,481**	**(1,910)**	**5,571**
Transmission			
Electric	**23,849**	**(5,016)**	**18,833**
Gas	**3,057**	**(939)**	**2,118**
Generation	**7,450**	**(2,955)**	**4,495**
Other	**5,198**	**(1,730)**	**3,468**
Assets under construction	**3,886**	**—**	**3,886**
Land	**465**	**—**	**465**
	67,669	**(16,783)**	**50,886**
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

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, 2025, assets under construction largely reflect ongoing transmission projects at ITC and UNS Energy, the second Roadrunner Reserve battery storage project at UNS Energy and the Eagle Mountain Pipeline project at FortisBC Energy.

The cost of PPE under finance lease as at December 31, 2025 was $333 million (2024 - $324 million) and related accumulated depreciation was $125 million (2024 - $119 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, 2025, interests in jointly owned facilities consisted of the following.

($ millions, except as indicated)	**Ownership** *(%)*	**Cost**	**Accumulated Depreciation**	**Net Book Value**
Transmission Facilities	Various	**1,743**	**(493)**	**1,250**
Springerville Common Facilities	86.0	**560**	**(342)**	**218**
Springerville Coal Handling Facilities	83.0	**285**	**(150)**	**135**
Four Corners Units 4 and 5 ("Four Corners")	7.0	**295**	**(156)**	**139**
Gila River Common Facilities	50.0	**139**	**(52)**	**87**
Luna Energy Facility ("Luna")	33.3	**100**	**8**	**108**
		3,122	**(1,185)**	**1,937**

11. INTANGIBLE ASSETS

($ millions)	**Cost**	**Accumulated Amortization**	**Net Book Value**
2025			
Computer software	**1,019**	**(417)**	**602**
Land, transmission and water rights	**1,170**	**(215)**	**955**
Other	**143**	**(90)**	**53**
Assets under construction	**113**	**—**	**113**
	2,445	**(722)**	**1,723**
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

Included in the cost of land, transmission and water rights as at December 31, 2025 was $124 million (2024 - $123 million) not subject to amortization. Amortization expense was $160 million for 2025 (2024 - $153 million). Amortization is estimated to average approximately $111 million for each of the next five years.

12. GOODWILL

($ millions)	**2025**	2024
Balance, beginning of year	**13,112**	12,184
Disposition of FortisTCI (Note 21)	**(50)**	—
Foreign currency translation impacts [(1)]	**(535)**	928
Balance, end of year	**12,527**	13,112

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

No goodwill impairment was recognized by the Corporation in 2025 or 2024.

13. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

($ millions)	**2025**	2024
Trade accounts payable	**1,148**	1,121
Customer and other deposits	**516**	360
Employee compensation and benefits payable	**364**	303
Dividends payable	**332**	314
Interest payable	**319**	305
Accrued taxes other than income taxes	**245**	304
Gas and fuel cost payable	**215**	221
Derivatives (Note 26)	**127**	169
Employee future benefits (Note 24)	**28**	29
Income tax payable	**24**	33
Other	**185**	194
	3,503	3,353

14. LONG-TERM DEBT

($ millions)	Maturity Date	**2025**	2024
ITC			
Secured U.S. First Mortgage Bonds -			
4.34% weighted average fixed rate (2024 - 4.34%)	2027-2055	**3,763**	3,944
Secured U.S. Senior Notes -			
4.16% weighted average fixed rate (2024 - 4.16%)	2028-2055	**1,441**	1,511
Unsecured U.S. Senior Notes -			
4.44% weighted average fixed rate (2024 - 4.37%)	2026-2043	**5,353**	5,610
Unsecured U.S. Shareholder Note -			
6.00% fixed rate (2024 - 6.00%)	2028	**273**	286
UNS Energy			
Unsecured U.S. Fixed Rate Notes -			
4.28% weighted average fixed rate (2024 - 4.09%)	2026-2055	**4,460**	4,172
Central Hudson			
Unsecured U.S. Promissory Notes - 4.54% weighted			
average fixed and variable rate (2024 - 4.38%)	2026-2060	**2,058**	1,974
FortisBC Energy			
Unsecured Debentures -			
4.54% weighted average fixed rate (2024 - 4.61%)	2026-2052	**3,495**	3,295
FortisAlberta			
Unsecured Debentures -			
4.64% weighted average fixed rate (2024 - 4.63%)	2034-2055	**3,035**	2,835
FortisBC Electric			
Unsecured Debentures -			
4.72% weighted average fixed rate (2024 - 4.72%)	2035-2054	**960**	960
Other Electric			
Secured First Mortgage Sinking Fund Bonds -			
5.19% weighted average fixed rate (2024 - 5.24%)	2026-2060	**850**	739
Secured First Mortgage Bonds -			
5.11% weighted average fixed rate (2024 - 5.29%)	2027-2061	**425**	320
Unsecured Senior Notes -			
4.61% weighted average fixed rate (2024 - 4.61%)	2041-2054	**207**	207
Unsecured U.S. Senior Loan Notes and Bonds -			
4.92% weighted average fixed and variable rate (2024 - 5.03%)	2028-2052	**521**	876
Corporate and Other			
Unsecured U.S. Senior Notes and Promissory Notes -			
3.79% weighted average fixed rate (2024 - 3.79%)	2026-2044	**2,073**	2,172
Unsecured Debentures -			
6.51% fixed rate (2024 - 6.51%)	2039	**200**	200
Unsecured Senior Notes -			
4.11% weighted average fixed rate (2024 - 4.11%)	2028-2033	**2,600**	2,000
Subordinated Notes - 5.10% fixed rate	2055	**750**	—
Long-term classification of credit facility borrowings		**1,515**	2,216
Fair value adjustment - ITC acquisition		**78**	88
Total long-term debt (Note 26)		**34,057**	33,405
Less: Deferred financing costs and debt discounts		**(188)**	(191)
Less: Current installments of long-term debt		**(3,146)**	(1,990)
		30,723	31,224

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 2025	**Month Issued**	**Interest Rate** *(%)*	**Maturity**	**Amount** *($ millions)*	**Use of Proceeds**
UNS Energy					
Unsecured senior notes	February	5.90	2055	**US $300**	(1) (2) 3)
Unsecured senior notes	October	5.38	2035	**US $50**	(1) (3)
Central Hudson					
Unsecured senior notes	April	(4)	(4)	**US $70**	(1) (3)
Unsecured senior notes	November	(5)	(5)	**US $80**	(3)
FortisBC Energy					
Unsecured debentures	October	3.38	2030	**200**	(1)
FortisAlberta					
Unsecured senior debentures	July	4.76	2055	**200**	(1) (2) (3)
Newfoundland Power					
First mortgage bonds	August	4.91	2055	**120**	(1) (2) (3)
Maritime Electric					
First mortgage bonds	July	4.94	2055	**120**	(1) (2)
Fortis					
Unsecured senior notes	March	4.09	2032	**600**	(1) (3)
Unsecured subordinated notes	September	5.10	2055	**750**	(1) (3)

(1) Repay credit facility borrowings
(2) Fund capital expenditures
(3) General corporate purposes
(4) Comprised of US$20 million at 5.61% due in 2035, US$30 million at 5.81% due in 2040 and US$20 million at 6.01% due in 2045
(5) Comprised of US$15 million at 5.25% due in 2035 and US$65 million at 5.90% due in 2045

As shown in the table above, Fortis issued fixed-to-fixed rate unsecured hybrid subordinated notes in 2025. The interest rate will be reset on December 4, 2030, and every five years thereafter, equal to the then five-year Government of Canada bond yield plus 2.09% provided that the interest rate will not be below the initial interest rate of 5.10%. The subordinated notes receive 50% equity treatment from credit rating agencies.

In January 2026, ITC issued US$250 million of secured senior notes consisting of US$125 million 10-year, 5.08% notes and US$125 million 20-year, 5.71% notes. Proceeds were used to repay credit facility borrowings, fund capital expenditures and for general corporate purposes.

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**
2026	3,146
2027	2,389
2028	1,880
2029	943
2030	1,714
Thereafter	23,985
	34,057

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, 2025, $500 million remained available under the ATM Program and $1.5 billion remained available under the short-form base shelf prospectus.

14. LONG-TERM DEBT (cont'd)

Credit Facilities

($ millions)	Regulated Utilities	Corporate and Other	2025	2024
Total credit facilities	4,196	1,577	**5,773**	6,342
Credit facilities utilized:				
Short-term borrowings [(1)]	(412)	—	**(412)**	(98)
Long-term debt (including current portion) [(2)]	(1,515)	—	**(1,515)**	(2,216)
Letters of credit outstanding	(83)	(22)	**(105)**	(102)
Credit facilities unutilized	2,186	1,555	**3,741**	3,926

(1) The weighted average interest rate was approximately 4.2% (2024 - 6.1%).
(2) The weighted average interest rate was approximately 3.8% (2024 - 4.6%). The current portion was $707 million (2024 - $1,860 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 $5.4 billion of the total credit facilities are committed with maturities ranging from 2027 through 2030.

In April 2025, FortisAlberta increased its operating credit facility from $250 million to $300 million and extended the maturity to April 2030.

In May 2025, the Corporation amended its $1.3 billion revolving term committed credit facility to extend the maturity to July 2030.

In September 2025, FortisUS Inc., a holding company subsidiary of Fortis, extended the maturity on its unsecured US$150 million revolving term credit facility to October 2027. Also in September 2025, the Corporation fully repaid its unsecured US$250 million non-revolving term credit facility.

Consolidated credit facilities of approximately $5.8 billion as at December 31, 2025 are itemized below.

($ millions)		Amount	Maturity
Unsecured committed revolving credit facilities			
Regulated utilities			
ITC [(1)]	**US**	**1,000**	2028
UNS Energy	**US**	**375**	2028
Central Hudson	**US**	**250**	2029
FortisBC Energy		**900**	2030
FortisAlberta		**300**	2030
FortisBC Electric		**200**	2030
Other Electric		**285**	[(2)]
Other Electric	**US**	**83**	2030
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**	2026
FortisBC Electric - unsecured demand overdraft facility		**10**	n/a
Other Electric - unsecured demand facilities		**20**	n/a
Corporate and Other			
Unsecured revolving facility	**US**	**150**	2027
Unsecured non-revolving facility		**22**	n/a

(1) ITC also has a US$400 million commercial paper program, under which US$237 million was outstanding as at December 31, 2025 (2024 - $nil)
(2) $90 million in 2027, $65 million in 2028, and $130 million in 2030
(3) $50 million in 2027 and $1.3 billion in 2030

15. LEASES

The Corporation and its subsidiaries lease office facilities, utility equipment, land, and communication tower space with remaining terms of up to 25 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 30 years.

Leases were presented on the consolidated balance sheets as follows.

($ millions)	**2025**	2024
Operating leases		
Other assets	**60**	64
Accounts payable and other current liabilities	**(16)**	(17)
Other liabilities	**(44)**	(47)
Finance leases [(1)]		
Regulatory assets	**145**	142
PPE, net	**208**	205
Accounts payable and other current liabilities	**(5)**	(4)
Finance leases	**(348)**	(343)

[(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.

The components of lease expense were as follows.

($ millions)	**2025**	2024
Operating lease cost	**20**	19
Finance lease cost:		
Amortization	**3**	2
Interest	**34**	33
Variable lease cost	**25**	21
Total lease cost	**82**	75

As at December 31, 2025, the present value of minimum lease payments was as follows.

($ millions)	Operating Leases	Finance Leases	**Total**
2026	19	38	**57**
2027	13	37	**50**
2028	7	38	**45**
2029	6	38	**44**
2030	5	38	**43**
Thereafter	21	936	**957**
	71	1,125	**1,196**
Less: Imputed interest	(11)	(772)	**(783)**
Total lease obligations	60	353	**413**
Less: Current installments	(16)	(5)	**(21)**
	44	348	**392**

15. LEASES (cont'd)

Supplemental lease information follows.

($ millions, except as indicated)	**2025**	2024
Weighted average remaining lease term *(years)*		
Operating leases	**7**	7
Finance leases	**30**	31
Weighted average discount rate *(%)*		
Operating leases	**4.8**	4.6
Finance leases	**5.1**	5.0

16. OTHER LIABILITIES

($ millions)	**2025**	2024
Employee future benefits (Note 24)	**429**	446
AROs (Note 3)	**260**	249
Stock-based compensation plans (Note 20)	**145**	113
Customer and other deposits	**118**	128
Manufactured gas plant site remediation [(1)]	**98**	101
Deferred compensation plan (Note 9)	**67**	63
Operating leases (Note 15)	**44**	47
Derivatives (Note 26)	**31**	66
Mine reclamation obligations [(2)]	**25**	40
Retail energy contract [(3)]	**14**	20
Other	**44**	41
	1,275	1,314

[(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.

[(3)] FortisAlberta has an agreement with a retail energy provider to act as its default retailer to eligible customers. 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.

	2025			2024		
	Net Earnings to Common Shareholders *($ millions)*	**Weighted Average Shares** *(# millions)*	**EPS** *($)*	Net Earnings to Common Shareholders *($ millions)*	Weighted Average Shares *(# millions)*	EPS *($)*
Basic EPS	**1,714**	**503.5**	**3.40**	1,606	495.0	3.24
Potential dilutive effect of stock-based compensation	**—**	**0.2**	**—**	—	0.2	—
Diluted EPS	**1,714**	**503.7**	**3.40**	1,606	495.2	3.24

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	2025 Number of Shares (thousands)	2025 Amount ($ millions)	2024 Number of Shares (thousands)	2024 Amount ($ millions)
Series F	**5,000**	**122**	5,000	122
Series G	**9,200**	**225**	9,200	225
Series H	**7,903**	**194**	7,665	188
Series I	**2,097**	**51**	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

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	4.18	1.0458	1.45	June 1, 2030	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, 2030	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
2025			
Unrealized foreign currency translation gains (losses)			
Net investments in foreign operations	**2,712**	**(990)**	**1,722**
Hedges of net investments in foreign operations	**(714)**	**54** (1)	**(660)**
Income tax recovery (expense)	**18**	**(7)**	**11**
	2,016	**(943)**	**1,073**
Other			
Interest rate hedges (Note 26)	**72**	**(37)**	**35**
Unrealized employee future benefits (losses) gains (Note 24)	**(7)**	**5**	**(2)**
Income tax (expense) recovery	**(14)**	**9**	**(5)**
	51	**(23)**	**28**
Accumulated other comprehensive income	**2,067**	**(966)**	**1,101**
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

(1) *Includes the derecognition of $86 million in foreign currency translation gains associated with dispositions in 2025 (Note 21)*

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, 2025, the Corporation had 0.9 million stock options outstanding (2024 - 1.5 million) with a weighted average exercise price of $50.96 (2024 - $48.96). All stock options were vested as of December 31, 2025 (2024 – 1.4 million vested).

In 2025, 0.6 million stock options were exercised (2024 - 0.4 million) for cash proceeds of $28 million (2024 - $15 million) and an intrinsic value realized by option holders of $13 million (2024 - $5 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.

	2025	2024
Number of units *(thousands)*		
Beginning of year	**241**	241
Granted	**20**	29
Notional dividends reinvested	**9**	10
Paid out	**(7)**	(39)
End of year	**263**	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 2025 or 2024.

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) a carbon reduction or climate-related performance measure.

The following table summarizes information related to PSUs.

	2025	2024
Number of units *(thousands)*		
Beginning of year	**2,171**	1,942
Granted	**811**	788
Notional dividends reinvested	**74**	78
Paid out	**(641)**	(609)
Cancelled/forfeited	**(35)**	(28)
End of year	**2,380**	2,171
Additional information *($ millions)*		
Compensation expense recognized	**109**	53
Compensation expense unrecognized (1)	**43**	34
Cash payout	**39**	44
Accrued liability as at December 31 (2)	**177**	105
Aggregate intrinsic value as at December 31 (3)	**220**	139

(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. Effective with the 2024 grant, RSUs granted under the Corporation's Omnibus Equity Plan can be settled through common shares of the Corporation. RSUs settled through common shares will be satisfied by issuing common shares from treasury.

The following table summarizes information related to RSUs.

	2025	2024
Number of units *(thousands)*		
Beginning of year	**1,201**	1,079
Granted	**463**	464
Notional dividends reinvested	**39**	38
Paid out	**(315)**	(357)
Cancelled/forfeited	**(30)**	(23)
End of year	**1,358**	1,201
Additional information *($ millions)*		
Compensation expense recognized	**41**	29
Compensation expense unrecognized [(1)]	**24**	21
Cash payout	**19**	19
Accrued liability as at December 31 [(2)]	**73**	54
Aggregate intrinsic value as at December 31 [(3)]	**97**	75

(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 2025 and 2024.

21. DISPOSITIONS

On September 2, 2025, Fortis sold its 100% ownership interest in FortisTCI. As s result of the sale, Fortis recognized a $32 million loss related to income taxes and closing costs, which has been reflected in the Corporate and Other segment.

On October 31, 2025, Fortis sold its 100% ownership in Fortis Belize and its 33% ownership in Belize Electricity. Fortis recognized a loss on sale of $31 million, which has been reflected in the Corporate and Other segment.

22. OTHER INCOME, NET

($ millions)	**2025**	2024
Equity component of AFUDC	**174**	139
Non-service component of net periodic benefit cost	**80**	73
Gain on derivatives, net	**46**	1
Interest income [(1)]	**43**	64
Equity income	**15**	14
Net foreign exchange gain (loss)	**13**	(10)
Pre-tax loss on dispositions (Note 21)	**(32)**	—
Other	**1**	7
	340	288

(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

($ millions)	**2025**	2024
Gross deferred income tax assets		
Regulatory liabilities	**701**	659
Tax loss and credit carryforwards	**677**	629
Employee future benefits	**111**	123
Other	**185**	216
	1,674	1,627
Valuation allowance	**(25)**	(50)
Net deferred income tax asset	**1,649**	1,577
Gross deferred income tax liabilities		
PPE	**(6,208)**	(5,993)
Regulatory assets	**(556)**	(432)
Intangible assets	**(177)**	(172)
	(6,941)	(6,597)
Net deferred income tax liability	**(5,292)**	(5,020)

Income Tax Expense

($ millions)	**2025**	2024
Canadian		
Earnings before income tax expense	**565**	518
Current income tax	**102**	154
Deferred income tax	**(23)**	(87)
Total Canadian	**79** [(1)]	67
Foreign		
Earnings before income tax expense	**1,789**	1,656
Current income tax	**39**	38
Deferred income tax	**275**	241
Total Foreign	**314**	279
Income tax expense	**393**	346

(1) *Includes $31 million of income tax expense associated with the repatriation of proceeds on the dispositions of FortisTCI, Fortis Belize and Belize Electricity*

Rate Reconciliation of Income Tax Expense

($ millions, except as indicated)	**2025**		2024	
Earnings before income tax expense	**2,354**		2,174	
Canadian federal statutory tax rate	**353**	**15.0 %**	326	15.0 %
Provincial income tax effect [(1)]	**50**	**2.1 %**	24	1.1 %
Effects of rate-regulated accounting	**(47)**	**(2.0)%**	(29)	(1.3)%
Other adjustments	**(9)**	**(0.4)%**	(6)	(0.3)%
Foreign tax rate effects				
United States				
Statutory tax rate difference between United States and Canada	**150**	**6.4 %**	132	6.1 %
Effects of rate-regulated accounting	**(61)**	**(2.6)%**	(50)	(2.3)%
Tax credits	**(28)**	**(1.2)%**	(34)	(1.6)%
Other foreign jurisdictions	**(15)**	**(0.6)%**	(17)	(0.8)%
Income tax expense and effective tax rate	**393**	**16.7 %**	346	15.9 %

(1) *Provincial taxes in British Columbia and Alberta contributed the majority of the tax effect in this category.*

23. INCOME TAXES (cont'd)

Income Tax Carryforwards[1]

($ millions)	Expiring Year	2025
Canadian		
Non-capital loss	2028-2045	**172**
Other tax credits and restricted interest and financing expenses[2]	2033-2045	**89**
		261
Foreign		
Federal and state net operating loss[3]	2026-2045	**143**
Other tax credits	2031-2045	**273**
		416
Total income tax carryforwards recognized		**677**

(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 2025 taxation years are still open for audit in Canadian jurisdictions, and its 2021 to 2025 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, 2022 for Newfoundland Power, certain FortisBC Energy and FortisBC Electric plans, FortisAlberta and FortisOntario; December 31, 2023 for the Corporation; December 31, 2024 for the remaining FortisBC Energy and FortisBC Electric plans; and December 31, 2025 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.

Allocation of Plan Assets

(weighted average %)	2025 Target Allocation	2025	2024
Equities	**46**	**45**	47
Fixed income	**46**	**47**	45
Real estate	**7**	**7**	7
Cash and other	**1**	**1**	1
	100	**100**	100

24. EMPLOYEE FUTURE BENEFITS (cont'd)

Fair Value of Plan Assets

($ millions)	Level 1 [(1)]	Level 2 [(1)]	Level 3 [(1)]	Total
2025				
Equities	**821**	**1,077**	**—**	**1,898**
Fixed income	**291**	**1,736**	**—**	**2,027**
Real estate	**—**	**—**	**309**	**309**
Cash and other	**16**	**25**	**—**	**41**
	1,128	**2,838**	**309**	**4,275**
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

(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)	2025	2024
Balance, beginning of year	**300**	291
Return on plan assets	**7**	5
Foreign currency translation	**(2)**	3
Purchases, sales and settlements	**4**	1
Balance, end of year	**309**	300

Funded Status

	DBP Plans		OPEB Plans	
($ millions)	**2025**	2024	**2025**	2024
Change in benefit obligation [(1)]				
Balance, beginning of year	**3,440**	3,347	**603**	596
Service costs	**71**	74	**23**	25
Employee contributions	**19**	17	**4**	4
Interest costs	**171**	161	**30**	29
Benefits paid	**(189)**	(181)	**(34)**	(35)
Actuarial losses (gains)	**27**	(115)	**(18)**	(49)
Plan amendments/past service credits	**40**	(3)	**—**	—
Foreign currency translation	**(84)**	140	**(19)**	33
Balance, end of year [(2)]	**3,495**	3,440	**589**	603
Change in value of plan assets				
Balance, beginning of year	**3,613**	3,313	**506**	430
Actual return on plan assets	**331**	249	**66**	50
Benefits paid	**(180)**	(174)	**(28)**	(31)
Employee contributions	**19**	17	**4**	4
Employer contributions	**54**	57	**7**	14
Foreign currency translation	**(93)**	151	**(24)**	39
Balance, end of year	**3,744**	3,613	**531**	506
Funded (unfunded) status	**249**	173	**(58)**	(97)
Balance sheet presentation				
Other assets (Note 9)	**474**	395	**174**	156
Other current liabilities (Note 13)	**(15)**	(16)	**(13)**	(13)
Other liabilities (Note 16)	**(210)**	(206)	**(219)**	(240)
	249	173	**(58)**	(97)

(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 $3,184 million as at December 31, 2025 (2024 - $3,144 million).*

24. EMPLOYEE FUTURE BENEFITS (cont'd)

For those DBP plans for which the projected benefit obligation exceeded the fair value of plan assets as at December 31, 2025, the obligation was $1,020 million compared to plan assets of $840 million (2024 - $1,668 million and $1,460 million, respectively).

For those DBP plans for which the accumulated benefit obligation exceeded the fair value of plan assets as at December 31, 2025, the obligation was $170 million compared to plan assets of $41 million (2024 - $195 million and $62 million, respectively).

For those OPEB plans for which the accumulated benefit obligation exceeded the fair value of plan assets as at December 31, 2025, the obligation was $268 million compared to plan assets of $46 million (2024 - $296 million and $44 million, respectively).

Net Benefit Cost [1]

	DBP Plans		OPEB Plans	
($ millions)	**2025**	2024	**2025**	2024
Service costs	**71**	74	**23**	25
Interest costs	**171**	161	**30**	29
Expected return on plan assets	**(214)**	(221)	**(28)**	(26)
Amortization of actuarial gains	**(15)**	(1)	**(33)**	(17)
Amortization of past service credits/plan amendments	**—**	(1)	**(1)**	(1)
Regulatory adjustments	**(2)**	(1)	**8**	2
	11	11	**(1)**	12

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

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)	**2025**	2024	**2025**	2024
Unamortized net actuarial losses (gains)	**6**	11	**(10)**	(11)
Unamortized past service costs	**2**	1	**4**	6
Income tax (recovery) expense	**(2)**	(3)	**1**	1
Accumulated other comprehensive income	**6**	9	**(5)**	(4)
Net actuarial (gains) losses	**(25)**	46	**(296)**	(283)
Plan amendments/past service credits	**39**	(1)	**(1)**	(2)
Other regulatory deferrals	**9**	12	**(1)**	4
	23	57	**(298)**	(281)
Regulatory assets (Note 8)	**192**	235	**—**	—
Regulatory liabilities (Note 8)	**(169)**	(178)	**(298)**	(281)
Net regulatory assets (liabilities)	**23**	57	**(298)**	(281)

24. EMPLOYEE FUTURE BENEFITS (cont'd)

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

	DBP Plans		OPEB Plans	
($ millions)	**2025**	2024	**2025**	2024
Net actuarial (gains) losses	**(5)**	(1)	**1**	(1)
Past service costs (credits)/plan amendments	**1**	—	**(2)**	—
Income tax expense	**1**	—	**—**	—
Total recognized in comprehensive income	**(3)**	(1)	**(1)**	(1)
Net actuarial gains	**(90)**	(142)	**(45)**	(72)
Plan amendments	**39**	—	**—**	—
Amortization of actuarial gains	**16**	1	**23**	16
Amortization of past service credits	**1**	1	**1**	1
Foreign currency translation	**3**	(2)	**9**	(12)
Regulatory adjustments	**(3)**	23	**(5)**	2
Total recognized in regulatory liabilities	**(34)**	(119)	**(17)**	(65)

Significant Assumptions

	DBP Plans		OPEB Plans	
(weighted average %)	**2025**	2024	**2025**	2024
Discount rate as at December 31 (1)	**5.24**	5.25	**5.36**	5.43
Expected long-term rate of return on plan assets (2)	**6.29**	6.51	**5.80**	6.05
Rate of compensation increase	**3.39**	3.52	**—**	—
Health care cost trend increase as at December 31 (3)	**—**	—	**4.40**	4.53

(1) The discount rate used during the year was 5.25% for DBP plans (2024 - 4.84%) and 5.43% for OPEB plans (2024 - 4.96%). 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 2026 health care cost trend rate is 6.60% and is assumed to decrease over the next 10 years to the ultimate health care cost trend rate of 4.40% in 2035 and thereafter.

Expected Benefit Payments

($ millions)	DBP Plans	OPEB Plans
2026	$ 202	$ 32
2027	205	32
2028	209	33
2029	216	34
2030	222	35
2031-2035	1,152	194

During 2026, the Corporation expects to contribute $52 million for DBP plans and $10 million for OPEB plans.

In 2025, the Corporation expensed $63 million (2024 - $58 million) related to defined contribution pension plans.

25. SUPPLEMENTARY CASH FLOW INFORMATION

($ millions)	2025	2024
Years ended December 31		
Cash paid (received) for		
Interest	**1,469**	1,361
Income taxes		
Canadian	**63**	(34)
Foreign	**(33)**	17
	30	(17)
Change in working capital		
Accounts receivable and other current assets	**(52)**	(2)
Prepaid expenses	**(12)**	(21)
Inventories	**(45)**	(73)
Regulatory assets - current portion	**(94)**	93
Accounts payable and other current liabilities	**195**	115
Regulatory liabilities - current portion	**(110)**	56
	(118)	168
Non-cash financing activity		
Common share dividends reinvested	**461**	434
As at December 31		
Non-cash investing and financing activities		
Accrued capital expenditures	**725**	722
Contributions in aid of construction	**11**	14

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 reliable in predicting the Corporation's future consolidated earnings or cash flow.

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, 2025, unrealized losses of $135 million (2024 - $175 million) were recognized as regulatory assets and unrealized gains of $37 million (2024 - $41 million) were recognized as regulatory liabilities.

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

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. Gains or losses associated with changes in the fair value of these energy contracts are recognized in revenue. In 2025, gains of $39 million (2024 - $48 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 $136 million and terms up to three years expiring at varying dates through January 2028. 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 2025, unrealized gains of $24 million (2024 - $12 million) 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 2027 and have a combined notional amount of US$448 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 2025, unrealized gains of $17 million (2024 - unrealized losses of $17 million) were recognized in other income, net.

Interest Rate Contracts

ITC has entered into five-year interest rate swap contracts with a combined notional value of US$755 million which 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. In 2025, unrealized losses of US$5 million (2024 - unrealized gains of US$4 million) were recorded in other comprehensive income.

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 2025, unrealized gains of $9 million (2024 - unrealized losses of $29 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 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, 2025				
Assets				
Energy contracts subject to regulatory deferral (2) (3)	**—**	**51**	**—**	**51**
Energy contracts not subject to regulatory deferral (2)	**—**	**4**	**—**	**4**
Total return swaps and foreign exchange contracts (2)	**—**	**37**	**—**	**37**
Other investments (4)	**190**	**—**	**—**	**190**
	190	**92**	**—**	**282**
Liabilities				
Energy contracts subject to regulatory deferral (3) (5)	**—**	**(149)**	**—**	**(149)**
Energy contracts not subject to regulatory deferral (5)	**—**	**(2)**	**—**	**(2)**
Interest rate contracts and cross-currency interest rate swaps (5)	**—**	**(23)**	**—**	**(23)**
	—	**(174)**	**—**	**(174)**
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)

(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, 2025				
Derivative assets	**55**	**(29)**	**15**	**41**
Derivative liabilities	**(151)**	**29**	**—**	**(122)**
As at December 31, 2024				
Derivative assets	70	(30)	15	55
Derivative liabilities	(199)	30	—	(169)

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

Volume of Derivative Activity

As at December 31, 2025, the Corporation had various energy contracts that will settle on various dates through 2030. The volumes related to electricity and natural gas derivatives are outlined below.

	2025	2024
Energy contracts subject to regulatory deferral [(1)]		
Electricity swap contracts *(GWh)*	**890**	774
Electricity power purchase contracts *(GWh)*	**395**	430
Gas swap contracts *(PJ)*	**183**	236
Gas supply contracts *(PJ)*	**147**	105
Energy contracts not subject to regulatory deferral [(1)]		
Wholesale trading contracts *(GWh)*	**1,430**	1,499
Gas swap contracts *(PJ)*	**2**	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 the Midcontinent Independent System Operator 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 work with 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.

ITC, 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 $99 million as at December 31, 2025 (2024 - $117 million).

Hedge of Foreign Net Investments

The reporting currency of ITC, UNS Energy, Central Hudson, and Caribbean Utilities is 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, 2025, US$1.9 billion (2024 - US$2.2 billion) of corporately issued U.S. dollar-denominated long-term debt has been designated as an effective hedge of net investments, leaving approximately US$13.2 billion (2024 - US$12.6 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, 2025, the carrying value of long-term debt, including the current portion, was $34.1 billion (2024 - $33.4 billion) compared to an estimated fair value of $32.3 billion (2024 - $31.3 billion).

27. COMMITMENTS AND CONTINGENCIES

As at December 31, 2025, 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)]	**6,592**	908	689	586	491	416	3,502
Renewable PPAs [(2)]	**2,374**	158	174	173	165	173	1,531
Waneta Expansion capacity agreement [(3)]	**2,307**	58	59	60	61	63	2,006
Power purchase obligations [(4)]	**1,135**	251	156	129	127	124	348
ITC easement agreement [(5)]	**342**	14	14	14	14	14	272
UNS Energy EPC agreement [(6)]	**269**	110	143	16	—	—	—
Debt collection agreement [(7)]	**96**	3	3	3	3	3	81
Renewable energy credit purchase agreements [(8)]	**50**	18	6	6	5	5	10
Other [(9)]	**122**	27	12	9	9	2	63
	13,287	**1,547**	**1,256**	**996**	**875**	**800**	**7,813**

[(1)] *FortisBC Energy ($5,295 million):* includes contracts of $2,737 million for the purchase of renewable natural gas expiring in 2047 and contracts of $2,558 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, 2025. The renewable gas supply obligations disclosed reflect the contracted price per gigajoule between the Corporation and the suppliers.

UNS Energy ($1,190 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, 2025. 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 power purchase agreements ("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 achieving 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 ($496 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 and operating costs for the life of the unit.

FortisOntario ($314 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 ($271 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 runs through December 2050, subject to 10 automatic 50-year renewals thereafter unless METC gives notice of non-renewal at least one year in advance.

[(6)] UNS Electric has an engineering, procurement and construction ("EPC") agreement for the development of four gas engine turbines at the Black Mountain Generation Station, which are expected to be placed in service in 2028.

[(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 has met the minimum equity capital contribution requirement of approximately $165 million 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 make additional 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.

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 $343 million for Four Corners. As at December 31, 2025, there was no obligation under these guarantees.

TEP has entered into an energy supply agreement to serve a customer expected to be located in TEP's service territory. The agreement, requiring potential power demand of approximately 300 MW, was approved by the ACC in December 2025 but remains subject to other contractual contingencies. The initial phase is expected to be operational as early as 2027, with a ramp schedule through 2029. TEP currently expects to serve the customer from its existing and planned capacity, including solar and battery storage projects currently in development.

TEP and UNS Electric have entered into long-term gas transportation precedent agreements to secure reliable access to natural gas. The agreements support the development of a new pipeline to be owned and operated by a third-party. Subject to the receipt of required regulatory approvals and other conditions, the pipeline is expected to be in service in 2029. Once the pipeline enters commercial operation, TEP and UNS Electric will enter into gas transportation service agreements with estimated purchase commitments of US$1.9 billion over 25 years.

Contingency

In November 2023, an explosion and fire occurred at a residence located in Wappingers Falls, New York, while a contractor was performing work on Central Hudson’s natural gas infrastructure adjacent to the residence. Civil actions seeking damages for bodily injuries, property damage and punitive damages remain pending. While these matters collectively could involve substantial amounts, based on the facts currently known, management is not able to estimate the potential loss, but believes their ultimate resolution will not have a material adverse effect on the financial position, results of operations, or cash flows of the Corporation.