FORTIS INC.

St. John's, NL - February 12, 2021

FORTIS INC. REPORTS 2020 RESULTS

Fortis Inc. ("Fortis" or the "Corporation") (TSX/NYSE: FTS), a well-diversified leader in the North American regulated electric and gas utility industry, released its 2020 fourth quarter and annual financial results[1] today.

Highlights

- Reported annual net earnings of $1,209 million, or $2.60 per common share in 2020
- Delivered adjusted net earnings[2] of $1,195 million, or $2.57 per common share, up from $1,115 million, or $2.55 per common share in 2019
- Executed record capital expenditures of $4.2 billion yielding annual rate base growth of 8.2%[3]
- Received constructive final order on Tucson Electric Power's general rate application with new customer rates effective January 1, 2021
- Established a new corporate-wide emissions reduction target of 75% by 2035

"2020 proved to be a successful year on many fronts. Despite the challenges presented by the pandemic, our 9,000 dedicated employees continued to reliably provide essential energy service to our customers and executed our largest annual capital program while achieving our best safety performance on record," said David Hutchens, President and Chief Executive Officer, Fortis. "Our teams also worked with their regulators and communities to help customers who have been most impacted by the pandemic, demonstrating our core values and the benefits of our local business model."

Net Earnings

The Corporation reported net earnings attributable to common equity shareholders for 2020 of $1,209 million, compared to $1,655 million for 2019. The change in net earnings reflects significant one-time items related to: (i) a $484 million gain on the disposition of the Waneta Expansion hydroelectric generating facility ("Waneta Expansion") in April 2019; and (ii) the $56 million net impact associated with the reversal of prior period liabilities as a result of the base return on common equity ("ROE") decisions made by the Federal Energy Regulatory Commission ("FERC") in November 2019 and May 2020.

Excluding these one-time items, earnings grew by $94 million in 2020 reflecting: (i) rate base growth of 8.2%; (ii) increased retail electricity sales at UNS Energy, driven largely by weather; and (iii) higher earnings from Belize, mainly from increased hydroelectric production. Earnings were also favourably impacted by mark-to-market accounting of natural gas derivatives at Aitken Creek which resulted in unrealized losses of $15 million in 2019. Fortis delivered this growth despite: (i) the delay in Tucson Electric Power's ("TEP") general rate application, resulting in approximately $1 billion of rate base not reflected in customer rates in 2020; and (ii) the impact of the COVID-19 pandemic, reflecting lower sales in the Caribbean and higher net operational expenses, including increased credit loss expense, largely at Central Hudson and UNS Energy.

For the fourth quarter of 2020, net earnings attributable to common equity shareholders were $331 million, compared to $346 million for the same period in 2019. The decrease was due to the reversal of prior period liabilities of $83 million in the fourth quarter of 2019 associated with the November 2019 FERC base ROE decision. Excluding this one-time item, quarterly earnings grew by $68 million reflecting: (i) the timing of earnings at ITC associated with the implementation of the November 2019 base ROE decision; (ii) rate base growth; (iii) the impact of mark-to-market accounting of natural gas derivatives at Aitken Creek; and (iv) higher earnings from Belize, mainly from increased hydroelectric production.

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

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

[3] Calculated on a constant United States dollar-to-Canadian dollar exchange rate.

Earnings per common share decreased by $0.06 and $1.19 for the fourth quarter and annual periods, respectively, as compared to 2019. In addition to the above-noted items, the decrease in earnings per common share also reflected a higher weighted average number of common shares outstanding, largely associated with the Corporation's $1.2 billion common equity issuance in the fourth quarter of 2019. The impact was a decrease in earnings per common share for the fourth quarter and annual periods of $0.03 and $0.15, respectively.

The common equity issuance and the Waneta Expansion disposition generated a significant portion of the equity funding required to execute our five-year capital plan, and strengthened the Corporation's balance sheet, liquidity and credit metrics. As at December 31, 2020, total consolidated credit facilities were $5.6 billion with $4.3 billion unutilized.

Adjusted Net Earnings
On an adjusted basis, net earnings attributable to common equity shareholders for 2020 were $1,195 million, or $2.57 per common share, an increase of $0.02 per common share compared to 2019. The increase reflected rate base growth as well as higher retail sales in Arizona and earnings from Belize. Fortis delivered growth in earnings per common share despite the delay in TEP's general rate application and the COVID-19 pandemic, as well as a higher weighted average number of common shares outstanding.

On an adjusted basis, for the fourth quarter of 2020, net earnings attributable to common equity shareholders were $320 million, or $0.69 per common share, an increase of $43 million, or $0.07 per common share compared to the fourth quarter of 2019. The increase in adjusted quarterly earnings was due to the timing of earnings at ITC associated with the implementation of the November 2019 base ROE decision, rate base growth and higher earnings from Belize, partially offset by a higher weighted average number of common shares outstanding.

COVID-19 Pandemic
Fortis continues to monitor developments and take appropriate measures to protect the health and safety of employees, customers and communities. The Corporation's utilities have instituted various customer relief initiatives, including the temporary suspension of non-payment disconnects and late fees, delayed customer rate increases and the deferred recovery of costs. Community investments by Fortis and our utilities were more than $15 million in 2020, including approximately $5 million for community support in response to the COVID-19 pandemic.

In addition to the efforts across the Fortis group to control costs during the pandemic, the Corporation's utilities have regulatory mechanisms that help stabilize cash flow and earnings which support the continued delivery of reliable service. Approximately 83% of the Corporation's revenues are either protected by regulatory mechanisms or are derived from residential sales which have generally increased as a result of work-from-home practices.

Excluding the impact of the delay in TEP's general rate application, the COVID-19 pandemic did not have a material impact on the Corporation's capital expenditures, revenue or earnings in 2020. The financial impact to Fortis approximated $0.05 per common share, reflecting reduced sales in the Caribbean and higher net operational expenses, including an increase in credit loss expense, largely at Central Hudson and UNS Energy.

Regulatory Proceedings
The Corporation's significant regulatory proceedings were concluded by the end of 2020.

In December 2020, the Arizona Corporation Commission issued a rate order on TEP's general rate application. The order established new customer rates effective January 1, 2021, including: (i) an increase in non-fuel revenue of $77 million (US$58 million); (ii) an allowed ROE of 9.15%, with a 0.20% return on the fair value increment and a capital structure of 53% common equity; and (iii) a rate base of approximately $3.5 billion (US$2.7 billion). The approved rate base includes the Gila River natural gas generation station Unit 2 and ten natural gas reciprocating internal combustion engine units that will help TEP transition its generation mix to more than 70% renewable by 2035.

In October 2020, the Alberta Utilities Commission ("AUC") concluded the 2021 generic cost of capital proceeding and set FortisAlberta's ROE for 2021 at 8.50% using a capital structure of 37% common equity, consistent with 2020.

In November 2020, the AUC issued a decision reversing proposed changes to the Alberta Electric System Operator's customer contribution policy resulting in FortisAlberta retaining approximately $400 million of unamortized customer contributions in its rate base.

Capital Expenditures
Capital expenditures in 2020 were $4.2 billion, $0.4 billion higher than in 2019 and broadly consistent with the 2020 capital plan.

The Corporation's five-year capital plan for 2021 through 2025 is $19.6 billion, up $0.8 billion from the prior five-year plan. The increase is largely due to: (i) two new major capital projects at FortisBC Energy; (ii) additional investment in information technology systems and storm hardening at Central Hudson; and (iii) interconnections and system rebuilds providing additional capacity and other improvements at ITC. Capital expenditures are expected to be funded primarily with cash from operations, debt issued at the regulated utilities and the Corporation's dividend reinvestment plan.

Focus on Sustainability
Fortis has targeted a reduction in carbon emissions of 75% by 2035 from a 2019 base year. The Corporation expects to achieve the majority of this target through delivering on TEP's plan to exit coal generation and replace it with wind, solar and energy storage. Clean energy initiatives across the Corporation's other utilities will also contribute to achieving this goal.

"Sustainability remains front and center across our utilities," said David Hutchens. "With the strength of our low-risk growth outlook and the talent of our North American team, we are positioned well to deliver a cleaner energy future."

Outlook
The Corporation maintains its positive long-term outlook. Fortis continues to enhance shareholder value through the execution of its capital plan, the balance and strength of its diversified portfolio of utility businesses, and growth opportunities within and proximate to its service territories. While uncertainty exists due to the COVID-19 pandemic, the Corporation does not currently expect it to have a material financial impact in 2021.

The Corporation's five-year capital plan is expected to increase rate base from $30.5 billion in 2020 to $36.4 billion by 2023 and $40.3 billion by 2025, translating into three- and five-year compound annual growth rates[3] of approximately 6.5% and 6.0%, respectively. Beyond the five-year capital plan, Fortis continues to pursue additional energy infrastructure opportunities, including: further expansion of liquefied natural gas infrastructure in British Columbia; the fully permitted, cross-border, Lake Erie Connector electric transmission project in Ontario; and the acceleration of cleaner energy infrastructure investments across our jurisdictions.

Fortis expects long-term growth in rate base will support earnings and dividend growth. The Corporation is targeting average annual dividend growth of approximately 6% through 2025. This dividend growth guidance is premised on the assumptions listed under "Forward-Looking Information" below, including no material impact from the COVID-19 pandemic, the expectation of reasonable outcomes for regulatory proceedings and the successful execution of the five-year capital plan.

Non-US GAAP Reconciliation

Periods ended December 31 *($ millions, except earnings per share)*	**2020**	2019	Variance	**Q4 2020**	Q4 2019	Variance
Net earnings attributable to common equity shareholders	**1,209**	1,655	(446)	**331**	346	(15)
Adjusting items:						
FERC base ROE decisions *(i)*	**(27)**	(83)	56	**—**	(83)	83
United States tax reform *(ii)*	**13**	12	1	**—**	12	(12)
Unrealized loss (gain) on mark-to-market of derivatives *(iii)*	**—**	15	(15)	**(11)**	2	(13)
Gain on disposition *(iv)*	**—**	(484)	484	**—**	—	—
Adjusted net earnings attributable to common equity shareholders	**1,195**	1,115	80	**320**	277	43
Adjusted basic earnings per share *($)*	**2.57**	2.55	0.02	**0.69**	0.62	0.07

(i) *Represents prior period impacts of the May 2020 and November 2019 FERC base ROE decisions, respectively*
(ii) *The finalization of United States tax reform regulations associated with anti-hybrid regulations in 2020 and base-erosion and anti-abuse tax in 2019*
(iii) *Represents timing differences related to the accounting of natural gas derivatives at Aitken Creek*
(iv) *Gain on sale of the Waneta Expansion, net of expenses, in April 2019*

3 Calculated on a constant United States dollar to Canadian dollar exchange rate.

About Fortis
Fortis is a well-diversified leader in the North American regulated electric and gas utility industry with 2020 revenue of $8.9 billion and total assets of $55 billion as at December 31, 2020. The Corporation's 9,000 employees serve utility customers in five Canadian provinces, nine US states and three Caribbean countries.

Forward-Looking Information
Fortis includes forward-looking information in this media release within the meaning of applicable Canadian securities laws and forward-looking statements within the meaning of the U.S. Private Securities Litigation Reform Act of 1995 (collectively referred to as "forward-looking information"). Forward-looking information reflects expectations of Fortis management regarding future growth, results of operations, performance and business prospects and opportunities. Wherever possible, words such as anticipates, believes, budgets, could, estimates, expects, forecasts, intends, may, might, plans, projects, schedule, should, target, will, would and the negative of these terms and other similar terminology or expressions have been used to identify the forward-looking information, which includes, without limitation: the 2035 carbon emissions reduction target; TEP's targeted 2035 generation mix; forecast capital expenditures for 2021-2025 and expected funding sources; the expectation that the COVID-19 pandemic will not have a material financial impact in 2021; forecast rate base and rate base growth for 2023 and 2025; the expectation that long-term growth in rate base will support earnings and dividend growth; and targeted average annual dividend growth through 2025.

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: no material impact from the COVID-19 pandemic; reasonable outcomes for regulatory proceedings and the expectation of regulatory stability; the successful execution of the five-year 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; the impact of fluctuations in foreign exchange; no significant variability in interest rates; and the Board 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 2020 Annual Results

A teleconference and webcast will be held on February 12 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 2020 annual results.

Shareholders, analysts, members of the media and other interested parties in North America are invited to participate by calling 1.877.223.4471. International participants may participate by calling 647.788.4922. Please dial in 10 minutes prior to the start of the call. No pass code is required.

A live and archived audio webcast of the teleconference will be available on the Corporation's website, www.fortisinc.com. A replay of the conference will be available two hours after the conclusion of the call until March 14, 2021. Please call 1.800.585.8367 or 416.621.4642 and enter pass code 1887263.

Additional Information
This media 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.sedar.com, or www.sec.gov.

For more information, please contact:

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

Media Enquiries:
Ms. Karen McCarthy
Vice President, Communications & Corporate Affairs
Fortis Inc.
709.737.5323
media@fortisinc.com

Management Discussion and Analysis

For the year ended December 31, 2020
Dated February 11, 2021

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This MD&A has been prepared in accordance with National Instrument 51-102 - *Continuous Disclosure Obligations*. It should be read in conjunction with the 2020 Annual Financial Statements and is subject to the cautionary statement and disclaimer provided under "Forward-Looking Information" on page 46. Further information about Fortis, including its Annual Information Form filed on SEDAR, can be accessed at www.fortisinc.com, www.sedar.com, or www.sec.gov.

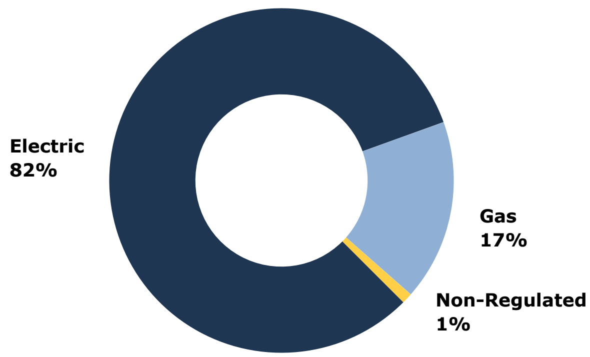
Financial information herein has been prepared in accordance with US GAAP (except for indicated Non-US GAAP Financial Measures) and, unless otherwise specified, is presented in Canadian dollars based, as applicable, on the following US dollar-to-Canadian dollar exchange rates: (i) average of 1.34 and 1.33 for the years ended December 31, 2020 and 2019, respectively; (ii) 1.27 and 1.30 as at December 31, 2020 and 2019, respectively; (iii) average of 1.30 and 1.32 for the quarters ended December 31, 2020 and 2019, respectively; and (iv) 1.32 for all forecast periods. Certain terms used in this MD&A are defined in the "Glossary" on page 48.

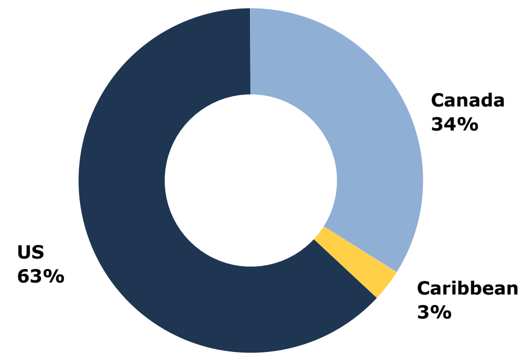
ABOUT FORTIS

Fortis (TSX/NYSE: FTS) is a well-diversified leader in the North American regulated electric and gas utility industry, with revenue of $8.9 billion and total assets of $55 billion as at December 31, 2020.

Regulated utilities account for 99% of the Corporation's assets with the remainder primarily attributable to non-regulated energy infrastructure. The Corporation's 9,000 employees serve 3.3 million utility customers in five Canadian provinces, nine US states and three Caribbean countries. As at December 31, 2020, 66% of the Corporation's assets were located outside Canada and 59% of 2020 revenue was derived from foreign operations.

Total Assets at December 31, 2020





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

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

Non-regulated energy infrastructure consists of Aitken Creek (natural gas storage facility - British Columbia), BECOL (three hydroelectric generation facilities - Belize) and the Waneta Expansion up to its disposition in April 2019.

Fortis has a unique operating model with a small head 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 most have a board of directors with a majority of independent 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 strives to provide safe, reliable and cost-effective energy service to customers using sustainable practices while delivering long-term profitable growth to shareholders. Management is focused on achieving growth 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 2020 Annual Financial Statements.

SIGNIFICANT ITEMS

COVID-19 Pandemic
The Corporation's utilities continue to reliably and safely deliver an essential service during the COVID-19 Pandemic. Developments are continuously monitored with commensurate measures being taken. The Corporation's utilities have assessed supply chain risk and other potential impacts of the pandemic to ensure that they can continue to provide safe, reliable service while supporting public health.

Excluding the impact of the delay in TEP's general rate application (see "Regulatory Highlights" on page 15), the COVID-19 Pandemic did not have a material impact on the Corporation's capital expenditures, revenue or earnings in 2020. The financial impact to Fortis approximated $0.05 per common share and reflected: (i) reduced sales in the Caribbean; and (ii) higher net operational expenses, including increased credit loss expense, largely at Central Hudson and UNS Energy.

Further information regarding the key impact areas for Fortis with respect to the pandemic is summarized below.

Revenue
Energy sales across all of the Corporation's utilities have been impacted by the closure and reopening of non-essential businesses along with stay-at-home orders and other economic impacts related to the COVID-19 Pandemic. Generally, work-from-home practices have resulted in an increase in residential sales while commercial and industrial sales have decreased.

Regulatory mechanisms function to protect approximately 62% of the Corporation's annual revenue from changes in sales. Of the remaining 38%, principally at UNS Energy and the Other Electric segment, approximately 21% is residential and 17% is commercial and industrial. Overall, approximately 83% of revenues are either protected by regulatory mechanisms or derived from residential sales.

Since the start of the COVID-19 Pandemic in 2020, as compared to the same period in 2019, residential electricity sales at UNS Energy increased by 17%, due mainly to warmer temperatures and work-from-home practices. Commercial and industrial electricity sales decreased by 2%, resulting in an overall sales increase of 7%. Excluding weather, retail electricity sales increased 2%.

Sales at the Other Electric segment decreased by 2% since the start of the COVID-19 Pandemic, as compared to the same period in 2019. This was comprised of a 3% increase in residential sales and an 8% decrease in commercial sales, due largely to reduced tourism-related activities in the Caribbean.

Overall, variations in 2020 sales associated with the COVID-19 Pandemic at UNS Energy and the Other Electric segment did not have a material impact on Fortis. While the Corporation does not expect the COVID-19 Pandemic to materially impact Fortis in 2021, the residential and commercial sales mix, particularly for UNS Energy and the Other Electric segment, will continue to be evaluated. Overall, the estimated annual impact on EPS of a 1% change in sales at each of UNS Energy and the Other Electric segment is approximately $0.01.

Capital Expenditures
Capital expenditures were not materially impacted by the COVID-19 Pandemic. Total expenditures of $4.2 billion were broadly consistent with the 2020 capital plan. The Corporation does not expect the COVID-19 Pandemic to impact its overall five-year capital plan, although certain planned expenditures may shift within the five-years depending on the length and severity of the pandemic.

Liquidity
Fortis is well positioned with strong liquidity due, in part, to a $1.2 billion common equity offering and the sale of the Waneta Expansion in 2019. As at December 31, 2020, total consolidated credit facilities were $5.6 billion with $4.3 billion unutilized.

Fortis and its utilities continue to be successful in accessing capital markets. See "Liquidity and Capital Resources" on page 19.

The economic impact of the COVID-19 Pandemic has affected customers' ability to pay their energy bills with commensurate short-term working capital impacts. The Corporation's utilities have instituted various customer relief initiatives, including the temporary suspension of non-payment disconnects and late fees, delayed customer rate increases and the deferred recovery of costs. The Corporation has seen an increase in accounts receivable and, accordingly, its allowance for credit losses in 2020. While not material to Fortis, UNS Energy and Central Hudson, in particular, experienced an increase in credit loss expense in 2020 associated with slower customer collections largely due to the COVID-19 Pandemic. See Note 6 in the 2020 Annual Financial Statements.

The unfavourable impact on cash flow in 2020 associated with slower collection of customer balances was offset by other changes in Operating Cash Flow (see "Performance at a Glance - Operating Cash Flow" on page 7).

Regulatory Matters
Regulator and other stakeholder work schedule disruptions caused delays and postponements for certain regulatory proceedings in 2020. See "Regulatory Highlights" on page 15. The Corporation's significant regulatory proceedings, as discussed below, were concluded by the end of 2020.

Pension Plans
The Corporation's exposure to changes in pension expense is limited by regulatory mechanisms which cover approximately 80% of defined benefit pension plans. The remaining 20% relates primarily to UNS Energy and its exposure is largely attributable to the use of a historical test year in setting rates.

Based upon pension plan valuations as at December 31, 2020, the change in pension expense at UNS Energy in 2021, as compared to 2020, is not material to Fortis.

Outlook
The continued uncertainty surrounding the evolution of the pandemic makes it difficult to predict the ultimate operational and financial impacts on Fortis. Potential impacts are discussed under "Business Risks" on page 28.

Significant Regulatory Decisions

TEP Rate Order
In December 2020, the ACC issued a rate order on TEP's general rate application establishing new customer rates effective January 1, 2021, including: (i) an increase in non-fuel revenue of $77 million (US$58 million); (ii) an allowed ROE of 9.15%, with a 0.20% return on the fair value increment and a capital structure of 53% common equity; and (iii) a Rate Base of approximately $3.5 billion (US$2.7 billion) which includes post-test year investments in Gila River Unit 2 and 10 RICE Units.

FortisAlberta 2021 GCOC
In October 2020, the AUC concluded the 2021 GCOC proceeding and set the ROE for 2021 at 8.50% using a capital structure of 37% common equity, consistent with 2020.

November 2020 AUC Decision
In November 2020, the AUC issued a decision with respect to the 2018 Independent System Operator Tariff Application reversing proposed changes to the AESO's customer contribution policy. This resulted in FortisAlberta retaining approximately $400 million of unamortized customer contributions in its Rate Base.

See "Regulatory Highlights" on page 15 for further information on these significant regulatory developments.

PERFORMANCE AT A GLANCE

Key Financial Metrics *($ millions, except as indicated)*	**2020**	2019	Variance
Common Equity Earnings			
Actual	**1,209**	1,655	(446)
Adjusted [1]	**1,195**	1,115	80
Basic EPS *($)*			
Actual	**2.60**	3.79	(1.19)
Adjusted [1]	**2.57**	2.55	0.02
Dividends			
Paid per Common Share *($)*	**1.9375**	1.8275	0.11
Actual Payout Ratio *(%)*	**74.5**	48.2	26.3
Adjusted Payout Ratio (%) [1]	**75.4**	71.7	3.7
Weighted Average Number of Common Shares Outstanding *(millions)*	**464.8**	436.8	28
Operating Cash Flow	**2,701**	2,663	38
Capital Expenditures [2]	**4,177**	3,818	359

(1) See "Non-US GAAP Financial Measures" on page 15
(2) Includes Fortis' $138 million share of development costs and capital spending for the Wataynikaneyap Transmission Power Project

TSR [1] *(%)*	**1-Year**	**3-Year**	**5-Year**	**10-Year**	**20-Year**
Fortis	**—**	**8.0**	**10.9**	**8.3**	**13.3**

(1) Annualized TSR per Bloomberg, as at December 31, 2020

Earnings and EPS

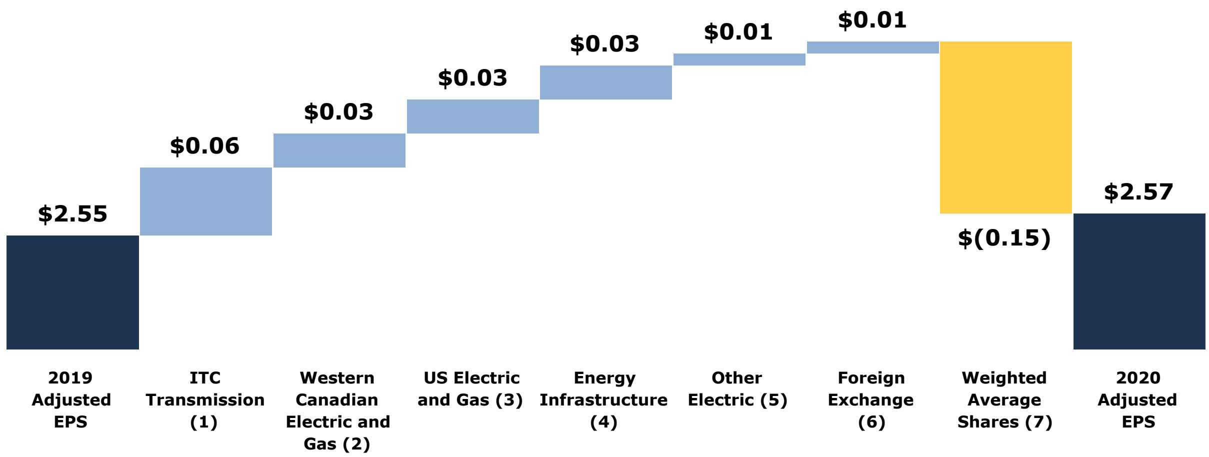
The $446 million decrease in Common Equity Earnings reflected significant one-time items: (i) a $484 million gain on the disposition of the Waneta Expansion in April 2019; and (ii) the $56 million net impact associated with the reversal of prior period liabilities as a result of the November 2019 and May 2020 FERC decisions at ITC (see "Regulatory Highlights" on page 15).

Excluding the significant one-time items, the Corporation delivered higher earnings of $94 million in 2020 reflecting: (i) Rate Base growth of 8.2%; (ii) increased retail electricity sales at UNS Energy, driven largely by weather; and (iii) higher earnings from Belize, mainly from increased hydroelectric production. Earnings were also favourably impacted by mark-to-market accounting of natural gas derivatives at Aitken Creek which resulted in unrealized losses of $15 million in 2019 compared to unrealized gains of less than $1 million in 2020. This growth was tempered by: (i) the delay in TEP's general rate application, resulting in approximately $1 billion of Rate Base not reflected in customer rates in 2020; and (ii) the impact of the COVID-19 Pandemic, reflecting lower sales in the Caribbean and higher net operational expenses, including increased credit loss expense, largely at Central Hudson and UNS Energy.

In addition to the above-noted items impacting earnings, the change in EPS reflected an increase in the weighted average number of common shares outstanding, largely associated with the Corporation's $1.2 billion common equity issuance in the fourth quarter of 2019.

Adjusted Common Equity Earnings and Adjusted Basic EPS increased by $80 million and $0.02, respectively. Refer to "Non-US GAAP Financial Measures" on page 15 for a reconciliation of these measures. The changes in Adjusted Basic EPS are illustrated in the chart below.

Changes in Adjusted Basic EPS



(1) *Primarily reflects Rate Base growth and an increase in the base ROE*
(2) *FortisBC Energy, FortisBC Electric and FortisAlberta. Primarily reflects Rate Base and customer growth, partially offset by the elimination of the PBR efficiency carry-over mechanism at FortisAlberta*
(3) *UNS Energy and Central Hudson. Increase at UNS Energy reflects higher retail sales driven by favourable weather, partially offset by higher costs associated with Rate Base growth not yet reflected in customer rates and higher net operational costs associated with the COVID-19 Pandemic. Increase at Central Hudson reflects Rate Base growth, partially offset by higher net operational expenses associated with the COVID-19 Pandemic.*
(4) *Primarily reflects increased hydroelectric production in Belize due to higher rainfall. Excludes the impact of the disposition of the Waneta Expansion, which was neutral on consolidated earnings.*
(5) *Primarily reflects higher equity income from Belize Electricity and Rate Base growth, partially offset by the impacts of the COVID-19 Pandemic, particularly in the Caribbean*
(6) *Average foreign exchange rate of $1.34 in 2020 compared to $1.33 in 2019*
(7) *Weighted average shares of 464.8 million in 2020 compared to 436.8 million in 2019*

Dividends and TSR

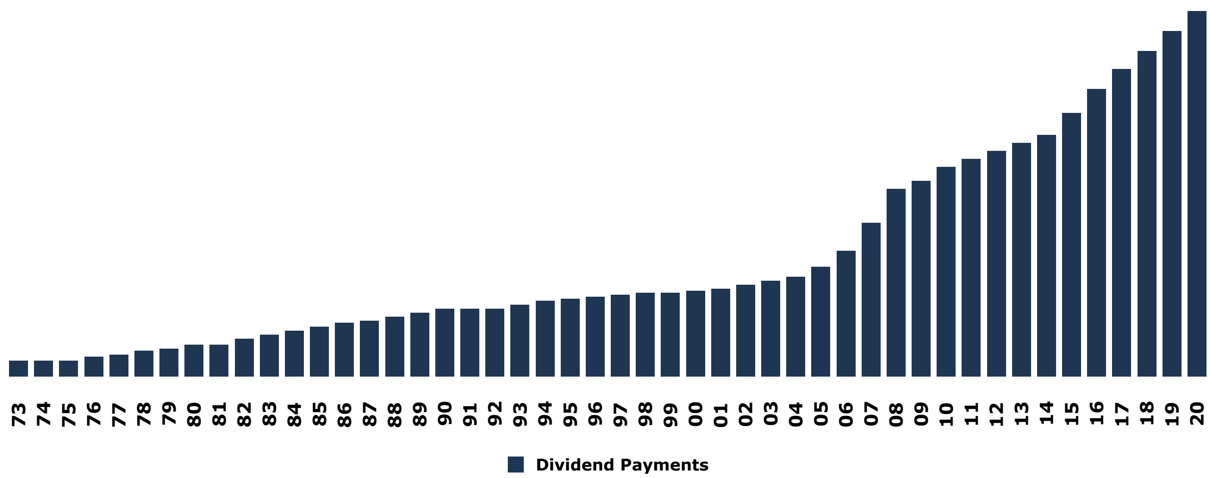
Fortis paid a dividend of $0.505 per common share in the fourth quarter of 2020, up from $0.4775 paid in each of the previous four quarters.

The total 2020 dividend paid per common share was $1.9375, up $0.11 or 6.0% from 2019 and in line with the Corporation's dividend guidance. The Actual Payout Ratio was 74.5% in 2020 compared to 48.2% in 2019 and an annual average of 65.5% over the five-year period of 2016 through 2020. The lower Actual Payout Ratio in 2019 was driven by the gain on the disposition of the Waneta Expansion.

Fortis has increased its common share dividend for 47 consecutive years. The one-year TSR was flat reflecting market conditions in 2020. Growth of dividends and the market price of the Corporation's common shares have together yielded a three-year, five-year, 10-year and 20-year TSR of 8.0%, 10.9%, 8.3% and 13.3%, respectively.

In September 2020 Fortis extended its targeted average annual dividend growth of approximately 6% through 2025.

47 Years of Common Share Dividend Increases



Operating Cash Flow

The $38 million increase in Operating Cash Flow was driven by higher cash earnings reflecting Rate Base growth, higher retail sales and fuel and non-fuel cost recoveries at UNS Energy, and an upfront payment received by FortisAlberta associated with a long-term energy retailer agreement. These were partially offset by: (i) higher transmission cost payments at FortisAlberta; (ii) the timing of recovery of higher gas costs at FortisBC Energy; and (iii) slower collections from customers due to the COVID-19 Pandemic.

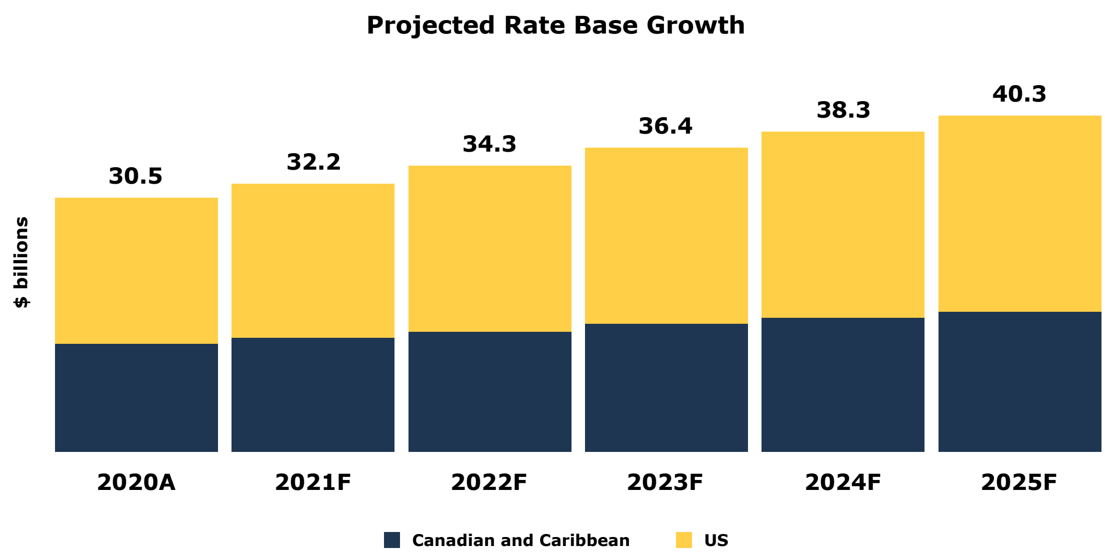
Capital Expenditures

Capital expenditures in 2020 were $4.2 billion, $0.4 billion higher than in 2019 and broadly consistent with the 2020 capital plan. For a detailed discussion of the Corporation's capital expenditure program, see "Capital Plan" on page 24.

The Corporation's five-year 2021-2025 capital plan is targeted at $19.6 billion, $0.8 billion higher than the 2020-2024 capital plan of $18.8 billion disclosed in the 2019 MD&A. The increase is largely due to: (i) two new major capital projects at FortisBC Energy including the Tilbury LNG Resiliency Tank project and the AMI project, with total expected capital spend of approximately $500 million; (ii) $200 million of additional investment in information technology systems and storm hardening at Central Hudson; and (iii) $100 million of interconnections and system rebuilds to provide additional capacity and other improvements at ITC.

The Corporation currently does not expect the COVID-19 Pandemic to impact its overall five-year capital plan. Funding of the capital plan is expected to be primarily through Operating Cash Flow, regulated utility debt and common equity from the Corporation's DRIP.

The five-year capital plan is expected to increase midyear Rate Base from $30.5 billion in 2020 to $36.4 billion by 2023 and $40.3 billion by 2025, representing three- and five-year CAGRs of approximately 6.5% and 6.0%, respectively. Fortis expects this growth in Rate Base will support earnings and dividend growth.



Beyond the five-year capital plan, Fortis continues to pursue additional energy infrastructure opportunities including: further expansion of LNG infrastructure in British Columbia; the fully permitted, cross-border, Lake Erie Connector electric transmission project in Ontario; and the acceleration of cleaner energy infrastructure investments across our jurisdictions.

THE INDUSTRY

The North American energy industry continues to transform. There is an understanding of the impacts of climate change and the need for an energy future with reduced carbon emissions. This creates the need for cleaner energy and energy conservation initiatives to preserve the environment for future generations. The trend toward carbon reduction creates the need for further technological advancements and has heightened customer expectations for cleaner energy. Renewable generation is key to a decarbonized future, with natural gas continuing as a key part of the energy mix. Over the long term, the use of hydrogen may also contribute to carbon reduction. Each of these factors, as well as the increasing affordability of cleaner energy, is driving significant investment opportunity in the utility sector.

Energy policies at the federal, state and provincial levels also reflect the rising focus on climate change, with clean energy and carbon reduction initiatives at the forefront. The regulatory and compliance operating environment is also evolving and becoming increasingly complex. These changes are creating additional opportunities to expand investment in new generation sources, including solar and wind, as well as transmission infrastructure to interconnect renewable energy sources to the grid. Investment opportunities in storage are also growing with the proliferation of various renewable generation sources and decreasing costs of energy storage technology. The electrification of the transportation sector is a significant opportunity for reducing GHG emissions. The Corporation's utilities are well positioned and actively involved in pursuing these opportunities.

New technology is driving change across all service territories. Energy delivery systems are being upgraded with advanced meters, additional grid automation, improved controls and more capable operational technology, providing utilities with detailed usage data. Energy management capabilities are expanding through emerging storage and demand response systems, and customers have been enabled with options to manage and reduce energy usage and access more affordable distributed generation technology. Grid hardening and resiliency technology investments are increasing in importance due to climate volatility resulting from more frequent and severe storms, hurricanes and wildfires.

While some of these new technologies challenge the traditional role of utilities as one-way service providers, they also offer strategic investment opportunities for improving and expanding service. The proliferation of information and operational technology, along with the exponential growth in data and grid interconnections, is driving the need for increased investment in cyber- and physical security systems.

The COVID-19 Pandemic has created a number of challenges for the industry, including the need for remote and socially-distanced work environments. Technological advances in communications, videoconferencing, and information sharing have enabled Fortis, and the industry, to maintain productivity and safe, reliable service to customers.

Meaningful customer engagement is increasingly important for utilities as customer expectations change and competition for customer attention becomes more intense. Customers want to make informed energy choices and become active participants in the delivery of their energy services. They also expect personalized service, customized service offerings and more real-time, digital communication. Our utilities are capitalizing on this as an investment opportunity to provide enhanced customer information systems and digital technologies to improve customer service.

Fortis is well positioned to capitalize on evolving industry opportunities. Its decentralized structure and customer-focused business culture support the efforts required to meet changing customer expectations, to work with regulators on energy and service solutions, and to be an industry leader in clean energy. Fortis' culture of innovation underlies a continuous drive to find a better way to safely, reliably and affordably deliver the energy and services that customers want and need. To further advance innovation, Fortis is a strategic partner in the Energy Impact Partners utility coalition, which is a strategic private equity fund that invests in emerging technologies, products, services and business models that are transforming the industry. By leveraging these strengths and partnerships, Fortis expects to remain at the forefront of this ever-changing industry.

OPERATING RESULTS

			Variance	
($ millions)	**2020**	2019	FX	Other
Revenue	**8,935**	8,783	59	93
Energy Supply Costs	**2,562**	2,520	14	28
Operating Expenses	**2,437**	2,452	19	(34)
Depreciation and Amortization	**1,428**	1,350	8	70
Gain on Disposition	**—**	577	—	(577)
Other Income, Net	**154**	138	(2)	18
Finance Charges	**1,042**	1,035	8	(1)
Income Tax Expense	**231**	289	—	(58)
Net Earnings	**1,389**	1,852	8	(471)
Net Earnings Attributable to:				
Non-Controlling Interests	**115**	130	1	(16)
Preference Equity Shareholders	**65**	67	—	(2)
Common Equity Shareholders	**1,209**	1,655	7	(453)
Net Earnings	**1,389**	1,852	8	(471)

Revenue

The increase in revenue was due primarily to: (i) overall higher flow-through costs in customer rates; (ii) Rate Base growth; (iii) higher retail electricity sales driven by favourable weather in Arizona; and (iv) a $40 million favourable base ROE adjustment at ITC related to prior periods as a result of the May 2020 FERC decision. The increase was partially offset by: (i) a $91 million favourable base ROE adjustment at ITC in 2019 related to prior periods as a result of the November 2019 FERC decision; and (ii) lower short-term wholesale sales at UNS Energy. See "Regulatory Highlights" on page 15 for further details on the November 2019 and May 2020 FERC decisions.

Energy Supply Costs

The increase in energy supply costs was due primarily to overall higher commodity costs, partially offset by the impact of lower wholesale sales at UNS Energy.

Operating Expenses
The decrease in operating expenses was due primarily to: (i) lower recoverable operating expenses at ITC due to temporary cost saving measures implemented in response to the COVID-19 Pandemic; and (ii) lower flow-through costs at TEP associated with Springerville Units 3 and 4. The decrease was partially offset by higher operating expenses at Central Hudson associated with general inflationary increases and storm events. UNS Energy and Central Hudson also had higher expenses in 2020 related to the COVID-19 Pandemic including an increase in credit loss expense.

Depreciation and Amortization
The increase in depreciation and amortization was due to continued investment in energy infrastructure at the Corporation's regulated utilities.

Gain on Disposition
The gain recorded in 2019 reflects the April 2019 disposition of the Waneta Expansion.

Other Income, Net
The increase in other income, net was due primarily to: (i) higher equity income from Belize Electricity; and (ii) the impact of non-service pension costs, partially offset by; (iii) an $11 million gain recognized in 2019 on the repayment of US$400 million of debt via tender offer.

Finance Charges
Finance charges were comparable to 2019. An increase in finance charges associated with continued capital investment was offset mainly by lower finance charges at Corporate due to the repayment of debt in 2019 using proceeds from the Waneta Expansion disposition and the $1.2 billion common equity offering.

Income Tax Expense
The decrease in income tax expense was driven by tax recorded in 2019 upon the disposition of the Waneta Expansion, partially offset by the impact of higher valuation allowances released in 2019.

Net Earnings
See "Performance at a Glance - Earnings and EPS" on page 5.

BUSINESS UNIT PERFORMANCE

Common Equity Earnings			Variance	
($ millions)	**2020**	2019	FX [1]	Other
Regulated Utilities				
ITC	**449**	471	8	(30)
UNS Energy	**302**	292	4	6
Central Hudson	**91**	85	—	6
FortisBC Energy	**175**	165	—	10
FortisAlberta	**133**	131	—	2
FortisBC Electric	**56**	54	—	2
Other Electric [2]	**112**	106	—	6
	1,318	1,304	12	2
Non-Regulated				
Energy Infrastructure [3]	**39**	18	—	21
Corporate and Other [4]	**(148)**	333	(5)	(476)
Common Equity Earnings	**1,209**	1,655	7	(453)

(1) *The reporting currency of ITC, UNS Energy, Central Hudson, Caribbean Utilities, FortisTCI and BECOL is the US dollar. The reporting currency of Belize Electricity is the Belizean dollar, which is pegged to the US dollar at BZ$2.00=US$1.00. The Corporate and Other segment includes certain transactions denominated in US dollars.*
(2) *Consists of the utility operations in eastern Canada and the Caribbean: Newfoundland Power; Maritime Electric; FortisOntario; Caribbean Utilities; FortisTCI; and Belize Electricity*
(3) *Primarily consists of long-term contracted generation assets in Belize, Aitken Creek in British Columbia and, until its April 16, 2019 disposition, the Waneta Expansion*
(4) *Includes Fortis net corporate expenses and non-regulated holding company expenses*

ITC			Variance	
($ millions)	**2020**	2019	FX	Other
Revenue [(1)]	**1,744**	1,761	22	(39)
Earnings [(1)]	**449**	471	8	(30)

(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 decrease in revenue, net of foreign exchange, was due primarily to: (i) a $91 million favourable base ROE adjustment recorded in 2019 related to prior periods as a result of the November 2019 FERC decision; and (ii) lower recoverable operating expenses due to cost saving measures implemented in response to the COVID-19 Pandemic. The decrease was partially offset by: (i) a $40 million favourable base ROE adjustment recorded in 2020 related to prior periods as a result of the May 2020 FERC decision; (ii) Rate Base growth; and (iii) an increase in the base ROE compared to 2019.

Earnings

The decrease in earnings, net of foreign exchange, was due to significant one-time items related to the reversal of prior period liabilities as a result of the base ROE decisions made by FERC in November 2019 and May 2020. The year over year impact of these one-time items was $56 million reflecting the net of: (i) an $83 million favourable adjustment in 2019; and (ii) a $27 million favourable adjustment in 2020. Excluding this impact, earnings from ITC grew by $26 million in 2020 reflecting growth in Rate Base, an increase in the base ROE compared to 2019, and lower business development costs.

See "Regulatory Highlights" on page 15 for further information on the November 2019 and May 2020 FERC decisions.

UNS Energy			Variance	
	2020	2019	FX	Other
Retail electricity sales *(GWh)*	**10,920**	10,431	—	489
Wholesale electricity sales *(GWh)* [(1)]	**5,843**	7,923	—	(2,080)
Gas sales *(PJ)*	**15**	16	—	(1)
Revenue *($ millions)*	**2,260**	2,212	24	24
Earnings *($ millions)*	**302**	292	4	6

(1) *Primarily short-term wholesale sales*

Sales

The increase in retail electricity sales was due primarily to higher air conditioning load as a result of warmer temperatures in 2020 as compared to unseasonably cool temperatures in 2019. The COVID-19 Pandemic has not had a material impact on sales as the decrease in consumption by commercial and industrial customers, due to the temporary closure of non-essential businesses, was offset by an increase in consumption by residential customers, due to work-from-home practices.

The decrease in wholesale electricity sales was due primarily to the expiration of a short-term capacity sales transaction, which was established to offset costs associated with a Gila River Unit 2 tolling PPA during 2019. The capacity sales transaction ended in December 2019 with the purchase of Gila River Unit 2. Revenue from short-term wholesale sales is primarily credited to customers through regulatory deferral mechanisms and, therefore, does not materially impact earnings.

Gas sales were comparable to 2019.

Revenue

The increase in revenue, net of foreign exchange, was due primarily to higher revenue related to the recovery of fuel and non-fuel costs through the normal operation of regulatory mechanisms and higher retail sales mainly driven by weather. The increase was partially offset by lower short-term wholesale sales and a decrease in flow-through costs related to Springerville Units 3 and 4.

Earnings
The increase in earnings, net of foreign exchange, was due primarily to higher retail electricity sales, partially offset by higher costs associated with Rate Base growth not reflected in customer rates in 2020. Beginning January 1, 2021, new customer rates are in effect following the conclusion of TEP's general rate application (see "Regulatory Highlights" on page 15). Higher net operational expenses associated with the COVID-19 Pandemic, including an increase in credit loss expense, also unfavourably impacted earnings.

Central Hudson			Variance	
	2020	2019	FX	Other
Electricity sales *(GWh)*	**4,969**	4,963	—	6
Gas sales *(PJ)*	**23**	22	—	1
Revenue *($ millions)*	**953**	917	9	27
Earnings *($ millions)*	**91**	85	—	6

Sales
Electricity sales were comparable to 2019. Higher average consumption by residential customers was largely offset by lower average consumption by commercial customers, both as a result of the COVID-19 Pandemic.

Gas sales were comparable to 2019.

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 primarily to an increase in gas and electricity delivery rates effective July 1, 2019 and July 1, 2020, reflecting a return on increased Rate Base assets as well as the recovery of higher operating and financing expenses (see "Regulatory Highlights" on page 15 for information on the July 1, 2020 rate increase). The increase was partially offset by the flow through of lower energy supply costs.

Earnings
The increase in earnings was due primarily to Rate Base growth, partially offset by higher net operational expenses associated with the COVID-19 Pandemic, including an increase in credit loss expense.

FortisBC Energy	**2020**	2019	Variance
Gas sales *(PJ)*	**219**	227	(8)
Revenue *($ millions)*	**1,385**	1,331	54
Earnings *($ millions)*	**175**	165	10

Sales
The decrease in gas sales was due primarily to lower consumption by transportation customers, partially offset by higher consumption from residential customers, due partly to work-from-home practices as a result of the COVID-19 Pandemic.

Revenue
The increase in revenue was due primarily to a higher cost of natural gas to be recovered from customers and Rate Base growth.

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

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	2020	2019	Variance
Electricity deliveries *(GWh)*	**16,092**	16,887	(795)
Revenue *($ millions)*	**596**	598	(2)
Earnings *($ millions)*	**133**	131	2

Deliveries
The decrease in electricity deliveries was due to lower average consumption by oil and gas and commercial customers, largely associated with the COVID-19 Pandemic and the downturn in the oil and gas sector. The decrease was partially offset by customer additions and higher average consumption by residential customers reflecting work-from-home practices as a result of the COVID-19 Pandemic.

As more than 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.

Revenue
The decrease in revenue was due primarily to: (i) the impact of the AUC's November 2020 decision with respect to the 2018 Independent System Operator Tariff Application reflecting the flow through of lower depreciation costs with no material impact on earnings (see "Regulatory Highlights" on page 15); and (ii) the recognition of revenue in 2019 associated with the PBR efficiency carry-over mechanism. The decrease was partially offset by Rate Base growth and customer additions.

Earnings
The increase in earnings was due primarily to Rate Base growth, customer additions and a lower deferred tax expense due to the utilization of tax loss carryforwards in 2019. The increase was partially offset by higher operating expenses and the impact of the PBR efficiency carry-over mechanism.

FortisBC Electric	2020	2019	Variance
Electricity sales *(GWh)*	**3,291**	3,326	(35)
Revenue *($ millions)*	**424**	418	6
Earnings *($ millions)*	**56**	54	2

Sales
The decrease in electricity sales was due to lower average consumption by commercial and industrial customers, partially offset by higher average residential consumption, both due to the impact of the COVID-19 Pandemic.

Revenue
The increase in revenue was due primarily to higher third-party contract work and Rate Base growth, partially offset by the absence of revenue associated with the provision of operating, maintenance and management services to the Waneta Expansion, which was sold in April 2019.

Earnings
The increase in earnings was due primarily to Rate Base growth, partially offset by the sale of the Waneta Expansion, discussed above.

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

Other Electric			Variance	
	2020	2019	FX	Other
Electricity sales *(GWh)*	**9,175**	9,366	—	(191)
Revenue *($ millions)*	**1,485**	1,467	4	14
Earnings *($ millions)*	**112**	106	—	6

Sales
The decrease in electricity sales was due primarily to overall lower average consumption driven by the COVID-19 Pandemic, largely reflecting the temporary closure of non-essential businesses and border closures affecting tourism-related sales in the Caribbean.

Revenue
The increase in revenue, net of foreign exchange, was due primarily to the flow through of overall higher energy supply costs and Rate Base growth, partially offset by lower sales.

Earnings
The increase in earnings was due to higher equity income from Belize Electricity and Rate Base growth, partially offset by the impact of the COVID-19 Pandemic, largely reflecting lower sales in the Caribbean.

Energy Infrastructure	**2020**	2019	Variance
Electricity sales *(GWh)*	**229**	144	85
Revenue *($ millions)*	**88**	82	6
Earnings *($ millions)*	**39**	18	21

Sales
The increase in electricity sales reflected increased hydroelectric production in Belize due to higher rainfall levels, partially offset by the Waneta Expansion disposition in 2019, which contributed sales of 80 GWh in that year.

Revenue and Earnings
The increases in revenue and earnings reflected: (i) higher hydroelectric production in Belize; and (ii) the favourable impact of mark-to-market accounting of natural gas derivatives at Aitken Creek which resulted in unrealized losses of $15 million in 2019 compared to unrealized gains of less than $1 million in 2020. The increases in revenue and earnings were partially offset by the Waneta Expansion disposition in 2019.

Aitken Creek is subject to commodity price risk, as it purchases and holds natural gas in storage to earn a profit margin from its ultimate sale. Aitken Creek mitigates this risk by using derivatives to materially lock in the profit margin that will be realized upon the sale of natural gas. The fair value accounting of these derivatives creates timing differences and the resultant earnings volatility can be significant.

Corporate and Other			Variance	
($ millions)	**2020**	2019	FX	Other
Net (expenses) income	**(148)**	333	(5)	(476)

The increase in net expenses was due to one-time items: (i) the net after-tax gain of $484 million on the April 2019 disposition of the Waneta Expansion; and (ii) a $7 million gain on the repayment of debt recognized in 2019. Excluding these one-time items, Corporate expenses, net of foreign exchange, decreased by $10 million. The decrease was driven by lower finance charges, due to the repayment of debt using proceeds from the Waneta Expansion disposition and the $1.2 billion common equity offering, and lower operating expenses, partially offset by an increase in tax expense due to valuation allowances released in 2019.

NON-US GAAP FINANCIAL MEASURES

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

Net earnings attributable to common equity shareholders (i.e., Common Equity Earnings) and basic EPS are the most directly comparable US 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 US GAAP measure to the Adjusted Payout Ratio.

Adjusted Common Equity Earnings and Adjusted Basic EPS reflect the removal of items that management excludes in its key decision-making processes and evaluation of operating results, and are reconciled as follows.

Non-US GAAP Reconciliation			
($ millions, except as shown)	**2020**	2019	Variance
Common Equity Earnings	**1,209**	1,655	(446)
Adjusting items:			
FERC base ROE decisions [(1)]	**(27)**	(83)	56
US tax reform [(2)]	**13**	12	1
Unrealized loss on mark-to-market of derivatives [(3)]	**—**	15	(15)
Gain on disposition [(4)]	**—**	(484)	484
Adjusted Common Equity Earnings	**1,195**	1,115	80
Adjusted Basic EPS *($)*	**2.57**	2.55	0.02

(1) *Represents prior period impacts of the May 2020 and November 2019 FERC base ROE decisions, respectively (see "Regulatory Highlights" below), included in the ITC segment*

(2) *The finalization of US tax reform regulations associated with anti-hybrid regulations in 2020 and base-erosion and anti-abuse tax in 2019, included in the Corporate and Other segment*

(3) *Represents timing differences related to the accounting of natural gas derivatives at Aitken Creek, included in the Energy Infrastructure segment*

(4) *Gain on sale of the Waneta Expansion, net of expenses, in April 2019, included in the Corporate and Other segment*

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 regulatory 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 generally depends 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 reflected in customer rates.

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

Additional information about regulation and the regulatory matters discussed below is provided in Note 2 in the 2020 Annual Financial Statements. Also refer to "Business Risks - Regulation" on page 28.

COVID-19 Pandemic Impacts

The COVID-19 Pandemic resulted in several customer relief initiatives as well as the delay and postponement of several regulatory proceedings in 2020, as described below. The Corporation's significant regulatory proceedings, including TEP's general rate application as well as FortisAlberta's 2021 GCOC and AESO customer contribution proceedings, were concluded by the end of 2020.

Customer Relief Initiatives

UNS Energy

Pursuant to the ACC's approval of the utility's customer relief initiatives, TEP refunded to customers approximately $11 million of collected demand side management funds in excess of program costs.

In December 2020, the ACC enacted a bill credit and payment program for residential electric customers who are behind on their electric bills as a result of the COVID-19 Pandemic, including automatic enrollment into an eight-month payment plan for qualified customers. TEP voluntarily created payment arrangements for commercial customers.

Central Hudson

In March 2020, as agreed with the PSC, Central Hudson postponed the collection in customer rates of approximately $4 million of deferred costs related mainly to environmental remediation until July 1, 2021.

FortisBC Energy and FortisBC Electric

In April 2020, pursuant to the BCUC's approval of the utilities' customer relief initiatives, FortisBC Energy and FortisBC Electric implemented three-month bill deferrals for certain customer classes, the repayment of which commenced in the third quarter of 2020. The BCUC also authorized the deferral of otherwise uncollectible revenue from customers, the recovery of which will be determined through a future rate filing once the financial impact of the pandemic is known.

Delayed and Postponed Regulatory Proceedings

UNS Energy

General Rate Application: TEP filed a rate application in April 2019 based on a 2018 test year. In December 2020 the ACC issued a rate order including new customer rates effective January 1, 2021. Provisions of the order include: (i) an increase in non-fuel revenue of $77 million (US$58 million); (ii) an allowed ROE of 9.15%, with a 0.20% return on the fair value increment and a capital structure of 53% common equity; and (iii) a Rate Base of approximately $3.5 billion (US$2.7 billion) which includes post-test year investments in Gila River Unit 2 and 10 RICE Units.

Central Hudson

2020 Rates: In June 2020, the PSC approved Central Hudson's request to postpone scheduled electric and gas delivery rate increases, reflecting an increase in the equity component of its capital structure from 49% to 50%, from July 1, 2020 to October 1, 2020. The deferred revenue associated with the delay is being collected over the nine-month period to June 30, 2021.

COVID-19 Proceeding: In June 2020, the PSC initiated a generic proceeding to identify and address the effects of the COVID-19 Pandemic. The outcome of this proceeding and potential impacts, if any, are unknown at this time.

FortisAlberta

Generic Cost of Capital Proceeding: In December 2018, the AUC initiated a GCOC proceeding to consider a formula-based approach to setting the allowed ROE beginning in 2021 and whether any process changes were necessary for determining capital structure in years in which a ROE formula is in place. In October 2020, given the time that had passed since initiation of the proceeding and ongoing economic uncertainty, the AUC concluded the proceeding and set the ROE for 2021 at 8.50% using a capital structure of 37% common equity, consistent with 2020. In December 2020, the AUC initiated a new GCOC proceeding to establish the cost of capital parameters for 2022 and possibly one or more future years. This proceeding is expected to be ongoing throughout 2021.

Other Electric
Caribbean Utilities: In August 2020, the Utility Regulation and Competition Office approved the postponement of Caribbean Utilities' scheduled June 1, 2020 annual rate adjustment to January 1, 2021 to provide customer relief from the economic effects of the COVID-19 Pandemic. The deferred revenue associated with the delay is being collected over a two-year period beginning January 2021.

FortisTCI: In February 2020, the Government of the Turks and Caicos Islands approved a 6.8% average increase in FortisTCI's electricity rates, effective April 1, 2020, including the recovery of hurricane-related costs incurred in 2017. In March 2020, to provide customer relief from the economic effects of the COVID-19 Pandemic, the effective date was postponed and new rates became effective July 22, 2020.

FortisTCI sought regulatory approval to defer its incremental operating expenses associated with the COVID-19 Pandemic. Approval was granted in December 2020 to allow the deferral of approximately $1.5 million in costs, to be amortized over the remaining 15-year life of FortisTCI's licence.

Significant Regulatory Developments

ITC
ROE Complaints: In May 2020, FERC issued an order on the rehearing of its November 2019 decision on the MISO transmission owner ROE complaints and set the base ROE for the periods from November 2013 through February 2015 and from September 2016 onward at 10.02%, up to a maximum of 12.62% with incentive adders. This represents an increase from the base ROE of 9.88%, up to a maximum of 12.24% with incentive adders, determined in FERC's November 2019 decision. Including incentive adders, the May 2020 FERC decision implies an all-in ROE for ITC's subsidiaries operating in the MISO region of 10.77%, up from 10.63% as set in the November 2019 decision.

Net regulatory liabilities of $6 million and $91 million were recorded at December 31, 2020 and 2019, respectively, reflecting: (i) the terms of the May 2020 and November 2019 decisions; and (ii) $42 million refunded to customers in 2020. The May 2020 FERC decision resulted in an increase in Fortis' net earnings of $29 million in 2020, including $27 million related to the reversal of liabilities established in prior periods (2019 - November 2019 FERC decision increased Fortis' net earnings by $63 million, including $83 million related to the reversal of liabilities established in prior periods).

Review of Transmission Incentives Policy: In March 2020, FERC issued a NOPR proposing to update its transmission incentives policy for transmission owners, including ITC, to grant incentives to projects based upon benefits to customers regarding reliability and cost savings through the reduction of transmission congestion. FERC proposed total ROE incentives of up to 250 basis points that would not be limited by the upper end of the base ROE zone of reasonableness. The NOPR also proposed, among other things, to eliminate the ROE adder for independent transmission ownership, and to increase the ROE adder for regional transmission owner participation. Comments from stakeholders, including ITC, were provided to FERC through July 2020. The outcome of these proceedings may impact future incentive adders that are included in transmission rates charged by transmission owners, including ITC.

Central Hudson
General Rate Application: In August 2020, Central Hudson filed a rate application with the PSC requesting an increase in electric and natural gas delivery revenue of $44 million and $19 million, respectively, effective July 1, 2021. An order from the PSC is expected in 2021.

FortisBC Energy and FortisBC Electric
Multi-Year Rate Plan Applications: In June 2020, the BCUC issued a decision on FortisBC Energy's and FortisBC Electric's MRP for 2020 to 2024. The decision sets the rate-setting framework for the five-year period including: (i) the level of operation and maintenance expense and growth capital to be included in customer rates, indexed for inflation less a fixed productivity adjustment factor; (ii) a forecast approach to sustainment capital; (iii) an innovation fund recognizing the need to accelerate investment in clean energy innovation; and (iv) a 50/50 sharing between customers and the utilities of variances from the allowed ROE. In the fourth quarter of 2020, the BCUC approved: (i) the January 1, 2020 delivery rate increase; and (ii) an increase in 2021 delivery rates, effective January 1, 2021, reflecting the terms of this decision.

Generic Cost of Capital Proceeding: In January 2021, the BCUC issued a notice that a GCOC proceeding will be initiated in the second quarter of 2021 and will include a review of the common equity component of capital structure and the allowed ROE effective January 1, 2022.

FortisAlberta
2018 Independent System Operator Tariff Application: In September 2019, the AUC issued a decision that addressed, among other things, a proposal to change how the AESO's customer contribution policy ("ACCP") is accounted for between distribution facility owners, such as FortisAlberta, and TFOs. The decision prevented any future investment by FortisAlberta under the policy and directed unamortized customer contributions of approximately $400 million as at December 31, 2017, which form part of FortisAlberta's Rate Base, be transferred to the incumbent TFO in FortisAlberta's service area.

In November 2020, the AUC issued a decision: (i) reversing the proposed changes to the ACCP resulting in FortisAlberta retaining its unamortized customer contributions; and (ii) directing a change in the depreciation rate for AESO contributions to reflect the parameters of the underlying transmission facilities. FortisAlberta has adjusted the estimated service life and the associated depreciation rate of the unamortized AESO contributions resulting in a decrease in depreciation expense and an associated decrease in revenue in 2020.

The AUC initiated a new proceeding in November 2020 to consider whether the ACCP should be modified on a prospective basis. A decision is expected in the second quarter of 2021.

FINANCIAL POSITION

Significant Changes between December 31, 2020 and 2019			
	Increase (Decrease)		
	FX	**Other**	
Balance Sheet Account	*($ millions)*	*($ millions)*	**Explanation**
Cash and cash equivalents	(3)	(118)	Related to the timing of debt and equity issuances, and the related reinvestment in capital and operating requirements.
Regulatory assets (current and long-term)	(25)	230	Due primarily to deferred income taxes, and the operation of energy management cost and employee future benefits deferrals, partially offset by lower derivative loss deferrals at UNS Energy.
Property, plant and equipment, net	(425)	2,435	Due to capital expenditures, partially offset by depreciation.
Goodwill	(212)	—	
Short-term borrowings	(10)	(370)	Reflects the repayment of short-term borrowings at UNS Energy and commercial paper at ITC.
Other liabilities	(16)	169	Reflects employee future benefits, refundable deposits received by ITC for transmission network upgrades, and an upfront payment received by FortisAlberta associated with a long-term energy retailer agreement.
Regulatory liabilities (current and long-term)	(48)	(207)	Due to ROE complaints liability at ITC, deferred income taxes, and the normal operation of rate stabilization and related accounts.
Deferred income tax liabilities	(34)	409	Due to higher temporary differences associated with ongoing capital investment.

Significant Changes between December 31, 2020 and 2019			
	Increase (Decrease)		
	FX	Other	
Balance Sheet Account	*($ millions)*	*($ millions)*	**Explanation**
Long-term debt (including current portion)	(296)	2,472	Reflects debt issuances, partially offset by debt repayments at the regulated utilities, largely at ITC and UNS Energy.
Shareholders' equity	(279)	445	Due primarily to: (i) Common Equity Earnings for 2020, less dividends declared on common shares; and (ii) the issuance of common shares.

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. 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 and there could be higher-than-normal working capital deficiencies in the short term, as the ongoing impacts of the COVID-19 Pandemic affects customers' ability to pay their energy bills. See "Business Risks" on page 28.

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

Although Fortis and its utilities continue to be successful in accessing capital markets, the ability to access cash through capital markets may be impacted by the COVID-19 Pandemic.

Credit facilities are syndicated primarily with large banks in Canada and the US, with no one bank holding more than approximately 25% of the total facilities. Approximately $5.3 billion of the total credit facilities are committed with maturities ranging from 2021 through 2025. Available credit facilities are summarized in the following table.

Credit Facilities As at December 31 *($ millions)*	Regulated Utilities	Corporate and Other	**2020**	2019
Total credit facilities [(1)]	3,700	1,881	**5,581**	5,590
Credit facilities utilized:				
Short-term borrowings	(132)	—	**(132)**	(512)
Long-term debt (including current portion)	(714)	(266)	**(980)**	(640)
Letters of credit outstanding	(77)	(53)	**(130)**	(114)
Credit facilities unutilized	2,777	1,562	**4,339**	4,324

(1) *Additional information about these credit facilities is provided in Note 14 in the 2020 Annual Financial Statements.*

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, 2020, consolidated fixed-term debt maturities/repayments are expected to average $891 million annually over the next five years and approximately 81% of the Corporation's consolidated long-term debt, excluding credit facility borrowings, had maturities beyond five years.

In December 2020, 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. As at December 31, 2020, $2.0 billion remained available under the short-form base shelf prospectus.

Fortis is well positioned with strong liquidity due, in part, to its $1.2 billion common equity offering and sale of the Waneta Expansion in 2019. See "Cash Flow Summary - Financing Activities" on page 20.

This combination of available credit facilities and manageable annual debt maturities/repayments provides flexibility in the timing of access to capital markets. Given current credit ratings and capital structures, the Corporation and its subsidiaries currently expect to continue to have reasonable access to long-term capital in 2021.

Fortis and its subsidiaries were in compliance with debt covenants as at December 31, 2020 and are expected to remain compliant in 2021.

CASH FLOW SUMMARY

Summary of Cash Flows Years ended December 31 *($ millions)*	**2020**	2019	Variance
Cash, beginning of year	**370**	332	38
Cash provided from (used in):			
Operating activities	**2,701**	2,663	38
Investing activities	**(4,132)**	(2,768)	(1,364)
Financing activities	**1,327**	154	1,173
Effect of exchange rate changes on cash and cash equivalents	**(17)**	(26)	9
Cash and change in cash associated with assets held for sale	**—**	15	(15)
Cash, end of year	**249**	370	(121)

Operating Activities
See "Performance at a Glance - Operating Cash Flow" on page 7.

Investing Activities
Cash used in investing activities reflects higher capital expenditures in 2020. See "Performance at a Glance - Capital Expenditures" on page 7 and "Capital Plan" on page 24. Cash used in investing activities in 2019 was partially offset by proceeds from the Waneta Expansion disposition.

Financing Activities
Cash flow 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 19.

In the fourth quarter of 2019, the Corporation issued approximately 22.8 million common shares at a price of $52.15 per share for gross proceeds of $1,190 million ($1,167 million net of commissions). The net proceeds were used to redeem US$500 million of its outstanding 2.10% unsecured senior notes due October 4, 2021, to repay credit facility borrowings and for general corporate purposes. Also in 2019, net proceeds of $995 million from the April 2019 Waneta Expansion disposition were used to repay credit facility borrowings and repurchase, via a tender offer, US$400 million of its outstanding 3.055% unsecured senior notes due in 2026.

Debt Financing

Long-Term Debt Issuances Year ended December 31, 2020 *($ millions, except %)*	**Month Issued**	**Interest Rate** *(%)*	**Maturity**		**Amount**	**Use of Proceeds**
ITC						
Unsecured term loan credit agreement	January	*(1)*	2021	US	75	*(2)(3)*
Unsecured term loan credit agreement *(4)*	January	*(5)*	2021	US	200	*(4)*
Unsecured senior notes	May	2.95	2030	US	700	*(2)(3)(6)*
First mortgage bonds	July	3.13	2051	US	180	*(2)(3)(7)*
Secured senior notes	October	3.02	2055	US	150	*(2)(3)(7)(8)*
UNS Energy						
Unsecured senior notes	April	4.00	2050	US	350	*(2)(3)*
Unsecured senior notes	August	1.50	2030	US	300	*(7)*
Unsecured senior notes	September	2.17	2032	US	50	*(2)(3)*
Central Hudson						
Unsecured senior notes	May	3.42	2050	US	30	*(3)*
Unsecured senior notes	July	3.62	2060	US	30	*(3)(7)*
Unsecured senior notes	September	2.03	2030	US	40	*(8)*
Unsecured senior notes	November	2.03	2030	US	30	*(3)(7)*
FortisBC Energy						
Unsecured debentures	July	2.54	2050		200	*(7)*
FortisAlberta						
Unsecured senior debentures	December	2.63	2051		175	*(2)*
FortisBC Electric						
Unsecured debentures	May	3.12	2050		75	*(2)*
Newfoundland Power						
First mortgage sinking fund bonds	April	3.61	2060		100	*(2)(3)*
FortisTCI						
Unsecured senior notes	June/October	5.30	2035	US	30	*(7)(8)*
Unsecured senior notes	October/December	3.25	2030	US	10	*(3)*

(1) *Floating rate of a one-month LIBOR plus a spread of 0.45%*
(2) *Repay credit facility borrowings*
(3) *General corporate purposes*
(4) *Maximum amount of borrowings under this agreement of US$400 million has been drawn; current period borrowings were used to repay an outstanding commercial paper balance.*
(5) *Floating rate of a two-month LIBOR plus a spread of 0.60%*
(6) *Early redemption of unsecured term loan borrowing of US$400 million*
(7) *Finance capital expenditures*
(8) *Repay maturing long-term debt*

Common Equity Financing

Common Equity Issuances and Dividends Paid Years ended December 31 *($ millions, except as indicated)*	2020	2019	Variance
Common shares issued:			
Cash [(1)]	**58**	1,442	(1,384)
Non-cash [(2)]	**116**	314	(198)
Total common shares issued	**174**	1,756	(1,582)
Number of common shares issued *(# millions)*	**3.5**	34.8	(31.3)
Common share dividends paid:			
Cash	**(786)**	(494)	(292)
Non-cash [(3)]	**(114)**	(299)	185
Total common share dividends paid	**(900)**	(793)	(107)
Dividends paid per common share *($)*	**1.9375**	1.8275	0.1100

(1) *Includes common shares issued under stock option and employee share purchase plans. For 2019, mainly reflects the issuance of shares in December 2019 and through the ATM Program.*
(2) *Common shares issued under the DRIP and stock option plan. Effective March 1, 2020, the 2% discount offered on common share issuances under the DRIP was terminated and effective December 1, 2020 was reinstated. See "Cash Flow Requirements" on page 19 for further information.*
(3) *Common share dividends reinvested under the DRIP*

On February 11, 2021, Fortis declared a dividend of $0.505 per common share payable on June 1, 2021. The payment of dividends is at the discretion of the board of directors and depends on the Corporation's financial condition and other factors.

CONTRACTUAL OBLIGATIONS

Contractual Obligations As at December 31, 2020 *($ millions)*	Total	Due Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Long-term debt:							
Principal [(1)]	**24,514**	1,254	823	1,786	1,088	484	19,079
Interest	**16,113**	980	949	919	859	824	11,582
Finance leases [(2)]	**1,225**	33	34	34	34	34	1,056
Other obligations	**557**	184	112	97	37	37	90
Other commitments: [(3)]							
Waneta Expansion capacity agreement	**2,576**	52	53	54	55	56	2,306
Gas and fuel purchase obligations	**2,355**	679	453	312	192	124	595
Power purchase obligations	**1,867**	249	208	188	191	180	851
Renewable PPAs	**1,380**	102	102	101	101	101	873
ITC easement agreement	**381**	13	13	13	13	13	316
Debt collection agreement	**112**	3	3	3	3	3	97
Renewable energy credit purchase agreements	**97**	15	14	16	9	7	36
Other	**116**	48	5	4	4	3	52
	51,293	3,612	2,769	3,527	2,586	1,866	36,933

(1) *Amounts not reduced by unamortized deferred financing and discount costs of $147 million. Additional information is provided in Note 14 in the 2020 Annual Financial Statements.*
(2) *Additional information is provided in Note 15 in the 2020 Annual Financial Statements.*
(3) *Additional information is provided in Note 28 in the 2020 Annual Financial Statements.*

Other Contractual Obligations

The Corporation's regulated utilities are obligated to provide service to customers within their respective service territories. Consolidated capital expenditures are forecast to be approximately $3.8 billion for 2021 and approximately $19.6 billion over the five-year 2021-2025 capital plan. See "Capital Plan" on page 24.

Under a funding framework with the Governments of Ontario and Canada, Fortis will contribute a minimum of approximately $155 million of equity capital to the Wataynikaneyap Partnership based on Fortis' proportionate 39% ownership interest and the final regulatory-approved capital cost of the related project. In October 2019 the Wataynikaneyap Partnership entered into loan agreements to finance the project during construction. In the event a lender under the loan agreements realizes security on the loans, Fortis may be required to accelerate its equity capital contributions, which may be in excess of the amount otherwise required of Fortis under the funding framework, to a maximum total funding of $235 million.

UNS Energy has joint generation performance guarantees with participants at San Juan, Four Corners, and Luna, with agreements expiring in 2022 through 2046, and at 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 Navajo, participants would seek financial recovery from the defaulting party. There is no maximum amount under these guarantees, except for a maximum of $318 million for Four Corners. As at December 31, 2020, there was no obligation under these guarantees.

Central Hudson is a participant in an investment with other utilities to jointly develop, own and operate electric transmission projects in New York State. Central Hudson's maximum commitment is $94 million, for which it has issued a parental guarantee. As at December 31, 2020, there was no obligation under this guarantee.

As at December 31, 2020, FortisBC Holdings Inc., a non-regulated holding company, had $69 million of parental guarantees outstanding to support storage optimization activities at Aitken Creek.

Off-Balance Sheet Arrangements
With the exception of letters of credit outstanding of $130 million as at December 31, 2020 and the unrecorded commitments in the table above, the Corporation had no off-balance sheet arrangements.

CAPITAL STRUCTURE AND CREDIT RATINGS

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

Consolidated Capital Structure *(%)*		
As at December 31	**2020**	2019
Debt [(1)]	**54.8**	53.1
Preference shares	**3.6**	3.8
Common shareholders' equity and minority interest [(2)]	**41.6**	43.1
	100.0	100.0

(1) *Includes long-term debt and finance leases, including current portion, and short-term borrowings, net of cash*
(2) *Includes minority interest of 3.5% as at December 31, 2020 (2019 - 3.7%)*

Outstanding Share Data
As at February 11, 2021, the Corporation had issued and outstanding 466.8 million common shares and the following First Preference Shares: 5.0 million Series F; 9.2 million Series G; 7.7 million Series H; 2.3 million Series I; 8.0 million Series J; 10.0 million Series K; and 24.0 million Series M.

Only 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, 2021, an additional 3.3 million common shares would be issued and outstanding.

Credit Ratings

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

Credit Ratings As at December 31, 2020	**Rating**	**Type**	**Outlook**
S&P	A-	Corporate	Negative
	BBB+	Unsecured debt	
DBRS Morningstar	BBB (high)	Corporate	Positive
	BBB (high)	Unsecured debt	
Moody's	Baa3	Issuer	Stable
	Baa3	Unsecured debt	

CAPITAL PLAN

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

The COVID-19 Pandemic did not have a material impact on capital expenditures in 2020. Capital expenditures of $4.2 billion were broadly consistent with the 2020 capital plan as disclosed in the 2019 MD&A.

2020 Capital Expenditures (1)	**Regulated Utilities**										
($ millions, except %)	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Other Electric	**Total Regulated Utilities**	**Non-Regulated** (2)	**Total**	***(%)***
Generation	—	639	—	—	—	26	42	**707**	**5**	**712**	**17**
Transmission	1,070	84	48	138	—	34	165	**1,539**	**—**	**1,539**	**37**
Distribution	—	330	188	207	333	46	167	**1,271**	**—**	**1,271**	**30**
Other (3)	112	147	103	126	87	29	37	**641**	**14**	**655**	**16**
Total	1,182	1,200	339	471	420	135	411	**4,158**	**19**	**4,177**	**100**
(%)	29	29	8	11	10	3	10	**100**	**—**	**100**	

(1) *Reflects cash outlay for property, plant and equipment and intangible assets as shown on the Consolidated Statements of Cash Flows in the 2020 Annual Financial Statements, as well as Fortis' $138 million share of development costs and capital spending for the Wataynikaneyap Transmission Power Project included in the Other Electric segment.*

(2) *Includes Energy Infrastructure and Corporate and Other segments*

(3) *Includes facilities, equipment, vehicles and information technology assets, as well as AESO transmission-related capital expenditures at FortisAlberta*

Planned capital expenditures are based on detailed forecasts of energy demand, labour and material costs, general economic conditions, foreign exchange rates and other factors. These could change and cause actual expenditures to differ from forecast or plan. The impact of the COVID-19 Pandemic on forecast capital expenditures will continue to be evaluated and, depending on the length and severity of the pandemic, certain planned expenditures may shift within the 2021-2025 capital plan.

Forecast 2021 Capital Expenditures (1)	**Regulated Utilities**										
($ millions, except %)	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Other Electric	**Total Regulated Utilities**	**Non-Regulated**	**Total**	***(%)***
Generation	—	117	1	—	—	24	189	**331**	**53**	**384**	**10**
Transmission	949	191	41	168	—	23	310	**1,682**	**—**	**1,682**	**44**
Distribution	—	270	167	184	266	81	173	**1,141**	**—**	**1,141**	**30**
Other	51	171	97	115	80	25	49	**588**	**18**	**606**	**16**
Total	1,000	749	306	467	346	153	721	**3,742**	**71**	**3,813**	**100**
(%)	26	20	8	12	9	4	19	**98**	**2**	**100**	

(1) *Excludes the non-cash equity component of AFUDC. Includes Fortis' share of development costs and capital spending for the Wataynikaneyap Transmission Power Project included in the Other Electric segment.*

Five-Year Capital Plan [1]						
($ billions)	2021	2022	2023	2024	2025	**Total**
	3.8	3.9	3.9	4.0	4.0	**19.6**

(1) *Excludes the non-cash equity component of AFUDC. Includes Fortis' share of development costs and capital spending for the Wataynikaneyap Transmission Power Project included in the Other Electric segment.*

The $19.6 billion five-year capital plan is $0.8 billion higher than the $18.8 billion five-year plan for 2020-2024, as disclosed in the 2019 MD&A. The increase is largely due to: (i) two new major capital projects at FortisBC Energy including the Tilbury LNG Resiliency Tank project and the AMI project, with total expected capital spend of approximately $500 million; (ii) $200 million of additional investment in information technology systems and storm hardening at Central Hudson; and (iii) $100 million of interconnections and system rebuilds to provide additional capacity and other improvements at ITC.

The capital plan is low risk and highly executable, with 99% of planned expenditures to occur at the regulated utilities and only 15% related to Major Capital Projects. Geographically, 55% of planned expenditures are expected in the US, including 26% at ITC, with 41% in Canada and the remaining 4% in the Caribbean.

Nature of Capital Expenditures	**Actual**	Forecast	Five-Year Plan
(%)	**2020**	2021	2021-2025
Growth [1]	**21**	31	26
Sustaining [2]	**65**	54	58
Other [3]	**14**	15	16
Total	**100**	100	100

(1) *Relates to the connection of new customers and infrastructure upgrades required to meet load growth, including AESO transmission-related investment at FortisAlberta*
(2) *Relates to the continued and enhanced performance, reliability and safety of generation, transmission and distribution assets*
(3) *Facilities, equipment, vehicles, information technology and other assets*

Midyear Rate Base [1]			
($ billions)	**2020**	2021	2025
ITC	**9.5**	9.9	12.5
UNS Energy	**5.7**	6.2	7.6
Central Hudson	**2.1**	2.3	3.2
FortisBC Energy	**5.1**	5.2	6.8
FortisAlberta	**3.7**	3.8	4.2
FortisBC Electric	**1.4**	1.5	1.7
Other Electric	**3.0**	3.3	4.3
Total	**30.5**	32.2	40.3

(1) *Simple average of Rate Base at beginning and end of the year*

Total midyear Rate Base is forecast to grow to $40.3 billion by 2025 under the five-year capital plan, representing a CAGR of approximately 6.0%, which is supportive of continuing growth in earnings and dividends.

Major Capital Projects [1]				Forecast		
		Pre-	Actual		2022-	Expected
($ millions)	Project	2020	2020	2021	2025	Completion
ITC [2]	Multi-Value Regional Transmission Projects	625	**17**	75	186	2023
	34.5 to 69 kV Transmission Conversion Project	352	**93**	41	107	Post-2025
UNS Energy	Vail-to-Tortolita Project	—	**—**	54	190	2023
	Oso Grande Wind Project	65	**509**	24	—	2021
FortisBC Energy	Lower Mainland Intermediate Pressure System Upgrade	388	**23**	18	—	2021
	Eagle Mountain Woodfibre Gas Line Project [3]	—	**—**	—	350	2025
	Transmission Integrity Management Capabilities Project	13	**8**	7	434	Post-2025
	Inland Gas Upgrades Project	9	**50**	53	177	2025
	Tilbury 1B	8	**12**	1	375	2025
	Tilbury LNG Resiliency Tank	—	**10**	11	198	Post-2025
	AMI Project	—	**—**	4	243	Post-2025
Other Electric	Wataynikaneyap Transmission Power Project [4]	40	**138**	330	206	2023
Total			**860**	618	2,466	

(1) *Includes applicable AFUDC*
(2) *Pre-2020 capital expenditures are from the date of the ITC acquisition on October 14, 2016*
(3) *Net of forecast customer contributions*
(4) *Fortis' share of estimated capital spending, including deferred development costs. Under the funding framework, Fortis will be funding its equity component only.*

Multi-Value Regional Transmission Projects
Four regional electric transmission projects that have been identified by MISO to address system capacity needs and reliability in various states. Three projects were completed pre-2020. The fourth project is expected to be placed in service in 2023.

34.5 to 69kV Transmission Conversion Project
Multiple capital initiatives designed to construct new 69 kV lines, upgrade existing 34.5 kV lines to 69 kV, and complete substation conversions with in service dates ranging from pre-2020 to post-2025.

Vail-to-Tortolita Project
A phase of the Southline Transmission Project that consists of new construction and upgrades to connect existing TEP substations. The project includes the construction of a new 230 kV line within TEP's service territory. Construction is expected to begin in early 2022 with an in-service date of 2023.

Oso Grande Wind Project
Construction of a 750 MW wind-powered electric generating facility that complements UNS Energy's existing renewable solar generation portfolio, of which UNS Energy owns 250 MW. Construction is expected to be completed and the facility placed in service in the first half of 2021.

Lower Mainland Intermediate Pressure System Upgrade
Addresses system capacity and pipeline condition issues for the gas supply system in the Lower Mainland of British Columbia. The project is substantially complete, with one pipeline segment to be replaced in 2021. Final allowable project costs are subject to review by the BCUC.

Eagle Mountain Woodfibre Gas Line Project
Gas line expansion to a proposed LNG site in Squamish, British Columbia. In March 2020 Woodfibre LNG Limited, the owner of the proposed LNG facility, requested an extension to its British Columbia Environmental Assessment Certificate due to production and supply chain disruptions resulting, in part, from the COVID-19 Pandemic. In October 2020, the BC Environmental Assessment Certificate was extended for another five years.

FortisBC Energy's proposed pipeline expansion remains contingent on Woodfibre LNG Limited making a final decision to proceed with construction of the LNG facility. At this time, should the project proceed, the earliest construction start date expected is late-2021.

Transmission Integrity Management Capabilities Project
This project improves gas line safety and transmission system integrity, including gas line modifications and looping. A CPCN application is expected to be filed with the BCUC in the first quarter of 2021.

Inland Gas Upgrades Project
Gas line modifications and replacements to enable in-line integrity inspection capabilities. In January 2020 the CPCN application was approved by the BCUC.

Tilbury 1B Project
Construction of additional liquefaction and dispensing, including on-shore piping, in support of marine bunkering and to further optimize the Tilbury Phase 1A Expansion Project. The project received an Order in Council from the Government of British Columbia in 2017. In February 2020 an initial project scope was filed with regulators to begin the federal impact assessment and provincial environmental assessment required to further expand the Tilbury site. Engineering design and related studies will continue in 2021.

Tilbury LNG Resiliency Tank
This project replaces the original LNG storage tank at the Tilbury site and increases the available regasification capacity to provide backup gas supply for lower mainland customers. In December 2020 FortisBC Energy filed a CPCN application for this project with the BCUC.

AMI Project
Replacement of residential and small commercial meters and installation of bypass valves to avoid future interruption of gas service. The project will assist in load management by allowing remote meter reading on a near real-time basis and remote shutoff of gas flow. FortisBC Energy plans to file a CPCN application for this project with the BCUC in the first half of 2021.

Wataynikaneyap Transmission Power Project
Construction of a 1,800 kilometre, Ontario Energy Board regulated transmission line to connect 17 remote First Nations communities in Northwestern Ontario to the main electricity grid, in which Fortis holds a 39% equity interest. FortisOntario is responsible for construction management and operation of the transmission line. The project is on track with completion expected in 2023.

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 - Lake Erie Connector
Proposed 1,000 MW, bi-directional, high-voltage direct current underwater transmission line to directly link the markets of the Ontario Independent Electricity System Operator and PJM Interconnection, LLC. The project would enable transmission customers to more efficiently access energy, capacity and renewable energy credit opportunities in both markets. The major permits have been approved. The project continues to advance through regulatory, operational and economic milestones. Ongoing activities include completing project cost refinements and securing transmission service agreements. Completion would take approximately four years from the commencement of construction.

FortisBC Energy - LNG
Pursuit of additional LNG infrastructure opportunities in British Columbia, including further expansion of the Tilbury LNG facility, which is uniquely positioned to meet customer demand for clean-burning natural gas. The site is scalable and can accommodate additional storage and liquefaction equipment and is relatively close to international shipping lanes. FortisBC Energy continues to have discussions with potential export customers.

Other Opportunities
Includes incremental regulated transmission investment, contracted transmission and grid modernization projects at ITC; renewable energy investments, energy storage projects, grid modernization, infrastructure resiliency, and transmission investments at UNS Energy; further gas infrastructure opportunities at FortisBC Energy; and cleaner energy infrastructure investments across our jurisdictions.

BUSINESS RISKS

Fortis has established an ERM process to help identify and evaluate risks by both severity of impact and probability of occurrence. Materiality thresholds are reviewed and, if necessary, updated annually. Non-financial risks that may impact the safety of employees, customers or the general public, as well as reputational risks, are also evaluated. Systems of internal controls are established to monitor and manage identified risks. The ERM process at the subsidiary level is overseen by each subsidiary’s board of directors and any material risks identified are communicated to Fortis management and form part of Fortis' ERM program. The Fortis board of directors, through the audit committee, oversees Fortis' ERM program, ensuring strategic objectives are achieved.

A summary of the Corporation's current significant business risks follows.

Regulation
Regulated utility assets represented approximately 99% of the Corporation's total assets as at December 31, 2020. Regulatory jurisdictions include five Canadian provinces, nine US states and three Caribbean countries, as well FERC regulation for transmission assets in the US.

Regulators administer legislation covering material aspects of the utilities' business, including: customer rates and the underlying 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 is particularly significant for UNS Energy given the use of historical test years in setting rates.

The ability to recover the actual cost of service and earn the approved ROE or ROA typically depends on achieving the forecasts established in the rate-setting process. Failure to do so could have a Material Adverse Effect. For those utilities subject to PBR mechanisms, rates reflect assumed inflation rates and productivity improvement factors, and variances therefrom could have a Material Adverse Effect. Under FortisAlberta's PBR mechanism there is an added risk that incremental incurred capital expenditures may not be approved for recovery in rates.

For transmission operations, the underlying elements of FERC-established formula rates can be, and have been, challenged by third parties which could result in, and has resulted in, lowered rates and customer refunds. These underlying elements include the assumed ROE, ROE adders for independent transmission ownership and deemed capital structure as well as operating and capital expenditures. These challenges could have a Material Adverse Effect.

Additionally, the US 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 US federal energy matters. Such changes could have a Material Adverse Effect.

The political and economic environments as well as their effect on energy laws and governmental energy policies have had, and may continue to have, negative impacts on regulatory decisions. While Fortis is well positioned to maintain constructive regulatory relationships through local management teams and boards comprised mostly of independent local members, it cannot predict future legislative or regulatory changes, whether caused by economic, political or other factors, or its ability to respond thereto in an effective and timely manner, or the resulting compliance costs. These dynamics could have a Material Adverse Effect.

Climate Change and Physical Risks
The provision of electric and gas service is subject to customary industry risks, including severe weather and natural disasters, wars, terrorism, critical equipment failure and other catastrophic events within and outside the Corporation's service territories. Resultant service disruption and repair and replacement costs 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.

Climate change is predicted to lead to more frequent and intense weather events, changing air temperatures, changing seasonal variations, and regulatory responses (see "Environmental Matters" on page 30), each of which could have a Material Adverse Effect. Severe weather impacts the Corporation’s service territories, primarily when thunderstorms, flooding, wildfires, hurricanes and snow or ice storms occur. Increased frequency of extreme weather events could increase the cost of providing service. Changes in precipitation that result in droughts could increase the risk of wildfire caused by the Corporation’s electricity assets or may cause water shortages that could adversely affect operations. Extreme weather conditions in general require system backup and can contribute to increased system stress, including service interruptions. Changing air temperatures could also result in system stress and decreased efficiencies to operating facilities over time. Longer-term climate change impacts, such as sustained higher temperatures, higher sea levels and larger storm surges, could result in service disruption, repair and replacement costs, and costs associated with strengthened design standards and systems, each of which 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.

Generating equipment and facilities are subject to risks, including equipment breakdown and flood and fire damage, that may result in the uncontrolled release of water, interruption of fuel supply, lower-than-expected operational efficiency or performance, and service disruption. There is no assurance that generating equipment and facilities will continue to operate in accordance with expectations.

The operation of transmission and distribution assets is subject to risks, including the potential to cause fires, mainly as a result of equipment failure, falling trees and lightning strikes to lines or equipment. Certain utilities operate in remote and mountainous terrain that can be difficult to access for timely repairs and maintenance, or otherwise face risk of loss or damage from forest fires, floods, washouts, landslides, earthquakes, avalanches and other acts of nature with a potential Material Adverse Effect.

The 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, and other accidents and issues that can lead to service disruption, spills and commensurate environmental liability, or other liability with a Material Adverse Effect.

Risks associated with fire damage vary depending on weather, forestation, the proximity of habitation and third-party facilities to utility facilities, and other factors. The utilities may become liable for fire-suppression costs, regeneration and timber value costs, and third-party claims if their facilities are held responsible for a fire, and such claims, if successful, could have a Material Adverse Effect.

Electricity and gas systems require ongoing maintenance, improvement and replacement. Service disruption, other effects and liability caused by the failure to properly implement or complete approved maintenance and capital expenditures, the occurrence of significant unforeseen equipment failures, or the inability to recover requisite costs in customer rates, could have a Material Adverse Effect.

The electricity and gas systems are designed to service customers under various contingencies in accordance with good utility practice. 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. The impacts of climate change may necessitate the acceleration of these standards, processes and procedures. Failure to do so may disrupt the ability of the utilities to safely provide service, which could cause reputational harm and other impacts with a Material Adverse Effect.

Pandemics and Public Health Crises, including the COVID-19 Pandemic

The Corporation could be negatively impacted by a widespread outbreak of communicable diseases or other public health crises that cause economic and/or other disruptions. The COVID-19 Pandemic continues to be an evolving situation that has adversely impacted economic activity and conditions around the world, including the Corporation's service territories (see "General Economic Conditions" and "Access to Capital" on page 34). The virus and efforts to reduce the health impacts and control its spread have led many jurisdictions around the world, including Canada, the US and the Caribbean, to institute restrictions on travel, gatherings and business operations. The Corporation and its utilities have been subjected to government and regulatory action in response to the COVID-19 Pandemic, including restrictions on business operations, customer deferrals and suspension of disconnections. Other potential impacts on the Corporation's operations may include reduced labour availability and productivity, disruptions to capital markets leading to share price volatility and liquidity issues, supply chain disruptions, project construction delays and a prolonged reduction in economic activity. An extended economic slowdown could reduce energy sales and adversely impact the ability of customers, contractors and suppliers to fulfill their obligations and could disrupt operations and capital expenditure programs or cause impairment of goodwill.

The overall impact will depend on the duration and severity of the pandemic, potential government actions to mitigate public health effects or aid economic recovery, and other factors beyond the Corporation's control. An extended period of economic disruption could have a Material Adverse Effect.

Environmental Matters
The Corporation's businesses are subject to environmental risks and environmental laws and regulations, including those which: (i) impose limitations or restrictions on the discharge of pollutants into the air, soil and water; (ii) establish standards for the management, treatment, storage, transportation and disposal of hazardous wastes; and/or (iii) impose obligations to investigate and remediate contamination.

The risk of contamination of air, soil and water at the electric businesses 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 the gas businesses 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.

Liabilities relating to contamination investigation and remediation, and 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 or whether it resulted from non-compliance with applicable environmental laws. Under some environmental laws, such liabilities may be joint and several, meaning that a party can be held responsible for more than its share of the liability involved or even the entire liability. These liabilities could lead to litigation and administrative proceedings that could result in substantial monetary judgments for clean-up costs, damages, fines and/or penalties. To the extent not fully covered by insurance, these costs could have a Material Adverse Effect.

The Corporation's businesses have incurred substantial expenses for environmental compliance, and they anticipate continuing to do so in the future. In particular, the management of GHG emissions is a major concern due to new and emerging federal, state and provincial GHG laws, regulations and guidelines.

The Corporation's businesses continue to develop compliance strategies and assess the impact of emerging legislative changes, but significant uncertainties remain. Increased compliance costs or additional operating restrictions from revised or additional regulation could have a Material Adverse Effect.

Growth
Fortis has a history of growth through acquisitions and organic growth from capital investment in existing service territories. Acquisitions include inherent risks that some or all of the expected benefits may fail to materialize, or may not occur within the time periods anticipated, and material unexpected costs may arise.

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 described under "Capital Plan" on page 24. Projects, particularly Major Capital Projects, are subject to risks of delay and cost overruns during construction caused by inflation, supply and labour costs, 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. These risks could impact the successful execution of a project by preventing the project from proceeding, delaying its completion, increasing its projected costs or negatively impacting its financing.

Weather Variability and Seasonality
Electricity consumption varies significantly in response to climate change and seasonal weather changes (see "Climate Change and Physical Risks" on page 28). In central and western Canada, Arizona and New York State, cool summers may reduce the use of air conditioning and other cooling equipment, while less severe winters may reduce heating load. Alternatively, severe weather could unexpectedly increase heating and cooling loads, negatively impacting system reliability.

Weather and seasonality have a significant impact on gas distribution volumes as a major portion of the gas is used for space heating by residential customers. The earnings of the Corporation's gas utilities and Aitken Creek are typically highest in the first and fourth quarters.

Hydroelectric generation is sensitive to rainfall levels.

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. Both the discontinuance of key regulatory mechanisms and their absence at other Fortis entities could result in significant and prolonged weather variations from seasonal norms having a Material Adverse Effect.

Natural Gas Competitiveness
Approximately 19% of the Corporation's revenue is derived from the delivery of natural gas. A decrease in the competitiveness of natural gas due to pricing or other factors could have a Material Adverse Effect.

In British Columbia, which accounts for 80% of the Corporation's natural gas revenue, natural gas primarily competes with electricity for space and hot water heating. Upfront capital costs for gas service continue to present competitive challenges for natural gas compared to electricity service. If gas becomes less competitive, 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, whereby system costs must be recovered from a smaller customer and sales base, leading to further reductions in competitiveness.

Government policy could also impact the competitiveness of natural gas in British Columbia. The provincial government has introduced changes to energy policy, including GHG emission reduction targets and a tax on carbon-based fuels which is expected to increase in the future. However, the Government of British Columbia has yet to introduce a carbon tax on imported electricity generated through the combustion of carbon-based fuels. As all levels of government become more active in the development of policies to address climate change, any resultant changes to energy policy may have a material impact on the competitiveness of natural gas relative to non-carbon based energy sources or other energy sources.

There are other competitive challenges that are impacting the penetration of natural gas into new housing stock such as green attributes of the energy source, and type of housing stock being built. In addition, 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. The municipalities can also provide incentives, such as higher density allowance, to builders to adopt carbon free options for their developments. These actions and policies may hinder the Corporation's ability to attract new customers or retain existing customers.

Commodity Price Volatility
Purchased power 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 (see "Business Unit Performance" on page 10); and (ii) price-risk management strategies such as the use of derivative contracts that effectively fix costs (see "Financial Instruments - Derivatives" on page 39).

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

Required Approvals
The acquisition, ownership and operation of electric and gas businesses require numerous licences, permits, agreements, orders, certificates and other approvals from various levels of government, regulators, government agencies, Indigenous Peoples and/or third parties. The external environment has become more complex with heightened expectations from permitting agencies, local municipalities and Indigenous Peoples to be able to review and provide feedback on projects, largely driven by policy responses to climate change. There is no assurance that: (i) all of these 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* requires owners, operators and users of the bulk electric system in the US 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, Alberta and Ontario. 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, such as the exclusion from customer rates of related costs including potentially significant penalties.

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

FortisAlberta has distribution assets on Indigenous Peoples' lands in Alberta with access permits held by TransAlta Utilities Corporation. To acquire these permits, FortisAlberta requires approval from First Nations and Crown-Indigenous Relations and Northern Affairs Canada. FortisAlberta may be unable to obtain such approvals or negotiate land-use agreements with reasonable terms. Significant failures in these regards could have a Material Adverse Effect.

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.

Wataynikaneyap Partnership, which is owned 51% by 24 First Nations communities and 49% by a partnership between Fortis (80%) and Algonquin Power & Utilities Corp. (20%), is responsible for the Wataynikaneyap Transmission Power Project. Fortis does not have sole discretion on decisions for the project and divergence in the interest of Fortis and the other partners could delay the project’s completion, increase its anticipated cost, or adversely affect the reputation of Fortis.

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.

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

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

Cybersecurity
As operators of critical energy infrastructure, the Corporation's utilities face the risk of cybercrime, which has increased in frequency, scope and potential impact in recent years. Their ability to operate effectively is dependent upon developing and maintaining complex information systems and infrastructure that: (i) support the operation of electric generation, transmission and distribution facilities, including 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 may be vulnerable to unauthorized access due to hacking, viruses, acts of war or terrorism, acts of vandalism and other causes. This can result in the disruption of energy service and other business operations, system failures and grid disturbances, property damage, corruption or unavailability of critical data, and the misappropriation and/or disclosure of sensitive, confidential and proprietary business, customer and employee information.

A material breach could adversely affect the financial performance of the Corporation, its reputation and standing with customers, regulators and financial markets, and expose it to claims for third-party damage. 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.

Technology Advances
The emergence of initiatives designed to reduce GHG emissions and control or limit the effects of climate change has increased the incentive for the development of new technologies that produce power, enable more efficient storage of energy or reduce power consumption.

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 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.

Interest Rates
Generally, the market price of the Corporation's common shares is inversely sensitive to interest rate changes. Additionally, allowed ROEs are exposed to changes in long-term interest rates. A low interest rate environment could reduce allowed ROEs. Alternatively, if interest rates rise, regulatory lag may cause delays in any compensatory ROE increases. Borrowings under variable-rate credit facilities and long-term debt, as well as new debt issuances, are also exposed to interest rate changes.

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

Foreign Exchange Exposure
The reporting currency of ITC, UNS Energy, Central Hudson, Caribbean Utilities, FortisTCI, BECOL and Belize Electricity is, or is pegged to, the US dollar. The earnings and cash flow from, and net investments in, these entities are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate.

Fortis has limited this exposure through hedging. As at December 31, 2020, US$2.3 billion (2019 - US$2.2 billion) of corporately issued US dollar-denominated long-term debt had been designated as an effective hedge of foreign net investments, leaving US$10.2 billion (2019 - US$9.7 billion) in foreign net investments unhedged. Fortis has also entered into foreign exchange contracts to manage a portion of its exposure to foreign currency risk.

Given only partial hedging, consolidated earnings and cash flow continue to be impacted by exchange rate fluctuations. On average, Fortis estimates that a five-cent increase or decrease in the US dollar relative to the Canadian dollar exchange rate of US$1.00=CA$1.34 as at December 31, 2020 would increase or decrease annual EPS by approximately six cents, which reflects the Corporation's hedging program.

The Corporation's $19.6 billion five-year capital plan for 2021 through 2025 also includes exposure to foreign exchange. On average, Fortis estimates that a five-cent increase or decrease in the US dollar relative to the Canadian dollar would increase or decrease capital expenditures by $400 million over the five-year planning period.

There is no assurance that existing hedging strategies will continue to be effective and the resultant financial impacts could have a Material Adverse Effect.

Access to Capital
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 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 such financing is subject to numerous factors, including the results of operations and financial condition of Fortis and its subsidiaries, the regulatory environments including regulatory decisions regarding capital structure and allowed ROEs, capital market conditions, general economic conditions and credit ratings. Changes in credit ratings could affect credit risk spreads on new long-term debt and credit facilities, as well as their availability.

There is no assurance that sufficient capital will continue to be available on acceptable terms. For further information see "Liquidity and Capital Resources" on page 19.

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 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 actual damage, liabilities or business interruption will be fully covered; (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 could have a Material Adverse Effect.

Talent Management
The delivery of safe, reliable and cost-effective service depends on the attraction, development and retention of skilled workforces. 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 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 the regulator disallows full recovery in rates, and could have a Material Adverse Effect.

Post-Retirement Obligations
Fortis and most of its subsidiaries maintain a combination of defined benefit pension 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. Market disruptions, significant declines in the market values of investments held to meet plan obligations, discount rate changes, participant demographics, and changes in laws and regulations may require additional plan funding. Significant increases in plan expenses and funding requirements could have a Material Adverse Effect.

General Economic Conditions
Fluctuations in general economic conditions, energy prices, employment levels, personal disposable incomes, housing starts, industrial activity and other factors may lower energy demand and reduce sales both directly and through reduced capital spending, particularly that related to new customer growth, which would affect Rate Base growth. A severe and prolonged economic downturn could have a Material Adverse Effect, including making it more difficult for customers to pay their bills.

Reputation, Relationships and Stakeholder Activism
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, could affect the Corporation’s reputation as well as have a significant impact on its operations and infrastructure development.

Additionally, external stakeholders are increasingly challenging utilities regarding climate change, sustainability, diversity, returns including ROEs, 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 maintain or respond to stakeholder activism could have a Material Adverse Effect.

Legal, Administrative and Other Proceedings
These 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

Financial Instruments
Effective January 1, 2020, the Corporation adopted ASU No. 2016-13, *Measurement of Credit Losses on Financial Instruments*, which requires the use of reasonable and supportable forecasts in the estimation of credit losses and the recognition of expected losses upon initial recognition of a financial instrument, in addition to using past events and current conditions. The new guidance also requires quantitative and qualitative disclosures regarding the activity in the allowance for credit losses for financial assets within the scope of the guidance. Adoption did not have a material impact on the 2020 Annual Financial Statements and related disclosures. Further information is provided in Note 3 in the 2020 Annual Financial Statements.

Critical Accounting Estimates

General
The preparation of the 2020 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, 2020, Fortis recognized regulatory assets of $3.6 billion (2019 - $3.4 billion) and regulatory liabilities of $3.1 billion (2019 - $3.4 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	**Defined Benefit Pension Plans**		**OPEB Plans**	
Years ended December 31	**2020**	2019	**2020**	2019
Funded status: [(1)] *($ millions)*				
Benefit obligation [(2)]	**(3,995)**	(3,632)	**(789)**	(712)
Plan assets	**3,528**	3,208	**391**	343
	(467)	(424)	**(398)**	(369)
Net benefit cost [(2)] *($ millions)*	**67**	65	**32**	28
Key assumptions: *(weighted average %)*				
Discount rate: [(3)]				
During the year	**3.16**	4.05	**3.22**	4.10
As at December 31	**2.63**	3.20	**2.64**	3.25
Expected long-term rate of return on plan assets [(4)]	**5.52**	5.78	**5.28**	5.50
Rate of compensation increase	**3.34**	3.33	**—**	—
Health care cost trend increase rate [(5)]	**—**	—	**4.61**	4.62

(1) *Periodic actuarial valuations determine funding contributions for the pension plans and US 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*
(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 2021 rate is 5.91% and is assumed to decrease over the next 11 years to the ultimate rate of 4.61% in 2031 and thereafter.*

Sensitivity Analysis Year ended December 31, 2020 *($ millions)*	**Rate of Return - 1% change**		**Discount Rate - 1% change**		**Health Care Costs Trend Rate - 1% change**	
	Increase	**Decrease**	**Increase**	**Decrease**	**Increase**	**Decrease**
Defined benefit pension plans:						
Net benefit cost	**(30)**	**25**	**(45)**	**63**	**n/a**	**n/a**
Projected benefit obligation	**44**	**(82)**	**(541)**	**691**	**n/a**	**n/a**
OPEB plans:						
Net benefit cost	**(4)**	**4**	**(9)**	**13**	**29**	**(21)**
Accumulated benefit obligation	**—**	**—**	**(113)**	**144**	**106**	**(84)**

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.

At FortisAlberta, cash contributions are expensed and reflected in customer rates with any difference between the cash contributions and the net benefit cost deferred as a regulatory asset/liability. 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, 2020, Fortis recognized property, plant and equipment and intangible assets of $37.3 billion (2019 - $35.2 billion) representing 67% of total assets (2019 - 66%). Depreciation and amortization totalled $1.4 billion for 2020 (2019 - $1.4 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 asset 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, 2020, this regulatory liability was $1.2 billion (2019 - $1.2 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, 2020, Fortis recognized goodwill of $11.8 billion (2019 - $12.0 billion), representing 21% of total assets (2019 - 22%). The decrease in goodwill was due to the impact of foreign exchange associated with the translation of US dollar-denominated goodwill.

Goodwill at each of the Corporation's 11 reporting units is tested for impairment annually and whenever an event or change in circumstances indicates that fair value may be below carrying value. If so determined, goodwill is written down to estimated fair value and an impairment loss is recognized.

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

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

Although the macro-economic impact of the COVID-19 Pandemic is pervasive throughout each reporting unit's service territory, it is expected to be short term in nature and therefore not expected to have a material impact on long-term sustaining cash flows. No goodwill impairment was recognized in 2020 or 2019, pursuant to the annual assessments.

Income Tax
As at December 31, 2020, deferred income tax liabilities, current income tax receivable included in accounts receivable, deferred income taxes included in regulatory assets, and deferred income taxes included in regulatory liabilities totalled $3.3 billion, $72 million, $1.7 billion and $1.4 billion, respectively (2019 - $3.0 billion, $35 million, $1.6 billion and $1.4 billion, respectively). Income tax expense was $231 million in 2020 (2019 - $289 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/liabilities reflect temporary differences between the tax and accounting basis of assets/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 tax expense/recovery normally recognized under US GAAP and that reflected in customer rates, which is expected to be recovered from/refunded to customers in future rates, are recognized as regulatory assets/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.

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

Contingencies
The Corporation and its subsidiaries are subject to various legal proceedings and claims arising in the ordinary course of business, including those generally described under "Business Risks - Indigenous Peoples' Land Claims" on page 32, for which no amounts have been accrued because the outcomes currently cannot be reasonably determined. Further information is provided in Note 28 in the 2020 Annual Financial Statements.

While Fortis currently believes that these matters are unlikely to have a Material Adverse Effect, there is no assurance that this will be the case.

FINANCIAL INSTRUMENTS

LONG-TERM DEBT AND OTHER

As at December 31, 2020, the carrying value of long-term debt, including the current portion, was $24.5 billion (2019 - $22.3 billion) compared to an estimated fair value of $29.1 billion (2019 - $25.3 billion). Since Fortis does not intend to settle long-term debt prior to maturity, the excess of fair value over carrying value does not represent an actual liability.

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

DERIVATIVES

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

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

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

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

Unrealized gains or losses associated with changes in the fair value of these energy contracts are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulators. As at December 31, 2020, unrealized losses of $73 million (2019 - $119 million) were recognized as regulatory assets and unrealized gains of $17 million (2019 - $2 million) were recognized as regulatory liabilities.

Energy contracts not subject to regulatory deferral
UNS Energy holds wholesale trading contracts to fix power prices and realize potential margin, of which 10% of any realized gains is shared with customers through rate stabilization accounts. Fair values are measured using a market approach incorporating, where possible, independent third-party information.

Aitken Creek holds gas swap contracts to manage its exposure to changes in natural gas prices, capture natural gas price spreads, and manage the financial risk posed by physical transactions. Fair values are measured using forward pricing from published market sources.

Unrealized gains or losses associated with changes in the fair value of these energy contracts are recognized in revenue and were not material for 2020 and 2019.

Total return swaps
The Corporation holds total return swaps to manage the cash flow risk associated with forecast future cash settlements of certain stock-based compensation obligations. The swaps have a combined notional amount of $113 million and terms of one to three years expiring at varying dates through January 2023. 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 and were not material for 2020 and 2019.

Foreign exchange contracts
The Corporation holds US dollar-denominated foreign exchange contracts to help mitigate exposure to foreign exchange rate volatility. The contracts expire at varying dates through February 2022 and have a combined notional amount of $245 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 and were not material for 2020 and 2019.

Interest rate swaps
ITC entered into forward-starting interest rate swaps to manage the interest rate risk associated with planned borrowings. The swaps, which had a combined notional value of $611 million, were terminated in May 2020 with the issuance of US$700 million senior notes. Realized losses of $31 million were recognized in other comprehensive income and are being reclassified to earnings as a component of interest expense over five years.

Other investments
ITC, UNS Energy and Central Hudson hold investments in trust associated with supplemental retirement benefit plans for select employees. These investments consist of mutual funds and money market accounts, which are recorded at fair value based on quoted market prices in active markets. Gains and losses are recognized in other income, net and were not material for 2020 and 2019.

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

($ millions)	Level 1 [(1)]	Level 2 [(1)]	Level 3 [(1)]	Total
As at December 31, 2020				
Assets [(2)]				
Energy contracts subject to regulatory deferral	**—**	**38**	**—**	**38**
Energy contracts not subject to regulatory deferral	**—**	**6**	**—**	**6**
Foreign exchange contracts and total return swaps	**16**	**—**	**—**	**16**
Other investments	**126**	**—**	**—**	**126**
	142	**44**	**—**	**186**
Liabilities [(3)]				
Energy contracts subject to regulatory deferral	**—**	**(94)**	**—**	**(94)**
Energy contracts not subject to regulatory deferral	**—**	**(12)**	**—**	**(12)**
	—	**(106)**	**—**	**(106)**
As at December 31, 2019				
Assets [(2)]				
Energy contracts subject to regulatory deferral	—	22	—	22
Energy contracts not subject to regulatory deferral	—	8	—	8
Foreign exchange contracts, interest rate and total return swaps	14	4	—	18
Other investments	121	—	—	121
	135	34	—	169
Liabilities [(3)]				
Energy contracts subject to regulatory deferral	(1)	(138)	—	(139)
Energy contracts not subject to regulatory deferral	—	(12)	—	(12)
	(1)	(150)	—	(151)

(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) *Current portion is included in accounts receivable and other current assets, with the remainder included in other assets*
(3) *Current portion is included in accounts payable and other current liabilities, with the remainder included in other liabilities*

Derivative Volumes

As at December 31	2020	2019
Energy contracts subject to regulatory deferral [(1)]		
Electricity swap contracts *(GWh)*	**522**	628
Electricity power purchase contracts *(GWh)*	**2,781**	3,198
Gas swap contracts *(PJ)*	**156**	168
Gas supply contract premiums *(PJ)*	**203**	241
Energy contracts not subject to regulatory deferral [(1)]		
Wholesale trading contracts *(GWh)*	**1,588**	1,855
Gas swap contracts *(PJ)*	**36**	43

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

SELECTED ANNUAL FINANCIAL INFORMATION

Years ended December 31 *($ millions, except as indicated)*	2020	2019	2018
Revenue	**8,935**	8,783	8,390
Net earnings	**1,389**	1,852	1,286
Common Equity Earnings	**1,209**	1,655	1,100
EPS: *($)*			
Basic	**2.60**	3.79	2.59
Diluted	**2.60**	3.78	2.59
Total assets	**55,481**	53,404	53,051
Long-term debt (excluding current portion)	**23,113**	21,501	23,159
Dividends declared: *($)*			
Per common share	**1.965**	1.855	1.750
Per first preference share:			
Series F	**1.2250**	1.2250	1.2250
Series G [(1)]	**1.0983**	1.0983	1.0345
Series H [(2)]	**0.5003**	0.6250	0.6250
Series I [(3)]	**0.4987**	0.7771	0.7116
Series J	**1.1875**	1.1875	1.1875
Series K [(4)]	**0.9823**	0.9823	1.0000
Series M [(5)]	**0.9783**	1.0133	1.0250

(1) *The annual dividend per share was reset to $1.0983 for the five-year period from September 1, 2018 up to but excluding September 1, 2023.*
(2) *The annual dividend per share was reset to $0.4588 for the five-year period from June 1, 2020 up to but excluding June 1, 2025.*
(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 to $0.9823 for the five-year period from March 1, 2019 up to but excluding March 1, 2024.*
(5) *The annual dividend per share was reset to $0.9783 for the five-year period from December 1, 2019 up to but excluding December 1, 2024.*

2020/2019
For a discussion of the changes in revenue, net earnings, Common Equity Earnings, EPS, total assets and long-term debt see "Performance at a Glance" on page 5, "Operating Results" on page 9, and "Financial Position" on page 18.

2019/2018
The increase in revenue reflected: (i) Rate Base growth, led by ITC; (ii) overall higher flow-through costs in customer rates; (iii) favourable foreign exchange; and (iv) a $91 million favourable adjustment associated with the November 2019 FERC decision at ITC. The increase was partially offset by: (i) lower revenue contribution from the Energy Infrastructure segment due primarily to the disposition of the Waneta Expansion and reduced hydroelectric production in Belize due to lower rainfall; and (ii) lower retail sales at UNS Energy due to weather.

The increase in Common Equity Earnings reflected the following significant one-time items: (i) a $484 million gain on the disposition of the Waneta Expansion; and (ii) an $83 million favourable adjustment resulting from the November 2019 FERC decision at ITC, discussed above.

Excluding the significant one-time items, the increase in Common Equity Earnings was primarily due to Rate Base growth; lower operating expenses, primarily at FortisAlberta; and favourable foreign exchange. The increase was partially offset by the impact of weather in Belize and Arizona, higher costs associated with Rate Base growth not reflected in customer rates at UNS Energy, regulatory decisions at ITC, and lower realized margins at Aitken Creek. One-time positive tax adjustments, primarily recognized in 2018, also contributed to the increase in earnings, as discussed below.

The one-time positive tax adjustments recognized in 2018 related to an election to file a consolidated state tax return and the designation of net assets related to the Waneta Expansion as held for sale totalling $30 million and $14 million, respectively. In addition, the finalization of US tax reform regulations associated with base-erosion and anti-abuse tax resulted in the recognition of income tax expense of $12 million in 2019.

The increase in EPS reflects the above-noted earnings increases, partially offset by a 12.1 million increase in the weighted average number of common shares outstanding associated with the Corporation's: (i) $1.2 billion common equity issuance in the fourth quarter of 2019; (ii) ATM Program; and (iii) DRIP and share purchase plan.

The increase in total assets was due to 2019 capital expenditures, partially offset by unfavourable foreign exchange on the translation of US dollar-denominated assets.

FOURTH QUARTER RESULTS

Sales	**2020**	2019	Variance
Regulated utilities			
UNS Energy			
Retail Electricity *(GWh)*	**2,345**	2,223	122
Wholesale Electricity *(GWh)*	**1,871**	1,814	57
Gas *(PJ)*	**5**	5	—
Central Hudson			
Electricity *(GWh)*	**1,200**	1,188	12
Gas *(PJ)*	**7**	6	1
FortisBC Energy *(PJ)*	**67**	71	(4)
FortisAlberta *(GWh)*	**4,138**	4,279	(141)
FortisBC Electric *(GWh)*	**894**	888	6
Other Electric *(GWh)*	**2,362**	2,427	(65)
Non-regulated			
Energy Infrastructure *(GWh)*	**103**	14	89

The increase in electricity sales was driven by: (i) higher retail electricity sales at UNS Energy due to favourable weather; and (ii) increased hydroelectric production in Belize due to higher rainfall levels. The increase was tempered by lower average consumption by oil and gas and commercial customers at FortisAlberta, largely associated with the COVID-19 Pandemic and the downturn in the oil and gas sector.

Gas volumes were slightly lower than 2019 due to lower consumption by transportation customers at FortisBC Energy.

Revenue and Common Equity Earnings	Revenue			Earnings		
($ millions, except as indicated)	**2020**	2019	Variance	**2020**	2019	Variance
Regulated utilities						
ITC	**419**	500	(81)	**109**	171	(62)
UNS Energy	**525**	510	15	**45**	38	7
Central Hudson	**242**	226	16	**35**	30	5
FortisBC Energy	**476**	428	48	**74**	77	(3)
FortisAlberta	**139**	150	(11)	**33**	33	—
FortisBC Electric	**117**	112	5	**13**	12	1
Other Electric	**381**	381	—	**32**	22	10
Non-regulated						
Energy Infrastructure	**47**	19	28	**27**	6	21
Corporate and Other	**—**	—	—	**(37)**	(43)	6
Total	**2,346**	2,326	20	**331**	346	(15)
Weighted average number of common shares outstanding *(millions)*				**465.8**	447.1	18.7
Basic EPS *($)*				**0.71**	0.77	(0.06)

The increase in revenue was driven by: (i) overall higher flow-through costs, mainly at FortisBC Energy; (ii) Rate Base growth; and (iii) the impact of favourable weather including higher retail sales in Arizona and hydroelectric production in Belize. The increase was partially offset by the $91 million favourable ROE adjustment recorded in the fourth quarter of 2019 by ITC associated with the November 2019 FERC decision (see "Regulatory Highlights" on page 15).

The decrease in Common Equity Earnings was due primarily to the implementation of the November 2019 FERC decision in the fourth quarter of 2019 including the reversal of prior period liabilities. This impact was partially offset by Rate Base growth, the favourable impact of mark-to-market accounting of natural gas derivatives at Aitken Creek, and higher hydroelectric production in Belize.

The decrease in basic EPS reflects lower Common Equity Earnings and an increase in the weighted average number of common shares outstanding associated with the Corporation's December 2019 common equity offering.

Cash Flows			
($ millions)	**2020**	2019	Variance
Cash, beginning of period	**494**	228	266
Cash from (used in):			
Operating activities	**700**	634	66
Investing activities	**(1,235)**	(1,104)	(131)
Financing activities	**308**	627	(319)
Foreign exchange	**(18)**	(15)	(3)
Cash, end of period	**249**	370	(121)

Operating Activities
The variance largely reflects the upfront payment received by FortisAlberta in the fourth quarter of 2020 associated with a long-term energy retailer agreement. An increase in Operating Cash Flow associated with higher energy sales was largely offset by the timing of the recovery of flow-through costs and slower collections from customers associated with the COVID-19 Pandemic.

Investing Activities
The variance reflects higher capital expenditures in accordance with the Corporation's capital plan.

Financing Activities
See "Cash Flow Summary" on page 20.

SUMMARY OF QUARTERLY RESULTS

Quarter Ended	Revenue ($ millions)	Common Equity Earnings ($ millions)	Basic EPS ($)	Diluted EPS ($)
December 31, 2020	**2,346**	**331**	**0.71**	**0.71**
September 30, 2020	**2,121**	**292**	**0.63**	**0.63**
June 30, 2020	**2,077**	**274**	**0.59**	**0.59**
March 31, 2020	**2,391**	**312**	**0.67**	**0.67**
December 31, 2019	2,326	346	0.77	0.77
September 30, 2019	2,051	278	0.64	0.63
June 30, 2019	1,970	720	1.66	1.66
March 31, 2019	2,436	311	0.72	0.72

Generally, within each calendar year, quarterly results fluctuate primarily in accordance with seasonality. Given the diversified nature of the Corporation's subsidiaries, seasonality varies. Most of the annual earnings of the gas utilities are realized in the first and fourth quarters due to space-heating requirements. Earnings for the electric distribution utilities in the US are generally 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 acquisitions and dispositions; (iii) any significant temperature fluctuations from seasonal norms; (iv) the timing and significance of any regulatory decisions; (v) for revenue, the flow through in customer rates of commodity costs; and (vi) for EPS, increases in the weighted average number of common shares outstanding.

December 2020/December 2019
See "Fourth Quarter Results" on page 42.

September 2020/September 2019
Common Equity Earnings increased by $14 million due mainly to: (i) Rate Base growth; (ii) increased retail sales at UNS Energy, driven largely by weather; and (iii) higher earnings from Belize, mainly from increased hydroelectric production. This growth was tempered by: (i) the delay in TEP's general rate application, resulting in approximately $1 billion of Rate Base not reflected in customer rates; and (ii) lower contributions from ITC, due to the timing of earnings associated with the FERC ROE decisions, and a lower effective tax rate in 2019. The $0.01 decrease in EPS was due primarily to an increase in the weighted average number of common shares outstanding, mainly associated with the Corporation's $1.2 billion common equity issuance in the fourth quarter of 2019, partially offset by the above noted factors.

June 2020/June 2019
Common Equity Earnings decreased by $446 million and basic EPS decreased by $1.07. Earnings for the quarter reflected significant one-time items: (i) a $484 million gain on the disposition of the Waneta Expansion in April 2019; and (ii) the reversal of a $13 million tax recovery, originally recognized in 2019, due to the finalization in April 2020 of anti-hybrid regulations associated with US tax reform, partially offset by; (iii) a $27 million favourable base ROE adjustment at ITC as a result of the May 2020 FERC decision reflecting the reversal of liabilities accrued in prior years. Notwithstanding the significant one-time items, the regulated utilities delivered improved financial results reflecting: (i) Rate Base growth; (ii) increased retail sales at UNS Energy, driven largely by weather; (iii) favourable foreign exchange; and (iv) timing of operating expenses at FortisBC Energy. This growth was tempered by lower sales in the Caribbean due to a decline in tourism-related activities and higher COVID-related expenses, driven by Central Hudson.

March 2020/March 2019
Common Equity Earnings were comparable with 2019. Rate Base growth, lower non-recoverable operating expenses at ITC, and lower expenses in the Corporate and Other segment were tempered by: (i) higher costs associated with Rate Base growth at UNS Energy not yet reflected in rates; (ii) financial market volatility that caused a decline in the market value of certain investments that support retirement benefits at UNS Energy; and (iii) unrealized losses on foreign exchange contracts in the Corporate and Other segment. The decrease in EPS was due primarily to an increase in the weighted average number of common shares outstanding, mainly associated with the Corporation's $1.2 billion common equity issuance in the fourth quarter of 2019.

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 2020 or 2019. Inter-company balances, transactions and profit between non-regulated and regulated entities are not eliminated on consolidation. These related-party transactions include: (i) the lease of gas storage capacity and gas sales by Aitken Creek to FortisBC Energy; and (ii) the sale of capacity by the Waneta Expansion to FortisBC Electric up to the April 16, 2019 disposition of the Waneta Expansion. These transactions, which are not eliminated on consolidation, did not have a material impact on consolidated earnings, financial position or cash flows.

As at December 31, 2020, accounts receivable included approximately $28 million due from Belize Electricity (2019 - $8 million).

Fortis periodically provides short-term financing to its subsidiaries to support capital expenditures, acquisitions and seasonal working capital requirements. As at December 31, 2020, there were no material inter-segment loans outstanding (2019 - $279 million). The interest charged on inter-segment loans in 2020 and 2019 was not material.

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 US securities laws. As of December 31, 2020, 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 US securities laws. Based on that evaluation, the CEO and CFO concluded that such DCP are effective as of December 31, 2020.

Internal Controls 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 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 US 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, 2020, 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, 2020, the Corporation's ICFR was effective.

During the year ended December 31, 2020, 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

The Corporation maintains its positive long-term outlook. Fortis continues to enhance shareholder value through the execution of its capital plan, the balance and strength of its diversified portfolio of utility businesses, and growth opportunities within and proximate to its service territories. While uncertainty exists due to the COVID-19 Pandemic, the Corporation does not currently expect it to have a material financial impact in 2021.

The Corporation's $19.6 billion five-year capital plan is expected to increase Rate Base from $30.5 billion in 2020 to $36.4 billion by 2023 and $40.3 billion by 2025, translating into three- and five-year CAGRs of approximately 6.5% and 6.0%, respectively. Beyond the five-year capital plan, Fortis continues to pursue additional energy infrastructure opportunities including: further expansion of LNG infrastructure in British Columbia; the fully permitted, cross-border, Lake Erie Connector electric transmission project in Ontario; and the acceleration of cleaner energy infrastructure investments across our jurisdictions.

Fortis expects long-term growth in Rate Base will support earnings and dividend growth. Fortis is targeting average annual dividend growth of approximately 6% through 2025. This dividend growth guidance is premised on the assumptions listed under "Forward-Looking Information" below, including no material impact from the COVID-19 Pandemic, the expectation of reasonable outcomes for regulatory proceedings, and the successful execution of the five-year capital plan.

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 the COVID-19 Pandemic will not have a material financial impact in 2021 and will not impact the five-year capital plan; targeted average annual dividend growth through 2025; forecast capital expenditures for 2021-2025 and expected funding sources; forecast Rate Base and Rate Base growth for 2023 and 2025; the expectation that long-term growth in Rate Base will support earnings and dividend growth; the expectation that Fortis will remain at the forefront of the industry and is well positioned to capitalize on evolving industry opportunities; expected timing, outcome and impact of regulatory decisions; expected or potential funding sources for operating expenses, interest costs and capital plans; the expectation that maintaining the targeted capital structure of the regulated operating subsidiaries will not have an impact on its 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 access to long-term capital and will remain compliant with debt covenants in 2021; the nature, timing, benefits and expected costs of certain capital projects including the Multi-Value Regional Transmission Projects, Transmission Conversion Project, Vail-to-Tortolita Project, Oso Grande Wind Project, Lower Mainland Intermediate Pressure System Upgrade, Eagle Mountain Woodfibre Gas Line Project, Transmission Integrity Management Capabilities Project, Inland Gas Upgrades Project, Tilbury 1B Project, Tilbury LNG Resiliency Tank, AMI Project, Wataynikaneyap Transmission Power Project and additional opportunities beyond the capital plan, including the Lake Erie Connector Project; and the expectation that the adoption of future accounting pronouncements will not have a Material Adverse Impact.

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: no material impact from the COVID-19 Pandemic; reasonable regulatory decisions and the expectation of regulatory stability; the successful execution of the five-year 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; the Board exercising its discretion to declare dividends, taking into account the financial performance and condition of the Corporation; no significant variability in interest rates; 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 2021 include, but are not limited to: uncertainty regarding the outcome of regulatory proceedings at the Corporation's utilities; risks associated with climate change, physical risks and service disruption; the impact of pandemics and public health crises, including the COVID-19 Pandemic; risks related to environmental laws and regulations; risks associated with capital projects and the impact on the Corporation's continued growth; and the impact of weather variability and seasonality on heating and cooling loads, gas distribution volumes and hydroelectric generation.

All forward-looking information herein is given as of February 11, 2021. 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

2020 Annual Financial Statements: *the Corporation's audited consolidated financial statements and notes thereto for the year ended December 31, 2020*

ACC: *Arizona Corporation Commission*

ACCP: *AESO customer contribution policy*

Actual Payout Ratio: *dividends 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-US GAAP Financial Measures" on page 15*

Adjusted Payout Ratio: *dividends per common share divided by Adjusted Basic EPS as shown under "Non-US GAAP Financial Measures" on page 15*

AESO: *Alberta Electric System Operator*

AFUDC: *allowance for funds used during construction*

Aitken Creek: *Aitken Creek Gas Storage ULC, a direct 93.8%-owned subsidiary of FortisBC Holdings Inc.*

AMI: *Advanced Metering Infrastructure*

ASU: *Accounting Standards Update*

ATM Program: *at-the-market common equity program*

AUC: *Alberta Utilities Commission*

BCUC: *British Columbia Utilities Commission*

BECOL: *Belize Electric Company Limited, an indirect wholly owned subsidiary of Fortis*

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

CAGR(s): *compound average 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 US dollar to Canadian dollar exchange rate*

Caribbean Utilities: *Caribbean Utilities Company, Ltd., an indirect approximately 60%-owned (as at December 31, 2020) subsidiary of Fortis, together with its subsidiary*

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

CEO: *Chief Executive Officer of Fortis*

CFO: *Chief Financial Officer of Fortis*

Common Equity Earnings: *net earnings attributable to common equity shareholders*

Corporation: *Fortis Inc.*

COS Regulation: *cost of service regulation*

COVID-19 Pandemic: declared by the World Health Organization in March 2020 as a result of a novel coronavirus

CPCN: *Certificate of Public Convenience and Necessity*

DBRS Morningstar: *DBRS Limited*

DCP: *disclosure controls and procedures*

DRIP: *dividend reinvestment plan*

EPS: *earnings per common share*

ERM: *enterprise risk management*

FERC: *Federal Energy Regulatory Commission*

Fortis: *Fortis Inc.*

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

FortisBC 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*

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

FX: *foreign exchange associated with the translation of US dollar-denominated amounts*

GCOC: *generic cost of capital*

GHG: *greenhouse gas*

Gila River Unit 2: *UNS Energy's Gila River natural gas generation station Unit 2*

GWh: *gigawatt hour(s)*

ICFR: *internal controls over financial reporting*

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*

LIBOR: *London Interbank Offered Rate*

LNG: *liquefied natural gas*

Luna: *Luna Energy Facility*

kV: *kilovolt*

Major Capital Projects: *projects, other than ongoing maintenance projects, individually costing $200 million or more*

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, 2020*

MISO: *Midcontinent Independent System Operator, Inc.*

MRP**:** *Multi-Year Rate Plan*

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

MW: *megawatt(s)*

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

Non-US GAAP Financial Measures: *financial measures that do not have a standardized meaning prescribed by US GAAP*

NOPR: *notice of proposed rulemaking*

NYSE: *New York Stock Exchange*

OEB: *Ontario Energy Board*

OPEB: *other post-employment benefits*

Operating Cash Flow: *cash from operating activities*

PBR: *performance-based rate-setting*

PJ: *petajoule(s)*

PPA: *power purchase agreement*

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*

RICE Units: *natural gas reciprocating internal combustion engine units*

ROA: *rate of return on Rate Base*

ROE: *rate of return on common equity*

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

San Juan: *San Juan Generating Station Unit 1*

SEDAR: *Canadian System for Electronic Document Analysis and Retrieval*

TEP: *Tucson Electric Power Company, a direct wholly owned subsidiary of UNS Energy*

TFO: *transmission facility owners*

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

US: *United States of America*

US GAAP: *accounting principles generally accepted in the US*

Waneta Expansion: *Waneta Expansion hydroelectric generation facility, in which Fortis held a 51% controlling interest prior to April 2019*

Wataynikaneyap Partnership: *Wataynikaneyap Power Limited Partnership*

FORTIS INC.

Audited Consolidated Financial Statements
As at and for the years ended December 31, 2020 and 2019

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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, 2020, 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, 2020, the Corporation's ICFR was effective.

The Corporation's ICFR as of December 31, 2020 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, 2020. Deloitte LLP issued an unqualified opinion for both audits.

February 11, 2021

/s/ David G. Hutchens

David G. Hutchens
President and Chief Executive Officer, Fortis Inc.

/s/ Jocelyn H. Perry

Jocelyn H. Perry
Executive Vice President, Chief Financial Officer, Fortis Inc.

St. John's, Canada

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, 2020 and 2019, 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, 2020, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Corporation as of December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2020, 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, 2020, 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, 2021, expressed an unqualified opinion on the Corporation's internal control over financial reporting.

Basis for Opinion

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

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

Critical Audit Matters

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

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

Critical Audit Matter Description

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

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

How the Critical Audit Matter was Addressed in the Audit

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

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

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

Critical Audit Matter Description

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

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

How the Critical Audit Matter was Addressed in the Audit

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

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

/s/ Deloitte LLP

Chartered Professional Accountants

St. John's, Canada
February 11, 2021

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, 2020, 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, 2020, 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, 2020, of the Corporation and our report dated February 11, 2021, 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, 2021

FORTIS INC.
Consolidated Balance Sheets
As at December 31
(in millions of Canadian dollars)

		2020		2019
ASSETS				
Current assets				
Cash and cash equivalents	**$**	**249**	$	370
Accounts receivable and other current assets (Note 6)		**1,369**		1,297
Prepaid expenses		**102**		88
Inventories (Note 7)		**422**		394
Regulatory assets (Note 8)		**470**		425
Total current assets		**2,612**		2,574
Other assets (Note 9)		**670**		620
Regulatory assets (Note 8)		**3,118**		2,958
Property, plant and equipment, net (Note 10)		**35,998**		33,988
Intangible assets, net (Note 11)		**1,291**		1,260
Goodwill (Note 12)		**11,792**		12,004
Total assets	**$**	**55,481**	$	53,404
LIABILITIES AND EQUITY				
Current liabilities				
Short-term borrowings (Note 14)	**$**	**132**	$	512
Accounts payable and other current liabilities (Note 13)		**2,321**		2,402
Regulatory liabilities (Note 8)		**441**		572
Current installments of long-term debt (Note 14)		**1,254**		690
Total current liabilities		**4,148**		4,176
Other liabilities (Note 16)		**1,599**		1,446
Regulatory liabilities (Note 8)		**2,662**		2,786
Deferred income taxes (Note 24)		**3,344**		2,969
Long-term debt (Note 14)		**23,113**		21,501
Finance leases (Note 15)		**331**		413
Total liabilities		**35,197**		33,291
Commitments and contingencies (Note 28)				
Equity				
Common shares (Note 17) [(1)]		**13,819**		13,645
Preference shares (Note 19)		**1,623**		1,623
Additional paid-in capital		**11**		11
Accumulated other comprehensive income (Note 20)		**34**		336
Retained earnings		**3,210**		2,916
Shareholders' equity		**18,697**		18,531
Non-controlling interests		**1,587**		1,582
Total equity		**20,284**		20,113
Total liabilities and equity	**$**	**55,481**	$	53,404

[(1)] *No par value. Unlimited authorized shares. 466.8 million and 463.3 million issued and outstanding as at December 31, 2020 and 2019, respectively*

Approved on Behalf of the Board

/s/ Douglas J. Haughey /s/ Tracey C. Ball

Douglas J. Haughey, Director **Tracey C. Ball, Director**

See accompanying Notes to Consolidated Financial Statements

FORTIS INC.

Consolidated Statements of Earnings

For the years ended December 31

(in millions of Canadian dollars, except per share amounts)

		2020		2019
Revenue (Note 5)	**$**	**8,935**	$	8,783
Expenses				
Energy supply costs		**2,562**		2,520
Operating expenses		**2,437**		2,452
Depreciation and amortization		**1,428**		1,350
Total expenses		**6,427**		6,322
Gain on disposition (Note 22)		**—**		577
Operating income		**2,508**		3,038
Other income, net (Note 23)		**154**		138
Finance charges		**1,042**		1,035
Earnings before income tax expense		**1,620**		2,141
Income tax expense (Note 24)		**231**		289
Net earnings	**$**	**1,389**	$	1,852
Net earnings attributable to:				
Non-controlling interests	**$**	**115**	$	130
Preference equity shareholders		**65**		67
Common equity shareholders		**1,209**		1,655
	$	**1,389**	$	1,852
Earnings per common share (Note 18)				
Basic	**$**	**2.60**	$	3.79
Diluted	**$**	**2.60**	$	3.78

See accompanying Notes to Consolidated Financial Statements

FORTIS INC.

Consolidated Statements of Comprehensive Income

For the years ended December 31

(in millions of Canadian dollars)

		2020		2019
Net earnings	**$**	**1,389**	$	1,852
Other comprehensive loss				
Unrealized foreign currency translation losses, net of hedging activities and income tax expense of $3 million and $13 million, respectively		**(311)**		(660)
Other, net of income tax recovery of $9 million and $5 million, respectively		**(27)**		(7)
		(338)		(667)
Comprehensive income	**$**	**1,051**	$	1,185
Comprehensive income attributable to:				
Non-controlling interests	**$**	**79**	$	55
Preference equity shareholders		**65**		67
Common equity shareholders		**907**		1,063
	$	**1,051**	$	1,185

See accompanying Notes to Consolidated Financial Statements

FORTIS INC.

Consolidated Statements of Cash Flows

For the years ended December 31

(in millions of Canadian dollars)

	2020	2019
Operating activities		
Net earnings	**$ 1,389**	$ 1,852
Adjustments to reconcile net earnings to net cash provided by operating activities:		
Depreciation - property, plant and equipment	**1,282**	1,199
Amortization - intangible assets	**131**	125
Amortization - other	**15**	26
Deferred income tax expense (Note 24)	**226**	247
Equity component, allowance for funds used during construction (Note 23)	**(78)**	(74)
Gain on disposition (Note 22)	**—**	(583)
Other	**165**	145
Change in long-term regulatory assets and liabilities	**5**	(106)
Change in working capital (Note 26)	**(434)**	(168)
Cash from operating activities	**2,701**	2,663
Investing activities		
Capital expenditures - property, plant and equipment	**(3,857)**	(3,499)
Capital expenditures - intangible assets	**(182)**	(221)
Contributions in aid of construction	**68**	102
Proceeds on disposition (Note 22)	**—**	995
Other	**(161)**	(145)
Cash used in investing activities	**(4,132)**	(2,768)
Financing activities		
Proceeds from long-term debt, net of issuance costs (Note 14)	**3,470**	937
Repayments of long-term debt, net of extinguishment costs, and finance leases	**(1,251)**	(1,676)
Borrowings under committed credit facilities	**5,648**	5,892
Repayments under committed credit facilities	**(5,299)**	(6,290)
Net change in short-term borrowings	**(413)**	472
Issue of common shares, net of costs, and dividends reinvested (Note 17)	**58**	1,442
Dividends		
Common shares, net of dividends reinvested	**(786)**	(494)
Preference shares	**(65)**	(67)
Subsidiary dividends paid to non-controlling interests	**(65)**	(73)
Other	**30**	11
Cash from financing activities	**1,327**	154
Effect of exchange rate changes on cash and cash equivalents	**(17)**	(26)
Change in cash and cash equivalents	**(121)**	23
Cash and change in cash associated with assets held for sale	**—**	15
Cash and cash equivalents, beginning of year	**370**	332
Cash and cash equivalents, end of year	**$ 249**	$ 370

Supplementary Cash Flow Information (Note 26)

See accompanying Notes to Consolidated Financial Statements

FORTIS INC.

Consolidated Statements of Changes in Equity

For the years ended December 31, 2020 and 2019

(in millions of Canadian dollars, except share numbers)

	Common Shares *(# millions)*	Common Shares *(Note 17)*	Preference Shares *(Note 19)*	Additional Paid-In Capital	Accumulated Other Comprehensive Income (Loss) *(Note 20)*	Retained Earnings	Non-Controlling Interests	Total Equity
As at December 31, 2019	**463.3**	**$ 13,645**	**$ 1,623**	**$ 11**	**$ 336**	**$ 2,916**	**$ 1,582**	**$ 20,113**
Net earnings	**—**	**—**	**—**	**—**	**—**	**1,274**	**115**	**1,389**
Other comprehensive loss	**—**	**—**	**—**	**—**	**(302)**	**—**	**(36)**	**(338)**
Common shares issued	**3.5**	**174**	**—**	**(3)**	**—**	**—**	**—**	**171**
Advances to non-controlling interests	**—**	**—**	**—**	**—**	**—**	**—**	**(13)**	**(13)**
Subsidiary dividends paid to non-controlling interests	**—**	**—**	**—**	**—**	**—**	**—**	**(65)**	**(65)**
Dividends declared on common shares ($1.965 per share)	**—**	**—**	**—**	**—**	**—**	**(915)**	**—**	**(915)**
Dividends on preference shares	**—**	**—**	**—**	**—**	**—**	**(65)**	**—**	**(65)**
Other	**—**	**—**	**—**	**3**	**—**	**—**	**4**	**7**
As at December 31, 2020	**466.8**	**$ 13,819**	**$ 1,623**	**$ 11**	**$ 34**	**$ 3,210**	**$ 1,587**	**$ 20,284**
As at December 31, 2018	428.5	$ 11,889	$ 1,623	$ 11	$ 928	$ 2,082	$ 1,923	$ 18,456
Net earnings	—	—	—	—	—	1,722	130	1,852
Other comprehensive loss	—	—	—	—	(592)	—	(75)	(667)
Common shares issued	34.8	1,756	—	(5)	—	—	—	1,751
Advances to non-controlling interests	—	—	—	—	—	—	(8)	(8)
Subsidiary dividends paid to non-controlling interests	—	—	—	—	—	—	(73)	(73)
Dividends declared on common shares ($1.855 per share)	—	—	—	—	—	(821)	—	(821)
Dividends on preference shares	—	—	—	—	—	(67)	—	(67)
Disposition (Note 22)	—	—	—	—	—	—	(318)	(318)
Other	—	—	—	5	—	—	3	8
As at December 31, 2019	463.3	$ 13,645	$ 1,623	$ 11	$ 336	$ 2,916	$ 1,582	$ 20,113

See accompanying Notes to Consolidated Financial Statements

1. DESCRIPTION OF BUSINESS

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

Regulated Utilities

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

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

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 in Pima County and parts of Cochise County, as well as in Santa Cruz and Mohave counties. TEP also sells wholesale electricity to other entities in the western United States. Together they own generating capacity of 3,233 megawatts ("MW"), including 54 MW of solar 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 Arizona's Mohave, Yavapai, Coconino, Navajo and Santa Cruz counties.

Central Hudson: CH Energy Group, Inc., which includes primarily 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 65 MW.

FortisBC Energy: FortisBC Energy Inc., which is the largest regulated distributor of natural gas in British Columbia, provides transmission and distribution services in over 135 communities. FortisBC Energy obtains 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. It 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 Partnership"); an approximate 60% controlling interest in Caribbean Utilities Company, Ltd. ("Caribbean Utilities"); FortisTCI Limited and Turks and Caicos Utilities Limited (collectively, "FortisTCI"); and a 33% equity investment in Belize Electricity Limited ("Belize Electricity").

Newfoundland Power is an integrated regulated electric utility and the principal distributor of electricity on the island portion of Newfoundland and Labrador with a generating capacity of 143 MW, of which 97 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 130 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 5 MW. Wataynikaneyap Partnership is a partnership between 24 First Nations communities, Fortis and Algonquin Power & Utilities Corp. with a mandate to connect remote First Nations communities to the electricity grid in Ontario through the development of new transmission lines.

Caribbean Utilities is an integrated regulated electric utility and the sole electricity provider on Grand Cayman with a diesel-powered generating capacity of 161 MW. FortisTCI consists of two integrated regulated electric utilities that provide electricity to certain Turks and Caicos Islands and has a diesel-powered generating capacity of 91 MW. Belize Electricity is an integrated electric utility and the principal distributor of electricity in Belize.

Non-Regulated

Energy Infrastructure: Long-term contracted generation assets in Belize and the Aitken Creek natural gas storage facility ("Aitken Creek") in British Columbia. Generation assets in Belize consist of three hydroelectric generating facilities with a combined generating capacity of 51 MW, held through the Corporation's indirectly wholly owned subsidiary Belize Electric Company Limited ("BECOL"). The output is sold to Belize Electricity under 50-year power purchase agreements ("PPAs"). Fortis indirectly owns 93.8% of Aitken Creek, with the remainder owned by BP Canada Energy Company. Aitken Creek is the only underground natural gas storage facility in British Columbia and has a working gas capacity of 77 billion cubic feet. The long-term contracted generation assets in British Columbia, the Waneta Expansion hydroelectric generating facility ("Waneta Expansion"), were sold on April 16, 2019.

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, including net corporate expenses of Fortis.

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 regulatory 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. There can be varying degrees of regulatory lag between when costs are incurred and when they are reflected in customer rates.

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).

Nature of Regulation

Regulated Utility	Regulatory Authority	Allowed Common Equity (%)	Allowed ROE [(1)] (%) 2020	2019	Significant Features
ITC [(2)] [(3)]	Federal Energy Regulatory Commission ("FERC")	60.0	**10.77**	10.63	Cost-based formula rates, with annual true-up mechanism [(4)] Incentive adders
TEP	Arizona Corporation Commission ("ACC") [(5)]	50.0	**9.75**	9.75	COS regulation Historical test year
	FERC [(6)]	54.0	**10.40**	10.40	Formula transmission rates
UNS Electric	ACC	52.8	**9.50**	9.50	
UNS Gas	ACC	50.8	**9.75**	9.75	
Central Hudson [(7)]	New York State Public Service Commission ("PSC")	50.0	**8.80**	8.80	COS regulation Future test year
FortisBC Energy	British Columbia Utilities Commission ("BCUC")	38.5	**8.75**	8.75	COS regulation with formula components and incentives [(8)]
FortisBC Electric	BCUC	40.0	**9.15**	9.15	Future test year
FortisAlberta	Alberta Utilities Commission ("AUC")	37.0	**8.50**	8.50	PBR [(9)]
Newfoundland Power	Newfoundland and Labrador Board of Commissioners of Public Utilities	45.0	**8.50**	8.50	COS regulation Future test year
Maritime Electric	Island Regulatory and Appeals Commission	40.0	**9.35**	9.35	COS regulation Future test year
FortisOntario [(10)]	Ontario Energy Board	40.0	**8.52-9.30**	8.78-9.30	COS regulation with incentive mechanisms
Caribbean Utilities [(11)]	Utility Regulation and Competition Office	N/A	**6.75-8.75**	7.50-9.50	COS regulation Rate-cap adjustment mechanism based on published consumer price indices
FortisTCI [(12)]	Government of the Turks and Caicos Islands	N/A	**15.00-17.50**	15.00-17.50	COS regulation Historical test year

(1) *ROA for Caribbean Utilities and FortisTCI*
(2) *Includes the allowed common equity and base ROE plus incentive adders for ITCTransmission, METC, and ITC Midwest*
(3) *Including incentive adders, the May 2020 FERC decision implies an all-in ROE for ITC's subsidiaries operating in the Midcontinent Independent System Operator ("MISO") region of 10.77%, up from 10.63% as set in the November 2019 decision. See "Significant Regulatory Developments" below*
(4) *Annual true-up reflected in rates within a two-year period*
(5) *Effective January 1, 2021, 53% allowed common equity and 9.15% ROE with 0.20% return on the fair value increment. See "COVID-19 Pandemic Impacts - Delayed and Postponed Regulatory Proceedings" below*
(6) *Approved effective August 1, 2019, subject to refund following hearing and settlement procedures. As at December 31, 2020, $19 million (2019 - $5 million) has been reserved as a regulatory liability*
(7) *Pursuant to a three-year settlement agreement arising from a 2017 general rate application, Central Hudson's rates reflect a capital structure of 48%, 49% and 50% common equity as of July 1, 2018, 2019 and 2020, respectively. See "COVID-19 Pandemic Impacts - Delayed and Postponed Regulatory Proceedings" below*
(8) *Formula and incentives have been set through 2024. See "Significant Regulatory Developments" below*
(9) *FortisAlberta is subject to PBR including mechanisms for flow-through costs and capital expenditures not otherwise recovered through customer rates. FortisAlberta's current PBR term expires as of December 31, 2022*
(10) *Two of FortisOntario's utilities follow COS regulation with incentive mechanisms, while the remaining utility is subject to a 35-year franchise agreement expiring in 2033*
(11) *Operates under licences from the Government of the Cayman Islands. Its exclusive transmission and distribution licence is for an initial 20-year period, expiring in April 2028, with a provision for automatic renewal. Its non-exclusive generation licence is for a 25-year term, expiring in November 2039*
(12) *Operates under 50-year licences from the Government of the Turks and Caicos Islands, which expire in 2036 and 2037*

COVID-19 Pandemic Impacts
The novel coronavirus ("COVID-19") pandemic resulted in several customer relief initiatives as well as the delay and postponement of several regulatory proceedings in 2020, as described below. The Corporation's significant regulatory proceedings, including TEP's general rate application as well as FortisAlberta's 2021 generic cost of capital ("GCOC") and Alberta Electric System Operator ("AESO") customer contribution proceedings, were concluded by the end of 2020.

Customer Relief Initiatives

UNS Energy
Pursuant to the ACC's approval of the utility's customer relief initiatives, TEP refunded to customers approximately $11 million of collected demand side management funds in excess of program costs.

In December 2020, the ACC enacted a bill credit and payment program for residential electric customers who are behind on their electric bills as a result of the COVID-19 pandemic, including automatic enrollment into an eight-month payment plan for qualified customers. TEP voluntarily created payment arrangements for commercial customers.

Central Hudson
In March 2020, as agreed with the PSC, Central Hudson postponed the collection in customer rates of approximately $4 million of deferred costs related mainly to environmental remediation until July 1, 2021.

FortisBC Energy and FortisBC Electric
In April 2020, pursuant to the BCUC's approval of the utilities' customer relief initiatives, FortisBC Energy and FortisBC Electric implemented three-month bill deferrals for certain customer classes, the repayment of which commenced in the third quarter of 2020. The BCUC also authorized the deferral of otherwise uncollectible revenue from customers, the recovery of which will be determined through a future rate filing once the financial impact of the pandemic is known.

Delayed and Postponed Regulatory Proceedings

UNS Energy
General Rate Application: TEP filed a rate application in April 2019 based on a 2018 test year. In December 2020 the ACC issued a rate order including new customer rates effective January 1, 2021 ("2020 Rate Order"). Provisions of the 2020 Rate Order include: (i) an increase in non-fuel revenue of $77 million (US$58 million); (ii) an allowed ROE of 9.15%, with a 0.20% return on the fair value increment and a capital structure of 53% common equity; and (iii) a rate base of approximately $3.5 billion (US$2.7 billion) which includes post-test year investments in Gila River natural gas generation station Unit 2 and 10 natural gas reciprocating internal combustion engine units.

Central Hudson
2020 Rates: In June 2020, the PSC approved Central Hudson's request to postpone scheduled electric and gas delivery rate increases, reflecting an increase in the equity component of its capital structure from 49% to 50%, from July 1, 2020 to October 1, 2020. The deferred revenue associated with the delay is being collected over the nine-month period to June 30, 2021.

COVID-19 Proceeding: In June 2020, the PSC initiated a generic proceeding to identify and address the effects of the COVID-19 pandemic. The outcome of this proceeding and potential impacts, if any, are unknown at this time.

FortisAlberta
Generic Cost of Capital Proceeding: In December 2018, the AUC initiated a GCOC proceeding to consider a formula-based approach to setting the allowed ROE beginning in 2021 and whether any process changes were necessary for determining capital structure in years in which a ROE formula is in place. In October 2020, given the time that had passed since initiation of the proceeding and ongoing economic uncertainty, the AUC concluded the proceeding and set the ROE for 2021 at 8.5% using a capital structure of 37% common equity, consistent with 2020. In December 2020, the AUC initiated a new GCOC proceeding to establish the cost of capital parameters for 2022 and possibly one or more future years. This proceeding is expected to be ongoing throughout 2021.

Other Electric

Caribbean Utilities: In August 2020, the Utility Regulation and Competition Office approved the postponement of Caribbean Utilities' scheduled June 1, 2020 annual rate adjustment to January 1, 2021 to provide customer relief from the economic effects of the COVID-19 pandemic. The deferred revenue associated with the delay is being collected over a two-year period beginning January 2021.

FortisTCI: In February 2020, the Government of the Turks and Caicos Islands approved a 6.8% average increase in FortisTCI's electricity rates, effective April 1, 2020, including the recovery of hurricane-related costs incurred in 2017. In March 2020, to provide customer relief from the economic effects of the COVID-19 pandemic, the effective date was postponed and new rates became effective July 22, 2020.

FortisTCI sought regulatory approval to defer its incremental operating expenses associated with the COVID-19 pandemic. Approval was granted in December 2020 to allow the deferral of approximately $1.5 million in costs, to be amortized over the remaining 15-year life of FortisTCI's licence.

Significant Regulatory Developments

ITC

ROE Complaints: In May 2020, FERC issued an order on the rehearing of its November 2019 decision on the MISO transmission owner ROE complaints and set the base ROE for the periods from November 2013 through February 2015 and from September 2016 onward at 10.02%, up to a maximum of 12.62% with incentive adders. This represents an increase from the base ROE of 9.88%, up to a maximum of 12.24% with incentive adders, determined in FERC's November 2019 decision. Including incentive adders, the May 2020 FERC decision implies an all-in ROE for ITC's subsidiaries operating in the MISO region of 10.77%, up from 10.63% as set in the November 2019 decision.

Net regulatory liabilities of $6 million and $91 million were recorded at December 31, 2020 and 2019, respectively, reflecting: (i) the terms of the May 2020 and November 2019 decisions; and (ii) $42 million refunded to customers in 2020. The May 2020 FERC decision resulted in an increase in Fortis' net earnings of $29 million in 2020, including $27 million related to the reversal of liabilities established in prior periods (2019 - November 2019 FERC decision increased Fortis' net earnings by $63 million, including $83 million related to the reversal of liabilities established in prior periods).

Review of Transmission Incentives Policy: In March 2020, FERC issued a notice of proposed rulemaking ("NOPR") that included a proposal to update its transmission incentives policy for transmission owners, including ITC, to grant incentives to projects based upon benefits to customers regarding reliability and cost savings through the reduction of transmission congestion. FERC proposed total ROE incentives of up to 250 basis points that would not be limited by the upper end of the base ROE zone of reasonableness. The NOPR also proposed, among other things, to eliminate the ROE adder for independent transmission ownership, and to increase the ROE adder for regional transmission owner participation. Comments from stakeholders, including ITC, were provided to FERC through July 2020. The outcome of these proceedings may impact future incentive adders that are included in transmission rates charged by transmission owners, including ITC.

Central Hudson

General Rate Application: In August 2020, Central Hudson filed a rate application with the PSC requesting an increase in electric and natural gas delivery revenue of $44 million and $19 million, respectively, effective July 1, 2021. An order from the PSC is expected in 2021.

FortisBC Energy and FortisBC Electric

Multi-Year Rate Plan Applications: In June 2020, the BCUC issued a decision on FortisBC Energy's and FortisBC Electric's multi-year rate plan applications for 2020 to 2024. The decision sets the rate-setting framework for the five-year period, including: (i) the level of operation and maintenance expense and growth capital to be included in customer rates, indexed for inflation less a fixed productivity adjustment factor; (ii) a forecast approach to sustainment capital; (iii) an innovation fund recognizing the need to accelerate investment in clean energy innovation; and (iv) a 50/50 sharing between customers and the utilities of variances from the allowed ROE. In the fourth quarter of 2020, the BCUC approved: (i) the January 1, 2020 delivery rate increase; and (ii) an increase in 2021 delivery rates, effective January 1, 2021, reflecting the terms of this decision.

Generic Cost of Capital Proceeding: In January 2021, the BCUC issued a notice that a GCOC proceeding will be initiated in the second quarter of 2021 and will include a review of the common equity component of capital structure and the allowed ROE effective January 1, 2022.

FortisAlberta
2018 Independent System Operator Tariff Application: In September 2019, the AUC issued a decision that addressed, among other things, a proposal to change how the AESO customer contribution policy ("ACCP") is accounted for between distribution facility owners, such as FortisAlberta, and transmission facility owners ("TFOs"). The decision prevented any future investment by FortisAlberta under the policy and directed that unamortized customer contributions of approximately $400 million as at December 31, 2017, which form part of FortisAlberta's rate base, be transferred to the incumbent TFO in FortisAlberta's service area.

In November 2020, the AUC issued a decision: (i) reversing the proposed changes to the ACCP resulting in FortisAlberta retaining its unamortized customer contributions; and (ii) directing a change in the depreciation rate for AESO contributions to reflect the parameters of the underlying transmission facilities. FortisAlberta has adjusted the estimated service life and the associated depreciation rate of the unamortized AESO contributions resulting in a decrease in depreciation expense and an associated decrease in revenue in 2020.

The AUC initiated a new proceeding in November 2020 to consider whether the ACCP should be modified on a prospective basis. A decision is expected in the second quarter of 2021.

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 ("US 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, and a controlled variable interest entity up to the date of its disposition on April 16, 2019 (Note 22). 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. Intercompany transactions have been eliminated, except for transactions between non-regulated and regulated entities in accordance with US GAAP for rate-regulated 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 (2019 - allowance for doubtful accounts) to reduce accounts receivable for amounts estimated to be uncollectible. The allowance for credit losses is estimated based on historical collection patterns, sales, and current and forecast economic and other conditions. Accounts receivable are written off in the period in which they are deemed uncollectible.

Inventories

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

Regulatory Assets and Liabilities

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

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

Investments

Investments accounted for using the equity method 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 asset removal costs not identified as a legal obligation. The provision is recognized as a long-term regulatory liability (Note 8) against which actual asset removal costs are netted when incurred.

Most of 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 2020 totalled $41 million (2019 - $40 million) and is reported as a reduction of finance charges and the equity component is reported as other income (Note 23). Both components are charged to earnings through depreciation expense over the estimated service lives of the applicable PPE.

At FortisAlberta the cost of PPE includes required contributions to AESO toward funding the construction of transmission facilities.

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

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

PPE is depreciated using the straight-line method based on the estimated service lives of the assets. Depreciation rates for regulated PPE are approved by the respective regulators. Depreciation rates for 2020 ranged from 0.9% to 39.8% (2019 - 0.9% to 35.0%). The weighted average composite rate of depreciation, before reduction for amortization of contributions in aid of construction, was 2.5% for 2020 (2019 – 2.6%).

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

	2020		2019	
(years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Distribution				
Electric	**5-80**	**32**	5-80	32
Gas	**18-95**	**38**	15-95	36
Transmission				
Electric	**20-90**	**43**	20-90	43
Gas	**10-85**	**35**	5-85	32
Generation	**1-85**	**24**	1-85	25
Other	**2-70**	**14**	3-70	14

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 2020 (2019 – 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.

	2020		2019	
(years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Computer software	**3-15**	**4**	3-10	4
Land, transmission and water rights	**43-90**	**56**	43-90	58
Other	**10-100**	**12**	10-100	12

Most of 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 carrying value may not exceed the total undiscounted cash flows expected to be generated by the asset. 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 11 reporting units is tested for impairment annually and whenever an event or change in circumstances indicates that fair value may be below carrying value. If so determined, goodwill is written down to estimated fair value and an impairment loss is recognized.

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

Deferred Financing Costs

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

Employee Future Benefits

Fortis and each subsidiary maintain one or a combination of defined benefit pension plans 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 defined benefit pension 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.

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

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

The net funded or unfunded status of defined benefit pension 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 defined benefit pension or OPEB plan costs ordinarily recognized under US 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 (Note 8).

For most of the Corporation's regulated utilities, any unamortized balances related to net actuarial gains and losses, past service costs and transitional obligations associated with defined benefit pension 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 all 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 AESO. This includes the collection of transmission revenue from its customers, which occurs through the transmission component of its regulator-approved rates. FortisAlberta reports transmission revenue and expenses on a net basis.

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

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

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

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.

Revenue is disaggregated by geography, regulatory status, and substantially autonomous utility operations (Note 5). This represents the level of disaggregation used by the Corporation's President and Chief Executive Officer ("CEO") to allocate resources and evaluate performance.

Stock-Based Compensation

Compensation expense related to stock options is measured at the grant date using the Black-Scholes fair value option-pricing model and each grant is amortized to compensation expense as a single award 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.

Fortis recognizes liabilities associated with its directors' Deferred Share Unit ("DSU"), Performance Share Unit ("PSU") and Restricted Share Unit ("RSU") Plans. DSUs, PSUs and RSUs issued pre-2020 represent cash-settled awards and RSUs issued in 2020 represent cash or share-settled awards, depending on settlement elections and share ownership requirements of the executive. 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 VWAP as at December 31, 2020 was $52.36 (2019 - $53.97). 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 the PSU and RSU Plans is over the lesser of three years or the period to retirement eligibility and for the DSU Plan is at the time of grant. Forfeitures are accounted for as they occur.

Foreign Currency Translation

Assets and liabilities of the Corporation's foreign operations, all of which have a US 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, 2020 was US$1.00=CA$1.27 (2019 – US$1.00=CA$1.30).

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$1.34 for 2020 (2019 - US$1.00=CA$1.33).

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 US dollar cash inflows and forecast future cash settlements of DSU, PSU and RSU obligations; (ii) UNS Energy, to meet forecast load and reserve requirements; and (iii) Aitken Creek, to manage commodity price risk, capture natural gas price spreads, and manage the financial risk of physical transactions. These 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 UNS Energy 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. Any hedge ineffectiveness is immediately recognized in earnings.

The Corporation's earnings from, and net investments in, foreign subsidiaries and certain equity-accounted investments are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has hedged a portion of this exposure through US 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 values of derivatives are recognized as current or long-term assets and liabilities depending on the timing of settlements and resulting cash flows. Derivatives under master netting agreements and collateral positions are presented on a gross basis. Cash flows associated with the settlement of all derivatives are presented in operating activities in the consolidated statements of cash flows.

Income Taxes

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

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

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

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

At FortisAlberta the capital cost allowance pool for certain PPE for rate-setting purposes is different from that prescribed for Canadian tax filing purposes. In a future reporting period yet to be determined, the difference may result in reported income tax expense exceeding that reflected in customer rates.

Fortis does not recognize deferred income taxes on temporary differences related to investments in foreign subsidiaries where it intends to indefinitely reinvest earnings. The difference between the carrying values of these foreign investments and their tax bases, resulting from unrepatriated earnings and currency translation adjustments, is approximately $3.4 billion as at December 31, 2020 (2019 - $2.8 billion). If such earnings are repatriated, the Corporation may be subject to income taxes and foreign withholding taxes. The determination of the amount of unrecognized deferred income tax liabilities on such amounts is impractical.

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

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

Asset Retirement Obligations

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

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

Contingencies

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

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

New Accounting Policies

Financial Instruments
Effective January 1, 2020, the Corporation adopted Accounting Standards Update ("ASU") No. 2016-13, *Measurement of Credit Losses on Financial Instruments*, which requires the use of reasonable and supportable forecasts in the estimation of credit losses and the recognition of expected losses upon initial recognition of a financial instrument, in addition to using past events and current conditions. The new guidance also requires quantitative and qualitative disclosures regarding the activity in the allowance for credit losses for financial assets within the scope of the guidance. Adoption did not have a material impact on the consolidated financial statements and related disclosures.

Use of Accounting Estimates

The preparation of these consolidated financial statements in accordance with US 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.

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.

4. SEGMENTED INFORMATION

General

Fortis segments its business based on regulatory jurisdiction and service territory, as well as the information used by its CEO in deciding how to allocate resources. Segment performance is evaluated principally on net earnings attributable to common equity shareholders.

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 2020 or 2019.

Inter-company balances, transactions and profit between non-regulated and regulated entities, which are not eliminated on consolidation, are summarized below.

(in millions)	**2020**	2019
Lease of gas storage capacity and gas sales from Aitken Creek to FortisBC Energy	**$ 25**	$ 23
Sale of capacity from the Waneta Expansion to FortisBC Electric [1]	**—**	17

[1] *Reflects amounts to the April 16, 2019 disposition of the Waneta Expansion (Note 22)*

As at December 31, 2020, accounts receivable included approximately $28 million due from Belize Electricity (2019 - $8 million).

Fortis periodically provides short-term financing to its subsidiaries to support capital expenditures, acquisitions and seasonal working capital requirements. As at December 31, 2020, there were no material inter-segment loans outstanding (2019 - $279 million). The interest charged on inter-segment loans in 2020 and 2019 was not material.

Year ended December 31, 2020 *(in millions)*	REGULATED								NON-REGULATED			
	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Other Electric	Sub total	Energy Infra-structure	Corporate and Other	Inter-segment eliminations	Total
Revenue	$ 1,744	$ 2,260	$ 953	$ 1,385	$ 596	$ 424	$ 1,485	$ 8,847	$ 88	$ —	$ —	$ 8,935
Energy supply costs	—	847	232	468	—	119	893	2,559	3	—	—	2,562
Operating expenses	438	627	503	341	148	117	194	2,368	30	39	—	2,437
Depreciation and amortization	295	330	90	237	212	61	183	1,408	16	4	—	1,428
Operating income	1,011	456	128	339	236	127	215	2,512	39	(43)	—	2,508
Other income, net	40	40	31	8	2	5	10	136	5	13	—	154
Finance charges	324	125	48	142	104	72	77	892	—	150	—	1,042
Income tax expense	179	69	20	29	1	4	21	323	5	(97)	—	231
Net earnings	548	302	91	176	133	56	127	1,433	39	(83)	—	1,389
Non-controlling interests	99	—	—	1	—	—	15	115	—	—	—	115
Preference share dividends	—	—	—	—	—	—	—	—	—	65	—	65
Net earnings attributable to common equity shareholders	$ 449	$ 302	$ 91	$ 175	$ 133	$ 56	$ 112	$ 1,318	$ 39	$ (148)	$ —	$ 1,209
Goodwill	$ 7,810	$ 1,758	$ 574	$ 913	$ 228	$ 235	$ 247	$ 11,765	$ 27	$ —	$ —	$ 11,792
Total assets	20,358	10,802	3,939	7,695	5,084	2,441	4,261	54,580	745	209	(53)	55,481
Capital expenditures	1,182	1,200	339	471	420	135	273	4,020	19	—	—	4,039

Year ended December 31, 2019 *(in millions)*												
Revenue	$ 1,761	$ 2,212	$ 917	$ 1,331	$ 598	$ 418	$ 1,467	$ 8,704	$ 82	$ —	$ (3)	$ 8,783
Energy supply costs	—	814	254	438	—	121	890	2,517	3	—	—	2,520
Operating expenses	489	650	451	333	145	107	188	2,363	36	56	(3)	2,452
Depreciation and amortization	270	297	79	235	214	62	171	1,328	20	2	—	1,350
Gain on disposition	—	—	—	—	—	—	—	—	—	577	—	577
Operating income	1,002	451	133	325	239	128	218	2,496	23	519	—	3,038
Other income, net	37	28	17	16	2	4	2	106	2	30	—	138
Finance charges	290	130	46	136	104	72	77	855	—	180	—	1,035
Income tax expense	174	57	19	39	6	6	20	321	(1)	(31)	—	289
Net earnings	575	292	85	166	131	54	123	1,426	26	400	—	1,852
Non-controlling interests	104	—	—	1	—	—	17	122	8	—	—	130
Preference share dividends	—	—	—	—	—	—	—	—	—	67	—	67
Net earnings attributable to common equity shareholders	$ 471	$ 292	$ 85	$ 165	$ 131	$ 54	$ 106	$ 1,304	$ 18	$ 333	$ —	$ 1,655
Goodwill	$ 7,970	$ 1,794	$ 586	$ 913	$ 228	$ 235	$ 251	$ 11,977	$ 27	$ —	$ —	$ 12,004
Total assets	19,799	10,205	3,726	7,305	4,831	2,328	4,185	52,379	711	641	(327)	53,404
Capital expenditures	1,148	915	317	463	423	106	295	3,667	28	25	—	3,720

5. REVENUE

(in millions)		**2020**		2019
Electric and gas revenue				
United States				
ITC	**$**	**1,726**	$	1,697
UNS Energy		**2,019**		1,966
Central Hudson		**941**		894
Canada				
FortisBC Energy		**1,336**		1,289
FortisAlberta		**580**		576
FortisBC Electric		**358**		362
Newfoundland Power		**707**		671
Maritime Electric		**215**		209
FortisOntario		**222**		206
Caribbean				
Caribbean Utilities		**238**		270
FortisTCI		**77**		85
Total electric and gas revenue		**8,419**		8,225
Other services revenue *(1)*		**325**		374
Revenue from contracts with customers		**8,744**		8,599
Alternative revenue *(2)*		**64**		116
Other revenue		**127**		68
Total revenue	**$**	**8,935**	$	8,783

(1) *Includes $227 million and $273 million from regulated operations for 2020 and 2019, respectively*
(2) *Includes a $40 million and $91 million base ROE adjustment associated with the May 2020 and November 2019 FERC decisions, respectively (Notes 2 and 8)*

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: (i) management fee revenue at UNS Energy for the operation of Springerville Units 3 and 4; (ii) revenue from storage optimization activities at Aitken Creek; and (iii) 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. UNS Energy's demand side management surcharge, which is approved by the ACC annually, compensates for the costs to design and implement cost-effective energy efficiency and demand response programs until such costs, along with a performance incentive, are reflected in non-fuel base rates.

FortisBC Energy and FortisBC Electric have an earnings sharing mechanism that provides for a 50/50 sharing of variances from the allowed ROE in 2020 (2019 - variances from formula-driven operation and maintenance expenses and capital expenditures). This mechanism is in place until the expiry of the current multi-year rate plan for 2020 to 2024. 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 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 and regulatory deferrals at FortisBC Energy and FortisBC Electric reflecting cost recovery variances from forecast.

6. ACCOUNTS RECEIVABLE AND OTHER CURRENT ASSETS

(in millions)	**2020**	2019
Trade accounts receivable	**$ 595**	$ 504
Unbilled accounts receivable	**571**	601
Allowance for credit losses [(1)]	**(64)**	(35)
	1,102	1,070
Income tax receivable	**72**	35
Other [(2)]	**195**	192
	$ 1,369	$ 1,297

(1) *Allowance for doubtful accounts for 2019*
(2) *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 27)*

Allowance for Credit Losses

The allowance for credit losses balance changed during 2020 as follows.

(in millions)	**2020**
Balance, beginning of year	**$ (35)**
Credit loss expensed	**(36)**
Credit loss deferred (Note 2)	**(6)**
Write-offs, net of recoveries	**14**
Foreign exchange	**(1)**
Balance, end of year	**$ (64)**

The allowance for doubtful accounts balance changed during 2019 as follows.

(in millions)		2019
Balance, beginning of year	$	(33)
Bad debt expensed		(21)
Write-offs, net of recoveries		18
Foreign exchange		1
Balance, end of year	**$**	**(35)**

7. INVENTORIES

(in millions)		**2020**		2019
Materials and supplies	**$**	**297**	$	294
Gas and fuel in storage		**101**		69
Coal inventory		**24**		31
	$	**422**	$	394

8. REGULATORY ASSETS AND LIABILITIES

(in millions)		**2020**		2019
Regulatory assets				
Deferred income taxes (Notes 3 and 24)	**$**	**1,697**	$	1,556
Employee future benefits (Notes 3 and 25)		**588**		530
Deferred energy management costs [(1)]		**334**		279
Rate stabilization and related accounts [(2)]		**213**		208
Deferred lease costs [(3)]		**122**		116
Manufactured gas plant site remediation deferral (Note 16)		**107**		81
Derivatives (Notes 3 and 27)		**73**		119
Generation early retirement costs [(4)]		**55**		88
Other regulatory assets [(5)]		**399**		406
Total regulatory assets		**3,588**		3,383
Less: Current portion		**(470)**		(425)
Long-term regulatory assets	**$**	**3,118**	$	2,958
Regulatory liabilities				
Deferred income taxes (Notes 3 and 24)	**$**	**1,361**	$	1,440
Asset removal cost provision (Note 3)		**1,206**		1,187
Rate stabilization and related accounts [(2)]		**104**		166
Renewable energy surcharge [(6)]		**100**		94
Energy efficiency liability [(7)]		**83**		101
Employee future benefits (Notes 3 and 25)		**43**		45
Electric and gas moderator account [(8)]		**28**		45
ROE complaints liability (Note 2)		**16**		91
Other regulatory liabilities [(5)]		**162**		189
Total regulatory liabilities		**3,103**		3,358
Less: Current portion		**(441)**		(572)
Long-term regulatory liabilities	**$**	**2,662**	$	2,786

(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 two 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) *Generation Early Retirement Costs:* TEP and the co-owners of Navajo Generating Station ("Navajo") retired Navajo in 2019, with related decommissioning activities continuing through 2054. TEP also retired Sundt Generating Facility Units 1 and 2 ("Sundt") in 2019. The ACC approved the recovery of the retirement costs of Navajo and Sundt over a 10-year period as part of the 2020 Rate Order (Note 2).

(5) *Other Regulatory Assets and Liabilities:* Comprised of regulatory assets and liabilities individually less than $40 million.

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

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

(7) *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.

(8) *Electric and Gas Moderator Account:* Under Central Hudson's 2018 three-year rate order certain regulatory assets and liabilities were approved by the PSC for offset, and an electric and gas moderator account was established, which will be used for future customer rate moderation.

Regulatory assets not earning a return: (i) totalled $1,678 million and $1,510 million as at December 31, 2020 and 2019, respectively; (ii) are primarily related to deferred income taxes and employee future benefits; and (iii) generally do not represent a past cash outlay as they are offset by related liabilities that, likewise, do not incur a carrying cost for rate-making purposes. Recovery periods vary or are yet to be determined by the respective regulators.

9. OTHER ASSETS

(in millions)		**2020**		2019
Supplemental Executive Retirement Plan ("SERP")	**$**	**155**	$	145
Renewable Energy Credits (Note 8)		**106**		99
Equity investment - Belize Electricity		**80**		71
Employee future benefits (Note 25)		**66**		63
Other investments		**66**		43
Operating leases (Note 15)		**40**		46
Deferred compensation plan		**36**		30
Equity Investment - Wataynikaneyap Partnership		**12**		12
Other [(1)]		**109**		111
	$	**670**	$	620

(1) *Includes the fair value of derivatives (Note 27)*

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 trust-owned life insurance policies and mutual funds. Assets in mutual and money market funds are recorded at fair value on a recurring basis (Note 27).

10. PROPERTY, PLANT AND EQUIPMENT

(in millions)		**Cost**		**Accumulated Depreciation**		**Net Book Value**
2020						
Distribution						
Electric	**$**	**11,921**	**$**	**(3,223)**	**$**	**8,698**
Gas		**5,546**		**(1,422)**		**4,124**
Transmission						
Electric		**15,888**		**(3,413)**		**12,475**
Gas		**2,360**		**(719)**		**1,641**
Generation		**6,441**		**(2,550)**		**3,891**
Other		**4,178**		**(1,347)**		**2,831**
Assets under construction		**2,012**		**—**		**2,012**
Land		**326**		**—**		**326**
	$	**48,672**	**$**	**(12,674)**	**$**	**35,998**
2019						
Distribution						
Electric	$	11,396	$	(3,125)	$	8,271
Gas		5,277		(1,330)		3,947
Transmission						
Electric		15,207		(3,293)		11,914
Gas		2,267		(681)		1,586
Generation		6,380		(2,472)		3,908
Other		4,042		(1,327)		2,715
Assets under construction		1,329		—		1,329
Land		318		—		318
	$	46,216	$	(12,228)	$	33,988

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")) or a hoop stress of less than 20% of standard minimum yield strength. 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) or a hoop stress of 20% or more of standard minimum yield strength. 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, information technology assets and Aitken Creek.

As at December 31, 2020, assets under construction were primarily associated with ongoing transmission projects at ITC and the addition of wind-powered electric generating capacity at UNS Energy.

The cost of PPE under finance lease as at December 31, 2020 was $322 million (2019 - $514 million) and related accumulated depreciation was $111 million (2019 - $206 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, 2020, interests in jointly owned facilities consisted of the following.

(in millions, except as noted)	**Ownership** *(%)*	**Cost**	**Accumulated Depreciation**	**Net Book Value**
Transmission Facilities	1.0-80.0	**$ 980**	**$ (381)**	**$ 599**
Springerville Common Facilities [(1)]	86.0	**505**	**(251)**	**254**
San Juan Unit 1 ("San Juan")	50.0	**370**	**(304)**	**66**
Springerville Coal Handling Facilities	83.0	**268**	**(121)**	**147**
Four Corners Units 4 and 5 ("Four Corners")	7.0	**235**	**(97)**	**138**
Gila River Common Facilities	50.0	**108**	**(36)**	**72**
Luna Energy Facility ("Luna")	33.3	**74**	**(2)**	**72**
		$ 2,540	**$ (1,192)**	**$ 1,348**

(1) *In December 2020 TEP purchased an additional 32.2% undivided interest in the Springerville Common Facilities, previously recorded as a finance lease (Note 15). Also in December 2020, TEP sold a 14% interest in the Springerville Common Facilities.*

11. INTANGIBLE ASSETS

(in millions)	Cost	Accumulated Amortization	Net Book Value
2020			
Computer software	**$ 932**	**$ (524)**	**$ 408**
Land, transmission and water rights	**898**	**(142)**	**756**
Other	**114**	**(64)**	**50**
Assets under construction	**77**	**—**	**77**
	$ 2,021	**$ (730)**	**$ 1,291**
2019			
Computer software	$ 946	$ (576)	$ 370
Land, transmission and water rights	890	(122)	768
Other	115	(61)	54
Assets under construction	68	—	68
	$ 2,019	$ (759)	$ 1,260

Included in the cost of land, transmission and water rights as at December 31, 2020 was $136 million (2019 - $133 million) not subject to amortization. Amortization expense was $131 million for 2020 (2019 - $125 million). Amortization is estimated to average approximately $81 million for each of the next five years.

12. GOODWILL

(in millions)	**2020**	2019
Balance, beginning of year	**$ 12,004**	$ 12,530
Foreign currency translation impacts [(1)]	**(212)**	(526)
Balance, end of year	**$ 11,792**	$ 12,004

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

No goodwill impairment was recognized by the Corporation in 2020 or 2019.

13. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

(in millions)	**2020**	2019
Trade accounts payable	**$ 707**	$ 754
Employee compensation and benefits payable	**248**	229
Dividends payable	**241**	228
Accrued taxes other than income taxes	**224**	223
Interest payable	**215**	212
Customer and other deposits	**214**	226
Gas and fuel cost payable	**188**	225
Fair value of derivatives (Note 27)	**56**	83
Manufactured gas plant site remediation (Note 16)	**31**	31
Employee future benefits (Note 25)	**26**	24
Other	**171**	167
	$ 2,321	$ 2,402

14. LONG-TERM DEBT

(in millions)	Maturity Date	**2020**	2019
ITC			
Secured US First Mortgage Bonds - 4.31% weighted average fixed rate (2019 - 4.46%)	2024-2055	**$ 2,755**	$ 2,624
Secured US Senior Notes - 4.00% weighted average fixed rate (2019 - 4.26%)	2040-2055	**923**	747
Unsecured US Senior Notes - 3.61% weighted average fixed rate (2019 - 3.79%)	2022-2043	**4,136**	3,312
Unsecured US Shareholder Note - 6.00% fixed rate (2019 - 6.00%)	2028	**253**	258
Unsecured US Term Loan Credit Agreement - 2.35% weighted average fixed rate	n/a	**—**	260
UNS Energy			
Unsecured US Tax-Exempt Bonds - 4.34% weighted average fixed and variable rate (2019 - 4.64%)	2029-2030	**362**	603
Unsecured US Fixed Rate Notes - 3.86% weighted average fixed rate (2019 - 4.38%)	2021-2050	**2,704**	1,851
Central Hudson			
Unsecured US Promissory Notes - 3.94% weighted average fixed and variable rate (2019 - 4.27%)	2021-2060	**1,078**	986
FortisBC Energy			
Unsecured Debentures - 4.72% weighted average fixed rate (2019 - 4.87%)	2026-2050	**2,995**	2,795
FortisAlberta			
Unsecured Debentures - 4.49% weighted average fixed rate (2019 - 4.64%)	2024-2052	**2,360**	2,185
FortisBC Electric			
Secured Debentures - 8.80% fixed rate (2019 - 8.80%)	2023	**25**	25
Unsecured Debentures - 4.87% weighted average fixed rate (2019 - 5.05%)	2021-2050	**785**	710
Other Electric			
Secured First Mortgage Sinking Fund Bonds - 5.61% weighted average fixed rate (2019 - 6.14%)	2022-2060	**634**	571
Secured First Mortgage Bonds - 5.66% weighted average fixed rate (2019 - 5.66%)	2025-2061	**220**	220
Unsecured Senior Notes - 4.45% weighted average fixed rate (2019 - 4.45%)	2041-2048	**152**	152
Unsecured US Senior Loan Notes and Bonds - 4.41% weighted average fixed and variable rate (2019 - 4.53%)	2022-2049	**648**	645
Corporate and Other			
Unsecured US Senior Notes and Promissory Notes - 3.81% weighted average fixed rate (2019 - 3.80%)	2021-2044	**2,685**	2,903
Unsecured Debentures - 6.50% fixed rate (2019 - 6.50%)	2039	**200**	200
Unsecured Senior Notes - 2.85% fixed rate (2019 - 2.85%)	2023	**500**	500
Long-term classification of credit facility borrowings		**980**	640
Fair value adjustment - ITC acquisition		**119**	133
Total long-term debt (Note 27)		**24,514**	22,320
Less: Deferred financing costs and debt discounts		**(147)**	(129)
Less: Current installments of long-term debt		**(1,254)**	(690)
		$ 23,113	$ 21,501

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.

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 dividends or any other restricted payments if, immediately thereafter, its consolidated debt to consolidated capitalization ratio would exceed 65%.

Long-Term Debt Issuances

(in millions, except as noted)	Month Issued	Interest Rate (%)	Maturity	Amount ($)	Use of Proceeds
ITC					
Unsecured term loan credit agreement	January	(1)	2021	**US 75**	(2)(3)
Unsecured term loan credit agreement (4)	January	(5)	2021	**US 200**	(4)
Unsecured senior notes	May	2.95	2030	**US 700**	(2)(3)(6)
First mortgage bonds	July	3.13	2051	**US 180**	(2)(3)(7)
Secured senior notes	October	3.02	2055	**US 150**	(2)(3)(7)(8)
UNS Energy					
Unsecured senior notes	April	4.00	2050	**US 350**	(2)(3)
Unsecured senior notes	August	1.50	2030	**US 300**	(7)
Unsecured senior notes	September	2.17	2032	**US 50**	(2)(3)
Central Hudson					
Unsecured senior notes	May	3.42	2050	**US 30**	(3)
Unsecured senior notes	July	3.62	2060	**US 30**	(3)(7)
Unsecured senior notes	September	2.03	2030	**US 40**	(8)
Unsecured senior notes	November	2.03	2030	**US 30**	(3)(7)
FortisBC Energy					
Unsecured debentures	July	2.54	2050	**200**	(7)
FortisAlberta					
Unsecured senior debentures	December	2.63	2051	**175**	(2)
FortisBC Electric					
Unsecured debentures	May	3.12	2050	**75**	(2)
Newfoundland Power					
First mortgage sinking fund bonds	April	3.61	2060	**100**	(2)(3)
FortisTCI					
Unsecured senior notes	June/October	5.30	2035	**US 30**	(7)(8)
Unsecured senior notes	October/December	3.25	2030	**US 10**	(3)

(1) *Floating rate of a one-month LIBOR plus a spread of 0.45%*
(2) *Repay credit facility borrowings*
(3) *General corporate purposes*
(4) *Maximum amount of borrowings under this agreement of US$400 million has been drawn; current period borrowings were used to repay an outstanding commercial paper balance.*
(5) *Floating rate of a two-month LIBOR plus a spread of 0.60%*
(6) *Early redemption of unsecured term loan borrowing of US$400 million*
(7) *Finance capital expenditures*
(8) *Repay maturing long-term debt*

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.

(in millions)	**Total**
2021	$ 1,254
2022	823
2023	1,786
2024	1,088
2025	484
Thereafter	19,079
	$ 24,514

In December 2020 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. As at December 31, 2020, $2.0 billion remained available under the short-form base shelf prospectus.

Credit Facilities

(in millions)	Regulated Utilities	Corporate and Other	**2020**	2019
Total credit facilities	$ 3,700	$ 1,881	**$ 5,581**	$ 5,590
Credit facilities utilized:				
Short-term borrowings [1]	(132)	—	**(132)**	(512)
Long-term debt (including current portion) [2]	(714)	(266)	**(980)**	(640)
Letters of credit outstanding	(77)	(53)	**(130)**	(114)
Credit facilities unutilized	$ 2,777	$ 1,562	**$ 4,339**	$ 4,324

(1) *The weighted average interest rate was approximately 0.8% (2019 - 3.2%).*

(2) *The weighted average interest rate was approximately 0.9% (2019 - 2.4%). The current portion was $651 million (2019 - $252 million).*

Credit facilities are syndicated primarily with large banks in Canada and the US, with no one bank holding more than approximately 25% of the total facilities. Approximately $5.3 billion of the total credit facilities are committed facilities with maturities ranging from 2021 through 2025.

Consolidated credit facilities of approximately $5.6 billion as at December 31, 2020 are itemized below.

(in millions)	Amount ($)	Maturity
Unsecured committed revolving credit facilities		
Regulated utilities		
ITC [(1)]	**US 900**	October 2023
UNS Energy	**US 500**	October 2022
Central Hudson	**US 200**	March 2025
FortisBC Energy	**700**	August 2024
FortisAlberta	**250**	August 2024
FortisBC Electric	**150**	April 2024
Other Electric	**190**	[(2)]
Other Electric	**US 70**	January 2025
Corporate and Other	**1,850**	[(3)]
Other facilities		
Regulated utilities		
Central Hudson - uncommitted credit facility	**US 30**	n/a
FortisBC Energy - uncommitted credit facility	**55**	March 2022
FortisBC Electric - unsecured demand overdraft facility	**10**	n/a
Other Electric - unsecured demand facilities	**20**	n/a
Other Electric - unsecured demand facility and emergency standby loan	**US 60**	June 2021
Corporate and Other - unsecured non-revolving facility	**30**	n/a

(1) *ITC also has a US$400 million commercial paper program, under which US$67 million was outstanding as at December 31, 2020, as reported in short-term borrowings.*
(2) *$40 million in June 2021, $50 million in February 2022 and $100 million in August 2024*
(3) *$500 million in April 2021, $50 million in April 2022 and $1.3 billion in July 2024*

15. LEASES

The Corporation and its subsidiaries lease office facilities, utility equipment, land, and communication tower space with remaining terms of up to 21 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 35 years.

Leases were presented on the consolidated balance sheets as follows.

(in millions)	**2020**	2019
Operating leases		
Other assets	**$ 40**	$ 46
Accounts payable and other current liabilities	**(7)**	(8)
Other liabilities	**(33)**	(38)
Finance leases (1) (2)		
Regulatory assets	**$ 122**	$ 116
PPE, net	**211**	308
Accounts payable and other current liabilities	**(2)**	(24)
Finance leases	**(331)**	(413)

(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.*

(2) *In December 2020 TEP purchased a 32.2% undivided interest in the Springerville Common Facilities, which had previously been leased (Note 10).*

The components of lease expense were as follows.

(in millions)	**2020**	2019
Operating lease cost	**$ 10**	$ 10
Finance lease cost:		
Amortization	**14**	17
Interest	**34**	48
Variable lease cost	**20**	39
Total lease cost	**$ 78**	$ 114

As at December 31, 2020, the present value of minimum lease payments was as follows.

(in millions)	Operating Leases	Finance Leases	**Total**
2021	$ 8	$ 33	**$ 41**
2022	7	34	**41**
2023	6	34	**40**
2024	4	34	**38**
2025	3	34	**37**
Thereafter	22	1,056	**1,078**
	50	1,225	**1,275**
Less: Imputed interest	(10)	(892)	**(902)**
Total lease obligations	40	333	**373**
Less: Current installments	(7)	(2)	**(9)**
	$ 33	$ 331	**$ 364**

Supplemental lease information was as follows.

(in millions, except as noted)	**2020**	2019
Weighted average remaining lease term *(years)*		
Operating leases	**10**	10
Finance leases	**35**	27
Weighted average discount rate *(%)*		
Operating leases	**4.0**	4.1
Finance leases	**5.1**	4.8
Cash payments related to lease liabilities		
Operating cash flows used for operating leases	**$ (10)**	$ (10)
Operating cash flows used for finance leases	**(2)**	(47)
Financing cash flows used for finance leases	**(25)**	(16)
Investing cash flows used for finance leases	**(87)**	(212)

See Note 26 for non-cash transactions that resulted in right-of-use assets obtained in exchange for new lease liabilities.

16. OTHER LIABILITIES

(in millions)	**2020**	2019
Employee future benefits (Note 25)	**$ 905**	$ 832
Customer and other deposits	**132**	70
AROs (Note 3)	**130**	148
Stock-based compensation plans (Note 21)	**86**	83
Manufactured gas plant site remediation (1)	**69**	48
Fair value of derivatives (Note 27)	**50**	68
Mine reclamation obligations (2)	**47**	43
Retail energy contract (3)	**46**	—
Deferred compensation plan (Note 9)	**43**	33
Operating leases	**33**	38
Other	**58**	83
	$ 1,599	$ 1,446

(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. As at December 31, 2020, an obligation of $96 million was recognized, including a current portion of $27 million recognized in accounts payable and other current liabilities (Note 13). Central Hudson has notified its insurers that it intends to seek reimbursement where insurance coverage exists. Differences between actual costs and the associated rate allowances are deferred as a regulatory asset for future recovery (Note 8).

(2) TEP pays ongoing reclamation costs related to two coal mines that supply generating facilities in which it has an ownership interest but does not operate. Costs are deferred as a regulatory asset and recovered from customers as permitted by the regulator. TEP's share of the reclamation costs is estimated to be $61 million upon expiry of the coal agreements between 2022 and 2031. The present value of the estimated future liability is shown in the table above.

(3) FortisAlberta entered into an eight-year agreement with an existing retail energy provider to continue to act as its default retailer to eligible customers under the regulated retail option. As part of this agreement FortisAlberta received an upfront payment in 2020 which will be amortized to earnings over the life of the agreement.

17. COMMON SHARES

During 2019 the Corporation issued approximately 4.1 million common shares under its at-the-market common equity program at an average price of $52.16 per share. The gross proceeds of $212 million ($209 million net of commissions) were used primarily to fund capital expenditures.

Also during 2019 the Corporation issued approximately 22.8 million common shares representing gross proceeds of $1,190 million ($1,167 million net of commissions) at a price of $52.15 per share. The net proceeds were used to redeem US$500 million of its outstanding 2.10% unsecured notes due on October 4, 2021, to repay credit facility borrowings, and for general corporate purposes.

18. EARNINGS PER COMMON SHARE

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

	2020			2019		
	Net Earnings to Common Shareholders *($ millions)*	**Weighted Average Shares** *(# millions)*	**EPS** *($)*	Net Earnings to Common Shareholders *($ millions)*	Weighted Average Shares *(# millions)*	EPS *($)*
Basic EPS	**$ 1,209**	**464.8**	**$ 2.60**	$ 1,655	436.8	$ 3.79
Potential dilutive effect of stock options	**—**	**0.6**	**—**	—	0.7	—
Diluted EPS	**$ 1,209**	**465.4**	**$ 2.60**	$ 1,655	437.5	$ 3.78

19. PREFERENCE SHARES

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

Issued and Outstanding	**2020**		2019	
First Preference Shares	**Number of Shares** *(in thousands)*	**Amount** *(in millions)*	Number of Shares *(in thousands)*	Amount *(in millions)*
Series F	**5,000**	**$ 122**	5,000	$ 122
Series G	**9,200**	**225**	9,200	225
Series H	**7,665**	**188**	7,025	172
Series I	**2,335**	**57**	2,975	73
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]	**Initial Yield** *(%)*	**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 [3]	4.75	1.1875	—	Currently Redeemable	25.25	—
Fixed rate reset [4] [5]						
Series G	5.25	1.0983	2.13	September 1, 2023	25.00	—
Series H [6]	4.25	0.4588	1.45	June 1, 2025	25.00	Series I
Series K	4.00	0.9823	2.05	March 1, 2024	25.00	Series L
Series M	4.10	0.9783	2.48	December 1, 2024	25.00	Series N
Floating rate reset [5] [7]						
Series I	2.10	—	1.45	June 1, 2025	25.00	Series H
Series L	—	—	—	—	—	Series K
Series N	—	—	—	—	—	Series M

(1) *Holders are entitled to receive a fixed or floating cumulative quarterly cash dividend as and when declared by the Board of Directors of the Corporation, payable in equal installments on the first day of each quarter.*
(2) *On or after the specified redemption dates, the Corporation has the option to redeem for cash the outstanding first preference shares, in whole or in part, at the specified per share redemption value plus all accrued and unpaid dividends up to but excluding the dates fixed for redemption, and in the case of the first preference shares that reset, on every fifth anniversary date thereafter.*
(3) *First Preference Shares, Series J are redeemable as of December 1, 2021 and thereafter at $25.00 per share.*
(4) *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.*
(5) *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.*
(6) *The annual dividend per share for the First Preference Shares, Series H was reset from $0.6250 to $0.4588 for the five-year period from June 1, 2020 up to but excluding June 1, 2025.*
(7) *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 June 1, 2020, 267,341 First Preference Shares, Series H were converted on a one-for-one basis into First Preference Shares, Series I, and 907,577 First Preference Shares, Series I were converted on a one-for-one basis into First Preference Shares, Series H.

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.

20. ACCUMULATED OTHER COMPREHENSIVE INCOME

(in millions)		Opening Balance		Net Change		Ending Balance
2020						
Unrealized foreign currency translation gains (losses)						
Net investments in foreign operations	**$**	**713**	**$**	**(336)**	**$**	**377**
Hedges of net investments in foreign operations		**(359)**		**60**		**(299)**
Income tax expense		**(3)**		**(3)**		**(6)**
		351		**(279)**		**72**
Other						
Cash flow hedges (Note 27)		**17**		**(21)**		**(4)**
Unrealized employee future benefits losses (Note 25)		**(38)**		**(11)**		**(49)**
Income tax recovery		**6**		**9**		**15**
		(15)		**(23)**		**(38)**
Accumulated other comprehensive income	**$**	**336**	**$**	**(302)**	**$**	**34**
2019						
Unrealized foreign currency translation gains (losses)						
Net investments in foreign operations	$	1,470	$	(757)	$	713
Hedges of net investments in foreign operations		(544)		185		(359)
Income tax recovery (expense)		10		(13)		(3)
		936		(585)		351
Other						
Cash flow hedges (Note 27)		11		6		17
Unrealized employee future benefits losses (Note 25)		(20)		(18)		(38)
Income tax recovery		1		5		6
		(8)		(7)		(15)
Accumulated other comprehensive income	$	928	$	(592)	$	336

21. STOCK-BASED COMPENSATION PLANS

Stock Options

Officers and certain key employees of Fortis and its subsidiaries are eligible for grants of options to purchase common shares of the Corporation. Options 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.

The following options were granted in 2020 and 2019.

	2020	2019
Options granted *(in thousands)*	**686**	852
Exercise price *($)* (1)	**58.40**	47.57
Grant date fair value *($)*	**4.20**	3.70
Valuation assumptions:		
Dividend yield *(%)* (2)	**3.7**	3.8
Expected volatility *(%)* (3)	**15.8**	15.2
Risk-free interest rate *(%)* (4)	**1.2**	1.8
Weighted average expected life *(years)* (5)	**5.2**	5.6

(1) *Five-day VWAP immediately preceding the grant date*
(2) *Reflects average annual dividend yield up to the grant date and the weighted average expected life of the options*
(3) *Reflects historical experience over a period equal to the weighted average expected life of the options*
(4) *Government of Canada benchmark bond yield at the grant date that covers the weighted average expected life of the options*
(5) *Reflects historical experience*

The following table summarizes information related to stock options for 2020.

	Total Options		Non-vested Options (1)	
(in thousands, except as noted)	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Grant Date Fair Value
Options outstanding, beginning of year	**3,418**	**$ 41.18**	**1,910**	**$ 3.43**
Granted	**686**	**$ 58.40**	**686**	**$ 4.20**
Exercised	**(825)**	**$ 39.21**	**n/a**	**n/a**
Vested	**n/a**	**n/a**	**(807)**	**$ 3.25**
Cancelled/Forfeited	**(17)**	**$ 50.02**	**(17)**	**$ 3.79**
Options outstanding, end of year	**3,262**	**$ 45.26**	**1,772**	**$ 3.81**
Options vested, end of year (2)	**1,490**	**$ 39.40**		

(1) *As at December 31, 2020, there was $7 million of unrecognized compensation expense related to stock options not yet vested, which is expected to be recognized over a weighted average period of approximately three years.*
(2) *As at December 31, 2020, the weighted average remaining term of vested options was six years with an aggregate intrinsic value of $19 million.*

The following table summarizes additional stock option information.

(in millions)	2020	2019
Stock options exercised:		
Cash received for exercise price	**$ 32**	$ 51
Intrinsic value realized by employees	**15**	22

DSU Plan

Directors of the Corporation who are not officers are eligible for grants of DSUs representing the equity portion of their annual compensation. Directors can further 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.

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.

The following table summarizes information related to DSUs.

	2020	2019
Number of units *(in thousands)*		
Beginning of year	**165**	177
Granted	**25**	29
Notional dividends reinvested	**6**	6
Paid out	**(49)**	(47)
End of year	**147**	165

The accrued liability has been recognized at the respective December 31st VWAP (Note 3) and included in long-term other liabilities (Note 16). The accrued liability, compensation expense and cash payout were not material for 2020 or 2019.

PSU Plans

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, is entitled to commensurate notional common share dividends, and is settled in cash. At the end of the three-year vesting period, cash payouts are the product of: (i) the numbers 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%.

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; and (ii) the Corporation's cumulative EPS, or for certain subsidiaries the Company's cumulative net income, as compared to the target established at the time of the grant.

The following table summarizes information related to PSUs.

	2020	2019
Number of units *(in thousands)*		
Beginning of year	**2,118**	1,763
Granted	**586**	690
Notional dividends reinvested	**71**	73
Paid out	**(735)**	(357)
Cancelled/forfeited	**(64)**	(51)
End of year	**1,976**	2,118
Additional information *(in millions)*		
Compensation expense recognized	**$ 58**	$ 74
Compensation expense unrecognized (1)	**32**	35
Cash payout	**54**	16
Accrued liability as at December 31 (2)	**108**	106
Aggregate intrinsic value as at December 31 (3)	**140**	141

(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 long-term other liabilities (Notes 13 and 16)*
(3) *Relates to outstanding PSUs and reflects a weighted average contractual life of one year*

RSU Plans

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 or immediately upon retirement eligibility of the holder, 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, beginning with the 2020 grant, common shares of the Corporation. RSUs issued in 2020 may be settled in cash, common shares, or an equal proportion of cash and common shares depending on an executives' settlement election and whether their share ownership requirements have been met.

The following table summarizes information related to RSUs.

		2020		2019
Number of units *(in thousands)*				
Beginning of year		**1,050**		717
Granted		**356**		429
Notional dividends reinvested		**37**		35
Paid out		**(355)**		(92)
Cancelled/forfeited		**(40)**		(39)
End of year		**1,048**		1,050
Additional information *(in millions)*				
Compensation expense recognized	**$**	**20**	$	24
Compensation expense unrecognized [(1)]		**15**		17
Cash payout		**19**		4
Accrued liability as at December 31 [(2)]		**39**		39
Aggregate intrinsic value as at December 31 [(3)]		**54**		56

(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*

22. DISPOSITION

On April 16, 2019, Fortis sold its 51% ownership interest in the 335 MW Waneta Expansion for proceeds of $995 million. A gain on disposition of $577 million ($484 million after tax), net of expenses, was recognized in the Corporate and Other segment, and the related non-controlling interest was removed from equity.

Up to the date of disposition, excluding the gain as noted above, the Waneta Expansion contributed $17 million to earnings before income tax expense, of which Fortis' share was 51%.

23. OTHER INCOME, NET

(in millions)		2020		2019
Equity component of AFUDC	**$**	**78**	$	74
Equity income		**20**		(1)
Derivative gains		**13**		17
Interest income		**13**		16
Gain on repayment of debt		**—**		11
Other		**30**		21
	$	**154**	$	138

24. INCOME TAXES

Deferred Income Tax Assets and Liabilities

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

(in millions)	**2020**	2019
Gross deferred income tax assets		
Regulatory liabilities	**$ 527**	$ 588
Tax loss and credit carryforwards	**494**	532
Employee future benefits	**175**	165
Unrealized foreign exchange losses on long-term debt [(1)]	**33**	40
Other	**83**	88
	1,312	1,413
Valuation allowance [(1)]	**(22)**	(22)
Net deferred income tax asset	**$ 1,290**	$ 1,391
Gross deferred income tax liabilities		
PPE	**$ (4,253)**	$ (3,986)
Regulatory assets	**(263)**	(269)
Intangible assets	**(118)**	(105)
	(4,634)	(4,360)
Net deferred income tax liability	**$ (3,344)**	$ (2,969)

(1) *These deferred income tax assets can be utilized only to the extent that the Corporation has capital gains to offset the underlying capital losses. Management believes that it is more likely than not that a $22 million shortfall exists in this regard and, therefore, the Corporation has recognized a $22 million valuation allowance. Management believes that, based on its historical pattern of taxable income, Fortis will generate the necessary income in the future to realize all other deferred income tax assets.*

Unrecognized Tax Benefits

(in millions)	**2020**	2019
Beginning of year	**$ 36**	$ 38
Additions related to current year	**3**	5
Adjustments related to prior years	**(6)**	(7)
End of year	**$ 33**	$ 36

Unrecognized tax benefits, if recognized, would reduce income tax expense by $1 million in 2020. Fortis has not recognized interest expense in 2020 and 2019 related to unrecognized tax benefits.

Income Tax Expense

(in millions)		**2020**		2019
Canadian				
Earnings before income tax expense	**$**	**333**	$	901
Current income tax		**20**		49
Deferred income tax		**(16)**		42
Total Canadian	**$**	**4**	$	91
Foreign				
Earnings before income tax expense	**$**	**1,287**	$	1,240
Current income tax		**(15)**		(7)
Deferred income tax		**242**		205
Total Foreign	**$**	**227**	$	198
Income tax expense	**$**	**231**	$	289

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

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

(in millions, except as noted)		**2020**		2019
Earnings before income tax expense	**$**	**1,620**	$	2,141
Combined Canadian federal and provincial statutory income tax rate *(%)*		**30.0**		28.5
Expected federal and provincial taxes at statutory rate	**$**	**486**	$	610
Decrease resulting from:				
Foreign and other statutory rate differentials		**(145)**		(124)
Difference between gain on sale for accounting and amounts calculated for tax purposes		**—**		(73)
Release of valuation allowance		**—**		(33)
AFUDC		**(20)**		(16)
Effects of rate-regulated accounting:				
Difference between depreciation claimed for income tax and accounting purposes		**(56)**		(48)
Items capitalized for accounting purposes but expensed for income tax purposes		**(26)**		(17)
Other		**(8)**		(10)
Income tax expense	**$**	**231**	$	289
Effective tax rate *(%)*		**14.3**		13.5

Income Tax Carryforwards

(in millions)	Expiring Year		2020
Canadian			
Capital loss	n/a	**$**	**27**
Non-capital loss	2035-2040		**200**
Other tax credits	2026-2040		**2**
			229
Unrecognized			**(26)**
			203
Foreign			
Federal and state net operating loss	2021-2040		**2,971**
Other tax credits	2022-2040		**34**
			3,005
Total income tax carryforwards recognized		**$**	**3,208**

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 and British Columbia). The Corporation's 2013 to 2020 taxation years are still open for audit in Canadian jurisdictions, and its 2011 to 2020 taxation years are still open for audit in United States jurisdictions.

25. EMPLOYEE FUTURE BENEFITS

For defined benefit pension 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, 2017 for the Corporation; December 31, 2018 for FortisBC Energy and FortisBC Electric (plan covering unionized employees); December 31, 2019 for the remaining FortisBC Electric plans, Newfoundland Power, FortisAlberta and FortisOntario; and December 31, 2020 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 defined benefit pension 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 %)	2020 Target Allocation	2020	2019
Equities	**46**	**48**	47
Fixed income	**47**	**45**	46
Real estate	**6**	**6**	6
Cash and other	**1**	**1**	1
	100	**100**	100

Fair Value of Plan Assets

(in millions)	Level 1 [(1)]	Level 2 [(1)]	Level 3 [(1)]	Total
2020				
Equities	**$ 713**	**$ 1,163**	**$ —**	**$ 1,876**
Fixed income	**197**	**1,580**	**—**	**1,777**
Real estate	**—**	**17**	**204**	**221**
Private equities	**—**	**—**	**20**	**20**
Cash and other	**8**	**17**	**—**	**25**
	$ 918	**$ 2,777**	**$ 224**	**$ 3,919**
2019				
Equities	$ 622	$ 1,050	$ —	$ 1,672
Fixed income	171	1,445	—	1,616
Real estate	—	16	207	223
Private equities	—	—	22	22
Cash and other	8	10	—	18
	$ 801	$ 2,521	$ 229	$ 3,551

(1) *See Note 27 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.

(in millions)	**2020**	2019
Balance, beginning of year	**$ 229**	$ 215
(Loss) return on plan assets	**(2)**	19
Foreign currency translation	**(1)**	(2)
Purchases, sales and settlements	**(2)**	(3)
Balance, end of year	**$ 224**	$ 229

Funded Status	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2020**	2019	**2020**	2019
Change in benefit obligation [1]				
Balance, beginning of year	**$ 3,632**	$ 3,207	**$ 712**	$ 655
Service costs	**98**	77	**32**	27
Employee contributions	**17**	16	**2**	2
Interest costs	**113**	124	**22**	25
Benefits paid	**(162)**	(144)	**(27)**	(27)
Actuarial losses	**350**	439	**62**	46
Past service (credits) costs/plan amendments	**—**	1	**(3)**	4
Foreign currency translation	**(53)**	(88)	**(11)**	(20)
Balance, end of year [2] [3]	**$ 3,995**	$ 3,632	**$ 789**	$ 712
Change in value of plan assets				
Balance, beginning of year	**$ 3,208**	$ 2,830	**$ 343**	$ 293
Actual return on plan assets	**444**	523	**55**	62
Benefits paid	**(155)**	(138)	**(27)**	(27)
Employee contributions	**17**	18	**2**	2
Employer contributions	**62**	53	**28**	28
Foreign currency translation	**(48)**	(78)	**(10)**	(15)
Balance, end of year [4]	**$ 3,528**	$ 3,208	**$ 391**	$ 343
Funded status	**$ (467)**	$ (424)	**$ (398)**	$ (369)
Balance sheet presentation				
Long-term assets (Note 9)	**$ 58**	$ 46	**$ 8**	$ 17
Current liabilities (Note 13)	**(13)**	(12)	**(13)**	(12)
Long-term liabilities (Note 16)	**(512)**	(458)	**(393)**	(374)
	$ (467)	$ (424)	**$ (398)**	$ (369)

(1) *Amounts reflect projected benefit obligation for defined benefit pension plans and accumulated benefit obligation for OPEB plans.*
(2) *The accumulated benefit obligation, which excludes assumptions about future salary levels, for defined benefit pension plans was $3,679 million as at December 31, 2020 (2019 - $3,352 million).*
(3) *The increases in the defined benefit pension and OPEB obligations were driven by the decrease in discount rates due to lower interest rates.*
(4) *The increases in the defined benefit pension and OPEB plan assets were driven by market returns.*

For those defined benefit pension plans for which the projected benefit obligation exceeded the fair value of plan assets as at December 31, 2020, the obligation was $3,290 million compared to plan assets of $2,777 million (2019 - $2,971 million and $2,511 million, respectively).

For those defined benefit pension plans for which the accumulated benefit obligation exceeded the fair value of plan assets as at December 31, 2020, the obligation was $3,037 million compared to plan assets of $2,741 million (2019 - $2,752 million and $2,478 million, respectively).

For those OPEB plans for which the accumulated benefit obligation exceeded the fair value of plan assets as at December 31, 2020, the obligation was $589 million compared to plan assets of $183 million (2019 - $537 million and $151 million, respectively).

Net Benefit Cost [1]	**Defined Benefit Pension Plans**		**OPEB Plans**	
(in millions)	**2020**	2019	**2020**	2019
Service costs	**$ 98**	$ 77	**$ 32**	$ 27
Interest costs	**113**	124	**22**	25
Expected return on plan assets	**(176)**	(161)	**(19)**	(16)
Amortization of actuarial losses (gains)	**33**	24	**(5)**	(4)
Amortization of past service credits/plan amendments	**(1)**	(1)	**(2)**	(7)
Regulatory adjustments	**—**	2	**4**	3
	$ 67	$ 65	**$ 32**	$ 28

[1] *The non-service 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.

	Defined Benefit Pension Plans		**OPEB Plans**	
(in millions)	**2020**	2019	**2020**	2019
Unamortized net actuarial losses (gains)	**$ 42**	$ 32	**$ (1)**	$ (2)
Unamortized past service costs	**1**	1	**7**	7
Income tax recovery	**(10)**	(8)	**(1)**	(1)
Accumulated other comprehensive income	**$ 33**	$ 25	**$ 5**	$ 4
Net actuarial losses (gains)	**$ 517**	$ 486	**$ 12**	$ (18)
Past service credits	**(7)**	(9)	**(8)**	(8)
Other regulatory deferrals	**13**	15	**18**	19
	$ 523	$ 492	**$ 22**	$ (7)
Regulatory assets (Note 8)	**$ 523**	$ 492	**$ 65**	$ 38
Regulatory liabilities (Note 8)	**—**	—	**(43)**	(45)
Net regulatory assets (liabilities)	**$ 523**	$ 492	**$ 22**	$ (7)

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

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2020**	2019	**2020**	2019
Current year net actuarial losses	**$ 9**	$ 11	**$ 1**	$ —
Past service costs/plan amendments	**—**	—	**—**	5
Amortization of actuarial losses	**1**	1	**—**	—
Foreign currency translation	**—**	1	**—**	—
Income tax recovery	**(2)**	(5)	**—**	—
Total recognized in comprehensive income	**$ 8**	$ 8	**$ 1**	$ 5
Current year net actuarial losses	**$ 69**	$ 64	**$ 25**	$ 3
Past service costs (credits)/plan amendments	**—**	—	**(3)**	—
Amortization of actuarial (losses) gains	**(31)**	(23)	**5**	4
Amortization of past service (costs) credits	**2**	(1)	**3**	8
Foreign currency translation	**(7)**	(10)	**—**	—
Regulatory adjustments	**(2)**	—	**(1)**	(8)
Total recognized in regulatory assets	**$ 31**	$ 30	**$ 29**	$ 7

Significant Assumptions	Defined Benefit Pension Plans		OPEB Plans	
(weighted average %)	**2020**	2019	**2020**	2019
Discount rate during the year [(1)]	**3.16**	4.05	**3.22**	4.10
Discount rate as at December 31	**2.63**	3.20	**2.64**	3.25
Expected long-term rate of return on plan assets [(2)]	**5.52**	5.78	**5.28**	5.50
Rate of compensation increase	**3.34**	3.33	**—**	—
Health care cost trend increase as at December 31 [(3)]	**—**	—	**4.61**	4.62

(1) *ITC and UNS 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 2021 weighted average health care cost trend rate is 5.91% and is assumed to decrease over the next 11 years to the weighted average ultimate health care cost trend rate of 4.61% in 2031 and thereafter.*

Expected Benefit Payments *(in millions)*	**Defined Benefit Pension Payments**	**OPEB Payments**
2021	$ 163	$ 27
2022	165	28
2023	170	30
2024	174	31
2025	180	32
2026-2030	984	174

During 2021 the Corporation expects to contribute $49 million for defined benefit pension plans and $33 million for OPEB plans.

In 2020 the Corporation expensed $42 million (2019 - $39 million) related to defined contribution pension plans.

26. SUPPLEMENTARY CASH FLOW INFORMATION

(in millions)		**2020**		2019
Cash paid (received) for				
Interest	**$**	**1,027**	$	1,007
Income taxes		**(26)**		(37)
Change in working capital				
Accounts receivable and other current assets	**$**	**(84)**	$	1
Prepaid expenses		**(15)**		(8)
Inventories		**(36)**		(13)
Regulatory assets - current portion		**(49)**		(75)
Accounts payable and other current liabilities		**(100)**		(8)
Regulatory liabilities - current portion		**(150)**		(65)
	$	**(434)**	$	(168)
Non-cash investing and financing activities				
Accrued capital expenditures	**$**	**400**	$	382
Common share dividends reinvested		**114**		299
Contributions in aid of construction		**13**		15
Right-of-use assets obtained in exchange for operating lease liabilities		**3**		55
Exercise of stock options into common shares		**3**		5
Finance leases		**2**		88

27. 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.

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

Cash flow associated with the settlement of all derivatives is included in operating activities on the consolidated statements of cash flows.

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, 2020, unrealized losses of $73 million (2019 - $119 million) were recognized as regulatory assets and unrealized gains of $17 million (2019 - $2 million) were recognized as regulatory liabilities.

Energy Contracts Not Subject to Regulatory Deferral
UNS Energy holds wholesale trading contracts to fix power prices and realize potential margin, of which 10% of any realized gains is shared with customers through rate stabilization accounts. Fair values are measured using a market approach incorporating, where possible, independent third-party information.

Aitken Creek holds gas swap contracts to manage its exposure to changes in natural gas prices, capture natural gas price spreads, and manage the financial risk posed by physical transactions. Fair values are measured using forward pricing from published market sources.

Unrealized gains or losses associated with changes in the fair value of these energy contracts are recognized in revenue and were not material for 2020 and 2019.

Total Return Swaps
The Corporation holds total return swaps to manage the cash flow risk associated with forecast future cash settlements of certain stock-based compensation obligations. The swaps have a combined notional amount of $113 million and terms of one to three years expiring at varying dates through January 2023. 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 and were not material for 2020 and 2019.

Foreign Exchange Contracts
The Corporation holds US dollar-denominated foreign exchange contracts to help mitigate exposure to foreign exchange rate volatility. The contracts expire at varying dates through February 2022 and have a combined notional amount of $245 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 and were not material for 2020 and 2019.

Interest Rate Swaps
ITC entered into forward-starting interest rate swaps to manage the interest rate risk associated with planned borrowings. The swaps, which had a combined notional value of $611 million, were terminated in May 2020 with the issuance of US$700 million senior notes. Realized losses of $31 million were recognized in other comprehensive income and are being reclassified to earnings as a component of interest expense over five years.

Other Investments
ITC, UNS Energy and Central Hudson hold investments in trust associated with supplemental retirement benefit plans for select employees. These investments consist of mutual funds and money market accounts, which are recorded at fair value based on quoted market prices in active markets. Gains and losses are recognized in other income, net and were not material for 2020 and 2019.

Recurring Fair Value Measures

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

(in millions)	Level 1 [(1)]	Level 2 [(1)]	Level 3 [(1)]	Total
As at December 31, 2020				
Assets				
Energy contracts subject to regulatory deferral [(2) (3)]	**$ —**	**$ 38**	**$ —**	**$ 38**
Energy contracts not subject to regulatory deferral [(2)]	**—**	**6**	**—**	**6**
Foreign exchange contracts and total return swaps [(2)]	**16**	**—**	**—**	**16**
Other investments [(4)]	**126**	**—**	**—**	**126**
	$ 142	**$ 44**	**$ —**	**$ 186**
Liabilities				
Energy contracts subject to regulatory deferral [(3) (5)]	**$ —**	**$ (94)**	**$ —**	**$ (94)**
Energy contracts not subject to regulatory deferral [(5)]	**—**	**(12)**	**—**	**(12)**
	$ —	**$ (106)**	**$ —**	**$ (106)**
As at December 31, 2019				
Assets				
Energy contracts subject to regulatory deferral [(2) (3)]	$ —	$ 22	$ —	$ 22
Energy contracts not subject to regulatory deferral [(2)]	—	8	—	8
Foreign exchange contracts, interest rate and total return swaps [(2)]	14	4	—	18
Other investments [(4)]	121	—	—	121
	$ 135	$ 34	$ —	$ 169
Liabilities				
Energy contracts subject to regulatory deferral [(3) (5)]	$ (1)	$ (138)	$ —	$ (139)
Energy contracts not subject to regulatory deferral [(5)]	—	(12)	—	(12)
	$ (1)	$ (150)	$ —	$ (151)

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

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.

(in millions)	Gross Amount Recognized in Balance Sheet	Counterparty Netting of Energy Contracts	Cash Collateral Received/ Posted	Net Amount
As at December 31, 2020				
Derivative assets	**$ 44**	**$ 26**	**$ 10**	**$ 8**
Derivative liabilities	**(106)**	**(26)**	**(9)**	**(71)**
As at December 31, 2019				
Derivative assets	$ 30	$ 22	$ 10	$ (2)
Derivative liabilities	(151)	(22)	(2)	(127)

Volume of Derivative Activity

As at December 31, 2020, the Corporation had various energy contracts that will settle on various dates through 2029. The volumes related to electricity and natural gas derivatives are outlined below.

	2020	2019
Energy contracts subject to regulatory deferral [(1)]		
Electricity swap contracts *(GWh)*	**522**	628
Electricity power purchase contracts *(GWh)*	**2,781**	3,198
Gas swap contracts *(PJ)*	**156**	168
Gas supply contract premiums *(PJ)*	**203**	241
Energy contracts not subject to regulatory deferral [(1)]		
Wholesale trading contracts *(GWh)*	**1,588**	1,855
Gas swap contracts *(PJ)*	**36**	43

(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. As a result of the impact of the COVID-19 pandemic, certain of the Corporation's utilities have temporarily suspended non-payment disconnects, delayed customer rate increases and deferred the recovery of costs (Note 2). The Corporation has seen an increase in accounts receivable and, accordingly, its allowance for credit losses during 2020 (Note 6).

ITC has a concentration of credit risk as approximately 70% of its revenue is derived from three customers. The 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 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.

UNS Energy, Central Hudson, FortisBC Energy, Aitken Creek and the Corporation may be exposed to credit risk in the event of non-performance by counterparties to derivatives. Credit risk is managed by net settling payments, when possible, and dealing only with counterparties that have investment-grade credit ratings. At UNS Energy and Central Hudson, 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 $88 million as at December 31, 2020 (2019 - $161 million).

Hedge of Foreign Net Investments

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

As at December 31, 2020, US$2.3 billion (2019 - US$2.2 billion) of corporately issued US dollar-denominated long-term debt has been designated as an effective hedge of net investments, leaving approximately US$10.2 billion (2019 - US$9.7 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, 2020, the carrying value of long-term debt, including current portion, was $24.5 billion (2019 - $22.3 billion) compared to an estimated fair value of $29.1 billion (2019 - $25.3 billion).

28. COMMITMENTS AND CONTINGENCIES

As at December 31, 2020, unconditional minimum purchase obligations were as follows.

(in millions)	**Total**	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Waneta Expansion capacity agreement *(1)*	**$2,576**	$ 52	$ 53	$ 54	$ 55	$ 56	$ 2,306
Gas and fuel purchase obligations *(2)*	**2,355**	679	453	312	192	124	595
Power purchase obligations *(3)*	**1,867**	249	208	188	191	180	851
Renewable PPAs *(4)*	**1,380**	102	102	101	101	101	873
ITC easement agreement *(5)*	**381**	13	13	13	13	13	316
Debt collection agreement *(6)*	**112**	3	3	3	3	3	97
Renewable energy credit purchase agreements *(7)*	**97**	15	14	16	9	7	36
Other *(8)*	**116**	48	5	4	4	3	52
	$8,884	$1,161	$ 851	$ 691	$ 568	$ 487	$ 5,126

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

(2) *FortisBC Energy ($1,482 million):* includes contracts for the purchase of 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, 2020.

UNS Energy ($747 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, and the purchase of transmission services for purchased power. 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 2040.

(3) *Maritime Electric ($910 million):* includes an agreement entitling Maritime Electric to approximately 4.55% of the output of New Brunswick Power's Point Lepreau nuclear generating station and requiring Maritime Electric to pay its share of the station's capital operating costs for the life of the unit. Maritime Electric also has two take-or-pay contracts for the purchase of either capacity or energy, expiring in December 2026.

FortisOntario ($599 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 ($295 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.

(4) TEP and UNS Electric are party to renewable PPAs, with expiry dates from 2027 through 2043, 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. Amounts are the estimated future payments.

(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 licences associated with the land over which its transmission lines cross. The agreement expires in December 2050, subject to 10 potential 50-year renewals thereafter unless METC gives notice of non-renewal at least one year in advance.

(6) 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, will be collected from customers in future rates.

(7) UNS Energy and Central Hudson are party to renewable energy credit 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.

(8) Includes a $24 million payment to be made in 2021 under the Oso Grande Wind Project build-transfer agreement by UNS Energy, as well as AROs and joint-use asset and shared service agreements.

Other Commitments

Under a funding framework with the Governments of Ontario and Canada, Fortis will contribute a minimum of approximately $155 million of equity capital to the Wataynikaneyap Partnership, based on Fortis' proportionate 39% ownership interest and the final regulatory-approved capital cost of the related project. In October 2019 the Wataynikaneyap Partnership entered into loan agreements to finance the project during construction. In the event a lender under the loan agreements realizes security on the loans, Fortis may be required to accelerate its equity capital contributions, which may be in excess of the amount otherwise required of Fortis under the funding framework, to a maximum total funding of $235 million.

UNS Energy has joint generation performance guarantees with participants at San Juan, Four Corners, and Luna, with agreements expiring in 2022 through 2046, and at 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 Navajo, participants would seek financial recovery from the defaulting party. There is no maximum amount under these guarantees, except for a maximum of $318 million for Four Corners. As at December 31, 2020, there was no obligation under these guarantees.

Central Hudson is a participant in an investment with other utilities to jointly develop, own and operate electric transmission projects in New York State. Central Hudson's maximum commitment is $94 million, for which it has issued a parental guarantee. As at December 31, 2020, there was no obligation under this guarantee.

As at December 31, 2020, FortisBC Holdings Inc. ("FHI") had $69 million of parental guarantees outstanding to support storage optimization activities at Aitken Creek.

Contingency

In April 2013 FHI and Fortis were named as defendants in an action in the British Columbia Supreme Court by the Coldwater Indian Band ("Band") regarding interests in a pipeline right-of-way on reserve lands. The pipeline was transferred by FHI (then Terasen Inc.) to Kinder Morgan Inc. in 2007. The Band seeks cancellation of the right-of-way and damages for wrongful interference with the Band's use and enjoyment of reserve lands. In May 2016 the Federal Court dismissed the Band's application for judicial review of the ministerial consent. In September 2017 the Federal Court of Appeal set aside the Minister's consent and returned the matter to the Minister for redetermination. No amount has been accrued as the outcome cannot yet be reasonably determined.