Looking Forward

FORTIS
ANNUAL REPORT

One Strong Connection Throughout North America

PURPOSE

Delivering a cleaner energy future

VALUES

- We value our **people**
- We keep it **local**
- We never compromise on **safety**
- We act with **courage** and **integrity**
- We are **community** champions
- We aim for **excellence** every day

Quick Facts

TSX/NYSE: FTS

Unless otherwise specified, all financial information is referenced in Canadian dollars and all numbers are as at December 31, 2021.

3.4 million customers

9,100 employees strong

Corporate-wide emissions **reduction target of 75%** by 2035 compared to 2019 levels

48 consecutive years of dividend payment increases

$58 billion in total assets

10 utilities in Canada, the U.S. and the Caribbean

The Fortis Board of Directors achieved **gender parity** and 60% of Fortis utilities have either a female CEO or Board Chair

More than $10 million of **community investment** in 2021

Advancing our Business Strategy

In 2021 we delivered steady growth and made significant progress on our long-term goals. We executed a $3.6 billion capital program; provided strong returns for our shareholders; further reduced our carbon emissions; outperformed industry averages for safety and reliability performance; and, achieved gender parity on our Board of Directors.

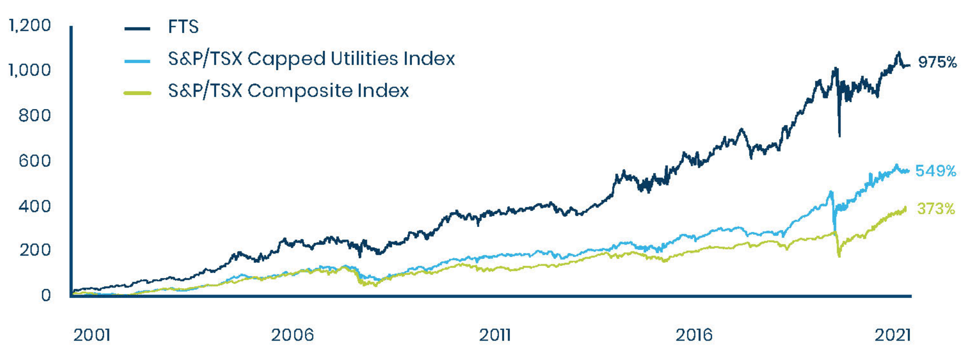
We advanced our business strategy and adapted to the challenges and uncertainties caused by the COVID-19 pandemic. The health and safety of our people and communities remains our top priority. Our people are the backbone of our success, and we are immensely grateful for their dedication and perseverance.

Delivering Returns to our Shareholders

Fortis delivered a strong one-year total shareholder return of 21.8% in 2021. Over a 20-year period, Fortis has delivered a total shareholder return of 975%, and an average annualized total return of 12.6%. Over the same 20-year period, the S&P/TSX Capped Utilities and S&P/TSX Composite indices delivered total returns of 549% and 373%, respectively.

For the past 48 consecutive years our company has delivered dividend increases to shareholders. In 2021 shareholders received $2.05 per common share, which is an increase of approximately 6% compared to 2020. We also reaffirmed our 6% average annual dividend growth guidance through 2025 supported by the long-term growth of our energy delivery businesses.

Superior 20-Year Total Shareholder Return



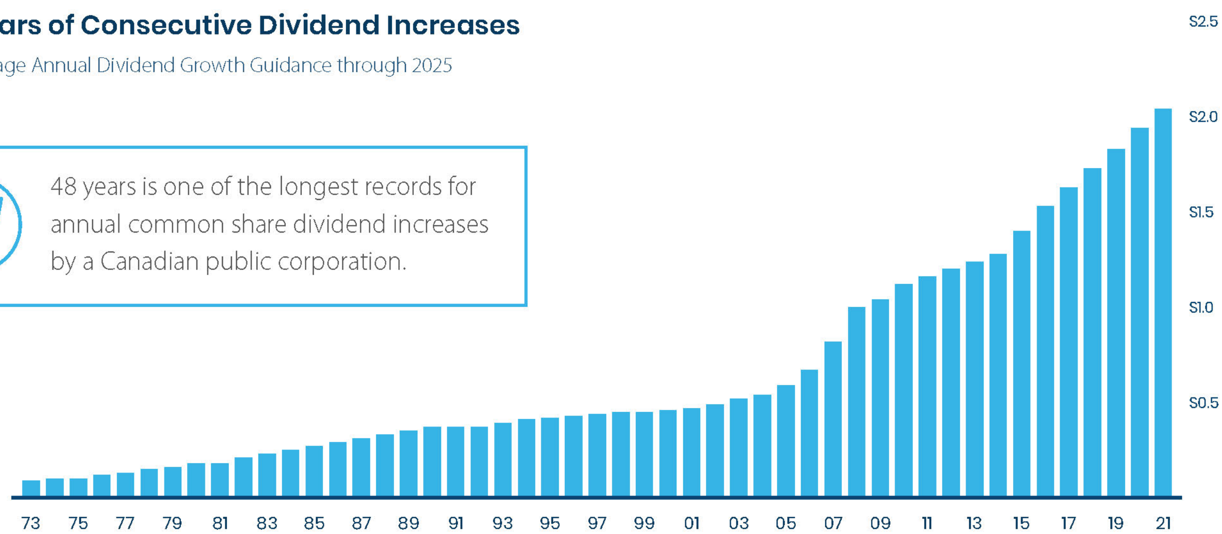
TOTAL SHAREHOLDER RETURNS (AVERAGE ANNUAL)	
1-Year	21.8%
5-Year	12.1%
10-Year	10.2%
20-Year	12.6%

Note: Cumulative 20-year total shareholder return as at December 31, 2021.

48 Years of Consecutive Dividend Increases

6% Average Annual Dividend Growth Guidance through 2025

48 years is one of the longest records for annual common share dividend increases by a Canadian public corporation.



Miranda Jackson, Civil Transmission Engineer

In 2021 net earnings attributable to common equity shareholders were $1,231 million, or $2.61 per common share, compared to $1,209 million, or $2.60 per common share, for 2020. We achieved adjusted net earnings per common share of $2.59 in 2021 compared to $2.57 in 2020.

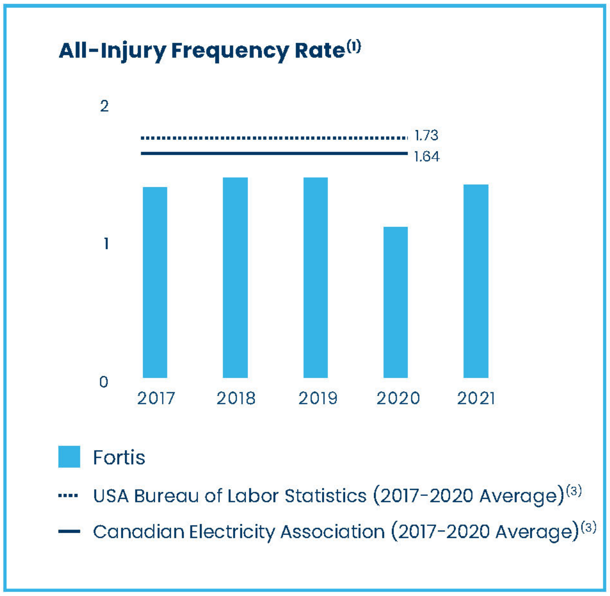
Rate base growth at our regulated utilities improved our earnings despite the unfavourable impact of foreign exchange of $48 million, or $0.10 per common share. Excluding foreign exchange, 2021 adjusted net earnings per common share increased by $0.12 or approximately 5% over 2020.

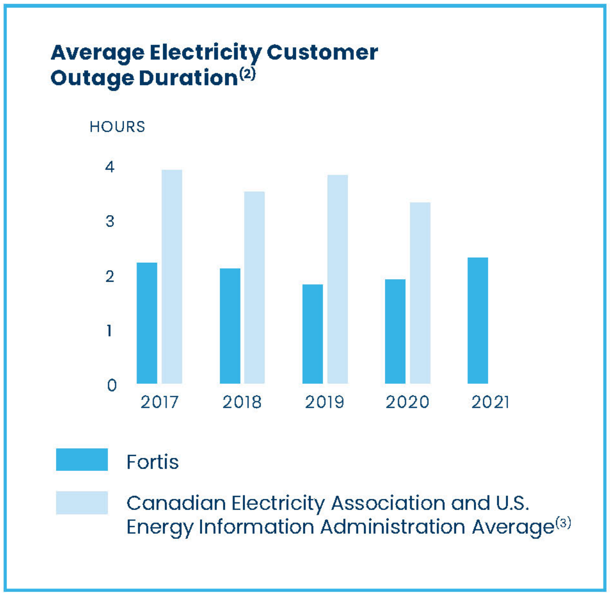
We raised more than $1 billion in long-term debt at attractive rates during 2021. Debt issued at Fortis Inc. was primarily used to refinance maturing debt, while our regulated utilities issued debt in support of their capital expenditure programs. Our continued focus on clean energy opened new financing options, with both ITC Holdings Corp. and Tucson Electric Power Company ("TEP") making use of green debt instruments in 2021. ITC Holdings Corp. priced US$150 million notes, of which half were green notes, while TEP amended its US$250 million revolving credit facility agreement that allows pricing adjustments linked to sustainability metrics.

Steadfast Focus on Safety and Reliability

Fortis continues to outperform industry averages for safety and reliability performance. Our utilities have a strong safety culture in delivering reliable electricity and natural gas to customers. We cannot have a safe and reliable system without a secure one. We deploy high cybersecurity standards and we have not had any reportable cybersecurity breaches since we began reporting this in 2018.

Our all-injury frequency rate, which represents the number of injuries for every 200,000 hours worked, was 1.40 in 2021. This compares to the Canadian and U.S. industry averages of 1.64 and 1.73, respectively. We continue to engage with employees on safety matters to further improve performance and, as always, will approach the future with a relentless focus on the safety of our employees, customers, and contractors.





(1) Injuries per 200,000 hours worked.
(2) Based on weighted average of Fortis' customer count in each jurisdiction.
(3) 2021 data not yet available.

Emergency response continues to be a hallmark of our operational excellence and enables us to minimize the interruption of service to customers. In 2021, our average hours of interruption per customer served was 2.3 hours, outperforming both Canadian and U.S. industry average outage durations.

2021 was another year of weather extremes across our service territories. From record heat and historic flooding in British Columbia, to a derecho storm in ITC's Midwest service area and a hurricane in Newfoundland and Labrador, nearly each of our jurisdictions was impacted by severe weather. Because of our operating model, our utilities were able to respond with the necessary local system knowledge, the best practices and resources provided under our Fortis umbrella to maintain the reliable provision of electricity and natural gas to our customers.

We are particularly proud of our teams at FortisAlberta and Newfoundland Power who received national recognition. FortisAlberta was awarded Excellence in the category of Canada's Safest Utilities and Electrical Employer at the 2021 Canada's Safest Employers Awards. Newfoundland Power was the recipient of the inaugural Reliability and Resiliency award from the Canadian Electricity Association.

TEP is making steady advances on its energy transition. In addition to bringing the 250-MW Oso Grande wind project online, the utility also now receives power from an additional 99-MW wind project, a 100-MW solar power system and a 30-MW battery energy storage system commissioned in 2021.

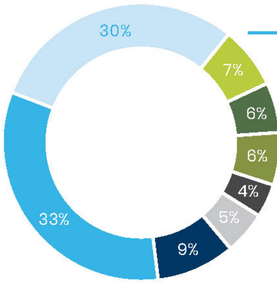
Investing in a Resilient Grid and Cleaner Energy

We executed a $3.6 billion capital program in 2021 while facing global supply chain challenges and pricing volatility. Our capital investments included resiliency, modernization, and sustainable energy projects.

Approximately $0.6 billion of our 2021 capital program was focused on delivering cleaner energy to customers. One significant achievement was the completion of the 250-MW Oso Grande Wind Project at TEP that will generate enough power each year to serve the annual electric needs of nearly 100,000 homes.

The Wataynikaneyap Transmission Power Project, which will bring many socio-economic benefits to 24 remote First Nations communities in Northern Ontario, was advanced in 2021. During peak construction periods, approximately 1,000 workers supported activities at various remote construction sites. The Wataynikaneyap Project was also chosen as a 2021 Clean50 Top Project award winner. Canada's Clean50 recognizes leaders in sustainability for contributions over the prior two years.

Five-Year (2022-2026) Capital Plan Supports Delivery of Cleaner Energy



$3.8 billion Cleaner Energy Investments(1)

$500M increase compared to prior 5-year plan

- Distribution
- Transmission supporting cleaner energy
- Clean Generation
- Information Technology
- Transmission
- RNG/LNG
- Traditional Generation
- Other

(1) Cleaner energy investments defined as capital that reduces air emissions, water usage and/or increase customer energy efficiency.

Our new five-year capital plan calls for the investment of $20 billion from 2022 through 2026, showing our ability to sustain strong underlying organic growth. We expect to invest $3.8 billion in cleaner energy infrastructure over the next five years, representing a $500 million increase compared to the prior five-year plan. This balanced, low-risk plan is expected to increase midyear rate base from $31.1 billion in 2021 to $41.6 billion by 2026, translating into a five-year compound annual growth rate of approximately 6%.

46% of overall project complete

50% of transmission line construction complete

35% of substation construction complete

2021 Clean50 Exceptional Contributors to Clean Capitalism / Contributeurs Exceptionnels au Capitalisme Propre TOP PROJECT

Sustainability for our People and Planet

Together, our utilities are executing on the transition to a cleaner energy future. Through the end of 2021, we reduced our Scope 1 emissions by 20% relative to 2019 levels, supporting our target to reduce carbon emissions 75% by 2035.

Our goal represents avoided emissions equivalent to taking approximately two million cars off the road in 2035 compared to 2019 levels. Upon achieving this target, we expect 99% of our assets will be focused on energy delivery and renewable, carbon-free generation.

In 2021, we became a supporter of the Task Force on Climate-Related Financial Disclosures ("TCFD") and agreed to fully implement the TCFD recommendations, including a climate scenario analysis to assess the resiliency of our energy delivery businesses which will be completed in the first quarter of 2022.

As part of our 2021 Sustainability Update, we increased our sustainability disclosures by adding over 50 new key performance indicators, further aligning with standards set forth by the Sustainability Accounting Standards Board.

Newfoundland Power and Maritime Electric received the Canadian Electricity Association Sustainable Electricity Company designation in 2021.


Fortis Inc. was invited to participate in the official Canadian delegation for COP26 and was pleased to meet with CEA members and staff to discuss climate transition in the energy sector.

Megan Cutcliffe, Customer Service Representative

Caroline Astley, Environment Manager, Major Projects

Our commitments are helping us forge a path towards being a strong and reliable global partner in combatting climate change and creating a more diverse and inclusive society.

We have made great strides in advancing inclusion and diversity, including achieving gender parity on our Board of Directors. Throughout our utilities, we are also providing a more creative, innovative, and welcoming environment that allows our people and our company to be as successful as possible. We recognize this is a journey and are committed to continue making progress and better reflect the communities we serve with the guidance of our Diversity and Inclusion Council.

The Fortis Board of Directors achieved **gender parity** and 60% of Fortis utilities have either a female CEO or Board Chair.

Our corporate governance practices, which have earned us industry recognition, ensure we operate as a well-governed sustainable company today and into the future. In 2021 we introduced a new measure in executive compensation to link incentive compensation to carbon reduction and climate change priorities. We also established a new board diversity policy whereby the board will seek to maintain a minimum of 40% women, and have at least two board members who are visible minorities or Indigenous persons by 2023.

Our charitable giving totaled more than $10 million in 2021 making our communities better and stronger. Our utility and head office employees met numerous needs in their communities through both financial and hands-on support.

Leadership that Embraces our Goals

We welcomed two new directors to our Board at our annual meeting in May: Lisa Durocher, Executive Vice President, Financial and Emerging Services for Rogers Communications Inc., and Gianna Manes, the former President and Chief Executive Officer of ENMAX Corporation. Both bring extensive experience, diversity, and valuable contributions to our Board.

At the end of 2021, Jim Laurito, Executive Vice President, Business Development and Chief Technology Officer, retired after a distinguished career in the energy sector. We appreciate Jim's immense contributions to Fortis and wish him all the best in retirement.

Gary Smith's role was expanded with his appointment as Executive Vice President of Operations and Innovation. Gary leads our innovation priorities throughout the Fortis group of companies and continues to provide leadership in key areas such as safety, reliability, and capital investment across the entire organization. Gary also oversees the company's cybersecurity and technology functions.

Stakeholder Value

Our core values always have and always will underpin the way we do business. We are focused on all our stakeholders, including our people, customers, communities, shareholders, and planet. Our continued success demonstrates that we have the right strategy and people to ensure Fortis is a sustainable company that will provide long-term value.

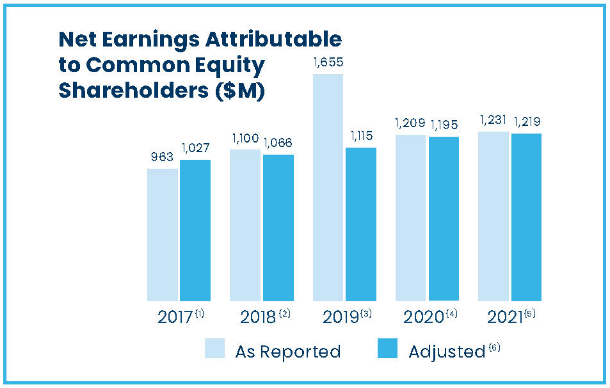
We look forward to your continued support as we deliver a cleaner energy future for the benefit of all. Together we must – and will – do our part.

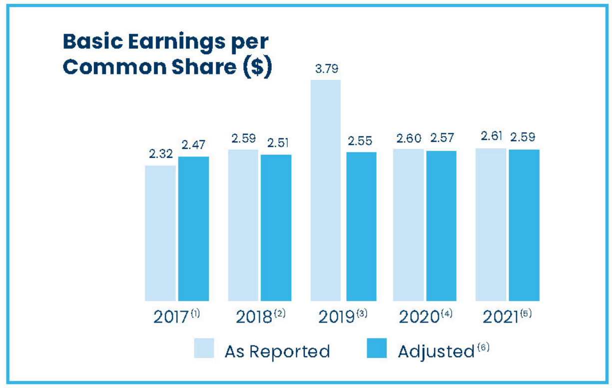
On behalf of the Board of Directors,

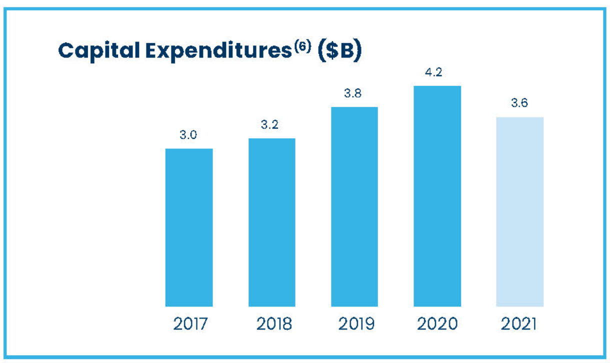
Douglas J. Haughey
Chair of the Board, Fortis Inc.

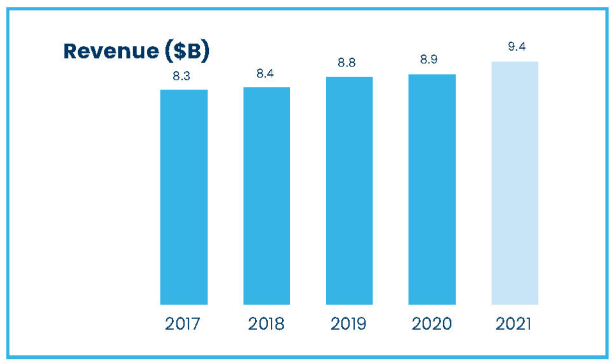
David G. Hutchens
President and CEO, Fortis Inc.

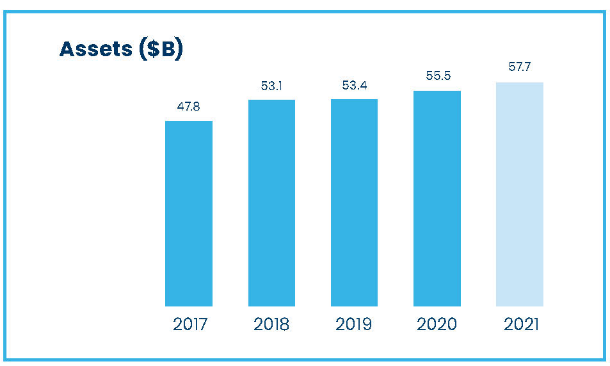
Financial Highlights

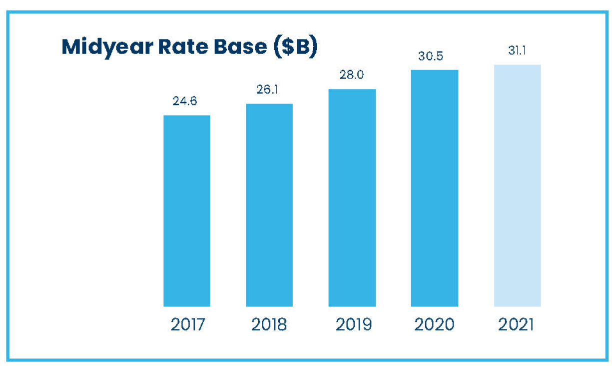












(1) Adjusted net earnings exclude the impact of U.S. tax reform and other non-operating items.

(2) Results were tempered by the ongoing impact of U.S. tax reform and a reduced independence incentive adder at ITC. Adjusted net earnings exclude certain non-operating items.

(3) Results were impacted by a gain on disposition of the Waneta Expansion and a favourable adjustment associated with a regulatory order at ITC. Adjusted net earnings exclude the gain on disposition, the favourable regulatory adjustment and other non-operating items.

(4) Results were impacted by a favourable adjustment associated with a regulatory order at ITC. Adjusted net earnings exclude the favourable regulatory adjustment and certain non-operating items.

(5) Results were tempered by the lower U.S.-to-Canadian dollar exchange rate. Adjusted net earnings exclude certain non-operating items.

(6) Non-U.S. GAAP financial measure

All financial information is presented in Canadian dollars. Information is for the fiscal years ended December 31.

Highly Regulated, Low-Risk and Diversified Utility Business

Regulated

	Customers Electric (#)	Customers Gas (#)	Employees (#)	Peak Demand Electric (MW)	Peak Demand Gas (TJ)	Electric Sales (GWh)	Gas Volumes (PJ)	Earnings ($M)	Total Assets ($B)	2022F[1] Midyear Rate Base ($B)	2022F[1] Capital Program ($M)
ITC[2]	–	–	705	22,920	–	–	–	426	21.0	10.1	998
UNS Energy	538,000	165,000	2,028	3,164	108	16,842	16	292	11.1	6.5	704
Central Hudson	300,000	80,000	1,076	1,148	134	5,000	23	93	4.4	2.4	344
FortisBC[3]	185,000	1,065,000	2,594	777	1,399	3,460	228	244	10.7	6.9	778
FortisAlberta	577,000	–	1,087	2,751	–	16,643	–	141	5.2	4.0	445
Other Electric[4]	474,000	–	1,479	1,956	–	9,266	–	118	4.3	3.6	621
	2,074,000	**1,310,000**	**8,969**	**32,716**	**1,641**	**51,211**	**267**	**1,314**	**56.7**	**33.5**	**3,890**

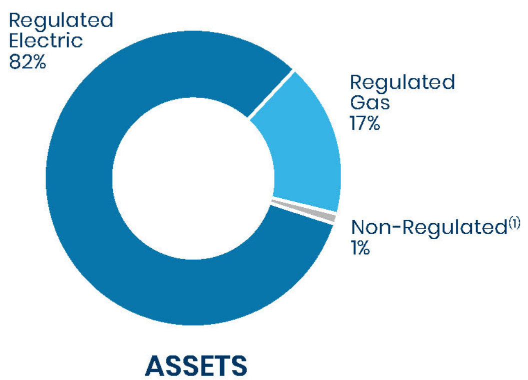
(1) Forecast

(2) Data reflects 100% of ITC's operations except for earnings, which represent the Corporation's 80.1% ownership interest. ITC has no retail customers.

(3) Includes FortisBC Energy and FortisBC Electric.

(4) Data reflects 100% of Caribbean Utilities' operations except earnings, which represent the Corporation's 60% ownership interest. Also includes Newfoundland Power, Maritime Electric, FortisOntario, a 39% equity investment in Wataynikaneyap Power Limited Partnership, Fortis Turks and Caicos, and a 33% equity investment in Belize Electricity.

99% Regulated Utilities



(1) Comprising of energy infrastructure investments in British Columbia and Belize.

Total Assets of
$58 billion
as at December 31, 2021.

Management Discussion and Analysis

Contents

Dated February 10, 2022

This MD&A has been prepared in accordance with National Instrument 51-102 - *Continuous Disclosure Obligations*. It should be read in conjunction with the 2021 Annual Financial Statements and is subject to the cautionary statement and disclaimer provided under "Forward-Looking Information" on page 52. 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.

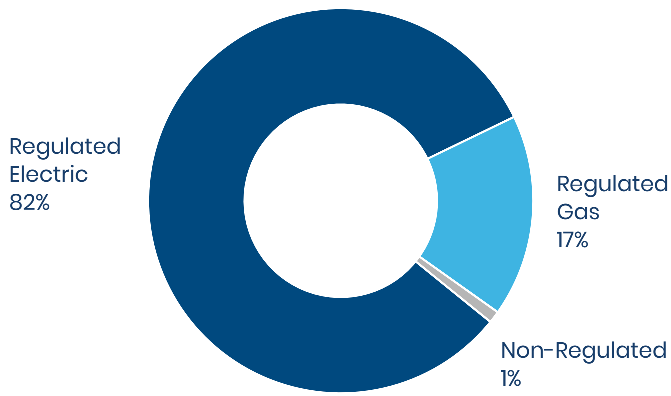
Financial information herein has been prepared in accordance with U.S. GAAP (except for indicated Non-U.S. GAAP Financial Measures) and, unless otherwise specified, is presented in Canadian dollars based, as applicable, on the following U.S. dollar-to-Canadian dollar exchange rates: (i) average of 1.25 and 1.34 for the years ended December 31, 2021 and 2020, respectively; (ii) 1.26 and 1.27 as at December 31, 2021 and 2020, respectively; (iii) average of 1.26 and 1.30 for the quarters ended December 31, 2021 and 2020, respectively; and (iv) 1.25 for all forecast periods. Certain terms used in this MD&A are defined in the "Glossary" on page 53.

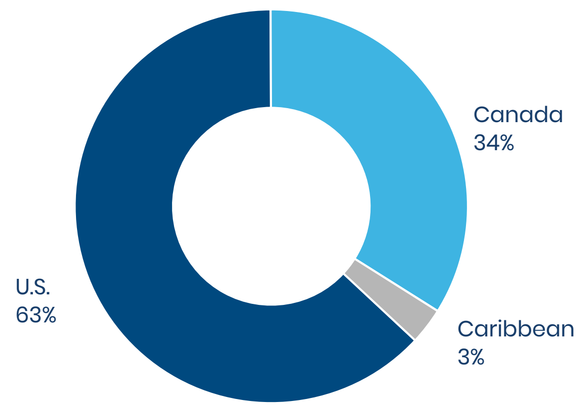
ABOUT FORTIS

Fortis (TSX/NYSE: FTS) is a well-diversified leader in the North American regulated electric and gas utility industry, with revenue of $9.4 billion in 2021 and total assets of $58 billion as at December 31, 2021.

Regulated utilities account for 99% of the Corporation's assets with the remainder primarily attributable to non-regulated energy infrastructure. The Corporation's 9,100 employees serve 3.4 million utility customers in five Canadian provinces, nine U.S. states and three Caribbean countries. As at December 31, 2021, 66% of the Corporation's assets were located outside Canada and 57% of 2021 revenue was derived from foreign operations.

TOTAL ASSETS AT DECEMBER 31, 2021





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 State); FortisBC Energy (natural gas transmission and distribution - British Columbia); FortisAlberta (electric distribution - Alberta); FortisBC Electric (integrated electric - British Columbia); Newfoundland Power (integrated electric - Newfoundland and Labrador); Maritime Electric (integrated electric - Prince Edward Island); FortisOntario (integrated electric - Ontario); Caribbean Utilities (integrated electric - Grand Cayman); and FortisTCI (integrated electric - Turks and Caicos Islands). Fortis also holds equity investments in the Wataynikaneyap Partnership (electric transmission - Ontario) and Belize Electricity (integrated electric - Belize).

Non-regulated energy infrastructure consists of BECOL (three hydroelectric generation facilities - Belize) and Aitken Creek (natural gas storage facility - British Columbia).

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

Fortis strives to provide safe, reliable and cost-effective energy service to customers while focusing on sustainability policies and practices. The Corporation has established delivering a cleaner energy future as its core purpose. In addition, management is focused on delivering long-term profitable growth for shareholders through the execution of its Capital Plan and the pursuit of investment opportunities within and proximate to its service territories.

Additional information about the Corporation's business and reporting units is provided in Note 1 in the 2021 Annual Financial Statements.

KEY DEVELOPMENTS

COVID-19 Pandemic

The Corporation's utilities continue to reliably and safely deliver an essential service during the COVID-19 Pandemic. Developments are monitored and commensurate measures taken, particularly with respect to the health and safety of our employees and the public. The Corporation's utilities are monitoring the impact of the pandemic on commodity prices and the supply chain, and are advancing procurement and hedging activities to mitigate the impact on customer rates. These and other potential impacts of the pandemic, including labour disruption risk, are evaluated and actions are taken to ensure that Fortis and its utilities can continue to provide safe, reliable and cost-effective service while supporting public health.

The Corporation continues to assess economic conditions in its service territories and the associated impacts on: (i) energy sales, particularly for UNS Energy and the Other Electric segment as revenue in these segments is not protected by regulatory mechanisms; (ii) the ability of customers to pay their energy bills and the related impact on Operating Cash Flow; (iii) the progress of regulatory proceedings and the ability to recover costs in a timely manner; and (iv) the execution of the Capital Plan. Except for the delay in TEP's general rate application in 2020, the COVID-19 Pandemic did not have a significant impact on financial performance for the years ended December 31, 2021 and 2020.

There continues to be uncertainty surrounding the pandemic, particularly with respect to the emergence of new variants of the virus, the long-term efficacy and global distribution of COVID-19 vaccines, the impact of vaccine mandates and isolation requirements on labour availability, potential government action to mitigate public health effects, and disruptions to the global supply chain. Potential financial and operating impacts of the COVID-19 Pandemic on Fortis are discussed under "Business Risks" on page 36.

U.S. Infrastructure Spending and Tax Proposals

In November 2021, the U.S. government approved significant infrastructure spending, including investments in transmission, electrification and economic development, as well as electrical grid resilience. Fortis continues to review the intended spending, as details become available, in order to assess the impact on its business.

The Biden administration has also been drafting significant tax proposals including, amongst other things, amendments to rules associated with international and minimum taxation, the introduction of a transmission investment tax credit, and the extension of clean energy tax credits. Proposals continue to evolve and while it is unknown when legislation incorporating these tax proposals could be enacted, it is currently expected in 2022.

In February 2022, the Department of Finance Canada released draft legislation including a proposal on interest deductibility. The proposal is open for public comment until May 2022 and it is unknown when the legislation may be enacted. In addition, in April 2021, the Canadian federal budget was released which proposed changes in relation to international taxation. There has been no significant update on this proposal, and it is unknown when draft legislation may be available.

Changes in tax legislation could affect the results of operations, financial condition and cash flows of the Corporation. Potential impacts of changes in tax laws are discussed under “Business Risks” on page 36. Fortis will continue to assess the impacts as more details on the U.S. and Canadian tax proposals become available.

PERFORMANCE AT A GLANCE

Key Financial Metrics

($ millions, except as indicated)	**2021**	2020	Variance
Common Equity Earnings			
Actual	**1,231**	1,209	22
Adjusted [(1)]	**1,219**	1,195	24
Basic EPS *($)*			
Actual	**2.61**	2.60	0.01
Adjusted [(1)]	**2.59**	2.57	0.02
Dividends			
Paid per common share *($)*	**2.0500**	1.9375	0.1125
Actual Payout Ratio *(%)*	**78.5**	74.5	4.0
Adjusted Payout Ratio *(%)* [(1)]	**79.2**	75.4	3.8
Weighted average number of common shares outstanding *(# millions)*	**470.9**	464.8	6.1
Operating Cash Flow	**2,907**	2,701	206
Capital Expenditures [(1)]	**3,564**	4,177	(613)

[(1)] *See "Non-U.S. GAAP Financial Measures" on page 24*

Earnings and EPS

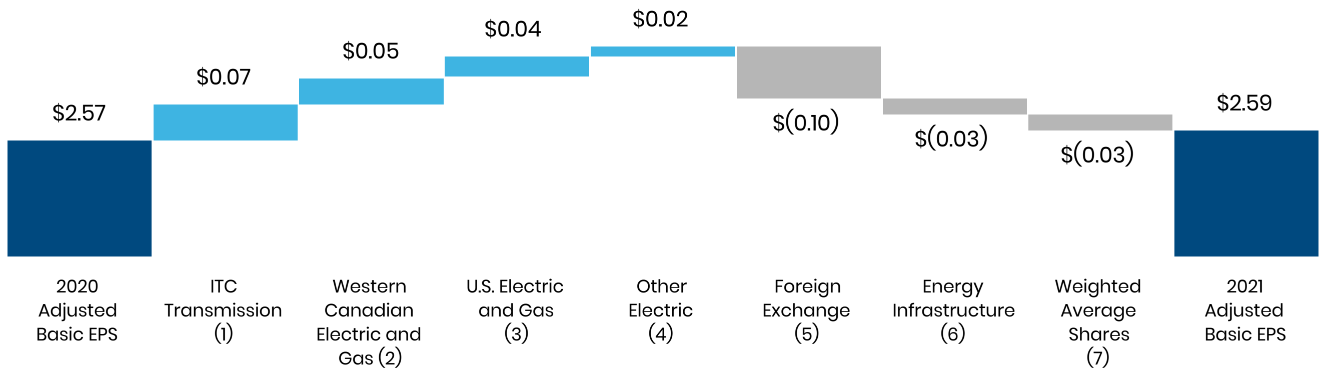
Common Equity Earnings increased by $22 million compared to 2020. Growth in Common Equity Earnings was tempered by the unfavourable impact of foreign exchange of $48 million, and significant one-time items recognized in 2020 of $14 million. The significant items in 2020 included an adjustment to ITC's base ROE, partially offset by the finalization of U.S. tax reform. These impacts were partially offset by unrealized mark-to-market gains of $12 million in 2021 on natural gas derivatives at Aitken Creek.

The Corporation delivered earnings growth of $72 million excluding the impact of the above noted items. Operational growth in 2021 reflected: (i) Rate Base growth; (ii) higher earnings in Arizona primarily due to new customer rates at TEP effective January 1, 2021, partially offset by lower sales due to unfavourable weather and higher operating costs; (iii) continued recovery in the Caribbean from economic conditions experienced in 2020 associated with the COVID-19 Pandemic; and (iv) higher sales at FortisAlberta associated with favourable weather, partially offset by a higher effective income tax rate. This growth was partially offset by lower hydroelectric production in Belize, and lower earnings at Aitken Creek due to realized losses on natural gas contracts.

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 DRIP.

Adjusted Common Equity Earnings and Adjusted Basic EPS increased by $24 million and $0.02, respectively. Refer to "Non-U.S. GAAP Financial Measures" on page 24 for a reconciliation of these measures. The changes in Adjusted Basic EPS, including the unfavourable impact of foreign exchange described above, are illustrated in the chart below.

CHANGES IN ADJUSTED BASIC EPS



(1) Primarily reflects Rate Base growth and an adjustment related to interest rate swaps, partially offset by higher non-recoverable expenses

(2) Includes FortisBC Energy, FortisAlberta and FortisBC Electric. Primarily reflects Rate Base growth, as well as higher sales due to favourable weather partially offset by a higher effective income tax rate at FortisAlberta

(3) Includes UNS Energy and Central Hudson. Increase at UNS Energy primarily reflects the impact of new customer rates at TEP partially offset by lower sales driven by unfavourable weather and higher operating costs mainly related to planned generation maintenance. Earnings at Central Hudson reflects the finalization of its general rate application effective July 1, 2021, partially offset by the impact of regulatory mechanisms and higher operating costs

(4) Primarily reflects higher earnings in the Caribbean, related to the continued recovery from economic conditions in 2020 associated with the COVID-19 Pandemic

(5) Average foreign exchange rate of 1.25 in 2021 compared to 1.34 in 2020

(6) Primarily reflects variations in hydroelectric production in Belize associated with rainfall levels, and lower earnings at Aitken Creek due to realized losses on natural gas contracts, as certain contracts were settled in 2021 in consideration of favourable forward curves

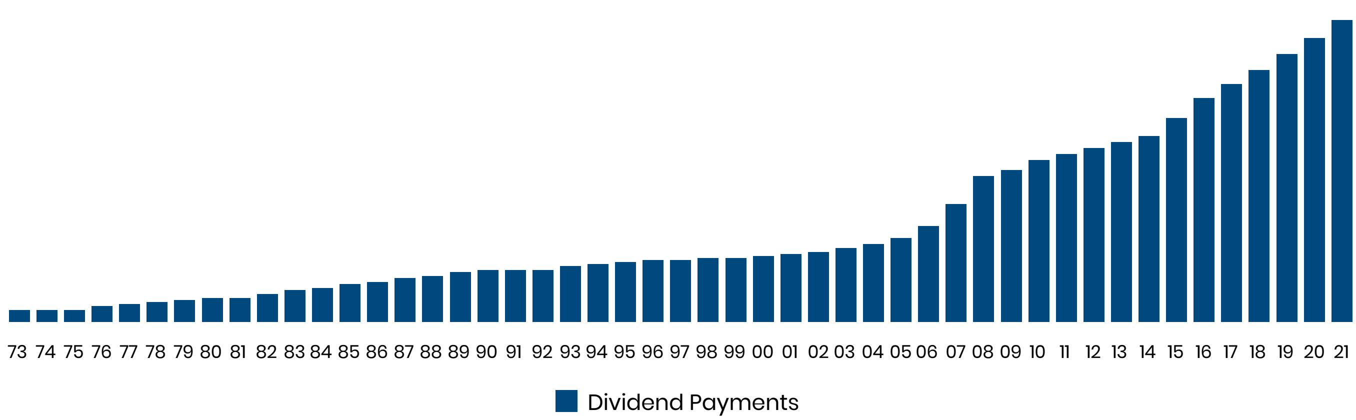
(7) Weighted average shares of 470.9 million in 2021 compared to 464.8 million in 2020

Dividends

Fortis paid a dividend of $0.535 per common share in the fourth quarter of 2021, up 5.9% from $0.505 paid in each of the previous four quarters and in line with the Corporation's dividend guidance. The Actual Payout Ratio was 78.5% in 2021 compared to 74.5% in 2020 and an annual average of 65.9% over the five-year period of 2017 through 2021.

Fortis has increased its common share dividend for 48 consecutive years. In September 2021, Fortis reaffirmed its targeted average annual dividend growth of approximately 6% through 2025.

48 YEARS OF CONSECUTIVE DIVIDEND INCREASES



Growth of dividends and the market price of the Corporation's common shares have together yielded the following TSR.

TSR [1] (%)	1-Year	5-Year	10-Year	20-Year
Fortis	**21.8**	**12.1**	**10.2**	**12.6**

[1] *Annualized TSR per Bloomberg, as at December 31, 2021*

Operating Cash Flow

The $206 million increase in Operating Cash Flow was due to higher cash earnings, reflecting Rate Base growth and new customer rates at TEP effective January 1, 2021, partially offset by higher operating costs at TEP and an upfront payment received by FortisAlberta in 2020 associated with a long-term energy retailer agreement. Favourable changes in regulatory deferrals due to the timing of flow-through costs in customer rates and lower transmission payments at FortisAlberta also contributed to the increase. The increase was partially offset by the lower U.S.-to-Canadian dollar exchange rate in 2021.

Capital Expenditures

Capital Expenditures were $3.6 billion, broadly consistent with the 2021 Capital Plan. For a detailed discussion of the Corporation's capital expenditure program, see "Capital Plan" on page 31. Capital Expenditures in 2021 were $0.6 billion lower than 2020 primarily due to the timing of costs associated with the construction of the Oso Grande generating facility at UNS Energy, and the impact of the lower average foreign exchange rate.

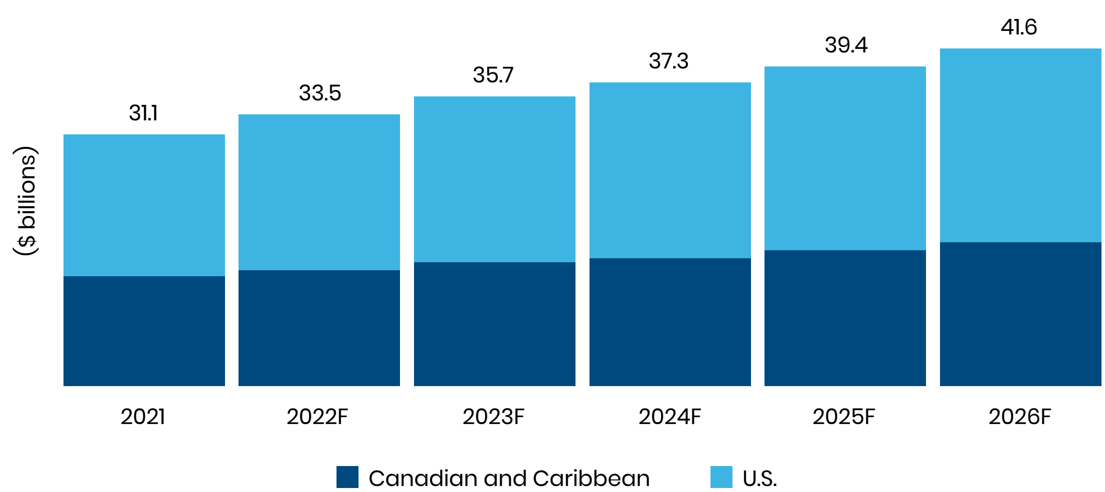
The Corporation's five-year 2022-2026 Capital Plan of $20.0 billion reflects $1.0 billion of additional capital investment at the Corporation's regulated utilities in comparison to the 2021-2025 Capital Plan disclosed in the 2020 MD&A. The increase largely reflects customer growth, enhancements to transmission reliability and capacity, and investments in cleaner energy. This growth is tempered by $600 million associated with the lower assumed foreign exchange rate of 1.25, down from a rate of 1.32 assumed in the Corporation's previous five-year Capital Plan.

Overall, the COVID-19 Pandemic did not have a material impact on capital expenditures in 2021. While the Corporation does not expect the COVID-19 Pandemic to materially impact its overall five-year Capital Plan, the timing of forecast capital expenditures will continue to be evaluated. Depending on the length and severity of the pandemic, including any impacts of supply chain disruptions, certain planned expenditures may shift within the 2022-2026 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 $31.1 billion in 2021 to $41.6 billion by 2026, representing a five-year CAGR of approximately 6%. Fortis expects this growth in Rate Base will support earnings and dividend growth.

Capital Expenditures and Capital Plan reflect Non-U.S. GAAP financial measures. Refer to "Non-U.S. GAAP Financial Measures" on page 24 and "Capital Plan" on page 31.

PROJECTED RATE BASE GROWTH



Additional opportunities to expand and extend growth include: further expansion of the electric transmission grid in the U.S. to facilitate the interconnection of cleaner energy, including infrastructure investments associated with MISO's long-range transmission plan; natural gas resiliency investments in pipelines and 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's transformation is accelerating at a rapid pace, driven by the impacts of climate change and the need for a cleaner energy future. This creates a growing need for the development of cleaner energy sources and the deployment of energy conservation measures to preserve the planet for future generations. The goal of carbon emission reduction creates the need for increased innovation, and associated advancements in technology have attracted interest from investors and customers. Renewable generation continues to be a key element in a decarbonized future, with electric transmission seen as a critical enabler of large-scale renewables. Natural gas also continues to be an important part of the energy mix, as supplemental generation to the intermittency of renewables, and as a cost-effective heating source. Longer term, advancements in the use of hydrogen and RNG 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 continue to reflect the rising focus on climate change, with clean energy and carbon reduction goals and initiatives at the forefront. In the U.S., legislation has been approved for significant infrastructure investments, including those in the energy sector involving renewables, transmission and storage. Additional legislation is under consideration, which would further increase the investments required to meet new and aggressive federal carbon reduction goals. With states and provinces also setting ambitious carbon reduction targets, the regulatory and compliance environment continues to evolve and become increasingly complex. These changes are creating opportunities to expand investment in new, renewable generation sources, including solar and wind, as well as transmission infrastructure to interconnect renewable energy sources to the grid. As the amount of renewables grow, investment opportunities in energy storage are also being created, driven by the decreasing costs of energy storage technology. The electrification of the transportation sector is gaining momentum and represents a significant opportunity to reduce GHG emissions while increasing the output and efficiency of the grid. The Corporation's utilities are well positioned and actively involved in pursuing these opportunities which will drive significant investment well into the future.

New technology is stimulating change across all service territories. Energy delivery systems are becoming more intelligent, with upgraded advanced meters, additional grid automation and more capable operational technology, providing utilities with detailed usage data and predictive maintenance information to improve cost efficiency and safety. 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 resilience is growing in importance with the increasing frequency of extreme weather events such as hurricanes, wildfires, tornadoes and storms. As a result, investments in grid hardening and resiliency are increasing in importance to improve the grid's ability to withstand and recover from these climate events.

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 need. To further advance innovation, Fortis is a 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. The Corporation is also involved in the Electric Power Research Institute's Low Carbon Resources Initiative, along with other major North American utilities. By leveraging these strengths and partnerships, Fortis expects to remain at the forefront of this ever-changing industry.

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

On the security front, with the advent of new and increasing cyber threats to our information and operational technology systems, increased focus and investment on protection and response to these events is an ongoing effort. Upgrades to the physical security environment is also required to keep pace with evolving challenges. All these technological advancements and challenges offer strategic investment opportunities for improving and expanding customer service and enhancing security.

Fortis is positioned to capitalize on evolving industry opportunities. The Corporation's decentralized structure and customer-focused business culture support the efforts required to meet changing customer expectations. Each of the utilities work constructively with regulators and all stakeholders on policy, energy and service solutions, and are an integral partner in all the communities they serve. Fortis is committed to be an industry leader in the clean energy transition.

FOCUS ON SUSTAINABILITY

Fortis is dedicated to being a strong energy partner for its communities by operating in an environmentally and socially responsible manner. Fortis believes that responsible environmental and sustainability management not only creates business value, but it is also good for our customers and the planet.

To bring focus and accountability to sustainability, oversight is coordinated at the most senior levels of Fortis and is a priority at each of our operating subsidiaries. Sustainability efforts are managed at the utility level to address applicable federal, provincial/state and municipal laws and regulations, which may differ in each service territory. Fortis' Executive Vice-President, Sustainability and Chief Human Resource Officer reports to the President and CEO and collectively they are responsible for enterprise-wide sustainability and stewardship at the executive level. The Board is responsible for risk management oversight and ensuring that business is conducted to meet high standards of environmental and social responsibility. The governance and sustainability committee of the Board is responsible for overseeing governance structure and sustainability programs and practices.

Key aspects of Fortis' sustainability program and practices are outlined below. Additional information may be found in the Corporation's Annual Information Form.

Climate Change and Environmental Matters

Fortis is primarily an energy delivery company with 93% of its assets dedicated to the movement of energy through our wires and natural gas lines. This presents a unique opportunity for Fortis to facilitate the delivery of cleaner energy to its customers and limits its impact on the environment when compared to energy generation-intensive businesses. Although Fortis has limited fossil-fuel generation exposure, it has a plan to transition to more sustainable energy for its customers.

The Corporation's direct GHG emissions come primarily from its generation assets, and largely include fossil fuel-based generation at TEP representing 5% of the Corporation's total assets. Fortis continues to build on its low emissions profile and is committed to achieve its corporate-wide target to reduce carbon emissions by 75% by 2035 from a 2019 base year. Fortis expects to achieve this target through delivering on TEP's plan to reduce carbon emissions, as well as clean energy initiatives across the Corporation's other utilities.

In 2021, Fortis' Scope 1 emissions were 20% lower relative to 2019 levels, equivalent to taking approximately 540,000 vehicles off the road in one year and marking significant progress to our 75% target. Closure of Navajo at TEP in late 2019 as well as recently commissioned renewable projects, such as the 250-MW Oso Grande wind project, the 99-MW Borderlands wind project and the 100-MW Wilmot solar project, have supported our carbon emissions reduction target to date.

The Corporation's environmental statement sets out its commitment to comply with all applicable laws and regulations relating to the protection of the environment, regularly conduct monitoring and audits of environmental management systems, seek feasible, cost-effective opportunities to decrease GHG emissions and increase renewable energy sources. Each operating subsidiary has extensive environmental compliance programs aligned with the ISO 14001 standard, regularly reviews its environmental management systems and protocols, strives for continual performance improvement and sets and reviews its own environmental objectives, targets and programs. Fortis' most recent sustainability update was released in July 2021 and included information on: (i) the Corporation's progress on reducing carbon emissions; (ii) updated sustainability key indicators; (iii) alignment with standards issued by the Sustainability Accounting Standards Board; and (iv) the Corporation's support of the Task Force on Climate-related Financial Disclosures. The Corporation is currently completing a climate scenario analysis to assess the resiliency of our energy delivery businesses with a progress update planned in 2022.

Safety and Reliability

Fortis is an industry leader in safety and reliability, with the Corporation consistently performing above industry averages. Fortis leverages its unique operating model and utility experience to deliver safe and reliable service to its customers and the communities it serves. Senior operational executives from all Fortis utilities meet regularly to share best practices and identify opportunities for collaboration on a range of operational areas including health and safety.

In 2021, $600 million in Capital Expenditures were focused on the delivery of cleaner energy to customers. In addition, in the development of the Corporation's five-year Capital Plan, each of the utilities consider investment required to deliver cleaner energy to customers, strengthen infrastructure, and improve network resiliency, with the intent of maintaining customer reliability, while also mitigating the expected impacts of climate change, such as more frequent and intense weather events, on utility infrastructure. Additional information on the Corporation's Capital Plan can be found in the "Capital Plan" section on page 31.

Customer Service and Community Efforts

Fortis' utilities work closely with their customers and communities to drive enhancements and improve the overall customer service experience. Customer satisfaction targets are established and customer service surveys are completed regularly focusing on customer satisfaction, reliability and accuracy of billing and metering, contact centre services and reliability of energy supply.

Fortis and its utilities consistently look for opportunities for growth, innovation and energy efficiency in the communities served. Regular community engagement through donations to local charities, partnerships with educational institutions, and participation on local boards, amongst other initiatives, enables Fortis to remain a meaningful contributor to our local communities.

Cybersecurity

Fortis' CRMP aims to continually improve information sharing and the culture of security. Fortis has an enterprise-wide CRMP that allows for the identification, measurement, monitoring and management of cybersecurity risks. Further, the Corporation and each of the utilities continually consider investments required in security, in both the corporate and grid environments, during the development of the five-year Capital Plan. Oversight of cybersecurity is the responsibility of Fortis' Vice President, Chief Information Officer and the respective boards and executive committees at Fortis and at each utility.

Human Capital Management

Fortis values its 9,100 employees and recognizes that success is dependent on a strong workforce which is safe, supported and empowered. Fortis has compensation and benefit programs designed to attract and retain talent. Fortis believes that the foundation for a healthy work environment starts with leadership from the most senior levels of the organization and must be reflected throughout the organization. The Corporation has established delivering a cleaner energy future as its core purpose, driven by values embedded at all levels of the organization.

Governance

Fortis has a Code of Conduct which is guided by the Corporation's purpose and values and sets out standards for the ethical conduct of its business, including all of its directors, officers, employees, consultants, contractors and representatives, as applicable. The core principles of the Fortis Code of Conduct apply universally across the organization, with each operating subsidiary adopting its own substantially similar Code. Fortis and its utilities hold regular Code of Conduct employee training and all Fortis employees annually certify compliance.

The Code of Conduct is supported by other policies that outline the behaviour expected from management and employees, including the Anti-Corruption Policy and Respectful Workplace Policy. All Fortis operating subsidiaries have policies in place that uphold the Corporation's values as contained in these policies and demonstrate their commitment to ensuring equal opportunity and providing safe, respectful work environments.

Fortis and each of its operating subsidiaries have a Speak Up Policy to support and facilitate the reporting of conduct that may breach the Code of Conduct or other workplace policies.

Diversity, Equity and Inclusion

The Corporation's Board and Executive Diversity Policy describes the principles and objectives for diversity among the Board and executive leadership, including a commitment to maintaining a Board where at least 40% of independent directors are women. Currently, 50% of the Board and 45% of its executive leadership team are women. 60% of Fortis utilities have either a female president or female board chair. Fortis has also recently introduced a target of two directors identifying as a visible minority or indigenous by 2023.

Advancing diversity, equity and inclusion is a priority at Fortis. The Corporation has a formal Inclusion and Diversity Commitment that applies to all employees at Fortis and its operating subsidiaries. The commitment is supported by a framework built upon three pillars - talent, culture and community. A Diversity, Equity and Inclusion Advisory Council with diverse, senior level representation from across the Fortis organization guides the inclusion and diversity strategy and its implementation.

OPERATING RESULTS

			Variance	
($ millions)	**2021**	2020	FX	Other
Revenue	**9,448**	8,935	(345)	858
Energy supply costs	**2,951**	2,562	(77)	466
Operating expenses	**2,523**	2,437	(107)	193
Depreciation and amortization	**1,505**	1,428	(52)	129
Other income, net	**173**	154	—	19
Finance charges	**1,003**	1,042	(40)	1
Income tax expense	**234**	231	(14)	17
Net earnings	**1,405**	1,389	(55)	71
Net earnings attributable to:				
Non-controlling interests	**111**	115	(7)	3
Preference equity shareholders	**63**	65	—	(2)
Common equity shareholders	**1,231**	1,209	(48)	70
Net Earnings	**1,405**	1,389	(55)	71

Revenue

The increase in revenue, net of foreign exchange, was due primarily to: (i) higher flow-through costs in customer rates; (ii) Rate Base growth; (iii) new customer rates, effective January 1, 2021 and higher wholesale sales at TEP; and (iv) higher retail electricity sales, primarily in Western Canada and the Caribbean, partially offset by lower sales in Arizona due to unfavourable weather. The increase was partially offset by a $40 million favourable base ROE adjustment recognized at ITC in 2020 as a result of the May 2020 FERC Decision.

Energy Supply Costs

The increase in energy supply costs, net of foreign exchange, was due primarily to overall higher commodity costs due to pricing and volumes, and the impact of higher wholesale sales at TEP.

Operating Expenses

The increase in operating expenses, net of foreign exchange, was due primarily to: (i) higher flow-through costs, particularly at ITC; (ii) higher operating costs mainly related to planned generation maintenance at UNS Energy; and (iii) general inflationary and employee-related cost increases. The increase was partially offset by lower credit loss expense.

Depreciation and Amortization

The increase in depreciation and amortization, net of foreign exchange, was due to continued investment in energy infrastructure at the Corporation's regulated utilities.

Other Income, Net

The increase, net of foreign exchange, was due primarily to non-service benefit costs and higher mark-to-market gains on total returns swaps associated with share price growth, partially offset by lower equity income from Belize Electricity.

Finance Charges

Finance charges, net of foreign exchange, were consistent with 2020. The impact of higher debt levels to support the Corporation's Capital Plan was largely offset by the benefit of refinancing debt at lower interest rates.

Income Tax Expense

The increase in income tax expense, net of foreign exchange, was driven by: (i) a higher consolidated state tax rate associated with changes in regional sales mix; and (ii) a higher effective income tax rate at FortisAlberta, partially offset by the reversal of a $13 million tax recovery in 2020 resulting from the finalization of U.S. tax reform and associated anti-hybrid regulations.

Net Earnings

See "Performance at a Glance - Earnings and EPS" on page 14.

BUSINESS UNIT PERFORMANCE

Common Equity Earnings

			Variance	
($ millions)	**2021**	2020	FX [(1)]	Other
Regulated Utilities				
ITC	**426**	449	(31)	8
UNS Energy	**292**	302	(20)	10
Central Hudson	**93**	91	(4)	6
FortisBC Energy	**185**	175	—	10
FortisAlberta	**141**	133	—	8
FortisBC Electric	**59**	56	—	3
Other Electric [(2)]	**118**	112	(2)	8
	1,314	1,318	(57)	53
Non-Regulated				
Energy Infrastructure [(3)]	**38**	39	—	(1)
Corporate and Other [(4)]	**(121)**	(148)	9	18
Common Equity Earnings	**1,231**	1,209	(48)	70

(1) The reporting currency of ITC, UNS Energy, Central Hudson, Caribbean Utilities, FortisTCI and BECOL is the U.S. dollar. The reporting currency of Belize Electricity is the Belizean dollar, which is pegged to the U.S. dollar at BZ$2.00=US$1.00. The Corporate and Other segment includes certain transactions denominated in U.S. 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 and Aitken Creek in British Columbia

(4) Includes Fortis net corporate expenses and non-regulated holding company expenses

ITC

($ millions)	2021	2020	Variance FX	Variance Other
Revenue [1]	**1,691**	1,744	(117)	64
Earnings [1]	**426**	449	(31)	8

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

Revenue

The increase in revenue, net of foreign exchange, reflected higher flow-through costs in customer rates and Rate Base growth. The increase was partially offset by a $40 million favourable base ROE adjustment recognized in 2020 as a result of the May 2020 FERC Decision.

Earnings

The increase in earnings, net of foreign exchange, reflected Rate Base growth and an adjustment related to the amortization of interest rate swaps. The increase was partially offset by a $27 million favourable base ROE adjustment as a result of the May 2020 FERC Decision, discussed above, and higher non-recoverable operating expenses related to an increase in stock-based compensation costs due to the Corporation's share price growth.

UNS Energy

($ millions, except as indicated)	2021	2020	Variance FX	Variance Other
Retail electricity sales *(GWh)*	**10,559**	10,920	—	(361)
Wholesale electricity sales *(GWh)* [1]	**6,283**	5,843	—	440
Gas sales *(PJ)*	**16**	15	—	1
Revenue	**2,334**	2,260	(147)	221
Earnings	**292**	302	(20)	10

[1] *Primarily short-term wholesale sales*

Sales

The decrease in retail electricity sales was largely due to unfavourable weather as compared to 2020.

The increase in wholesale electricity sales was due primarily to favourable market conditions, including customer demand in the first quarter of 2021 resulting from a severe winter storm in southwestern U.S. in February 2021. 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 consistent with 2020.

Revenue

The increase in revenue, net of foreign exchange, was due primarily to: (i) new customer rates effective January 1, 2021 at TEP; (ii) higher wholesale electricity sales reflecting favourable market conditions; (iii) higher transmission revenue; and (iv) the recovery of higher fuel and non-fuel costs through the normal operation of regulatory mechanisms. The increase was partially offset by lower retail electricity sales, discussed above.

Earnings

The increase in earnings, net of foreign exchange, was due to the impact of new customer rates and higher transmission revenue at TEP, partially offset by: (i) higher operating costs mainly related to planned generation maintenance in 2021, including outages at the Springerville and Sundt generating facilities; and (ii) lower retail electricity sales driven by unfavourable weather.

Central Hudson

($ millions, except as indicated)	2021	2020	Variance FX	Variance Other
Electricity sales (GWh)	**5,000**	4,969	—	31
Gas sales (PJ)	**23**	23	—	—
Revenue	**1,000**	953	(60)	107
Earnings	**93**	91	(4)	6

Sales

Electricity and gas sales were largely consistent with 2020.

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: (i) the flow through of higher energy supply costs driven by higher commodity prices; and (ii) the finalization of Central Hudson's general rate application including an increase in gas and electricity delivery rates with retroactive effect to July 1, 2021, reflecting a return on increased Rate Base assets, the recovery of higher operating and finance expenses, and the recovery of finance charges which had not been billed to customers since the second quarter of 2020. See "Regulatory Highlights" on page 25 for further details. The increase in revenue was partially offset by the normal operation of regulatory mechanisms to be reflected in future customer rates.

Earnings

The increase in earnings, net of foreign exchange, was due primarily to the finalization of Central Hudson's general rate application, partially offset by the operation of regulatory mechanisms, discussed above, as well as higher operating costs.

FortisBC Energy

($ millions, except as indicated)	2021	2020	Variance
Gas sales (PJ)	**228**	219	9
Revenue	**1,715**	1,385	330
Earnings	**185**	175	10

Sales

The increase in gas sales was due primarily to higher consumption by residential and commercial customers due to colder temperatures in the fourth quarter of 2021 as compared to the same period in 2020.

Revenue

The increase in revenue was due primarily to a higher cost of natural gas recovered from customers, Rate Base growth, and the normal operation of regulatory deferrals.

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

($ millions, except as indicated)	2021	2020	Variance
Electricity deliveries (GWh)	**16,643**	16,092	551
Revenue	**644**	596	48
Earnings	**141**	133	8

Deliveries

The increase in electricity deliveries was due to: (i) higher average consumption by residential and small commercial customers due to favourable weather largely in the first and third quarters of 2021; (ii) customer additions; and (iii) higher load from industrial customers.

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

Revenue and Earnings

The increases in revenue and earnings were due to: (i) Rate Base growth and customer additions; (ii) higher revenue associated with significantly colder and warmer temperatures in the first and third quarters of 2021, respectively; and (iii) higher revenue associated with a long-term energy retailer agreement. The increase in earnings was partially offset by the impact of a higher effective income tax rate associated with lower available tax deductions in 2021 as compared to 2020, and higher operating costs.

FortisBC Electric

($ millions, except as indicated)	**2021**	2020	Variance
Electricity sales *(GWh)*	**3,460**	3,291	169
Revenue	**468**	424	44
Earnings	**59**	56	3

Sales

The increase in electricity sales was due primarily to: (i) higher average consumption, as a result of warmer temperatures in the second quarter of 2021 and colder temperatures in the fourth quarter of 2021 compared to the same periods in 2020; and (ii) higher average consumption by commercial and industrial customers due, in part, to the impact of the COVID-19 Pandemic, which resulted in tighter public health restrictions during 2020 as compared to 2021.

Revenue

The increase in revenue was due primarily to: (i) higher electricity sales, partially offset by the normal operation of regulatory deferrals; (ii) Rate Base growth; and (iii) an increase in third-party contract work.

Earnings

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

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

Other Electric

			Variance	
($ millions, except as indicated)	**2021**	2020	FX	Other
Electricity sales *(GWh)*	**9,266**	9,175	—	91
Revenue	**1,498**	1,485	(21)	34
Earnings	**118**	112	(2)	8

Sales

The increase in electricity sales was due primarily to overall higher average consumption, reflecting the continued recovery from the impacts of the COVID-19 Pandemic in 2020, including the temporary closure of non-essential businesses and lower tourism-related activities in the Caribbean.

Revenue

The increase in revenue, net of foreign exchange, reflected higher sales, the flow through of overall higher energy supply costs, and Rate Base growth.

Earnings

The increase in earnings, net of foreign exchange, primarily reflected the continued recovery of economic conditions in the Caribbean and Rate Base growth, partially offset by lower equity income from Belize Electricity.

Energy Infrastructure

($ millions, except as indicated)	**2021**	2020	Variance
Electricity sales *(GWh)*	**147**	229	(82)
Revenue	**98**	88	10
Earnings	**38**	39	(1)

Sales

The change in electricity sales reflected variations in hydroelectric production in Belize associated with rainfall levels.

Revenue

The increase in revenue was due to year-over-year changes at Aitken Creek, including unrealized gains associated with mark-to-market accounting of natural gas derivatives partially offset by realized losses on natural gas contracts, as certain contracts were settled in 2021 in consideration of favourable forward curves. The increase in revenue was also partially offset by lower hydroelectric production in Belize.

Earnings

The decrease in earnings was primarily due to lower hydroelectric production in Belize, partially offset by higher earnings at Aitken Creek as discussed above.

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)	**2021**	2020	FX	Other
Net expenses	**(121)**	(148)	9	18

The decrease in net expenses, net of foreign exchange, was due primarily to: (i) the reversal of a $13 million tax recovery in 2020, originally recognized in 2019, resulting from the finalization of U.S. tax reform and associated anti-hybrid regulations; (ii) lower operating expenses; and, (iii) higher mark-to-market gains on total returns swaps associated with share price growth. The decrease was partially offset by a lower income tax recovery resulting from a higher consolidated state tax rate associated with changes in regional sales mix.

NON-U.S. GAAP FINANCIAL MEASURES

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

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

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

Non-U.S. GAAP Reconciliation

($ millions, except as indicated)	2021	2020	Variance
Adjusted Common Equity Earnings, Adjusted Basic EPS and Adjusted Payout Ratio			
Common Equity Earnings	**1,231**	1,209	22
Adjusting items:			
Unrealized gain on mark-to-market of derivatives (1)	**(12)**	—	(12)
May 2020 FERC decision (2)	**—**	(27)	27
U.S. tax reform (3)	**—**	13	(13)
Adjusted Common Equity Earnings	**1,219**	1,195	24
Adjusted Basic EPS (4) ($)	**2.59**	2.57	0.02
Adjusted Payout Ratio (5) (%)	**79.2**	75.4	3.8
Capital Expenditures			
Additions to property, plant and equipment	**3,189**	3,857	(668)
Additions to intangible assets	**197**	182	15
Adjusting item:			
Wataynikaneyap Transmission Power Project (6)	**178**	138	40
Capital Expenditures	**3,564**	4,177	(613)

(1) *Represents timing differences related to the accounting of natural gas derivatives at Aitken Creek, net of income tax expense of $5 million in 2021 (2020 - $nil), included in the Energy Infrastructure segment*
(2) *Represents prior period impacts of the May 2020 FERC Decision, net of income tax expense of $11 million, included in the ITC segment*
(3) *Represents income tax expense resulting from the finalization of U.S. tax reform and associated anti-hybrid regulations, included in the Corporate and Other segment*
(4) *Calculated using Adjusted Common Equity Earnings divided by weighted average common shares of 470.9 million in 2021 (2020 - 464.8 million)*
(5) *Calculated using dividends paid per common share of $2.05 in 2021 (2020 - $1.9375) divided by Adjusted Basic EPS*
(6) *Represents Fortis' 39% share of capital spending for the Wataynikaneyap Transmission Power Project, included in the Other Electric 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 U.S. are regulated federally by FERC. Remaining utility operations in the U.S. and Canada are regulated by state or provincial regulators. Utility operations in the Caribbean are regulated by governmental authorities.

Additional information about regulation and the regulatory matters discussed below is provided in Note 2 in the 2021 Annual Financial Statements. Also refer to "Business Risks - Utility Regulation" on page 36.

Significant Regulatory Developments

ITC

Transmission Incentives: In April 2021, FERC issued a supplemental NOPR on transmission incentives modifying the proposal in the initial NOPR released in March 2020. The supplemental NOPR proposes to eliminate the 50-basis point RTO ROE incentive adder for existing RTO members that have been members longer than three years, like ITC. In June 2021, ITC filed its comments on the supplemental NOPR supporting the continuation of the ROE incentive adder for RTO members. The timeline for FERC to issue a final rule in this proceeding and the likely outcome cannot be determined at this time. Although any potential impact to Fortis remains uncertain, every 10-basis point change in ROE at ITC impacts Fortis' annual EPS by approximately $0.01.

UNS Energy

FERC Rate Case: In 2019, FERC issued an order accepting formula transmission rates proposed by TEP, subject to refund following hearing and settlement procedures. A settlement in principle was reached in August 2021, and a settlement agreement including an ROE of 9.79% was filed with FERC in December 2021. Until conclusion of the proceeding, customer rates continue to be charged under the 2019 FERC order and remain subject to refund pending the final order. The timing and outcome of this proceeding remains unknown.

Central Hudson

General Rate Application: In November 2021, the PSC approved a three-year rate plan for Central Hudson with retroactive application to July 1, 2021, including an ROE of 9.0%, and a common equity component of capital structure of 50% declining by 1% annually to 48% in the third rate year. The three-year rate plan also reflects the use of existing regulatory balances and other measures to reduce customer bill impacts, the recovery of finance charges which had not been billed to customers since the second quarter of 2020, as well as initiatives to support New York State's climate goals.

FortisBC Energy and FortisBC Electric

GCOC Proceeding: In January 2021, the BCUC announced the initiation of a GCOC proceeding including a review of the common equity component of capital structure and the allowed ROE. The timing and outcome of this proceeding, including the effective date of any change in the cost of capital for 2022 or beyond, remains unknown.

FortisAlberta

2022 GCOC Proceeding: In March 2021, the AUC concluded the 2022 GCOC proceeding and extended the existing allowed ROE of 8.5% using a 37% equity component of capital structure through 2022.

2023 COS Application: The final year of FortisAlberta's second PBR term is 2022. In June 2021, the AUC issued a decision confirming the approach to be adopted by Alberta distribution utilities for the COS rebasing year in 2023. In November 2021, FortisAlberta filed its 2023 COS application and a decision is expected in the third quarter of 2022.

2023/2024 GCOC Proceeding: In January 2022, the AUC initiated proceedings to establish the cost of capital parameters for 2023 and to consider a formula-based approach to setting the allowed ROE for 2024 and beyond. The AUC is considering extending the existing allowed ROE of 8.5% using a 37% equity component of capital structure through 2023. Comments on this proposal are due in February 2022 and a decision is expected in the first quarter of 2022. The GCOC proceeding for 2024 and beyond is expected to commence in the third quarter of 2022, with a decision expected in 2023.

Third PBR Term: In July 2021, the AUC issued a decision confirming that Alberta distribution utilities will be subject to a third PBR term commencing in 2024 with going-in rates based on the 2023 COS rebasing. The AUC also initiated a new proceeding to consider the design of the third PBR term. FortisAlberta will submit comments with respect to the design of the third PBR term in 2022 and a decision from the AUC is expected in 2023.

Independent System Operator Tariff Proceeding: In April 2021, the AUC issued a decision confirming that distribution facility owners, such as FortisAlberta, will no longer be permitted to earn a return on AESO contributions made on a prospective basis from the date of the decision. Contributions made prior to that date are not impacted. The decision did not have a material financial impact on the Corporation in 2021 and it is not expected to materially impact future periods. In January 2022, the Alberta Court of Appeal granted a full appeal on this matter. In doing so, the Alberta Court of Appeal also permitted a related appeal regarding the legality of the AUC's AESO customer contribution policy. FortisAlberta will fully participate in the appeal regarding the legality of the AESO customer contribution policy and will closely monitor the preceding related to earned returns on future AESO contributions.

FINANCIAL POSITION

Significant Changes between December 31, 2021 and 2020

Balance Sheet Account	**Variance**		
($ millions)	**FX**	**Other**	**Explanation**
Cash and cash equivalents	(1)	(117)	Reflects the timing of debt issuances, and the related reinvestment in capital and operating requirements.
Accounts receivable and other current assets	(5)	147	Due primarily to the flow through of higher energy supply costs and an increase in the fair value of energy contracts, partially offset by a lower income tax receivable.
Other assets	(4)	289	Due primarily to an increase in employee future benefit assets, largely at Central Hudson, driven by higher discount rates.
Property, plant and equipment, net	(156)	1,974	Due to capital expenditures, partially offset by depreciation.

Significant Changes between December 31, 2021 and 2020

Balance Sheet Account	Variance		
($ millions)	FX	Other	Explanation
Short-term borrowings	(1)	116	Reflects the issuance of commercial paper at ITC to finance working capital and capital investment requirements.
Accounts payable & other current liabilities	(8)	257	Due to higher energy supply costs at FortisBC Energy and UNS Energy.
Other liabilities	(6)	(184)	Due primarily to a decrease in employee future benefit liabilities driven by higher discount rates.
Regulatory liabilities (current and long-term)	(15)	134	Due to the normal operation of regulatory mechanisms including employee future benefits, largely at Central Hudson, and the fair value of energy contracts at UNS Energy, partially offset by a reduction in deferred income taxes.
Deferred income tax liabilities	(13)	296	Due to higher temporary differences associated with ongoing capital investment.
Long-term debt (including current portion)	(112)	1,080	Reflects debt issuances, partially offset by debt repayments, at Corporate and the regulated utilities, as well as higher borrowings under committed credit facilities.
Shareholders' equity	(82)	673	Due primarily to: (i) Common Equity Earnings for 2021, less dividends declared on common shares; and (ii) the issuance of common shares, largely under the DRIP.

LIQUIDITY AND CAPITAL RESOURCES

Cash Flow Requirements

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

Cash required of Fortis to support subsidiary growth is generally derived from borrowings under the Corporation's committed credit facility, the operation of 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 financing. Financing needs also arise to refinance maturing debt.

Credit facilities are syndicated primarily with large banks in Canada and the U.S., with no one bank holding more than approximately 20% of the total facilities. Approximately $4.6 billion of the total credit facilities are committed with maturities ranging from 2022 through 2026. Available credit facilities are summarized in the following table.

Credit Facilities

As at December 31 ($ millions)	Regulated Utilities	Corporate and Other	2021	2020
Total credit facilities [1]	3,466	1,380	**4,846**	5,581
Credit facilities utilized:				
Short-term borrowings	(247)	—	**(247)**	(132)
Long-term debt (including current portion)	(1,019)	(286)	**(1,305)**	(980)
Letters of credit outstanding	(70)	(45)	**(115)**	(130)
Credit facilities unutilized	2,130	1,049	**3,179**	4,339

[1] *Additional information about the Corporation's credit facilities is provided in Note 14 in the 2021 Annual Financial Statements*

In April 2021, the Corporation's unsecured $500 million revolving one-year term committed credit facility expired and was not renewed, and in June 2021 the Corporation extended its unsecured $1.3 billion revolving term committed credit facility to July 2026. In October 2021, UNS Energy terminated a US$150 million revolving credit facility and entered into an arrangement with Fortis.

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, 2021, consolidated fixed-term debt maturities/repayments are expected to average $1,209 million annually over the next five years and approximately 75% 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. In May 2021, the Corporation issued 7-year $500 million unsecured senior notes at 2.18% and, as at December 31, 2021, $1.5 billion remained available under the short-form base shelf prospectus.

Fortis is well positioned with strong liquidity. This combination of available credit facilities and manageable annual debt maturities/repayments provides flexibility in the timing of access to capital markets. Given current credit ratings and capital structures, the Corporation and its subsidiaries currently expect to continue to have reasonable access to long-term capital in 2022.

Fortis and its subsidiaries were in compliance with debt covenants as at December 31, 2021 and are expected to remain compliant in 2022.

Cash Flow Summary

Summary of Cash Flows

Years ended December 31

($ millions)	**2021**	2020	Variance
Cash and cash equivalents, beginning of year	**249**	370	(121)
Cash from (used in):			
Operating activities	**2,907**	2,701	206
Investing activities	**(3,488)**	(4,132)	644
Financing activities	**451**	1,327	(876)
Effect of exchange rate changes on cash and cash equivalents	**12**	(17)	29
Cash and cash equivalents, end of year	**131**	249	(118)

Operating Activities

See "Performance at a Glance - Operating Cash Flow" on page 16.

Investing Activities

The decrease in cash used in investing activities reflects higher capital expenditures in 2020, largely related to the Oso Grande generating facility at UNS Energy, as well as the lower U.S.-to-Canadian dollar exchange rate. See "Performance at a Glance - Capital Expenditures" on page 16 and "Capital Plan" on page 31.

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 27.

Debt Financing

Long-Term Debt Issuances

Year ended December 31, 2021	Month Issued	Interest Rate (%)	Maturity		Amount ($ millions)	Use of Proceeds
ITC						
Series A secured senior notes [1]	August	2.90	2051	**US**	**75**	[2]
UNS Energy						
Unsecured senior notes	May	3.25	2051	**US**	**325**	[3][4]
Central Hudson						
Unsecured senior notes	March	3.29	2051	**US**	**75**	[3][4]
Unsecured senior notes	October	3.22	2051	**US**	**55**	[3][5]
FortisBC Energy						
Unsecured debentures	April	2.42	2031		**150**	[5]
Maritime Electric						
Secured first mortgage bonds	December	3.40	2051		**40**	[5]
Fortis						
Unsecured senior notes	May	2.18	2028		**500**	[3][4][5]

(1) *US$75 million Series B secured senior notes were priced at 3.05% with issuance expected in May 2022*
(2) *Fund or refinance a portfolio of eligible green projects*
(3) *General corporate purposes*
(4) *Repay maturing long-term debt*
(5) *Repay credit facility borrowings*

In January 2022, ITC issued 30-year US$150 million secured first mortgage bonds at 2.93%. The net proceeds are expected to be used to repay credit facility borrowings, fund or refinance a portfolio of eligible green projects, fund capital expenditures and for other general corporate purposes.

In January 2022, Central Hudson issued 5-year US$50 million unsecured senior notes at 2.37% and 7-year US$60 million unsecured senior notes at 2.59%. The net proceeds are expected to be used to repay maturing long-term debt and for general corporate purposes.

Common Equity Financing

Common Equity Issuances and Dividends Paid

Years ended December 31 *($ millions, except as indicated)*	2021	2020	Variance
Common shares issued:			
Cash [1]	**60**	58	2
Non-cash [2]	**358**	116	242
Total common shares issued	**418**	174	244
Number of common shares issued *(# millions)*	**8.0**	3.5	4.5
Common share dividends paid:			
Cash	**(608)**	(786)	178
Non-cash [3]	**(356)**	(114)	(242)
Total common share dividends paid	**(964)**	(900)	(64)
Dividends paid per common share *($)*	**2.0500**	1.9375	0.1125

(1) *Includes common shares issued under stock option and employee share purchase plans*
(2) *Common shares issued under the DRIP and stock option plan. The 2% discount offered on common share issuances under the DRIP was reinstated effective December 1, 2020.*
(3) *Common share dividends reinvested under the DRIP*

On November 18, 2021 and February 10, 2022, Fortis declared a dividend of $0.535 per common share payable on March 1, 2022 and June 1, 2022, respectively. The payment of dividends is at the discretion of the Board and depends on the Corporation's financial condition and other factors.

Contractual Obligations

Contractual Obligations

As at December 31, 2021

($ millions)	**Total**	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Long-term debt:							
Principal [1]	**25,482**	1,628	1,275	1,750	101	2,595	18,133
Interest	**15,859**	982	951	892	859	836	11,339
Finance leases [2]	**1,202**	35	34	34	34	35	1,030
Other obligations [3]	**532**	168	106	101	36	37	84
Other commitments: [4]							
Waneta Expansion capacity agreement	**2,525**	53	54	55	56	58	2,249
Gas and fuel purchase obligations	**2,464**	787	446	252	169	121	689
Renewable power purchase agreements	**1,918**	122	122	122	122	122	1,308
Power purchase obligations	**1,783**	288	254	194	184	185	678
ITC easement agreement	**366**	13	13	13	13	13	301
Debt collection agreement	**109**	3	3	3	3	3	94
Renewable energy credit purchase agreements	**87**	17	16	11	8	6	29
Other	**158**	66	7	7	6	4	68
	52,485	4,162	3,281	3,434	1,591	4,015	36,002

[1] *Amounts not reduced by unamortized deferred financing and discount costs of $147 million. Additional information is provided in Note 14 in the 2021 Annual Financial Statements.*

[2] *Additional information is provided in Note 15 in the 2021 Annual Financial Statements*

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

[4] *Represents unrecorded commitments. Additional information is provided in Note 26 in the 2021 Annual Financial Statements*

Other Contractual Obligations

The Corporation's regulated utilities are obligated to provide service to customers within their respective service territories. Capital Expenditures are forecast to be approximately $4.0 billion for 2022 and approximately $20.0 billion over the five-year 2022-2026 Capital Plan. See "Capital Plan" on page 31.

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. The Wataynikaneyap Partnership has loan agreements in place 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.

Development projects at ITC may result in payments to developers that are contingent on the projects reaching certain milestones indicating that the projects are financially viable. It is reasonably possible that ITC will be required to make these contingent development payments up to a maximum amount of $88 million upon financial close of the projects. In the event it becomes probable that these payments will be made, the liability and the corresponding intangible asset would be recognized.

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, 2021, 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 $83 million, for which it has issued a parental guarantee. As at December 31, 2021, there was no obligation under this guarantee.

As at December 31, 2021, 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 $115 million as at December 31, 2021 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	**2021**		2020	
As at December 31	*($ millions)*	*(%)*	*($ millions)*	*(%)*
Debt [1]	**25,784**	**55.2**	24,581	54.8
Preference shares	**1,623**	**3.5**	1,623	3.6
Common shareholders' equity and non-controlling interests [2]	**19,293**	**41.3**	18,661	41.6
	46,700	**100.0**	44,865	100.0

(1) Includes long-term debt and finance leases, including current portion, and short-term borrowings, net of cash
(2) Includes shareholders equity, net of preference shares, and non-controlling interests. Non-controlling interests represented 3.5% as at December 31, 2021 (December 31, 2020 - 3.5%)

Outstanding Share Data

As at February 10, 2022, the Corporation had issued and outstanding 474.9 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 10, 2022, an additional 2.8 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.

As at December 31, 2021	**Rating**	Type	Outlook
S&P	A-	Corporate	Stable
	BBB+	Unsecured debt	
DBRS Morningstar	A (low)	Corporate	Stable
	A (low)	Unsecured debt	
Moody's	Baa3	Issuer	Stable
	Baa3	Unsecured debt	

In January 2022, S&P revised Central Hudson's outlook to negative from stable in consideration of the PSC's order on the company's general rate application, projected elevated capital expenditures, and the resulting impact on the company's financial measures.

Capital Plan

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

Capital Expenditures of $3.6 billion were slightly lower than the 2021 Capital Plan of $3.8 billion as disclosed in the 2020 MD&A. The reduction reflected: (i) a lower-than-planned U.S.-to-Canadian dollar exchange rate; and (ii) the timing of Capital Expenditures, including delays at the Wataynikaneyap Transmission Power Project and at Caribbean Utilities due to the COVID-19 Pandemic. This decrease was partially offset by higher-than-anticipated Capital Expenditures at ITC, largely reflecting various incremental projects as well as restoration costs following a derecho storm in the Midwestern U.S. in December 2021.

2021 Capital Expenditures [1]

($ millions, except as indicated)	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Other Electric	**Total Regulated Utilities**	**Non-Regulated [2]**	**Total**	**(%)**
	Regulated Utilities										
Generation	—	177	1	—	—	18	62	**258**	**—**	**258**	**7**
Transmission	939	161	33	200	—	44	211	**1,588**	**—**	**1,588**	**45**
Distribution	—	205	160	203	320	43	187	**1,118**	**—**	**1,118**	**31**
Other [3]	107	167	97	72	69	29	39	**580**	**20**	**600**	**17**
Total	1,046	710	291	475	389	134	499	**3,544**	**20**	**3,564**	**100**
(%)	29	20	8	13	11	4	14	**99**	**1**	**100**	

(1) See "Non-U.S. GAAP Financial Measures" on page 24
(2) Energy Infrastructure segment
(3) Includes facilities, equipment, vehicles and information technology assets

Capital Expenditures of $600 million in 2021 were focused on delivering cleaner energy to customers.

Forecast 2022 Capital Expenditures [1][2]

($ millions, except as indicated)	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Other Electric	**Total Regulated Utilities**	**Non-Regulated**	**Total**	**(%)**
	Regulated Utilities										
Generation	—	85	9	—	—	15	162	**271**	**60**	**331**	**8**
Transmission	948	243	45	270	—	14	205	**1,725**	**—**	**1,725**	**44**
Distribution	—	244	184	185	358	98	193	**1,262**	**—**	**1,262**	**32**
Other	50	132	106	167	87	29	61	**632**	**17**	**649**	**16**
Total	998	704	344	622	445	156	621	**3,890**	**77**	**3,967**	**100**
(%)	25	18	9	16	11	4	15	**98**	**2**	**100**	

(1) Represents a forward-looking non-GAAP financial measure calculated in the same manner as Capital Expenditures. See "Non-U.S. GAAP Financial Measures" on page 24.
(2) Excludes the non-cash equity component of AFUDC

2022-2026 Capital Plan [1]

($ billions)	2022	2023	2024	2025	2026	**Total [2][3]**
Five-year capital plan	4.0	3.8	4.0	4.0	4.2	**20.0**

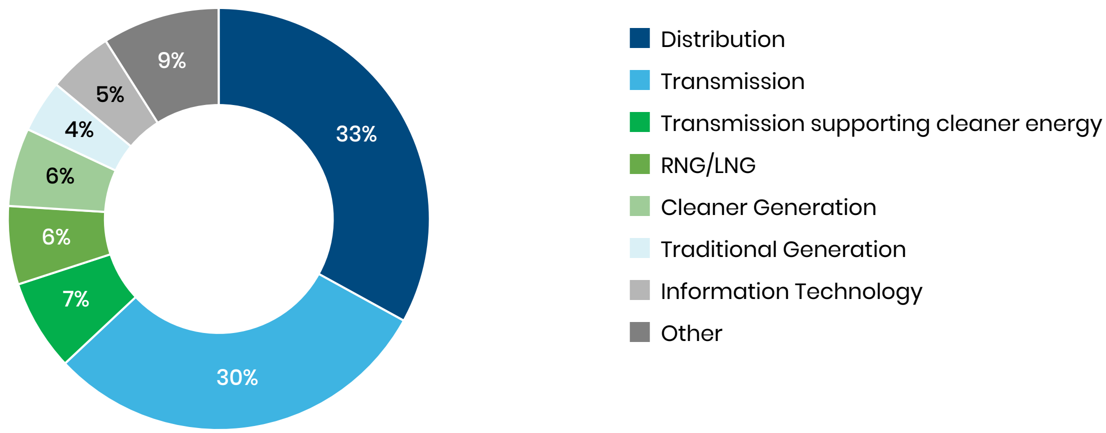
(1) Capital Plan is a forward-looking non-GAAP financial measure calculated in the same manner as Capital Expenditures. See "Non-U.S. GAAP Financial Measures" on page 24.
(2) Reflects an assumed U.S.:CAD foreign exchange rate of 1.25. On average, Fortis estimates that a five-cent increase or decrease in the U.S. dollar relative to the Canadian dollar would increase or decrease Capital Expenditures by approximately $450 million over the five-year planning period
(3) Excludes the non-cash equity component of AFUDC

In comparison to the prior five-year plan totaling $19.6 billion as disclosed in the 2020 MD&A, the 2022-2026 Capital Plan reflects $1.0 billion of additional capital investments at the Corporation's regulated utilities, largely reflecting customer growth, enhancements to transmission reliability and capacity, and investments in cleaner energy. This growth is tempered by $600 million associated with the lower assumed foreign exchange rate of 1.25, down from a rate of 1.32 assumed in the Corporation's previous five-year plan.

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. The composition of the 2022-2026 Capital Plan includes 27% related to growth, 56% sustaining and 17% for other areas. Geographically, 53% of planned expenditures are expected in the U.S., including 25% at ITC, with 43% in Canada and the remaining 4% in the Caribbean.

The investments included in the 2022-2026 Capital Plan are summarized as follows:

FIVE-YEAR CAPITAL PLAN



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. While the Corporation does not expect the COVID-19 Pandemic to impact its overall five-year Capital Plan, the timing of forecast capital expenditures will continue to be evaluated. Depending on the length and severity of the pandemic, including any impact of supply chain disruptions, certain planned expenditures may shift within the 2022-2026 Capital Plan.

Midyear Rate Base [(1)]

($ billions)	**2021**	2022	2026
ITC	**9.5**	10.1	12.6
UNS Energy	**5.8**	6.5	8.0
Central Hudson	**2.2**	2.4	3.1
FortisBC Energy	**5.2**	5.4	7.1
FortisAlberta	**3.8**	4.0	4.7
FortisBC Electric	**1.5**	1.5	1.8
Other Electric	**3.1**	3.6	4.3
Total	**31.1**	33.5	41.6

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

Total midyear Rate Base is forecast to grow to $41.6 billion by 2026 under the five-year Capital Plan, representing a CAGR of approximately 6%, which is supportive of continuing growth in earnings and dividends.

Major Capital Projects [1] ($ millions)	Pre-2021	Actual 2021	Forecast 2022	Forecast 2023-2026	Expected Completion
ITC [2]					
Multi-Value Regional Transmission Projects	642	**68**	81	73	2023
34.5 to 69kV Transmission Conversion Project	445	**37**	68	77	Post-2026
UNS Energy					
Vail-to-Tortolita Project	—	**21**	58	182	2025
Oso Grande Generating Facility	554	**39**	—	—	2021
FortisBC Energy					
Lower Mainland Intermediate Pressure System Upgrade	411	**16**	—	—	2021
Eagle Mountain Woodfibre Gas Line Project [3]	—	**—**	—	350	2026
Transmission Integrity Management Capabilities Project	21	**9**	10	212	Post-2026
Inland Gas Upgrade Project	59	**69**	79	65	2025
Okanagan Capacity Upgrade	9	**7**	16	185	2024
Tilbury 1B Project	20	**9**	33	322	Post-2026
Tilbury LNG Storage Expansion	10	**6**	8	449	Post-2026
AMI Project	—	**—**	5	375	Post-2026
Other Electric					
Wataynikaneyap Transmission Power Project [4]	178	**177**	248	109	2024
Total		**458**	606	2,399	

[1] *Includes applicable AFUDC*
[2] *Pre-2021 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. 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-2021. The fourth project is expected to be placed in service in 2023.

34.5 to 69kV Transmission Conversion Project
Multiple projects designed to convert the 34.5kV system to 69kV operating voltage. Projects include construction of new 69kV lines, rebuild of existing 34.5kV lines to 69kV, and substation conversions. In service dates range from pre-2021 to post-2026.

Vail-to-Tortolita Project
Construction and upgrades to connect existing TEP substations to a new 230kV line within TEP's service territory. Construction is expected to begin in 2023 with an in service date of 2025.

Oso Grande Generating Facility
In May 2021, construction of UNS Energy's 250 MW wind-powered electric generating facility was completed.

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 has been completed, with the final pipeline segment 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. FortisBC Energy's proposed pipeline expansion remains contingent on Woodfibre LNG Limited making a final decision to proceed with construction of the LNG facility.

Transmission Integrity Management Capabilities Project
This project improves gas line safety and transmission system integrity, including gas line modifications and looping. In February 2021, FortisBC Energy filed a CPCN application with the BCUC for the coastal transmission system section of this project.

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.

Okanagan Capacity Upgrade
Construction of a new section of pipeline and associated facilities to address expected load growth in the Okanagan region. In November 2020, FortisBC Energy filed a CPCN application with the BCUC for this project.

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 2022.

Tilbury LNG Storage Expansion
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, and if approved, the project is expected to begin in 2022.

AMI Project
Replacement of residential and small commercial meters with advanced meters and installation of bypass valves to support the safety, resiliency, and efficient operation of the gas distribution system. In May 2021, FortisBC Energy filed a CPCN application with the BCUC for this project.

Wataynikaneyap Transmission Power Project
Construction of a 1,800 kilometre, OEB-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 expected to be completed in 2024.

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 IESO 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 project is fully permitted in the U.S. and Canada and continues to advance through regulatory, operational and economic milestones. In 2021, the Canada Infrastructure Bank announced it would fund 40% of the approximate $1.7 billion project and the Ontario government authorized IESO to commence contract negotiations. Negotiation of transmission service agreements is required to advance to the construction phase. Completion would take approximately four years from the commencement of construction.

ITC - MISO LRTP
A comprehensive effort by MISO is underway to identify and construct the regional transmission required in the MISO region to support the ongoing evolution of the electric industry. ITC has a large footprint in the MISO region, specifically including but not limited to wind-rich regions in Iowa and Minnesota. MISO is currently requesting FERC authorization for cost allocation and finalizing planning for an initial tranche of LRTP projects.

UNS Energy - TEP 2020 IRP
Outlines the resource energy transition required at TEP to meet its customers' energy needs through 2035 as it exits coal-fired resources by 2032 and replaces it with wind and solar resources as part of a cleaner energy portfolio that will reduce carbon emissions 80 percent by 2035. This plan supports reliable and affordable service from sustainable resources and is expected to provide capital investment opportunities that extends beyond the Capital Plan. The IRP may be impacted by various federal and state energy policies, including policies currently under consideration.

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 and grid modernization projects at ITC; 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 program to identify and evaluate risks by both severity of impact and probability of occurrence. Materiality thresholds are reviewed and, if necessary, updated annually. Financial risks, as well as risks that may impact the safety of employees, customers or the general public, as well as reputational risks, are evaluated. Systems of internal controls are used to monitor and manage identified risks. The ERM program 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, through the audit committee, oversees Fortis' ERM program ensuring that management has an effective risk management system to support strategic planning.

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

Utility Regulation

Regulated utility assets represented approximately 99% of the Corporation's total assets as at December 31, 2021. Regulatory jurisdictions include five Canadian provinces, nine U.S. states and three Caribbean countries, as well FERC regulation for transmission assets in the U.S.

Regulators administer legislation covering material aspects of the utilities' business, including: customer rates 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. FortisAlberta's PBR mechanism gives rise to 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 ROE, ROE adders for independent transmission ownership and deemed capital structure, as well as operating and capital expenditures.

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

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. Any of the foregoing potential regulatory changes could have a Material Adverse Effect.

Climate Change and Physical Risks

The provision of electric and gas service is subject to 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 and changing seasonal variations, and the Corporation expects that regulatory responses to such changes will occur in the coming years (see "Environmental Regulation" on page 37). Severe weather impacts the Corporation's service territories, primarily in the form of thunderstorms, flooding, wildfires, hurricanes and snow or ice storms. Increased frequency of extreme weather events could increase the cost of providing service through increased repairs and use of contingency plans. 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 efficiency of 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.

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 and the transition to a cleaner energy future will require the Corporation's utilities to effectively manage evolving regulatory and legislative requirements, new resiliency standards, the integration of new technologies and impacts on customer demand and rates. Failure to do so may disrupt the ability of the utilities to provide safe and cost-effective service, which could cause reputational harm and other impacts. Any of the foregoing potential impacts of climate change could have a Material Adverse Effect.

The operation of transmission and distribution assets has the potential to cause fires, mainly as a result of equipment failure, falling trees and lightning strikes to lines or equipment. Also, 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.

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.

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 and climate changes may increase the frequency of such failures occurring.

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.

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

Environmental Regulation

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

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. Future legislation relating to GHG emissions could impact generation assets, operations, energy supply, operational costs, reporting obligations and other material aspects of the Corporation's business.

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.

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, including the disruption of global supply chains. The outbreak of communicable diseases, as well as efforts to reduce the health impacts and control disease spread can lead to worldwide restrictions on business operations, including business closures and the potential impacts of reduced labour availability and productivity, supply chain disruptions, project construction delays, disruptions to capital markets, governmental and regulatory action, and a prolonged reduction in economic activity. An extended economic slowdown could reduce energy sales and adversely impact the ability of customers, contractors and suppliers to fulfill their obligations and could disrupt operations and capital expenditure programs or cause impairment of goodwill (see "General Economic Conditions" on page 42).

There continues to be uncertainty surrounding the duration and severity of the COVID-19 Pandemic, particularly with respect to the emergence of new variants of the virus, the long-term efficacy and global distribution of COVID-19 vaccines, the impact of vaccine mandates and isolation requirements on labour availability, potential government action to mitigate public health effects, disruptions to the global supply chain, and other factors beyond the Corporation's control. An extended period of economic or supply chain disruption 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 31. Projects, particularly Major Capital Projects, are subject to risks of delay and cost overruns during construction caused by inflation, commodity price fluctuations, 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.

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. The ability of the Corporation's utilities to operate effectively is dependent upon using and maintaining complex information systems and infrastructure that: (i) support the operation of 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, computer 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 cybersecurity 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 and 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 available to customers include energy derived from renewable sources, customer-owned generation, energy-efficient appliances, battery storage and control systems. Advances in these or other technologies could have a significant impact on retail sales with a potential Material Adverse Effect.

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 36). 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 natural gas is used for space heating by residential customers. The earnings of the Corporation's gas utilities are typically highest in the first and fourth quarters.

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 22% of the Corporation's revenue is derived from the delivery of natural gas. A decrease in the competitiveness of natural gas due to pricing, government policy or other factors could have a Material Adverse Effect.

In British Columbia, which accounts for 83% 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 reductions in competitiveness.

Government policy could also impact the competitiveness of natural gas in British Columbia. In October 2021, the provincial government released an update to its economic and climate action plan, including a series of actions designed to achieve GHG emission reduction targets and the transition to a low-carbon economy. As all levels of government become more active in the development of policies to address climate change, any resultant changes to energy policy may impact the competitiveness of natural gas relative to non-carbon based 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 the 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. Municipalities can also provide incentives, such as higher density allowance, to builders to adopt carbon free energy options for their developments. These actions and policies may hinder the Corporation's ability to attract new natural gas customers or retain existing customers.

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 20); and (ii) price-risk management strategies such as the use of derivative contracts that effectively fix costs (see "Financial Instruments - Derivatives" on page 45).

There is no assurance that current regulator-approved mechanisms or strategies will continue to exist in the future. Additionally, despite these mechanisms and strategies, severe and prolonged commodity price increases could result in rates that customers are unable to pay and/or could affect consumption and sales growth. 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 and is not being generated by the Corporation's utilities. A disruption in the wholesale energy markets, or a failure on the part of energy or fuel suppliers or operators of energy delivery systems that connect to the Corporation's utilities, could result in a loss and/or increase in the cost of purchased power, which 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 U.S. to meet mandatory reliability standards developed by the North American Electric Reliability Corporation and its regional entities, which are approved and enforced by FERC. Many of these, or similar, standards have been adopted in certain Canadian provinces including British Columbia, 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 of related costs from customer rates and other potentially significant penalties.

Indigenous Peoples' Land Claims

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

FortisAlberta has distribution assets on Indigenous Peoples' lands in Alberta with access permits held by 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.

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 such that a low interest rate environment could reduce allowed ROEs. 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.

Taxation

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

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 U.S. dollar. The earnings and cash flow from, and net investments in, these entities are exposed to fluctuations in the U.S. dollar-to-Canadian dollar exchange rate.

Fortis has limited this U.S. dollar currency exposure through hedging. As at December 31, 2021, US$2.2 billion (2020 - US$2.3 billion) of corporately issued U.S. dollar-denominated long-term debt had been designated as an effective hedge of foreign net investments, leaving US$10.8 billion (2020 - US$10.2 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 U.S. dollar relative to the Canadian dollar exchange rate of US$1.00=CA$1.25 as at December 31, 2021 would increase or decrease average annual EPS by approximately six cents, which reflects the Corporation's hedging program.

The Corporation's $20.0 billion five-year Capital Plan for 2022 through 2026 also includes exposure to foreign exchange. On average, Fortis estimates that a five-cent increase or decrease in the U.S. dollar relative to the Canadian dollar would increase or decrease capital expenditures by $450 million over the five-year planning period.

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

Access to Capital

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

Operating Cash Flow may not be sufficient to fund the repayment of all outstanding liabilities when due or fund anticipated capital expenditures. The ability to meet long-term debt repayments is dependent upon obtaining sufficient and cost-effective financing to replace maturing indebtedness.

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

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 27.

Insurance

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

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

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, inflation, 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 of Major Capital Projects, could affect the Corporation's reputation as well as have a significant impact on its operations and infrastructure development.

Additionally, external stakeholders, including shareholders and investors, 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

Critical Accounting Estimates

General

The preparation of the 2021 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, 2021, Fortis recognized regulatory assets of $3.6 billion (2020 - $3.6 billion) and regulatory liabilities of $3.2 billion (2020 - $3.1 billion).

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

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

Employee Future Benefits

Key Estimates and Assumptions Years ended December 31 *($ millions, except as indicated)*	**Defined Benefit Pension Plans**		**OPEB Plans**	
	2021	2020	**2021**	2020
Funded status: [1]				
Benefit obligation [2]	**(3,922)**	(3,995)	**(747)**	(789)
Plan assets	**3,722**	3,528	**440**	391
	(200)	(467)	**(307)**	(398)
Net benefit cost [2]	**64**	67	**35**	32
Key assumptions: *(weighted average %)*				
Discount rate: [3]				
During the year	**2.60**	3.16	**2.60**	3.22
As at December 31	**3.00**	2.63	**2.97**	2.64
Expected long-term rate of return on plan assets [4]	**5.40**	5.52	**4.88**	5.28
Rate of compensation increase	**3.30**	3.34	**—**	—
Health care cost trend increase rate [5]	**—**	—	**4.49**	4.61

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

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

(3) *Reflects market interest rates on high-quality bonds with cash flows that match the timing and amount of expected pension payments*

(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 2022 rate is 5.75% and is assumed to decrease over the next 11 years to the ultimate rate of 4.49% in 2032 and thereafter.*

Sensitivity Analysis Year ended December 31, 2021 *($ 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	**(33)**	**28**	**(48)**	**65**	**n/a**	**n/a**
Projected benefit obligation	**32**	**(75)**	**(520)**	**649**	**n/a**	**n/a**
OPEB plans:						
Net benefit cost	**(4)**	**4**	**(10)**	**12**	**16**	**(14)**
Accumulated benefit obligation	**—**	**—**	**(112)**	**135**	**100**	**(91)**

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, 2021, Fortis recognized property, plant and equipment and intangible assets of $39.2 billion (2020 - $37.3 billion) representing 68% of total assets (2020 - 67%). Depreciation and amortization of these assets totalled $1.4 billion for 2021 (2020 - $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 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, 2021, this regulatory liability was $1.2 billion (2020 - $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, 2021, Fortis recognized goodwill of $11.7 billion (2020 - $11.8 billion), representing 20% of total assets (2020 - 21%). The decrease in goodwill was due to the impact of foreign exchange associated with the translation of U.S. 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.

Income Tax

As at December 31, 2021, deferred income tax liabilities, current income tax payable included in accounts payable, deferred income taxes included in regulatory assets, and deferred income taxes included in regulatory liabilities totalled $3.6 billion, $31 million, $1.8 billion and $1.3 billion, respectively (2020 - $3.3 billion, current income tax receivable of $72 million, $1.7 billion and $1.4 billion, respectively). Income tax expense was $234 million in 2021 (2020 - $231 million).

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

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

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

The Corporation and certain of its subsidiaries are subject to taxation in Canada, the United States and other foreign jurisdictions. The material jurisdictions in which the Corporation is subject to potential income tax compliance examinations include the United States (Federal, Arizona, Kansas, Iowa, Michigan, Minnesota and New York) and Canada (Federal, British Columbia and Alberta). The Corporation's 2013 to 2021 taxation years are still open for audit in Canadian jurisdictions, and its 2011 to 2021 taxation years are still open for audit in U.S. jurisdictions. The impact of such income tax compliance examinations could be material to the Corporation's financial statements (see "Business Risks - Taxation" on page 41).

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

Contingencies
The Corporation and its subsidiaries are subject to various legal proceedings and claims arising in the ordinary course of business, including those generally described under "Business Risks - Indigenous Peoples' Land Claims" on page 40, for which no amounts have been accrued because the outcomes currently cannot be reasonably determined. Further information is provided in Note 26 in the 2021 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, 2021, the carrying value of long-term debt, including the current portion, was $25.5 billion (2020 - $24.5 billion) compared to an estimated fair value of $28.8 billion (2020 - $29.1 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, 2021, unrealized losses of $20 million (2020 - $73 million) were recognized as regulatory assets and unrealized gains of $52 million (2020 - $17 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. In 2021, unrealized gains of $21 million (2020 - $3 million) were recognized in revenue.

Total return swaps
The Corporation holds total return swaps to manage the cash flow risk associated with forecast future cash settlements of certain stock-based compensation obligations. The swaps have a combined notional amount of $112 million and terms of one to three years expiring at varying dates through January 2024. Fair value is measured using an income valuation approach based on forward pricing curves. Unrealized gains and losses associated with changes in fair value are recognized in other income, net. In 2021, unrealized gains of $17 million (2020 - unrealized losses of $9 million) were recognized in other income, net.

Foreign exchange contracts

The Corporation holds U.S. dollar-denominated foreign exchange contracts to help mitigate exposure to foreign exchange rate volatility. The contracts expire at varying dates through November 2022 and have a combined notional amount of $161 million. Fair value was measured using independent third-party information. Unrealized gains and losses associated with changes in fair value are recognized in other income, net. In 2021, unrealized losses of $11 million (2020 - unrealized gains of $11 million) were recognized in other income, net.

Interest rate swaps

In 2021, ITC entered into interest rate swaps with a total notional value of US$375 million to manage the interest rate risk associated with the refinancing of long-term debt due in November 2022. The swaps have five-year terms, include mandatory early termination provisions, and will be terminated no later than the effective date of November 15, 2022. Fair value was measured using a discounted cash flow method based on LIBOR rates. Unrealized gains and losses associated with the changes in fair value are recognized in other comprehensive income, will be reclassified to earnings as a component of interest expense over the life of the debt, and were not material for 2021.

Other investments

ITC and Central Hudson hold investments in trust associated with supplemental retirement benefit plans for select employees. These investments include 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. In 2021, unrealized gains of $9 million (2020 - $7 million) were recognized in other income, net.

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, 2021				
Assets [2]				
Energy contracts subject to regulatory deferral	**—**	**78**	**—**	**78**
Energy contracts not subject to regulatory deferral	**—**	**16**	**—**	**16**
Foreign exchange contracts, total return and interest rate swaps	**23**	**2**	**—**	**25**
Other investments	**137**	**—**	**—**	**137**
	160	**96**	**—**	**256**
Liabilities [3]				
Energy contracts subject to regulatory deferral	**—**	**(46)**	**—**	**(46)**
Energy contracts not subject to regulatory deferral	**—**	**(3)**	**—**	**(3)**
	—	**(49)**	**—**	**(49)**
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)

(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	2021	2020
Energy contracts subject to regulatory deferral [(1)]		
Electricity swap contracts *(GWh)*	**509**	522
Electricity power purchase contracts *(GWh)*	**731**	2,781
Gas swap contracts *(PJ)*	**151**	156
Gas supply contract premiums *(PJ)*	**144**	203
Energy contracts not subject to regulatory deferral [(1)]		
Wholesale trading contracts *(GWh)*	**1,886**	1,588
Gas swap contracts *(PJ)*	**29**	36

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

SELECTED ANNUAL FINANCIAL INFORMATION

Years ended December 31 *($ millions, except as indicated)*	2021	2020	2019
Revenue	**9,448**	8,935	8,783
Net earnings	**1,405**	1,389	1,852
Common Equity Earnings	**1,231**	1,209	1,655
EPS: *($)*			
Basic	**2.61**	2.60	3.79
Diluted	**2.61**	2.60	3.78
Total assets	**57,659**	55,481	53,404
Long-term debt (excluding current portion)	**23,707**	23,113	21,501
Dividends declared: *($)*			
Per common share	**2.080**	1.965	1.855
Per first preference share:			
Series F	**1.2250**	1.2250	1.2250
Series G	**1.0983**	1.0983	1.0983
Series H [(1)]	**0.4588**	0.5003	0.6250
Series I [(2)]	**0.3926**	0.4987	0.7771
Series J	**1.1875**	1.1875	1.1875
Series K	**0.9823**	0.9823	0.9823
Series M [(3)]	**0.9783**	0.9783	1.0133

(1) *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.*

(2) *Floating quarterly dividend rate is reset every quarter based on the then current three-month Government of Canada Treasury Bill rate plus the applicable reset dividend yield.*

(3) *The annual dividend per share was reset to $0.9783 for the five-year period from December 1, 2019 up to but excluding December 1, 2024.*

2021/2020

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 14, "Operating Results" on page 19, and "Financial Position" on page 26.

2020/2019

The increase in revenue reflected: (i) overall higher flow-through costs in customer rates; (ii) Rate Base growth; (iii) higher 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.

The 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.

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. 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.

The increase in total assets was due to 2020 capital expenditures, partially offset by unfavourable foreign exchange on the translation of U.S. dollar-denominated assets.

FOURTH QUARTER RESULTS

Sales

(Gwh, except as indicated)	**2021**	2020	Variance
Regulated Utilities			
UNS Energy			
Retail Electricity	**2,206**	2,345	(139)
Wholesale Electricity	**1,749**	1,871	(122)
Gas *(PJ)*	**5**	5	—
Central Hudson			
Electricity	**1,203**	1,200	3
Gas *(PJ)*	**6**	7	(1)
FortisBC Energy *(PJ)*	**74**	67	7
FortisAlberta	**4,147**	4,138	9
FortisBC Electric	**927**	894	33
Other Electric	**2,449**	2,362	87
Non-Regulated			
Energy Infrastructure	**13**	103	(90)

The decrease in electricity sales was driven by: (i) UNS Energy, due to lower retail electricity sales resulting from milder weather and lower wholesale sales; and (ii) BECOL, due to lower hydroelectric production in Belize caused by variations in rainfall levels. The decrease was partially offset by higher electricity sales in the Caribbean reflecting the continued recovery from the impacts of the COVID-19 Pandemic in 2020.

The increase in gas volumes was due to higher consumption by residential and commercial customers at FortisBC Energy due to colder temperatures.

Revenue and Common Equity Earnings

	Revenue			Earnings		
($ millions, except as indicated)	**2021**	2020	Variance	**2021**	2020	Variance
Regulated Utilities						
ITC	**418**	419	(1)	**103**	109	(6)
UNS Energy	**540**	525	15	**33**	45	(12)
Central Hudson	**283**	242	41	**39**	35	4
FortisBC Energy	**592**	476	116	**78**	74	4
FortisAlberta	**156**	139	17	**23**	33	(10)
FortisBC Electric	**133**	117	16	**14**	13	1
Other Electric	**401**	381	20	**29**	32	(3)
Non-regulated						
Energy Infrastructure	**60**	47	13	**40**	27	13
Corporate and Other	**—**	—	—	**(31)**	(37)	6
Total	**2,583**	2,346	237	**328**	331	(3)
Weighted average number of common shares outstanding *(# millions)*				**473.7**	465.8	7.9
Basic EPS *($)*				**0.69**	0.71	(0.02)

The increase in revenue was driven by: (i) overall higher flow-through costs, mainly at FortisBC Energy and Central Hudson; (ii) Rate Base growth; (iii) higher electricity sales in the Caribbean reflecting the impact of the COVID-19 Pandemic in 2020; and, (iv) unrealized gains on the mark-to-market of natural gas derivatives at Aitken Creek. New customer rates and higher transmission revenue at TEP also contributed to the increase. These factors were partially offset by the unfavourable impact of foreign exchange.

The decrease in Common Equity Earnings was driven by: (i) lower earnings in Arizona, due to the reduction in sales as noted above, and lower gains on certain investments that support retirement benefits, partially offset by higher transmission revenue; (ii) the timing of earnings at FortisAlberta, due the reversal of income tax expense in the fourth quarter of 2020; (iii) the operation of regulatory mechanisms at Central Hudson; and, (iv) higher non-recoverable costs at ITC. Lower earnings in Belize and the impact of foreign exchange also unfavourably impacted earnings for the quarter. The decrease in earnings was partially offset by growth in Rate Base, the finalization of Central Hudson's rate application with retroactive application to July 1, 2021, and the favourable impact of mark-to-market accounting at Aitken Creek.

The decrease in basic EPS reflects lower Common Equity Earnings and an increase in the weighted average number of common shares outstanding, largely associated with the Corporation's DRIP.

Cash Flows

($ millions)	**2021**	2020	Variance
Cash and cash equivalents, beginning of period	**225**	494	(269)
Cash from (used in):			
Operating activities	**717**	700	17
Investing activities	**(985)**	(1,235)	250
Financing activities	**174**	308	(134)
Effect of exchange rate changes on cash and cash equivalents	**—**	(18)	18
Cash and cash equivalents, end of period	**131**	249	(118)

Operating Activities

Operating Cash Flow increased during the quarter due to: (i) Rate Base growth; (ii) new customer rates at TEP effective January 1, 2021; and, (iii) favourable changes in regulatory deferrals due to the timing of flow-through costs in customer rates. These increases were largely offset by an upfront payment received by FortisAlberta in the fourth quarter of 2020 associated with a long-term energy retailer agreement, and the lower foreign exchange rate in 2021.

Investing Activities

The variance reflects lower capital expenditures in accordance with the Corporation's 2021 Capital Plan.

Financing Activities

See "Cash Flow Summary" on page 28.

SUMMARY OF QUARTERLY RESULTS

Quarter ended	**Revenue** *($ millions)*	**Common Equity Earnings** *($ millions)*	**Basic EPS** *($)*	**Diluted EPS** *($)*
December 31, 2021	**2,583**	**328**	**0.69**	**0.69**
September 30, 2021	**2,196**	**295**	**0.63**	**0.62**
June 30, 2021	**2,130**	**253**	**0.54**	**0.54**
March 31, 2021	**2,539**	**355**	**0.76**	**0.76**
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

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 U.S. 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 significant temperature fluctuations from seasonal norms; (iii) the timing and significance of any regulatory decisions; (iv) changes in the U.S.-to-Canadian dollar exchange rate; (v) any acquisitions and dispositions; (vi) for revenue, the flow through in customer rates of commodity costs; and (vii) for EPS, increases in the weighted average number of common shares outstanding.

December 2021/December 2020

See "Fourth Quarter Results" on page 48.

September 2021/September 2020

Common Equity Earnings and basic EPS were relatively consistent with the same period in 2020. Growth in Common Equity Earnings was tempered by a lower U.S.-to-Canadian dollar exchange rate, unfavourably impacting earnings by $13 million.

Excluding the impact of foreign exchange, Common Equity Earnings increased by $16 million due to: (i) Rate Base growth; (ii) higher sales, largely associated with favourable weather, and the timing of expenditures at FortisAlberta; (iii) continued recovery in the Caribbean from economic conditions experienced in 2020 associated with the COVID-19 Pandemic; and (iv) an adjustment related to the amortization of interest rate swaps at ITC. New customer rates effective January 1, 2021 at TEP also contributed to results. The increase in earnings was partially offset by: (i) lower sales in Arizona due to cooler weather; (ii) realized losses on natural gas contracts at Aitken Creek; and (iii) the delay in Central Hudson's general rate application. The change in basic EPS also reflected an increase in the weighted average number of common shares outstanding, largely associated with the DRIP.

June 2021/June 2020

Common Equity Earnings decreased by $21 million and basic EPS decreased by $0.05 due primarily to: (i) a lower U.S.-to-Canadian dollar exchange rate, resulting in a $24 million unfavourable variance; and (ii) significant one-time items totalling $14 million recognized in the second quarter of 2020. The significant items included an adjustment to ITC's base ROE, partially offset by the finalization of U.S. tax reform and associated regulations.

Excluding the impact of foreign exchange and the one-time items, Common Equity Earnings increased by $17 million due to: (i) Rate Base growth; (ii) higher earnings in Arizona driven by warmer weather and new customer rates at TEP, partially offset by higher operating expenses; and (iii) higher earnings in the Caribbean, reflecting the continued recovery from economic conditions experienced in 2020 associated with the COVID-19 Pandemic. This growth was partially offset by a lower income tax recovery at Corporate and the impact of mark-to-market accounting of natural gas derivatives at Aitken Creek. The change in basic EPS also reflected an increase in weighted average number of common shares outstanding, largely associated with the DRIP.

March 2021/March 2020

Common Equity Earnings increased by $43 million and basic EPS increased by $0.09, due primarily to Rate Base growth, new customer rates at TEP effective January 1, 2021 and higher hydroelectric production in Belize. The impact of losses on retirement investments and foreign exchange contracts recognized in March 2020 at UNS Energy and Corporate, respectively, also favourably impacted the year-over-year change. The increase was partially offset by higher operating expenses mainly related to planned generation maintenance at UNS Energy and unfavourable foreign exchange. The change in basic EPS also reflected an increase in the weighted average number of common shares outstanding, largely associated with the DRIP.

RELATED-PARTY AND INTER-COMPANY TRANSACTIONS

Related-party transactions are in the normal course of operations and are measured at the amount of consideration agreed to by the related parties. There were no material related-party transactions in 2021 or 2020.

Inter-company transactions between non-regulated and regulated entities not eliminated on consolidation include the lease of gas storage capacity and gas sales by Aitken Creek to FortisBC Energy. These transactions did not have a material impact on consolidated earnings, financial position or cash flows.

As at December 31, 2021, accounts receivable included $22 million due from Belize Electricity (2020 - $28 million).

Fortis periodically provides short-term financing, the impacts of which are eliminated on consolidation, to subsidiaries to support capital expenditures, acquisitions and seasonal working capital requirements. In October 2021, Fortis entered into a non-revolving term credit facility with UNS Energy to lend a maximum of US$175 million, maturing December 2022. As at December 31, 2021, inter-segment loans of $126 million were outstanding related to this agreement. Interest charged on inter-segment loans was not material in 2021 and 2020.

MANAGEMENT'S EVALUATION OF CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

DCP are designed to provide reasonable assurance that information required to be disclosed in reports filed with, or submitted to, securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under Canadian and U.S. securities laws. As of December 31, 2021, an evaluation was carried out under the supervision of, and with the participation of, the Corporation's management, including the CEO and CFO, of the effectiveness of the Corporation's DCP, as defined in the applicable Canadian and U.S. securities laws. Based on that evaluation, the CEO and CFO concluded that such DCP are effective as of December 31, 2021.

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

The Corporation's management, including the Corporation's CEO and CFO, assessed the effectiveness of the Corporation's ICFR as of December 31, 2021, 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, 2021, the Corporation's ICFR was effective.

During the year ended December 31, 2021, 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's long-term outlook remains unchanged. 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 2022.

Fortis is executing on the transition to a cleaner energy future and is on plan to achieve its corporate-wide target to reduce carbon emissions by 75% by 2035. Upon achieving this target, 99% of the Corporation's assets will be focused on energy delivery and renewable, carbon-free generation.

The Corporation's $20 billion five-year Capital Plan is expected to increase midyear Rate Base from $31.1 billion in 2021 to $41.6 billion by 2026, translating into a five-year CAGR of approximately 6%. Above and beyond the five-year Capital Plan, Fortis continues to pursue additional energy infrastructure opportunities.

Additional opportunities to expand and extend growth include: further expansion of the electric transmission grid in the U.S. to facilitate the interconnection of cleaner energy including infrastructure investments associated with MISO's long-range transmission plan; natural gas resiliency investments in pipelines and 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".

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: targeted average annual dividend growth through 2025; forecast capital expenditures for 2022-2026; the expectation that the COVID-19 Pandemic will not have a material financial impact in 2022 and will not impact the five-year capital plan; forecast Rate Base and Rate Base growth for 2022 through 2026; the expectation that long-term growth in Rate Base will support earnings and dividend growth; the expectation that Fortis is well positioned to capitalize on evolving industry opportunities, including additional investment opportunities beyond the Capital Plan; the 2035 carbon emission reduction target, how that target is expected to be achieved and the projected asset mix upon achieving the target; the expected timing of updates on climate scenario analysis work; the expected timing for achieving new board diversity targets; the expected timing, outcome and impact of regulatory decisions; the 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 the Corporation's ability to pay dividends in the foreseeable future; the expected consolidated fixed-term debt maturities and repayments over the next five years; the expectation that the Corporation and its subsidiaries will continue to have access to long-term capital and will remain compliant with debt covenants in 2022; the expected uses of proceeds from debt financings; the targeted capital structure; and the nature and expected timing, benefits and costs of certain capital projects including the Multi-Value Regional Transmission Projects, Transmission Conversion Project, Vail-to-Tortolita Project, Lower Mainland Intermediate Pressure System Upgrade, Okanagan Capacity Upgrade, Eagle Mountain Woodfibre Gas Line Project, Transmission Integrity Management Capabilities Project, Inland Gas Upgrades Project, Tilbury 1B Project, Tilbury LNG Storage Expansion, AMI Project, Wataynikaneyap Transmission Power Project and additional opportunities beyond the capital plan.

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 2022 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, including cybersecurity risk; risks related to environmental laws and regulations; the impact of weather variability and seasonality on heating and cooling loads, gas distribution volumes and hydroelectric generation; risks associated with the competitiveness of natural gas; the impact of pandemics and public health crises, including the COVID-19 Pandemic; risks associated with capital projects and the impact on the Corporation's continued growth; risks associated with commodity price volatility and supply of purchased power; and interest rate and foreign exchange risks.

All forward-looking information herein is given as of February 10, 2022. 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

2021 Annual Financial Statements: the Corporation's audited consolidated financial statements and notes thereto for the year ended December 31, 2021

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-U.S. GAAP Financial Measures" on page 24

Adjusted Payout Ratio: dividends per common share divided by Adjusted Basic EPS as shown under "Non-U.S. GAAP Financial Measures" on page 24

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

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

Board: Board of Directors of the Corporation

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 U.S. dollar to Canadian dollar exchange rate

Capital Expenditures: cash outlay for additions to property, plant and equipment and intangible assets as shown in the 2021 Annual Financial Statements, as well as Fortis' 39% share of capital spending for the Wataynikaneyap Transmission Power Project. See "Non-US GAAP Financial Measures" on page 24

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

Caribbean Utilities: Caribbean Utilities Company, Ltd., an indirect approximately 60%-owned (as at December 31, 2021) subsidiary of Fortis, together with its subsidiary

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

CEO: Chief Executive Officer of Fortis

CFO: Chief Financial Officer of Fortis

Common Equity Earnings: net earnings attributable to common equity shareholders

Corporation: Fortis Inc.

COS: cost of service

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

CRMP: Cybersecurity Risk Management Program

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 U.S. dollar-denominated amounts. Foreign exchange is calculated by applying the change in the U.S.-to-Canadian dollar FX rates to the prior period U.S. dollar balance.

GCOC: generic cost of capital

GHG: greenhouse gas

GWh: gigawatt hour(s)

ICFR: internal controls over financial reporting

IESO: Independent Electricity System Operator

IRP: Integrated Resource Plan

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

LIBOR: London Interbank Offered Rate

LNG: liquefied natural gas

LRTP: MISO Long Range Transmission Plan

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

May 2020 FERC Decision: a FERC order issued in May 2020, on rehearing of the FERC's November 2019 decision, increasing the base ROE for ITC's MISO Subsidiaries from that determined in November 2019

MD&A: the Corporation's management discussion and analysis for the year ended December 31, 2021

MISO: Midcontinent Independent System Operator, Inc.

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

MW: megawatt(s)

Navajo: Navajo Generating Station

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

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

NOPR: notice of proposed rulemaking

NYSE: New York Stock Exchange

OEB: Ontario Energy Board

OPEB: other post-employment benefits

Operating Cash Flow: cash from operating activities

PBR: performance-based rate-setting

PJ: petajoule(s)

PSC: New York State Public Service Commission

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

RNG: renewable natural gas

ROA: rate of return on Rate Base

ROE: rate of return on common equity

RTO: regional transmission organization

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

Springerville: Springerville Generating Station

Sundt: H. Wilson Sundt Generating Station

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

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.

U.S.: United States of America

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

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

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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, 2021, 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, 2021, the Corporation's ICFR was effective.

The Corporation's ICFR as of December 31, 2021 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, 2021. Deloitte LLP issued an unqualified opinion for both audits.

February 10, 2022

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

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Fortis Inc. and subsidiaries (the "Corporation") as of December 31, 2021 and 2020, 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, 2021, 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, 2021 and 2020, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2021, 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, 2021, 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 10, 2022, 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.

Deloitte LLP

Deloitte LLP

Chartered Professional Accountants

St. John's, Canada
February 10, 2022

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, 2021, 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, 2021, 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, 2021, of the Corporation and our report dated February 10, 2022, 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.

Deloitte LLP

Deloitte LLP
Chartered Professional Accountants

St. John's, Canada
February 10, 2022

CONSOLIDATED BALANCE SHEETS

FORTIS INC.

As at December 31 (in millions of Canadian dollars)	**2021**	2020
ASSETS		
Current assets		
Cash and cash equivalents	**$ 131**	$ 249
Accounts receivable and other current assets (Note 6)	**1,511**	1,369
Prepaid expenses	**116**	102
Inventories (Note 7)	**478**	422
Regulatory assets (Note 8)	**492**	470
Total current assets	**2,728**	2,612
Other assets (Note 9)	**955**	670
Regulatory assets (Note 8)	**3,097**	3,118
Property, plant and equipment, net (Note 10)	**37,816**	35,998
Intangible assets, net (Note 11)	**1,343**	1,291
Goodwill (Note 12)	**11,720**	11,792
Total assets	**$ 57,659**	$ 55,481
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings (Note 14)	**$ 247**	$ 132
Accounts payable and other current liabilities (Note 13)	**2,570**	2,321
Regulatory liabilities (Note 8)	**357**	441
Current installments of long-term debt (Note 14)	**1,628**	1,254
Total current liabilities	**4,802**	4,148
Regulatory liabilities (Note 8)	**2,865**	2,662
Deferred income taxes (Note 22)	**3,627**	3,344
Long-term debt (Note 14)	**23,707**	23,113
Finance leases (Note 15)	**333**	331
Other liabilities (Note 16)	**1,409**	1,599
Total liabilities	**36,743**	35,197
Commitments and contingencies (Note 26)		
Equity		
Common shares [(1)]	**14,237**	13,819
Preference shares (Note 18)	**1,623**	1,623
Additional paid-in capital	**10**	11
Accumulated other comprehensive (loss) income (Note 19)	**(40)**	34
Retained earnings	**3,458**	3,210
Shareholders' equity	**19,288**	18,697
Non-controlling interests	**1,628**	1,587
Total equity	**20,916**	20,284
Total liabilities and equity	**$ 57,659**	$ 55,481

[(1)] No par value. Unlimited authorized shares. 474.8 million and 466.8 million issued and outstanding as at December 31, 2021 and 2020, respectively

Approved on Behalf of the Board

Douglas J. Haughey,
Director

Maura J. Clark,
Director

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF EARNINGS

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars, except per share amounts)		**2021**		2020
Revenue (Note 5)	**$**	**9,448**	$	8,935
Expenses				
Energy supply costs		**2,951**		2,562
Operating expenses		**2,523**		2,437
Depreciation and amortization		**1,505**		1,428
Total expenses		**6,979**		6,427
Operating income		**2,469**		2,508
Other income, net (Note 21)		**173**		154
Finance charges		**1,003**		1,042
Earnings before income tax expense		**1,639**		1,620
Income tax expense (Note 22)		**234**		231
Net earnings	**$**	**1,405**	$	1,389
Net earnings attributable to:				
Non-controlling interests	**$**	**111**	$	115
Preference equity shareholders		**63**		65
Common equity shareholders		**1,231**		1,209
	$	**1,405**	$	1,389
Earnings per common share (Note 17)				
Basic	**$**	**2.61**	$	2.60
Diluted	**$**	**2.61**	$	2.60

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

For the years ended December 31 (in millions of Canadian dollars)		**2021**		2020
Net earnings	**$**	**1,405**	$	1,389
Other comprehensive loss				
Unrealized foreign currency translation losses, net of hedging activities and income tax expense of $2 million and $3 million, respectively		**(93)**		(311)
Other, net of income tax expense (recovery) of $3 million and $(9) million, respectively		**8**		(27)
		(85)		(338)
Comprehensive income	**$**	**1,320**	$	1,051
Comprehensive income attributable to:				
Non-controlling interests	**$**	**100**	$	79
Preference equity shareholders		**63**		65
Common equity shareholders		**1,157**		907
	$	**1,320**	$	1,051

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

FORTIS INC.

For the year ended December 31 (in millions of Canadian dollars)	**2021**	2020
Operating activities		
Net earnings	**$ 1,405**	$ 1,389
Adjustments to reconcile net earnings to net cash provided by operating activities:		
Depreciation - property, plant and equipment	**1,313**	1,282
Amortization - intangible assets	**136**	131
Amortization - other	**56**	15
Deferred income tax expense (Note 22)	**147**	226
Equity component, allowance for funds used during construction (Note 21)	**(77)**	(78)
Other	**71**	170
Change in working capital (Note 24)	**(144)**	(434)
Cash from operating activities	**2,907**	2,701
Investing activities		
Additions to property, plant and equipment	**(3,189)**	(3,857)
Additions to intangible assets	**(197)**	(182)
Contributions in aid of construction	**93**	68
Other	**(195)**	(161)
Cash used in investing activities	**(3,488)**	(4,132)
Financing activities		
Proceeds from long-term debt, net of issuance costs (Note 14)	**1,324**	3,470
Repayments of long-term debt and finance leases	**(634)**	(1,251)
Borrowings under committed credit facilities	**5,082**	5,648
Repayments under committed credit facilities	**(4,749)**	(5,299)
Net change in short-term borrowings	**115**	(413)
Issue of common shares, net of costs, and dividends reinvested	**60**	58
Dividends		
Common shares, net of dividends reinvested	**(608)**	(786)
Preference shares	**(63)**	(65)
Subsidiary dividends paid to non-controlling interests	**(58)**	(65)
Other	**(18)**	30
Cash from financing activities	**451**	1,327
Effect of exchange rate changes on cash and cash equivalents	**12**	(17)
Change in cash and cash equivalents	**(118)**	(121)
Cash and cash equivalents, beginning of year	**249**	370
Cash and cash equivalents, end of year	**$ 131**	$ 249

Supplementary Cash Flow Information (Note 24)

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars, except share numbers)	**Common Shares** *(# millions)*	**Common Shares**	**Preference Shares** (Note 18)	**Additional Paid-In Capital**	**Accumulated Other Comprehensive Income (Loss)** (Note 19)	**Retained Earnings**	**Non-Controlling Interests**	**Total Equity**
As at December 31, 2020	**466.8**	**$ 13,819**	**$ 1,623**	**$ 11**	**$ 34**	**$ 3,210**	**$ 1,587**	**$ 20,284**
Net earnings	**—**	**—**	**—**	**—**	**—**	**1,294**	**111**	**1,405**
Other comprehensive loss	**—**	**—**	**—**	**—**	**(74)**	**—**	**(11)**	**(85)**
Common shares issued	**8.0**	**418**	**—**	**(2)**	**—**	**—**	**—**	**416**
Subsidiary dividends paid to non-controlling interests	**—**	**—**	**—**	**—**	**—**	**—**	**(58)**	**(58)**
Dividends declared on common shares ($2.08 per share)	**—**	**—**	**—**	**—**	**—**	**(983)**	**—**	**(983)**
Dividends on preference shares	**—**	**—**	**—**	**—**	**—**	**(63)**	**—**	**(63)**
Other	**—**	**—**	**—**	**1**	**—**	**—**	**(1)**	**—**
As at December 31, 2021	**474.8**	**$ 14,237**	**$ 1,623**	**$ 10**	**$ (40)**	**$ 3,458**	**$ 1,628**	**$ 20,916**
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

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 3,485 megawatts ("MW"), including 53 MW of solar capacity and 252 MW of wind capacity. Several generating assets in which they have an interest are jointly owned.

UNS Gas is a regulated gas distribution utility serving retail customers in Arizona's Mohave, Yavapai, Coconino, Navajo and Santa Cruz counties.

Central Hudson: CH Energy Group, Inc., which primarily includes Central Hudson Gas & Electric Corporation. Central Hudson is a regulated electric and gas transmission and distribution utility that serves portions of New York State's Mid-Hudson River Valley and owns gas-fired and hydroelectric generating capacity totalling 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 94 MW. Belize Electricity is an integrated electric utility and the principal distributor of electricity in Belize.

1. DESCRIPTION OF BUSINESS (cont'd)

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.

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 and non-regulated holding company expenses.

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).

2. REGULATION (cont'd)

Nature of Regulation

Regulated Utility	Regulatory Authority	Allowed Common Equity (%)	Allowed ROE [1] (%) 2021	Allowed ROE [1] (%) 2020	Significant Features
ITC [2]	Federal Energy Regulatory Commission ("FERC")	60.0	**10.77**	10.77	Cost-based formula rates, with annual true-up mechanism [3] Incentive adders
TEP	Arizona Corporation Commission ("ACC") [4]	53.0	**9.15**	9.75	COS regulation Historical test year
	FERC	[5]	**[5]**	[5]	Formula transmission rates
UNS Electric	ACC	52.8	**9.50**	9.50	
UNS Gas	ACC	50.8	**9.75**	9.75	
Central Hudson [6]	New York State Public Service Commission ("PSC")	50.0	**9.00**	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 [7]
FortisBC Electric	BCUC	40.0	**9.15**	9.15	Future test year
FortisAlberta	Alberta Utilities Commission ("AUC")	37.0	**8.50**	8.50	PBR [8]
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 [9]	Ontario Energy Board	40.0	**8.52-9.30**	8.52-9.30	COS regulation with incentive mechanisms
Caribbean Utilities [10]	Utility Regulation and Competition Office	N/A	**6.00-8.00**	6.75-8.75	COS regulation Rate-cap adjustment mechanism based on published consumer price indices
FortisTCI [11]	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. See "Significant Regulatory Developments" below*
(3) *Annual true-up collected or refunded in rates within a two-year period*
(4) *Effective January 1, 2021, an approved ROE of 9.15% with a 0.20% return on the fair value increment. The common equity component of capital structure for 2020 was 50%*
(5) *The allowed common equity component for FERC transmission rates is formulaic, and is updated annually based on TEP's actual equity ratio. See "Significant Regulatory Developments" below*
(6) *Allowed common equity percentage is updated annually on July 1st. See "Significant Regulatory Developments" below*
(7) *Formula and incentives have been set through 2024. See "Significant Regulatory Developments" below*
(8) *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. See "Significant Regulatory Developments" below*
(9) *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*
(10) *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*
(11) *Operates under 50-year licences from the Government of the Turks and Caicos Islands, which expire in 2036 and 2037*

Significant Regulatory Developments

ITC

Transmission Incentives: In April 2021, FERC issued a supplemental notice of proposed rulemaking ("NOPR") on transmission incentives modifying the proposal in the initial NOPR released in March 2020. The supplemental NOPR proposes to eliminate the 50-basis point regional transmission organization ("RTO") ROE incentive adder for existing RTO members that have been members longer than three years, like ITC. In June 2021, ITC filed its comments on the supplemental NOPR supporting the continuation of the ROE incentive adder for RTO members. The timeline for FERC to issue a final rule in this proceeding as well as the likely outcome and potential impacts to Fortis cannot be determined at this time.

2. REGULATION (cont'd)

UNS Energy

FERC Rate Case: In 2019, FERC issued an order accepting formula transmission rates proposed by TEP, subject to refund following hearing and settlement procedures. A settlement in principle was reached in August 2021, and a settlement agreement including an ROE of 9.79% was filed with FERC in December 2021. Until conclusion of the proceeding, customer rates continue to be charged under the 2019 FERC order and remain subject to refund pending the final order. The timing and outcome of this proceeding remains unknown.

Central Hudson

General Rate Application: In November 2021, the PSC approved a three-year rate plan for Central Hudson with retroactive application to July 1, 2021, including an ROE of 9.0%, and a common equity component of capital structure of 50% declining by 1% annually to 48% in the third rate year. The three-year rate plan also reflects the use of existing regulatory balances and other measures to reduce customer bill impacts, the recovery of finance charges which had not been billed to customers since the second quarter of 2020, as well as initiatives to support New York State's climate goals.

FortisBC Energy and FortisBC Electric

Generic Cost of Capital ("GCOC") *Proceeding:* In January 2021, the BCUC announced the initiation of a GCOC proceeding including a review of the common equity component of capital structure and the allowed ROE. The timing and outcome of this proceeding, including the effective date of any change in the cost of capital for 2022 or beyond, remains unknown.

FortisAlberta

2022 GCOC Proceeding: In March 2021, the AUC concluded the 2022 GCOC proceeding and extended the existing allowed ROE of 8.5% using a 37% equity component of capital structure through 2022.

2023 COS Application: The final year of FortisAlberta's second PBR term is 2022. In June 2021, the AUC issued a decision confirming the approach to be adopted by Alberta distribution utilities for the COS rebasing year in 2023. In November 2021, FortisAlberta filed its 2023 COS application and a decision is expected in the third quarter of 2022.

2023/2024 GCOC Proceeding: In January 2022, the AUC initiated proceedings to establish the cost of capital parameters for 2023 and to consider a formula-based approach to setting the allowed ROE for 2024 and beyond. The AUC is considering extending the existing allowed ROE of 8.5% using a 37% equity component of capital structure through 2023. Comments on this proposal are due in February 2022 and a decision is expected in the first quarter of 2022. The GCOC proceeding for 2024 and beyond is expected to commence in the third quarter of 2022, with a decision expected in 2023.

Third PBR Term: In July 2021, the AUC issued a decision confirming that Alberta distribution utilities will be subject to a third PBR term commencing in 2024 with going-in rates based on the 2023 COS rebasing. The AUC also initiated a new proceeding to consider the design of the third PBR term. FortisAlberta will submit comments with respect to the design of the third PBR term in 2022 and a decision from the AUC is expected in 2023.

Independent System Operator Tariff Proceeding: In April 2021, the AUC issued a decision confirming that distribution facility owners, such as FortisAlberta, will no longer be permitted to earn a return on contributions made to the Alberta Electric System Operator ("AESO") on a prospective basis from the date of the decision. Contributions made prior to that date are not impacted. The decision did not have a material financial impact on the Corporation in 2021 and it is not expected to materially impact future periods. In January 2022, the Alberta Court of Appeal granted a full appeal on this matter. In doing so, the Alberta Court of Appeal also permitted a related appeal regarding the legality of the AUC's AESO customer contribution policy. FortisAlberta will fully participate in the appeal regarding the legality of the AESO customer contribution policy and will closely monitor the preceding related to earned returns on future AESO contributions.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

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

These consolidated financial statements include the accounts of the Corporation and its subsidiaries. They reflect the equity method of accounting for entities in which Fortis has significant influence, but not control, and proportionate consolidation for assets that are jointly owned with non-affiliated entities. Intercompany transactions have been eliminated, except for transactions between non-regulated and regulated entities in accordance with U.S. 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.

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

Allowance for Credit Losses

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

Inventories

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

Regulatory Assets and Liabilities

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

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

Investments

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

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

Through methodologies established by their respective regulators, the Corporation's regulated utilities capitalize: (i) overhead costs that are not directly attributable to specific PPE but relate to the overall capital expenditure plan; and (ii) an allowance for funds used during construction ("AFUDC"). The debt component of AFUDC for 2021 totalled $39 million (2020 - $41 million) and is reported as a reduction of finance charges and the equity component is reported as other income (Note 21). Both components are recorded to earnings through depreciation expense over the estimated service lives of the applicable PPE.

At FortisAlberta, through December 31, 2020, the cost of PPE includes contributions to AESO toward funding the construction of transmission facilities (Note 2).

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

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

PPE is depreciated using the straight-line method based on the estimated service lives of the assets. Depreciation rates for regulated PPE are approved by the respective regulators. Depreciation rates for 2021 ranged from 0.9% to 39.8% (2020 - 0.9% to 39.8%). The weighted average composite rate of depreciation, before reduction for amortization of contributions in aid of construction, was 2.6% for 2021 (2020 – 2.5%).

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

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

	2021		2020	
(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**	18-95	38
Transmission				
Electric	**20-90**	**42**	20-90	43
Gas	**10-85**	**35**	10-85	35
Generation	**5-95**	**23**	1-85	24
Other	**3-70**	**13**	2-70	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 2021 (2020 – 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.

	2021		2020	
(years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Computer software	**3-15**	**4**	3-15	4
Land, transmission and water rights	**34-90**	**55**	43-90	56
Other	**10-100**	**11**	10-100	12

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

Impairment of Long-Lived Assets

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

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

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 U.S. GAAP and those recovered from customers in current rates is subject to deferral account treatment and is expected to be recovered from, or refunded to, customers in future rates (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.

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

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 probable.

Revenue excludes sales and municipal taxes collected from customers.

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

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 and PSUs, as well as RSUs issued through 2019 represent cash-settled awards. Effective January 1, 2020, new RSU issuances represent cash or share-settled awards, depending on settlement elections and the 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, 2021 was $61.08 (2020 - $52.36). 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 U.S. dollar functional currency, are translated at the exchange rate in effect at the balance sheet date and the resultant unrealized translation gains and losses are recognized in accumulated other comprehensive income. The exchange rate as at December 31, 2021 was US$1.00=CA$1.26 (2020 – US$1.00=CA$1.27).

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$1.25 for 2021 (2020 - US$1.00=CA$1.34).

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.

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

Derivatives and Hedging

Derivatives Not Designated as Hedges

Derivatives not designated as hedges are used by: (i) Fortis, to manage cash flow risk associated with forecast U.S. dollar cash inflows and forecast future cash settlements of DSU, PSU and RSU obligations; (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.

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

Presentation of Derivatives

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

Income Taxes

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

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

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

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

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 $4.1 billion as at December 31, 2021 (2020 - $3.4 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.

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

Asset Retirement Obligations

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

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

Contingencies

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

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

Use of Accounting Estimates

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

Future Accounting Pronouncements

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

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 2021 or 2020.

The lease of gas storage capacity and gas sales from Aitken Creek to FortisBC Energy of $38 million in 2021 (2020 - $25 million) are inter-company transactions between non-regulated and regulated entities, which were not eliminated on consolidation.

As at December 31, 2021, accounts receivable included $22 million due from Belize Electricity (2020 - $28 million).

Fortis periodically provides short-term financing, the impacts of which are eliminated on consolidation, to subsidiaries to support capital expenditures, acquisitions and seasonal working capital requirements. In October 2021, Fortis entered into a non-revolving term credit facility with UNS Energy to lend a maximum of US$175 million, maturing December 2022. As at December 31, 2021, inter-segment loans of $126 million were outstanding related to this agreement. Interest charged on inter-segment loans was not material in 2021 and 2020 .

4. SEGMENTED INFORMATION (cont'd)

	Regulated								Non-Regulated			
($ millions)	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**
Year ended December 31, 2021												
Revenue	1,691	2,334	1,000	1,715	644	468	1,498	**9,350**	**98**	**—**	**—**	**9,448**
Energy supply costs	—	919	285	713	—	136	895	**2,948**	**3**	**—**	**—**	**2,951**
Operating expenses	466	648	498	355	157	128	201	**2,453**	**33**	**37**	**—**	**2,523**
Depreciation and amortization	291	345	91	281	231	65	181	**1,485**	**17**	**3**	**—**	**1,505**
Operating income	934	422	126	366	256	139	221	**2,464**	**45**	**(40)**	**—**	**2,469**
Other income, net	42	41	34	12	2	5	5	**141**	**1**	**31**	**—**	**173**
Finance charges	300	120	46	144	106	73	71	**860**	**—**	**143**	**—**	**1,003**
Income tax expense	156	51	21	48	11	12	21	**320**	**8**	**(94)**	**—**	**234**
Net earnings	520	292	93	186	141	59	134	**1,425**	**38**	**(58)**	**—**	**1,405**
Non-controlling interests	94	—	—	1	—	—	16	**111**	**—**	**—**	**—**	**111**
Preference share dividends	—	—	—	—	—	—	—	**—**	**—**	**63**	**—**	**63**
Net earnings attributable to common equity shareholders	426	292	93	185	141	59	118	**1,314**	**38**	**(121)**	**—**	**1,231**
Additions to property, plant and equipment and intangible assets	1,046	710	291	475	389	134	321	**3,366**	**20**	**—**	**—**	**3,386**
As at December 31, 2021												
Goodwill	7,755	1,746	570	913	228	235	246	**11,693**	**27**	**—**	**—**	**11,720**
Total assets	21,020	11,126	4,356	8,135	5,201	2,540	4,357	**56,735**	**777**	**295**	**(148)**	**57,659**
Year ended December 31, 2020												
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
Additions to property, plant and equipment and intangible assets	1,182	1,200	339	471	420	135	273	4,020	19	—	—	4,039
As at December 31, 2020												
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

5. REVENUE

($ millions)	**2021**	2020
Electric and gas revenue		
United States		
ITC	**1,694**	1,726
UNS Energy	**2,071**	2,019
Central Hudson	**962**	941
Canada		
FortisBC Energy	**1,645**	1,336
FortisAlberta	**622**	580
FortisBC Electric	**404**	358
Newfoundland Power	**701**	707
Maritime Electric	**223**	215
FortisOntario	**211**	222
Caribbean		
Caribbean Utilities	**248**	238
FortisTCI	**89**	77
Total electric and gas revenue	**8,870**	8,419
Other services revenue (1)	**382**	325
Revenue from contracts with customers	**9,252**	8,744
Alternative revenue (2)	**(18)**	64
Other revenue	**214**	127
Total revenue	**9,448**	8,935

(1) *Includes $260 million and $227 million from regulated operations for 2021 and 2020, respectively*
(2) *2020 includes a $40 million favourable base ROE adjustment associated with the May 2020 FERC decision, which set the all-in ROE for ITC's subsidiaries operating in the Midcontinent Independent System Operator, Inc. "MISO" region at 10.77%*

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. This mechanism is in place until the expiry of the current multi-year rate plan in 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, as well as regulatory deferrals at FortisBC Energy and FortisBC Electric reflecting cost recovery variances from forecast.

6. ACCOUNTS RECEIVABLE AND OTHER CURRENT ASSETS

($ millions)	**2021**	2020
Trade accounts receivable	**621**	595
Unbilled accounts receivable	**701**	571
Allowance for credit losses	**(53)**	(64)
	1,269	1,102
Income tax receivable	**—**	72
Other [(1)]	**242**	195
	1,511	1,369

[(1)] *Consists mainly of customer billings for non-core services, gas mitigation costs and collateral deposits for gas purchases, and the fair value of derivative instruments (Note 25)*

Allowance for Credit Losses

The allowance for credit losses changed as follows.

($ millions)	**2021**	2020
Balance, beginning of year	**(64)**	(35)
Credit loss expensed	**(7)**	(36)
Credit loss deferral	**—**	(6)
Write-offs, net of recoveries	**18**	14
Foreign exchange	**—**	(1)
Balance, end of year	**(53)**	(64)

7. INVENTORIES

($ millions)	**2021**	2020
Materials and supplies	**318**	297
Gas and fuel in storage	**131**	101
Coal inventory	**29**	24
	478	422

8. REGULATORY ASSETS AND LIABILITIES

($ millions)	**2021**	2020
Regulatory assets		
Deferred income taxes (Notes 3 and 22)	**1,806**	1,697
Employee future benefits (Notes 3 and 23)	**388**	588
Deferred energy management costs [(1)]	**384**	334
Rate stabilization and related accounts [(2)]	**339**	213
Deferred lease costs [(3)]	**127**	122
Manufactured gas plant site remediation deferral (Note 16)	**96**	107
Generation early retirement costs [(4)]	**48**	55
Derivatives (Notes 3 and 25)	**20**	73
Other regulatory assets [(5)]	**381**	399
Total regulatory assets	**3,589**	3,588
Less: Current portion	**(492)**	(470)
Long-term regulatory assets	**3,097**	3,118
Regulatory liabilities		
Deferred income taxes (Notes 3 and 22)	**1,289**	1,361
Future cost of removal (Note 3)	**1,217**	1,206
Employee future benefits (Notes 3 and 23)	**196**	43
Rate stabilization and related accounts [(2)]	**116**	104
Renewable energy surcharge [(6)]	**107**	100
Energy efficiency liability [(7)]	**83**	83
Derivatives (Notes 3 and 25)	**52**	17
Other regulatory liabilities [(5)]	**162**	189
Total regulatory liabilities	**3,222**	3,103
Less: Current portion	**(357)**	(441)
Long-term regulatory liabilities	**2,865**	2,662

(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. In 2020, the ACC approved the recovery of the retirement costs of Navajo and Sundt over a 10-year period.

(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.

8. REGULATORY ASSETS AND LIABILITIES (cont'd)

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.

Regulatory assets not earning a return: (i) totalled $1,727 million and $1,678 million as at December 31, 2021 and 2020, respectively; (ii) are primarily related to deferred income taxes and employee future benefits; and (iii) generally do not represent a past cash outlay as they are offset by related liabilities that, likewise, do not incur a carrying cost for rate-making purposes. Recovery periods vary or are yet to be determined by the respective regulators.

9. OTHER ASSETS

($ millions)	**2021**	2020
Employee future benefits (Note 23)	**259**	66
Supplemental Executive Retirement Plan ("SERP")	**165**	155
RECs (Note 8)	**112**	106
Other investments	**86**	66
Equity investment - Belize Electricity	**80**	80
Deferred compensation plan	**42**	36
Operating leases (Note 15)	**40**	40
Derivatives	**40**	4
Equity investment - Wataynikaneyap Partnership	**12**	12
Other	**119**	105
	955	670

ITC, UNS Energy and Central Hudson provide additional post-employment benefits through SERPs and deferred compensation plans for directors and officers. The assets held to support these plans are reported separately from the related liabilities (Note 16). Most plan assets are held in trust and funded mainly through life insurance policies and mutual funds. Assets in mutual and money market funds are recorded at fair value on a recurring basis (Note 25).

10. PROPERTY, PLANT AND EQUIPMENT

($ millions)	**Cost**	**Accumulated Depreciation**	**Net Book Value**
2021			
Distribution			
Electric	**12,321**	**(3,359)**	**8,962**
Gas	**5,838**	**(1,504)**	**4,334**
Transmission			
Electric	**17,104**	**(3,610)**	**13,494**
Gas	**2,453**	**(756)**	**1,697**
Generation	**7,014**	**(2,691)**	**4,323**
Other	**4,362**	**(1,454)**	**2,908**
Assets under construction	**1,759**	**—**	**1,759**
Land	**339**	**—**	**339**
	51,190	**(13,374)**	**37,816**

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

($ 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

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 assets associated with natural gas storage at Aitken Creek.

As at December 31, 2021, assets under construction largely reflect ongoing transmission projects at ITC and UNS Energy.

The cost of PPE under finance lease as at December 31, 2021 was $323 million (2020 - $322 million) and related accumulated depreciation was $113 million (2020 - $111 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, 2021, interests in jointly owned facilities consisted of the following.

($ millions, except as indicated)	Ownership (%)	Cost	Accumulated Depreciation	Net Book Value
Transmission Facilities	1.0-80.0	**958**	**(290)**	**668**
Springerville Common Facilities	86.0	**504**	**(262)**	**242**
San Juan Unit 1 ("San Juan")	50.0	**361**	**(340)**	**21**
Springerville Coal Handling Facilities	83.0	**264**	**(120)**	**144**
Four Corners Units 4 and 5 ("Four Corners")	7.0	**243**	**(102)**	**141**
Gila River Common Facilities	50.0	**109**	**(38)**	**71**
Luna Energy Facility ("Luna")	33.3	**76**	**(4)**	**72**
		2,515	**(1,156)**	**1,359**

11. INTANGIBLE ASSETS

($ millions)	Cost	Accumulated Amortization	Net Book Value
2021			
Computer software	**952**	**(518)**	**434**
Land, transmission and water rights	**941**	**(154)**	**787**
Other	**113**	**(69)**	**44**
Assets under construction	**78**	**—**	**78**
	2,084	**(741)**	**1,343**
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

Included in the cost of land, transmission and water rights as at December 31, 2021 was $137 million (2020 - $136 million) not subject to amortization. Amortization expense was $136 million for 2021 (2020 - $131 million). Amortization is estimated to average approximately $82 million for each of the next five years.

12. GOODWILL

($ millions)	2021	2020
Balance, beginning of year	**11,792**	12,004
Foreign currency translation impacts (1)	**(72)**	(212)
Balance, end of year	**11,720**	11,792

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

No goodwill impairment was recognized by the Corporation in 2021 or 2020.

13. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

($ millions)	2021	2020
Trade accounts payable	**774**	707
Employee compensation and benefits payable	**283**	248
Gas and fuel cost payable	**269**	188
Dividends payable	**259**	241
Accrued taxes other than income taxes	**238**	224
Customer and other deposits	**222**	214
Interest payable	**218**	215
Derivatives (Note 25)	**43**	56
Income taxes payable	**31**	—
Employee future benefits (Note 23)	**26**	26
Manufactured gas plant site remediation (Note 16)	**13**	31
Other	**194**	171
	2,570	2,321

14. LONG-TERM DEBT

($ millions)	Maturity Date	**2021**	2020
ITC			
Secured U.S. First Mortgage Bonds - 4.31% weighted average fixed rate (2020 - 4.31%)	2024-2055	**2,736**	2,755
Secured U.S. Senior Notes - 3.90% weighted average fixed rate (2020 - 4.00%)	2040-2055	**1,011**	923
Unsecured U.S. Senior Notes - 3.61% weighted average fixed rate (2020 - 3.61%)	2022-2043	**4,108**	4,136
Unsecured U.S. Shareholder Note - 6.00% fixed rate (2020 - 6.00%)	2028	**252**	253
UNS Energy			
Unsecured U.S. Tax-Exempt Bonds - 4.34% weighted average fixed and variable rate (2020 - 4.34%)	2029-2030	**359**	362
Unsecured U.S. Fixed Rate Notes - 3.62% weighted average fixed rate (2020 - 3.86%)	2023-2051	**2,780**	2,704
Central Hudson			
Unsecured U.S. Promissory Notes - 3.83% weighted average fixed and variable rate (2020 - 3.94%)	2022-2060	**1,177**	1,078
FortisBC Energy			
Unsecured Debentures - 4.61% weighted average fixed rate (2020 - 4.72%)	2026-2050	**3,145**	2,995
FortisAlberta			
Unsecured Debentures - 4.49% weighted average fixed rate (2020 - 4.49%)	2024-2052	**2,360**	2,360
FortisBC Electric			
Secured Debentures - 8.80% fixed rate (2020 - 8.80%)	2023	**25**	25
Unsecured Debentures - 4.77% weighted average fixed rate (2020 - 4.87%)	2035-2050	**760**	785
Other Electric			
Secured First Mortgage Sinking Fund Bonds - 5.61% weighted average fixed rate (2020 - 5.61%)	2022-2060	**627**	634
Secured First Mortgage Bonds - 5.31% weighted average fixed rate (2020 - 5.66%)	2025-2061	**260**	220
Unsecured Senior Notes - 4.45% weighted average fixed rate (2020 - 4.45%)	2041-2048	**152**	152
Unsecured U.S. Senior Loan Notes and Bonds - 4.36% weighted average fixed and variable rate (2020 - 4.41%)	2022-2049	**609**	648
Corporate and Other			
Unsecured U.S. Senior Notes and Promissory Notes - 3.82% weighted average fixed rate (2020 - 3.81%)	2023-2044	**2,509**	2,685
Unsecured Debentures - 6.50% fixed rate (2020 - 6.50%)	2039	**200**	200
Unsecured Senior Notes - 2.52% weighted average fixed rate (2020 - 2.85%)	2023-2028	**1,000**	500
Long-term classification of credit facility borrowings		**1,305**	980
Fair value adjustment - ITC acquisition		**107**	119
Total long-term debt (Note 25)		**25,482**	24,514
Less: Deferred financing costs and debt discounts		**(147)**	(147)
Less: Current installments of long-term debt		**(1,628)**	(1,254)
		23,707	23,113

14. LONG-TERM DEBT (cont'd)

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 restricted payments, including special or extraordinary dividends, if immediately thereafter its consolidated debt to consolidated capitalization ratio would exceed 65%.

Long-Term Debt Issuances in 2021	Month Issued	Interest Rate (%)	Maturity		Amount ($ millions)	Use of Proceeds
ITC						
Series A secured senior notes [1]	August	2.90	2051	**US**	**75**	[2]
UNS Energy						
Unsecured senior notes	May	3.25	2051	**US**	**325**	[3][4]
Central Hudson						
Unsecured senior notes	March	3.29	2051	**US**	**75**	[3][4]
Unsecured senior notes	October	3.22	2051	**US**	**55**	[3][5]
FortisBC Energy						
Unsecured debentures	April	2.42	2031		**150**	[5]
Maritime Electric						
Secured first mortgage bonds	December	3.40	2051		**40**	[5]
Fortis						
Unsecured senior notes	May	2.18	2028		**500**	[3][4][5]

(1) *US$75 million Series B secured senior notes were priced at 3.05% with issuance expected in May 2022*
(2) *Fund or refinance a portfolio of eligible green projects*
(3) *General corporate purposes*
(4) *Repay maturing long-term debt*
(5) *Repay credit facility borrowings*

In January 2022, ITC issued 30-year US$150 million secured first mortgage bonds at 2.93%. The net proceeds are expected to be used to repay credit facility borrowings, fund or refinance a portfolio of eligible green projects, fund capital expenditures and for other general corporate purposes.

In January 2022, Central Hudson issued 5-year US$50 million unsecured senior notes at 2.37% and 7-year US$60 million unsecured senior notes at 2.59%. The net proceeds are expected to be used to repay maturing long-term debt and for general corporate purposes.

Long-Term Debt Repayments

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

($ millions)	**Total**
2022	1,628
2023	1,275
2024	1,750
2025	101
2026	2,595
Thereafter	18,133
	25,482

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. In May 2021, the Corporation issued $500 million unsecured senior notes as shown above and, as at December 31, 2021, $1.5 billion remained available under the short-form base shelf prospectus.

14. LONG-TERM DEBT (cont'd)

Credit Facilities

($ millions)	Regulated Utilities	Corporate and Other	2021	2020
Total credit facilities	3,466	1,380	**4,846**	5,581
Credit facilities utilized:				
Short-term borrowings (1)	(247)	—	**(247)**	(132)
Long-term debt (including current portion) (2)	(1,019)	(286)	**(1,305)**	(980)
Letters of credit outstanding	(70)	(45)	**(115)**	(130)
Credit facilities unutilized	2,130	1,049	**3,179**	4,339

(1) *The weighted average interest rate was approximately 0.6% (2020 - 0.8%).*
(2) *The weighted average interest rate was approximately 0.9% (2020 - 0.9%). The current portion was $888 million (2020 - $651 million).*

Credit facilities are syndicated primarily with large banks in Canada and the U.S., with no one bank holding more than approximately 20% of the total facilities. Approximately $4.6 billion of the total credit facilities are committed facilities with maturities ranging from 2022 through 2026.

Consolidated credit facilities of approximately $4.8 billion as at December 31, 2021 are itemized below. In April 2021, the Corporation's unsecured $500 million revolving one-year term committed credit facility expired and was not renewed. In October 2021, UNS Energy terminated a US$150 million revolving credit facility and entered into an arrangement with Fortis (Note 4).

($ millions)		Amount	Maturity
Unsecured committed revolving credit facilities			
Regulated utilities			
ITC (1)	**US**	**900**	2024
UNS Energy	**US**	**375**	2026
Central Hudson	**US**	**200**	2025
FortisBC Energy		**700**	2026
FortisAlberta		**250**	2026
FortisBC Electric		**150**	2026
Other Electric		**215**	(2)
Other Electric	**US**	**70**	2025
Corporate and Other		**1,350**	(3)
Other facilities			
Regulated utilities			
Central Hudson - uncommitted credit facility	**US**	**30**	n/a
FortisBC Energy - uncommitted credit facility		**55**	2023
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**	2022
Corporate and Other - unsecured non-revolving facility		**30**	n/a

(1) *ITC also has a US$400 million commercial paper program, under which US$155 million was outstanding as at December 31, 2021 (2020 - US$67 million) , as reported in short-term borrowings.*
(2) *$50 million in 2024, $65 million in 2024 and $100 million in 2026*
(3) *$50 million in 2023 and $1.3 billion in 2026*

15. LEASES

The Corporation and its subsidiaries lease office facilities, utility equipment, land, and communication tower space with remaining terms of up to 20 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 34 years.

Leases were presented on the consolidated balance sheets as follows.

($ millions)	**2021**	2020
Operating leases		
Other assets	**40**	40
Accounts payable and other current liabilities	**(8)**	(7)
Other liabilities	**(32)**	(33)
Finance leases [(1)]		
Regulatory assets	**127**	122
PPE, net	**210**	211
Accounts payable and other current liabilities	**(4)**	(2)
Finance leases	**(333)**	(331)

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

The components of lease expense were as follows.

($ millions)	**2021**	2020
Operating lease cost	**8**	10
Finance lease cost:		
Amortization	**2**	14
Interest	**32**	34
Variable lease cost	**19**	20
Total lease cost	**61**	78

As at December 31, 2021, the present value of minimum lease payments was as follows.

($ millions)	Operating Leases	Finance Leases	**Total**
2022	8	35	**43**
2023	7	34	**41**
2024	6	34	**40**
2025	5	34	**39**
2026	3	35	**38**
Thereafter	20	1,030	**1,050**
	49	1,202	**1,251**
Less: Imputed interest	(9)	(865)	**(874)**
Total lease obligations	40	337	**377**
Less: Current installments	(8)	(4)	**(12)**
	32	333	**365**

15. LEASES (cont'd)

Supplemental lease information follows.

($ millions, except as indicated)	**2021**	2020
Weighted average remaining lease term *(years)*		
Operating leases	**10**	10
Finance leases	**34**	35
Weighted average discount rate *(%)*		
Operating leases	**3.8**	4.0
Finance leases	**5.1**	5.1
Cash payments related to lease liabilities		
Operating cash flows used for operating leases	**(8)**	(10)
Operating cash flows used for finance leases	**—**	(2)
Financing cash flows used for finance leases	**(2)**	(25)
Investing cash flows used for finance leases	**—**	(87)

16. OTHER LIABILITIES

($ millions)	**2021**	2020
Employee future benefits (Note 23)	**740**	905
AROs (Note 3)	**184**	130
Customer and other deposits	**99**	132
Stock-based compensation plans (Note 20)	**96**	86
Manufactured gas plant site remediation [(1)]	**83**	69
Deferred compensation plan (Note 9)	**50**	43
Mine reclamation obligations [(2)]	**44**	47
Retail energy contract [(3)]	**40**	46
Operating leases	**32**	33
Derivatives (Note 25)	**7**	50
Other	**34**	58
	1,409	1,599

(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, 2021, an obligation of $91 million was recognized, including a current portion of $8 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 $56 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) In 2020, 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 which is being amortized to revenue over the life of the agreement.

17. EARNINGS PER COMMON SHARE

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

	2021			2020		
	Net Earnings to Common Shareholders	**Weighted Average Shares**	**EPS**	Net Earnings to Common Shareholders	Weighted Average Shares	EPS
	($ millions)	*(# millions)*	*($)*	*($ millions)*	*(# millions)*	*($)*
Basic EPS	**1,231**	**470.9**	**2.61**	1,209	464.8	2.60
Potential dilutive effect of stock options	**—**	**0.5**	**—**	—	0.6	—
Diluted EPS	**1,231**	**471.4**	**2.61**	1,209	465.4	2.60

18. PREFERENCE SHARES

Authorized

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

Issued and Outstanding

	2021		2020	
	Number of Shares	**Amount**	Number of Shares	Amount
First Preference Shares	*(thousands)*	*($ millions)*	*(thousands)*	*($ millions)*
Series F	**5,000**	**122**	5,000	122
Series G	**9,200**	**225**	9,200	225
Series H	**7,665**	**188**	7,665	188
Series I	**2,335**	**57**	2,335	57
Series J	**8,000**	**196**	8,000	196
Series K	**10,000**	**244**	10,000	244
Series M	**24,000**	**591**	24,000	591
	66,200	**1,623**	66,200	1,623

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	4.75	1.1875	—	Currently Redeemable	25.00	—
Fixed rate reset [(3) (4)]						
Series G	5.25	1.0983	2.13	September 1, 2023	25.00	—
Series H [(5)]	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 [(4) (6)]						
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) *On the redemption and/or conversion option date, and on each five-year anniversary thereafter, the reset annual dividend per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date, plus the applicable reset dividend yield.*

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

(5) *The 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.*

(6) *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.*

18. PREFERENCE SHARES *(cont'd)*

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.

19. ACCUMULATED OTHER COMPREHENSIVE INCOME

($ millions)	Opening Balance	Net Change	Ending Balance
2021			
Unrealized foreign currency translation gains (losses)			
Net investments in foreign operations	**377**	**(104)**	**273**
Hedges of net investments in foreign operations	**(299)**	**23**	**(276)**
Income tax expense	**(6)**	**(2)**	**(8)**
	72	**(83)**	**(11)**
Other			
Cash flow hedges (Note 25)	**(4)**	**(1)**	**(5)**
Unrealized employee future benefits (losses) gains (Note 23)	**(49)**	**13**	**(36)**
Income tax recovery (expense)	**15**	**(3)**	**12**
	(38)	**9**	**(29)**
Accumulated other comprehensive income	**34**	**(74)**	**(40)**
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 25)	17	(21)	(4)
Unrealized employee future benefits losses (Note 23)	(38)	(11)	(49)
Income tax recovery	6	9	15
	(15)	(23)	(38)
Accumulated other comprehensive income	336	(302)	34

20. 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.

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

The following options were granted in 2021 and 2020.

	2021	2020
Options granted *(thousands)*	**431**	686
Exercise price *($)* (1)	**50.33**	58.40
Grant date fair value *($)*	**4.91**	4.20
Valuation assumptions:		
Dividend yield *(%)* (2)	**3.8**	3.7
Expected volatility *(%)* (3)	**20.0**	15.8
Risk-free interest rate *(%)* (4)	**0.9**	1.2
Weighted average expected life *(years)* (5)	**5.0**	5.2

(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 2021.

	Total Options		**Non-vested Options** (1)	
(thousands, except as indicated)	**Number of Options**	**Weighted Average Exercise Price** *($)*	**Number of Options**	**Weighted Average Grant Date Fair Value** *($)*
Options outstanding, beginning of year	**3,262**	**45.26**	**1,772**	**3.81**
Granted	**431**	**50.33**	**431**	**4.91**
Exercised	**(777)**	**40.80**	**n/a**	**n/a**
Vested	**n/a**	**n/a**	**(715)**	**3.67**
Cancelled/Forfeited	**—**	**—**	**—**	**—**
Options outstanding, end of year	**2,916**	**47.20**	**1,488**	**4.20**
Options vested, end of year (2)	**1,428**	**42.76**		

(1) *As at December 31, 2021, there was $6 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, 2021, the weighted average remaining term of vested options was six years with an aggregate intrinsic value of $26 million.*

The following table summarizes additional stock option information.

($ millions)	2021	2020
Stock options exercised:		
Cash received for exercise price	**32**	32
Intrinsic value realized by employees	**11**	15

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.

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

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.

	2021	2020
Number of units *(thousands)*		
Beginning of year	**147**	165
Granted	**30**	25
Notional dividends reinvested	**6**	6
Paid out	**—**	(49)
End of year	**183**	147

The accrued liability has been recognized at the respective December 31st VWAP (Note 3) and included in other liabilities (Note 16). The accrued liability, compensation expense and cash payout were not material for 2021 or 2020.

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 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.

	2021	2020
Number of units *(thousands)*		
Beginning of year	**1,976**	2,118
Granted	**587**	586
Notional dividends reinvested	**60**	71
Paid out	**(697)**	(735)
Cancelled/forfeited	**(28)**	(64)
End of year	**1,898**	1,976
Additional information *($ millions)*		
Compensation expense recognized	**74**	58
Compensation expense unrecognized (1)	**33**	32
Cash payout	**50**	54
Accrued liability as at December 31 (2)	**132**	108
Aggregate intrinsic value as at December 31 (3)	**165**	140

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

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

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. Effective January 1, 2020, new RSU issuances 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.

	2021	2020
Number of units *(thousands)*		
Beginning of year	**1,048**	1,050
Granted	**378**	356
Notional dividends reinvested	**32**	37
Paid out	**(371)**	(355)
Cancelled/forfeited	**(27)**	(40)
End of year	**1,060**	1,048
Additional information *($ millions)*		
Compensation expense recognized	**26**	20
Compensation expense unrecognized [(1)]	**17**	15
Cash payout	**21**	19
Accrued liability as at December 31 [(2)]	**46**	39
Aggregate intrinsic value as at December 31 [(3)]	**63**	54

[(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*

21. OTHER INCOME, NET

($ millions)	**2021**	2020
Equity component of AFUDC	**77**	78
Non-service benefit cost	**45**	31
Derivative gains	**30**	13
Equity income	**7**	20
Interest income	**5**	13
Other	**9**	(1)
	173	154

22. INCOME TAXES

Deferred Income Tax Assets and Liabilities

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

($ millions)	**2021**	2020
Gross deferred income tax assets		
Regulatory liabilities	**560**	527
Tax loss and credit carryforwards	**556**	494
Employee future benefits	**169**	175
Other	**91**	116
	1,376	1,312
Valuation allowance	**(23)**	(22)
Net deferred income tax asset	**1,353**	1,290
Gross deferred income tax liabilities		
PPE	**(4,571)**	(4,253)
Regulatory assets	**(283)**	(263)
Intangible assets	**(126)**	(118)
	(4,980)	(4,634)
Net deferred income tax liability	**(3,627)**	(3,344)

Unrecognized Tax Benefits

($ millions)	**2021**	2020
Beginning of year	**33**	36
Additions related to current year	**2**	3
Adjustments related to prior years [1]	**(33)**	(6)
End of year	**2**	33

(i) UNS Energy received approval from the Internal Revenue Service to change its accounting method related to an uncertain tax position which resulted in a decrease in uncertain tax benefits..

Unrecognized tax benefits, if recognized, would reduce income tax expense by $1 million in 2021. Fortis has not recognized interest expense in 2021 and 2020 related to unrecognized tax benefits.

Income Tax Expense

($ millions)	**2021**	2020
Canadian		
Earnings before income tax expense	**427**	333
Current income tax	**84**	20
Deferred income tax	**(35)**	(16)
Total Canadian	**49**	4
Foreign		
Earnings before income tax expense	**1,212**	1,287
Current income tax	**3**	(15)
Deferred income tax	**182**	242
Total Foreign	**185**	227
Income tax expense	**234**	231

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.

22. INCOME TAXES (cont'd)

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

($ millions, except as indicated)	**2021**	2020
Earnings before income tax expense	**1,639**	1,620
Combined Canadian federal and provincial statutory income tax rate *(%)*	**30.0**	30.0
Expected federal and provincial taxes at statutory rate	**492**	486
Decrease resulting from:		
Foreign and other statutory rate differentials	**(157)**	(145)
AFUDC	**(16)**	(20)
Effects of rate-regulated accounting:		
Difference between depreciation claimed for income tax and accounting purposes	**(47)**	(56)
Items capitalized for accounting purposes but expensed for income tax purposes	**(13)**	(26)
Other	**(25)**	(8)
Income tax expense	**234**	231
Effective tax rate *(%)*	**14.3**	14.3

Income Tax Carryforwards

($ millions)	Expiring Year	**2021**
Canadian		
Capital loss	n/a	**15**
Non-capital loss	2028-2041	**308**
Other tax credits	2026-2041	**2**
		325
Unrecognized		**(15)**
		310
Foreign		
Federal and state net operating loss	2022-2041	**3,070**
Other tax credits	2023-2041	**90**
		3,160
Total income tax carryforwards recognized		**3,470**

The Corporation and certain of its subsidiaries are subject to taxation in Canada, the United States and other foreign jurisdictions. The material jurisdictions in which the Corporation is subject to potential income tax compliance examinations include the United States (Federal, Arizona, Kansas, Iowa, Michigan, Minnesota and New York) and Canada (Federal, British Columbia and Alberta). The Corporation's 2013 to 2021 taxation years are still open for audit in Canadian jurisdictions, and its 2011 to 2021 taxation years are still open for audit in United States jurisdictions.

23. 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, 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; December 31, 2020 for the Corporation; and December 31, 2021 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.

23. EMPLOYEE FUTURE BENEFITS (cont'd)

Allocation of Plan Assets

(weighted average %)	**2021 Target Allocation**	**2021**	2020
Equities	**47**	**48**	48
Fixed income	**46**	**45**	45
Real estate	**6**	**6**	6
Cash and other	**1**	**1**	1
	100	**100**	100

Fair Value of Plan Assets

($ millions)	**Level 1** [(1)]	**Level 2** [(1)]	**Level 3** [(1)]	**Total**
2021				
Equities	**749**	**1,271**	**—**	**2,020**
Fixed income	**219**	**1,642**	**—**	**1,861**
Real estate	**—**	**—**	**235**	**235**
Private equities	**—**	**—**	**21**	**21**
Cash and other	**10**	**15**	**—**	**25**
	978	**2,928**	**256**	**4,162**
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

(1) *See Note 25 for a description of the fair value hierarchy.*

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

($ millions)	**2021**	2020
Balance, beginning of year	**224**	229
Return (loss) on plan assets	**32**	(2)
Foreign currency translation	**—**	(1)
Purchases, sales and settlements	**—**	(2)
Balance, end of year	**256**	224

23. EMPLOYEE FUTURE BENEFITS (cont'd)

Funded Status

($ millions)	Defined Benefit Pension Plans 2021	Defined Benefit Pension Plans 2020	OPEB Plans 2021	OPEB Plans 2020
Change in benefit obligation (1)				
Balance, beginning of year	**3,995**	3,632	**789**	712
Service costs	**109**	98	**35**	32
Employee contributions	**18**	17	**2**	2
Interest costs	**98**	113	**19**	22
Benefits paid	**(170)**	(162)	**(25)**	(27)
Actuarial (gains) losses	**(111)**	350	**(70)**	62
Past service credits/plan amendments	**(2)**	—	**—**	(3)
Foreign currency translation	**(15)**	(53)	**(3)**	(11)
Balance, end of year (2)	**3,922**	3,995	**747**	789
Change in value of plan assets				
Balance, beginning of year	**3,528**	3,208	**391**	343
Actual return on plan assets	**291**	444	**48**	55
Benefits paid	**(158)**	(155)	**(21)**	(27)
Employee contributions	**18**	17	**2**	2
Employer contributions	**55**	62	**22**	28
Foreign currency translation	**(12)**	(48)	**(2)**	(10)
Balance, end of year	**3,722**	3,528	**440**	391
Funded status	**(200)**	(467)	**(307)**	(398)
Balance sheet presentation				
Other assets (Note 9)	**204**	58	**55**	8
Other current liabilities (Note 13)	**(13)**	(13)	**(13)**	(13)
Other liabilities (Note 16)	**(391)**	(512)	**(349)**	(393)
	(200)	(467)	**(307)**	(398)

(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 $3,586 million as at December 31, 2021 (2020 - $3,679 million).

For those defined benefit pension plans for which the projected benefit obligation exceeded the fair value of plan assets as at December 31, 2021, the obligation was $2,188 million compared to plan assets of $1,799 million (2020 - $3,290 million and $2,777 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, 2021, the obligation was $1,243 million compared to plan assets of $1,063 million (2020 - $3,037 million and $2,741 million, respectively).

For those OPEB plans for which the accumulated benefit obligation exceeded the fair value of plan assets as at December 31, 2021, the obligation was $398 million compared to plan assets of $36 million (2020 - $589 million and $183 million, respectively).

Net Benefit Cost (1)

($ millions)	Defined Benefit Pension Plans 2021	Defined Benefit Pension Plans 2020	OPEB Plans 2021	OPEB Plans 2020
Service costs	**109**	98	**35**	32
Interest costs	**98**	113	**19**	22
Expected return on plan assets	**(177)**	(176)	**(19)**	(19)
Amortization of actuarial losses (gains)	**36**	33	**(2)**	(5)
Amortization of past service credits/plan amendments	**(1)**	(1)	**(1)**	(2)
Regulatory adjustments	**(1)**	—	**3**	4
	64	67	**35**	32

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

23. EMPLOYEE FUTURE BENEFITS (cont'd)

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

	Defined Benefit Pension Plans		OPEB Plans	
($ millions)	**2021**	2020	**2021**	2020
Unamortized net actuarial losses (gains)	**33**	42	**(5)**	(1)
Unamortized past service costs	**1**	1	**7**	7
Income tax recovery	**(8)**	(10)	**—**	(1)
Accumulated other comprehensive income	**26**	33	**2**	5
Net actuarial losses (gains)	**260**	517	**(81)**	12
Past service credits	**(5)**	(7)	**(6)**	(8)
Other regulatory deferrals	**10**	13	**14**	18
	265	523	**(73)**	22
Regulatory assets (Note 8)	**376**	523	**12**	65
Regulatory liabilities (Note 8)	**(111)**	—	**(85)**	(43)
Net regulatory assets (liabilities)	**265**	523	**(73)**	22

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

	Defined Benefit Pension Plans		OPEB Plans	
($ millions)	**2021**	2020	**2021**	2020
Current year net actuarial (gains) losses	**(10)**	9	**(4)**	1
Amortization of actuarial losses	**1**	1	**—**	—
Income tax expense (recovery)	**2**	(2)	**1**	—
Total recognized in comprehensive income	**(7)**	8	**(3)**	1
Current year net actuarial (gains) losses	**(220)**	69	**(95)**	25
Past service credits/plan amendments	**—**	—	**—**	(3)
Amortization of actuarial (losses) gains	**(35)**	(31)	**2**	5
Amortization of past service credits	**2**	2	**2**	3
Foreign currency translation	**(2)**	(7)	**—**	—
Regulatory adjustments	**(3)**	(2)	**(4)**	(1)
Total recognized in regulatory (liabilities) assets	**(258)**	31	**(95)**	29

Significant Assumptions

	Defined Benefit Pension Plans		OPEB Plans	
(weighted average %)	**2021**	2020	**2021**	2020
Discount rate during the year (1)	**2.60**	3.16	**2.60**	3.22
Discount rate as at December 31	**3.00**	2.63	**2.97**	2.64
Expected long-term rate of return on plan assets (2)	**5.40**	5.52	**4.88**	5.28
Rate of compensation increase	**3.30**	3.34	**—**	—
Health care cost trend increase as at December 31 (3)	**—**	—	**4.49**	4.61

(1) *ITC and UNS Energy use the split discount rate methodology for determining current service and interest costs. All other subsidiaries use the single discount rate approach.*

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

(3) *The projected 2022 weighted average health care cost trend rate is 5.75% and is assumed to decrease over the next 11 years to the weighted average ultimate health care cost trend rate of 4.49% in 2032 and thereafter.*

23. EMPLOYEE FUTURE BENEFITS (cont'd)

Expected Benefit Payments ($ millions)	**Defined Benefit Pension Payments**	**OPEB Payments**
2022	$ 168	$ 28
2023	172	29
2024	176	30
2025	181	32
2026	189	33
2027-2031	1,019	175

During 2022, the Corporation expects to contribute $49 million for defined benefit pension plans and $27 million for OPEB plans.

In 2021, the Corporation expensed $44 million (2020 - $42 million) related to defined contribution pension plans.

24. SUPPLEMENTARY CASH FLOW INFORMATION

($ millions)	**2021**	2020
Cash paid (received) for		
Interest	**986**	1,027
Income taxes	**(13)**	(26)
Change in working capital		
Accounts receivable and other current assets	**(88)**	(84)
Prepaid expenses	**(15)**	(15)
Inventories	**(56)**	(36)
Regulatory assets - current portion	**(99)**	(49)
Accounts payable and other current liabilities	**164**	(100)
Regulatory liabilities - current portion	**(50)**	(150)
	(144)	(434)
Non-cash investing and financing activities		
Accrued capital expenditures	**432**	400
Common share dividends reinvested	**356**	114
Contributions in aid of construction	**13**	13

25. 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.

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

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, 2021, unrealized losses of $20 million (2020 - $73 million) were recognized as regulatory assets and unrealized gains of $52 million (2020 - $17 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. In 2021, unrealized gains of $21 million (2020 - $3 million) were recognized in revenue.

Total Return Swaps

The Corporation holds total return swaps to manage the cash flow risk associated with forecast future cash settlements of certain stock-based compensation obligations. The swaps have a combined notional amount of $112 million and terms of one to three years expiring at varying dates through January 2024. Fair value is measured using an income valuation approach based on forward pricing curves. Unrealized gains and losses associated with changes in fair value are recognized in other income, net. In 2021, unrealized gains of $17 million (2020 - unrealized losses of $9 million) were recognized in other income, net.

Foreign Exchange Contracts

The Corporation holds U.S. dollar-denominated foreign exchange contracts to help mitigate exposure to foreign exchange rate volatility. The contracts expire at varying dates through November 2022 and have a combined notional amount of $161 million. Fair value was measured using independent third-party information. Unrealized gains and losses associated with changes in fair value are recognized in other income, net. In 2021, unrealized losses of $11 million (2020 - unrealized gains of $11 million) were recognized in other income, net.

Interest Rate Swaps

In 2021, ITC entered into interest rate swaps with a total notional value of US$375 million to manage the interest rate risk associated with the refinancing of long-term debt due in November 2022. The swaps have five-year terms, include mandatory early termination provisions, and will be terminated no later than the effective date of November 15, 2022. Fair value was measured using a discounted cash flow method based on LIBOR rates. Unrealized gains and losses associated with the changes in fair value are recognized in other comprehensive income, will be reclassified to earnings as a component of interest expense over the life of the debt, and were not material for 2021.

Other Investments

ITC and Central Hudson hold investments in trust associated with supplemental retirement benefit plans for select employees. These investments include 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. In 2021, unrealized gains of $9 million (2020 - $7 million) were recognized in other income, net.

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

Recurring Fair Value Measures

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

($ millions)	Level 1 [1]	Level 2 [1]	Level 3 [1]	Total
As at December 31, 2021				
Assets				
Energy contracts subject to regulatory deferral [2] [3]	**—**	**78**	**—**	**78**
Energy contracts not subject to regulatory deferral [2]	**—**	**16**	**—**	**16**
Foreign exchange contracts, total return and interest rate swaps [2]	**23**	**2**	**—**	**25**
Other investments [4]	**137**	**—**	**—**	**137**
	160	**96**	**—**	**256**
Liabilities				
Energy contracts subject to regulatory deferral [3] [5]	**—**	**(46)**	**—**	**(46)**
Energy contracts not subject to regulatory deferral [5]	**—**	**(3)**	**—**	**(3)**
	—	**(49)**	**—**	**(49)**
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)

[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*

Energy Contracts

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

($ millions)	Gross Amount Recognized In Balance Sheet	Counterparty Netting of Energy Contracts	Cash Collateral Received/Posted	Net Amount
As at December 31, 2021				
Derivative assets	**94**	**25**	**7**	**62**
Derivative liabilities	**(49)**	**(25)**	**—**	**(24)**
As at December 31, 2020				
Derivative assets	44	26	10	8
Derivative liabilities	(106)	(26)	(9)	(71)

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

Volume of Derivative Activity

As at December 31, 2021, 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.

	2021	2020
Energy contracts subject to regulatory deferral [(1)]		
Electricity swap contracts *(GWh)*	**509**	522
Electricity power purchase contracts *(GWh)*	**731**	2,781
Gas swap contracts *(PJ)*	**151**	156
Gas supply contract premiums *(PJ)*	**144**	203
Energy contracts not subject to regulatory deferral [(1)]		
Wholesale trading contracts *(GWh)*	**1,886**	1,588
Gas swap contracts *(PJ)*	**29**	36

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

Credit Risk

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

ITC has a concentration of credit risk as approximately 70% of its revenue is derived from three customers. 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 $59 million as at December 31, 2021 (2020 - $88 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 U.S. dollar. The earnings and cash flow from, and net investments in, these entities are exposed to fluctuations in the U.S. dollar-to-Canadian dollar exchange rate. The Corporation has limited this exposure through hedging.

As at December 31, 2021, US$2.2 billion (2020 - US$2.3 billion) of corporately issued U.S. dollar-denominated long-term debt has been designated as an effective hedge of net investments, leaving approximately US$10.8 billion (2020 - US$10.2 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, 2021, the carrying value of long-term debt, including current portion, was $25.5 billion (2020 - $24.5 billion) compared to an estimated fair value of $28.8 billion (2020 - $29.1 billion).

26. COMMITMENTS AND CONTINGENCIES

As at December 31, 2021, unconditional minimum purchase obligations were as follows.

($ millions)	**Total**	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Waneta Expansion capacity agreement (1)	**2,525**	53	54	55	56	58	2,249
Gas and fuel purchase obligations (2)	**2,464**	787	446	252	169	121	689
Renewable PPAs (3)	**1,918**	122	122	122	122	122	1,308
Power purchase obligations (4)	**1,783**	288	254	194	184	185	678
ITC easement agreement (5)	**366**	13	13	13	13	13	301
Debt collection agreement (6)	**109**	3	3	3	3	3	94
Renewable energy credit purchase agreements (7)	**87**	17	16	11	8	6	29
Other (8)	**158**	66	7	7	6	4	68
	9,410	1,349	915	657	561	512	5,416

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

(2) *FortisBC Energy ($1,686 million):* includes contracts for the purchase of gas, renewable gas, gas transportation and storage services, expiring in 2062. FortisBC Energy's gas purchase obligations are based on gas commodity indices that vary with market prices and the obligations are based on index prices as at December 31, 2021. The renewable gas supply obligations disclosed reflect the contracted price per GJ between the Corporation and the suppliers.

UNS Energy ($670 million): includes long-term contracts for the purchase and delivery of coal to fuel generating facilities, the purchase of gas transportation services to meet load requirements, the purchase of transmission services for purchased power, as well as natural gas commodity agreements based on projected market prices as of December 31, 2021. 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) TEP and UNS Electric are party to renewable PPAs, with expiry dates from 2027 through 2051, that require TEP and UNS Electric to purchase 100% of the output of certain renewable energy generating facilities and RECs associated with the output delivered once commercial operation is achieved. Amounts are the estimated future payments.

(4) *Maritime Electric ($815 million):* includes an energy purchase agreement and transmission capacity contract for 30MW of capacity to PEI with New Brunswick Power, expiring December 2026 and November 2032, respectively. The agreements entitle Maritime Electric to approximately 4.55% of the output of New Brunswick Power's Point Lepreau nuclear generating station and require Maritime Electric to pay its share of the station's capital operating costs for the life of the unit.

FortisOntario ($544 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 ($276 million): includes 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.

UNS Energy ($118 million): an agreement with Salt River Project Agricultural Improvement and Power District to purchase up to 300 MW of capacity, power and ancillary services through 2023. TEP will pay monthly capacity charges and variable power charges.

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

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

(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 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.

The Wataynikaneyap Partnership has loan agreements in place 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.

26. COMMITMENTS AND CONTINGENCIES (cont'd)

Development projects at ITC may result in payments to developers that are contingent on the projects reaching certain milestones indicating that the projects are financially viable. It is reasonably possible that ITC will be required to make these contingent development payments up to a maximum amount of $88 million upon financial close of the projects. In the event it becomes probable that these payments will be made, the liability and the corresponding intangible asset would be recognized.

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, 2021, 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 $83 million, for which it has issued a parental guarantee. As at December 31, 2021, there was no obligation under this guarantee.

As at December 31, 2021, 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.

Historical Financial Summary

Statements of Earnings *(in $ millions)*	**2021**	2020	2019[1]
Revenue	**9,448**	8,935	8,783
Energy supply costs and operating expenses	**5,474**	4,999	4,972
Depreciation and amortization	**1,505**	1,428	1,350
Gain on disposition	**–**	–	577
Other income, net	**173**	154	138
Finance charges	**1,003**	1,042	1,035
Income tax expense	**234**	231	289
Earnings from continuing operations	**1,405**	1,389	1,852
Earnings from discontinued operations, net of tax	**–**	–	–
Extraordinary gain, net of tax	**–**	–	–
Net earnings	**1,405**	1,389	1,852
Net earnings attributable to non-controlling interests	**111**	115	130
Net earnings attributable to preference equity shareholders	**63**	65	67
Net earnings attributable to common equity shareholders	**1,231**	1,209	1,655
Balance Sheets *(in $ millions)*			
Current assets	**2,728**	2,612	2,574
Property, plant and equipment, non-utility capital assets[2] and intangible assets	**39,159**	37,289	35,248
Goodwill	**11,720**	11,792	12,004
Other long-term assets	**4,052**	3,788	3,578
Total assets	**57,659**	55,481	53,404
Current liabilities	**4,802**	4,148	4,176
Long-term debt (excluding current portion)	**23,707**	23,113	21,501
Other long-term liabilities	**8,234**	7,936	7,614
Total liabilities	**36,743**	35,197	33,291
Total equity	**20,916**	20,284	20,113
Cash Flows *(in $ millions)*			
Operating activities	**2,907**	2,701	2,663
Investing activities	**(3,488)**	(4,132)	(2,768)
Financing activities, excluding dividends	**1,180**	2,243	788
Dividends	**(729)**	(916)	(634)
Financial Statistics			
Return on average book common shareholders' equity *(%)*	**7.09**	7.12	10.40
Capitalization Ratios *(%)* (year end)			
Total debt and finance leases (net of cash)	**57.2**	56.8	55.1
Preference shares	**3.6**	3.7	4.0
Common shareholders' equity	**39.2**	39.5	40.9
Interest Coverage *(x)*			
Debt	**2.5**	2.4	2.9
All fixed charges	**2.5**	2.4	2.9
Capital Expenditures *(in $ millions)*	**3,564**	4,177	3,818
Common share data			
Book value per share (year end) *($)*	**37.21**	36.58	36.49
Average common shares outstanding *(in millions)*	**470.9**	464.8	436.8
Basic earnings per common share *($)*	**2.61**	2.60	3.79
Dividends declared per common share *($)*	**2.08**	1.965	1.855
Dividends paid per common share *($)*	**2.05**	1.9375	1.8275
Dividend payout ratio *(%)*	**78.5**	74.5	48.2
Price earnings ratio *(x)*	**23.4**	20.0	14.2
Share trading summary (TSX)			
High price *($)*	**61.54**	59.28	56.94
Low price *($)*	**48.97**	41.52	44.00
Closing price *($)*	**61.03**	52.00	53.88
Volume *(in thousands)*	**386,673**	441,457	297,490

[1] Results were impacted by non-recurring items, largely associated with the disposition of the Waneta Expansion in 2019, the acquisition of ITC in 2016, the sale of non-core assets in 2015, the acquisition of UNS Energy in 2014 and the acquisition of Central Hudson in 2013.

[2] Non-utility capital assets were sold as part of the sale of commercial real estate and hotel assets in 2015.

2018	2017	2016 (1)	2015 (1)	2014 (1)	2013 (1)	2012
8,390	8,301	6,838	6,757	5,401	4,047	3,654
4,782	4,611	4,372	4,465	3,690	2,654	2,390
1,243	1,179	983	873	688	541	470
–	–	–	–	–	–	–
60	116	53	197	(25)	(31)	4
974	914	678	553	547	389	366
165	588	145	223	66	32	61
1,286	1,125	713	840	385	400	371
–	–	–	–	5	–	–
–	–	–	–	–	20	–
1,286	1,125	713	840	390	420	371
120	97	53	35	11	10	9
66	65	75	77	62	57	47
1,100	963	585	728	317	353	315
3,261	2,207	2,166	1,857	1,787	1,296	1,093
33,957	30,749	30,348	20,136	18,304	12,612	10,574
12,530	11,644	12,364	4,173	3,732	2,075	1,568
3,303	3,222	3,026	2,638	2,410	1,925	1,715
53,051	47,822	47,904	28,804	26,233	17,908	14,950
4,252	3,504	3,944	2,638	2,676	2,084	1,350
23,159	20,691	20,817	10,784	9,911	6,424	5,741
7,184	6,878	6,693	5,029	4,534	3,024	2,449
34,595	31,073	31,454	18,451	17,121	11,532	9,540
18,456	16,749	16,450	10,353	9,112	6,376	5,410
2,604	2,756	1,884	1,673	982	899	992
(3,252)	(3,025)	(6,891)	(1,368)	(4,199)	(2,164)	(1,096)
1,254	932	5,491	(14)	3,627	1,434	396
(610)	(593)	(441)	(332)	(266)	(248)	(225)
7.78	7.31	5.56	9.75	5.45	8.06	8.06
59.7	59.2	60.6	54.8	56.4	56.2	55.3
3.9	4.4	4.4	8.3	9.1	9.0	9.7
36.4	36.4	35.0	36.9	34.5	34.8	35.0
2.3	2.7	2.1	2.7	1.6	1.9	2.0
2.3	2.7	2.1	2.7	1.6	1.9	2.0
3,218	3,024	2,061	2,243	1,725	1,175	1,146
34.80	31.77	32.31	28.62	24.89	22.38	20.84
424.7	415.5	308.9	278.6	225.6	202.5	190.0
2.59	2.32	1.89	2.61	1.41	1.74	1.66
1.75	1.65	1.55	1.43	1.30	1.25	1.21
1.725	1.625	1.525	1.40	1.28	1.24	1.20
66.6	70.0	80.7	53.6	90.8	71.3	72.3
17.6	19.9	21.9	14.3	27.6	17.5	20.6
47.36	48.73	44.87	42.23	40.83	35.14	34.98
39.38	40.59	35.53	34.16	29.78	29.51	31.70
45.51	46.11	41.46	37.41	38.96	30.45	34.22
269,284	205,261	293,991	172,038	174,566	120,470	115,962

Investor Information

Expected Dividend* and Earnings Release Dates

Dividend Record Dates

May 17, 2022	August 19, 2022
November 17, 2022	February 15, 2023

Dividend Payment Dates

June 1, 2022	September 1, 2022
December 1, 2022	March 1, 2023

Earnings Release Dates

May 4, 2022	July 28, 2022
October 28, 2022	February 10, 2023

* *The setting of dividend record dates and the declaration and payment of dividends are subject to the Board of Directors' approval.*

Transfer Agent and Registrar

Computershare Trust Company of Canada ("Computershare" or "Transfer Agent") is responsible for the maintenance of shareholder records and the issuance, transfer and cancellation of stock certificates. Transfers can be effected at its Montreal and Toronto offices in Canada and at the co-transfer agent's Canton, MA, Jersey City, NJ, and Louisville, KY offices in the United States. Computershare also distributes dividends and shareholder communications. Inquiries with respect to these matters and corrections to shareholder information should be addressed to the Transfer Agent.

Computershare Trust Company of Canada

8th Floor, 100 University Avenue, Toronto, ON M5J 2Y1
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W: www.investorcentre.com/fortisinc

Computershare Trust Company N.A.

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First Class, Registered, or Certified Mail: P.O. Box 505005, Louisville, KY 40233-5005 T: 1.800.962.4284 F: 781-575-3603

Direct Deposit of Dividends

Shareholders may arrange for automatic electronic deposit of dividends to their designated Canadian and U.S. financial institutions by contacting the Transfer Agent.

Duplicate Annual Reports

While every effort is made to avoid duplications, some shareholders may receive extra reports as a result of multiple share registrations. Shareholders wishing to consolidate these accounts should contact the Transfer Agent.

Eligible Dividend Designation

For purposes of the enhanced dividend tax credit rules contained in the Income Tax Act (Canada) and any corresponding provincial and territorial tax legislation, all dividends paid on common and preferred shares after December 31, 2005 by Fortis to Canadian residents are designated as "eligible dividends." Unless stated otherwise, all dividends paid by Fortis hereafter are designated as "eligible dividends" for the purposes of such rules.

Annual and Special Meeting

Thursday, May 5, 2022 – 10:30 a.m. NDT

Dividend Reinvestment Plan

Fortis offers a Dividend Reinvestment Plan ("DRIP") as a convenient method for Common Shareholders to increase their investments in Fortis. Participants have dividends plus any optional contributions (minimum of $100, maximum of $30,000 annually) automatically deposited in the plan to purchase additional Common Shares. Shares can be purchased quarterly on March 1, June 1, September 1 and December 1 at the average market price then prevailing on the Toronto Stock Exchange. The DRIP currently offers a 2% discount on the purchase of Common Shares, issued from treasury, with the reinvested dividends. Inquiries should be directed to the Transfer Agent.

Share Listings

The Common Shares; First Preference Shares, Series F; First Preference Shares, Series G; First Preference Shares, Series H; First Preference Shares, Series I; First Preference Shares, Series J; First Preference Shares, Series K; and First Preference Shares, Series M of Fortis Inc. are listed on the Toronto Stock Exchange and trade under the ticker symbols FTS, FTS.PR.F, FTS.PR.G, FTS.PR.H, FTS.PR.I, FTS.PR.J, FTS.PR.K and FTS.PR.M, respectively. The Common Shares are also listed on the New York Stock Exchange and trade under the ticker symbol FTS.

Valuation Day

For capital gains purposes, the valuation day prices are as follows:

December 22, 1971	**$1.531**
February 22, 1994	**$7.156**

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President and Chief Executive Officer

Jocelyn H. Perry
Executive Vice President, Chief Financial Officer

Nora M. Duke
Executive Vice President, Sustainability and
Chief Human Resource Officer

James R. Reid
Executive Vice President, Chief Legal Officer and
Corporate Secretary

Gary J. Smith
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✷ Human Resources Committee
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For Board of Directors' biographies,
please visit **www.fortisinc.com**.

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