

## Management Discussion and Analysis

For the year ended December 31, 2019  
Dated February 12, 2020

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This MD&A has been prepared in accordance with National Instrument 51-102 - *Continuous Disclosure Obligations*. It should be read in conjunction with the 2019 Annual Financial Statements and is subject to the cautionary statement and disclaimer provided under "Forward-Looking Information" on page 45. Further information about Fortis, including its Annual Information Form filed on SEDAR, can be accessed at [www.fortisinc.com](http://www.fortisinc.com), [www.sedar.com](http://www.sedar.com), or [www.sec.gov](http://www.sec.gov).

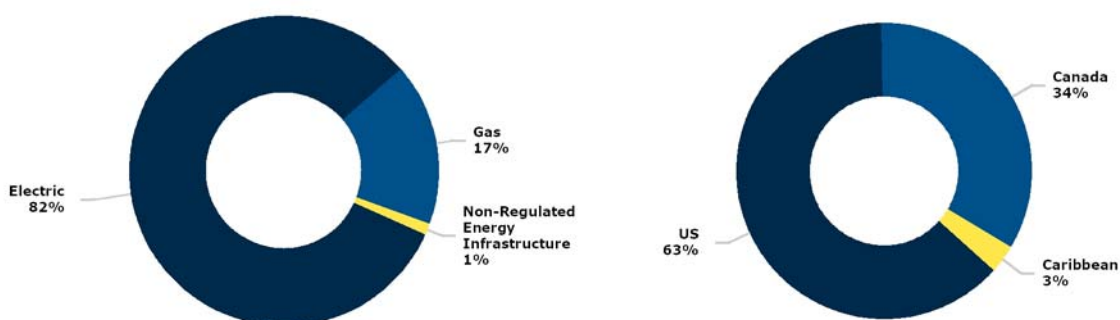
Financial information herein has been prepared in accordance with US GAAP (except for indicated Non-US GAAP Financial Measures) and, unless otherwise specified, is presented in Canadian dollars based, as applicable, on the following US-to-Canadian dollar exchange rates: (i) average of 1.33 and 1.30 for the years ended December 31, 2019 and 2018, respectively; (ii) 1.30 and 1.36 as at December 31, 2019 and 2018, respectively; and (iii) 1.32 for all forecast periods. Certain terms used in this MD&A are defined in the "Glossary" on page 46.

### ABOUT FORTIS

Fortis (TSX/NYSE: FTS) is a well-diversified leader in the North American regulated electric and gas utility industry, with revenue of \$8.8 billion and total assets of \$53 billion as at December 31, 2019.

Regulated utilities account for 99% of the Corporation's assets with the remainder primarily attributable to non-regulated energy infrastructure. The Corporation's 9,000 employees serve 3.3 million utility customers in five Canadian provinces, nine US states and three Caribbean countries. As at December 31, 2019, 66% of the Corporation's assets were located outside Canada and 60% of 2019 revenue was derived from foreign operations.

*Total Assets at December 31, 2019*



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. EPS and TSR are the primary measures of financial performance.

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

Non-regulated energy infrastructure is comprised of Aitken Creek (natural gas storage facility - British Columbia), BECOL (three hydroelectric generation facilities - Belize) and the Waneta Expansion up to its disposition in April 2019 (see "Significant Items" on page 3).

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

Fortis strives to provide safe, reliable and cost-effective energy service to customers using sustainable practices while delivering long-term profitable growth to shareholders. Management is focused on achieving growth through the execution of the consolidated capital plan and the pursuit of additional investment opportunities within and proximate to existing service territories (see "Capital Plan" on page 21).

Additional information about the Corporation's business and reporting units is provided in Note 1 in the 2019 Annual Financial Statements.

## SIGNIFICANT ITEMS

### Disposition

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

Fortis used the net proceeds to repay credit facility borrowings and repurchase, via a tender offer, US\$400 million of its outstanding 3.055% unsecured senior notes due in 2026. The reduced earnings from the Waneta Expansion were offset by lower finance charges and a gain on repayment of the 3.055% notes.

### Common Equity Offering

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

### November 2019 FERC Order

In November 2019 FERC issued an order reducing the base ROE for ITC's MISO Subsidiaries to 9.88%, up to a maximum of 12.24% with incentive adders. Including incentive adders, this implies an all-in ROE for ITC's MISO subsidiaries of 10.63% compared to the previous all-in ROE of 11.07%. The net impact was a \$63 million increase in earnings, comprised of \$83 million related to the net reversal of liabilities established in prior periods, partially offset by \$20 million related to the 2019 impact of the reduced ROE. See "Regulatory Highlights" on page 13 for further information.

## PERFORMANCE AT A GLANCE

Key Financial Metrics			
<i>(\$ millions, except as indicated)</i>	2019	2018	Variance
Common Equity Earnings			
Actual	1,655	1,100	555
Adjusted <sup>(1)</sup>	1,115	1,066	49
Basic EPS (\$)			
Actual	3.79	2.59	1.20
Adjusted <sup>(1)</sup>	2.55	2.51	0.04
Dividends			
Paid per Common Share (\$)	1.8275	1.7250	0.1025
Actual Payout Ratio (%)	48.2	66.6	(18.4)
Adjusted Payout Ratio <sup>(1)</sup> (%)	71.7	68.7	3.0
Weighted Average Number of Common Shares Outstanding ( <i>millions</i> )	436.8	424.7	12.1
Operating Cash Flow	2,663	2,604	59
Capital Expenditures	3,818	3,218	600

<sup>(1)</sup> See "Non-US GAAP Financial Measures" on page 12

TSR <sup>(1)</sup> (%)	1-Year	5-Year	10-Year	20-Year
Fortis	22.7%	10.8%	10.6%	14.3%

<sup>(1)</sup> Total annualized shareholder return per Bloomberg, as at December 31, 2019

### Earnings and EPS

The \$555 million increase in Common Equity Earnings reflects significant one-time items, Rate Base growth driven by the Corporation's capital plan at the regulated utilities and favourable foreign exchange, partially offset by the impact of weather in Belize and Arizona, regulatory decisions at ITC and one-time positive tax adjustments primarily recognized in 2018.

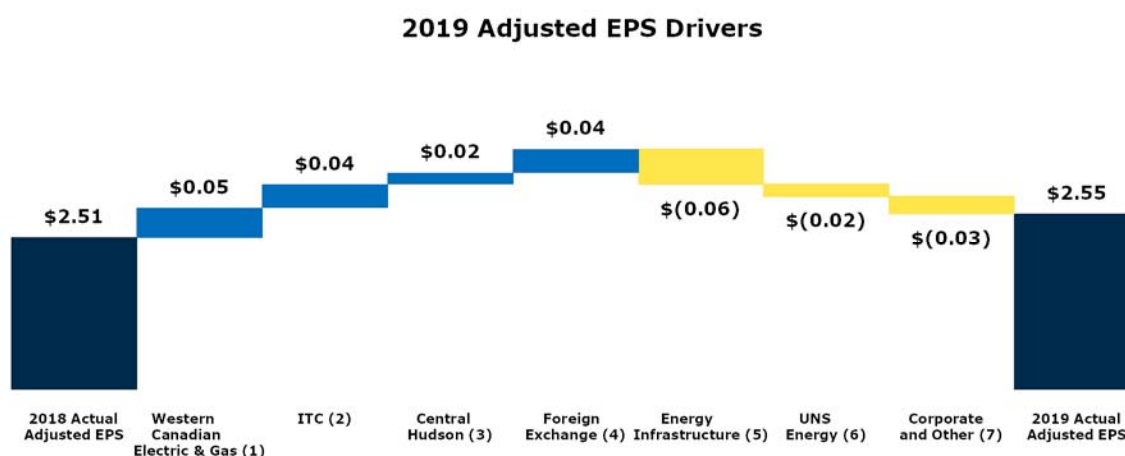
The significant one-time items were a \$484 million gain on the disposition of the Waneta Expansion and an \$83 million favourable adjustment resulting from the November 2019 FERC Order (see "Regulatory Highlights" on page 13), which resulted in the 2019 net reversal of liabilities established in prior years.

The regulated utilities delivered positive financial results reflecting Rate Base growth, driven by ITC, lower operating expenses, primarily at FortisAlberta, and favourable foreign exchange. This growth was tempered by: (i) a lower ROE at ITC due to the November 2019 FERC Order and lower ROE incentive adders effective April 2018; (ii) lower earnings contribution from UNS Energy due to lower retail sales, driven by cooler weather, and higher costs associated with Rate Base growth not yet reflected in rates; and (iii) lower earnings contribution from the Energy Infrastructure segment due to lower hydroelectric production in Belize and lower realized margins at Aitken Creek.

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

Finally, a 12.1 million increase in the weighted average number of common shares outstanding associated with the Corporation's (i) \$1.2 billion common equity issuance in the fourth quarter of 2019 (see "Significant Items" on page 3), (ii) ATM Program, and (iii) DRIP and share purchase plan, resulted in a \$0.07 decrease in basic EPS.

Adjusted Common Equity Earnings and Adjusted Basic EPS increased by \$49 million and \$0.04, respectively. Refer to "Non-US GAAP Financial Measures" on page 12 for a reconciliation of these measures. The change in Adjusted Basic EPS is illustrated in the chart below.



- (1) Includes FortisBC Energy, FortisBC Electric and FortisAlberta. Driven primarily by Rate Base growth and lower operating expenses
- (2) Driven by Rate Base growth, partially offset by a lower 2019 ROE due to the November 2019 FERC Order
- (3) Driven by Rate Base growth
- (4) Average FX of \$1.33 for 2019 compared to \$1.30 for 2018
- (5) Driven primarily by reduced hydroelectric production at Belize due to lower rainfall
- (6) Driven primarily by higher costs associated with Rate Base growth not yet reflected in customer rates and lower retail sales due mainly to unfavourable weather
- (7) Weighted average shares of 436.8 million in 2019 compared to 424.7 million in 2018, partially offset by favourable foreign exchange contracts and higher income tax recoveries

**Dividends and TSR**

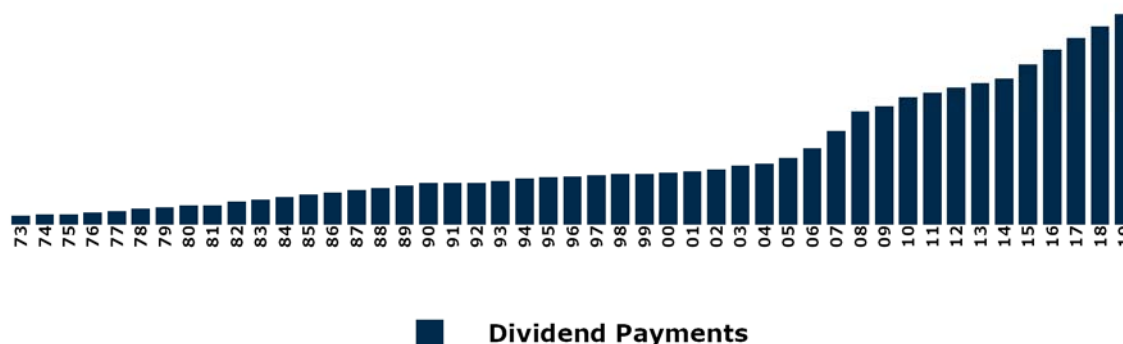
Fortis paid a dividend of \$0.4775 per common share in the fourth quarter of 2019, up from \$0.45 paid in each of the previous four quarters.

The total 2019 dividend paid per common share was \$1.8275, up \$0.1025 or nearly 6.0% from 2018 and in line with the Corporation's dividend guidance. The Actual Payout Ratio was 48.2% in 2019 compared to 66.6% in 2018 and an annual average of 61.4% over the five-year period of 2015 through 2019. The decrease in the 2019 Actual Payout Ratio was driven by the gain on disposition of the Waneta Expansion (see "Significant Items" on page 3).

Fortis has increased its common share dividend for 46 consecutive years. Growth of dividends and the market price of the Corporation's common shares have together yielded a 1-year, 5-year, 10-year and 20-year TSR of 22.7%, 10.8%, 10.6% and 14.3%, respectively.

In September 2019 Fortis extended its targeted average annual dividend per common share growth of approximately 6% through 2024.

**46 Years of Common Share Dividend Increases**



**Operating Cash Flow**

The \$59 million increase was due to higher cash earnings, driven by Rate Base growth at the regulated utilities, led by ITC. The increase was partially offset by: (i) unfavourable changes due to the normal operation of long-term regulatory deferrals at ITC; (ii) unfavourable changes in working capital, due primarily to timing differences, partially offset by income tax refunds received in 2019; and (iii) lower cash earnings from the Energy Infrastructure segment (see "Business Unit Performance - Energy Infrastructure" on page 11).

**Capital Expenditures**

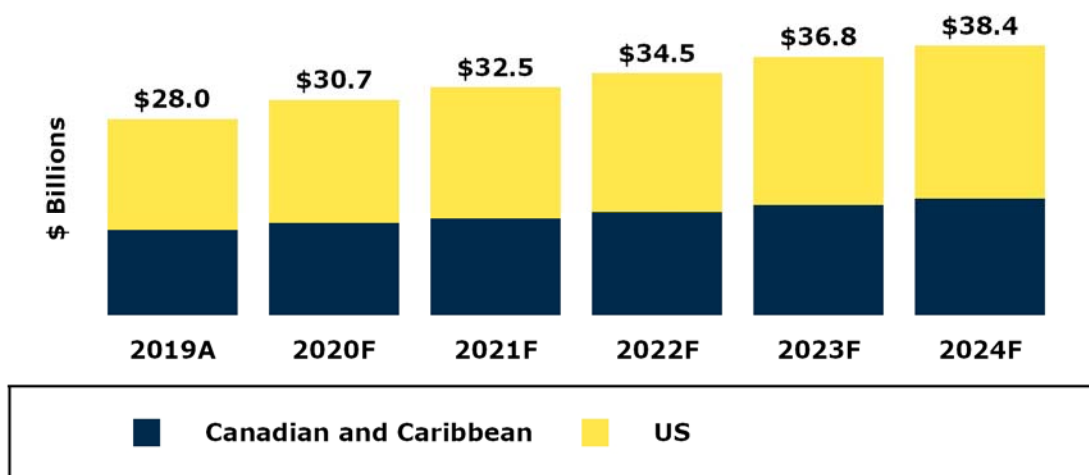
Capital expenditures in 2019 were \$3.8 billion, \$0.6 billion higher than in 2018 and \$0.5 billion lower than forecast in the Q3 2019 MD&A. The \$0.6 billion increase over the prior year was driven by higher spending at the US regulated utilities. The \$0.5 billion decrease from forecast was due to: (i) a \$0.3 billion delayed payment related to the construction of the Oso Grande Wind Project as the performance obligations were not fulfilled until January 2020; (ii) a revised forecast and timeline related to the Southline Transmission Project resulting in \$0.1 billion being deferred until 2021; and (iii) revisions to various smaller projects resulting in \$0.1 billion being deferred until 2021. See "Capital Plan" on page 21 for further information.

The Corporation's five-year 2020-2024 capital plan is targeted at \$18.8 billion, approximately \$0.5 billion higher than the \$18.3 billion capital plan disclosed in the Q3 2019 MD&A. The increase reflects the shift in spending that was originally planned for December 2019 but was made in January 2020 related to UNS Energy's Oso Grande Wind Project, as well as the timing of other spend that shifted to 2021.

Funding of the capital plan is expected to be primarily through Operating Cash Flow, utility debt and common equity from the Corporation's DRIP.

The five-year capital plan is expected to increase midyear Rate Base from \$28.0 billion in 2019 to \$34.5 billion by 2022 and \$38.4 billion by 2024, representing three- and five-year CAGRs of 7.2% and 6.5%, respectively. These CAGRs are supportive of continuing growth in earnings and dividends.

**Projected Rate Base Growth**



Beyond the base capital plan, Fortis continues to pursue additional energy infrastructure opportunities. Key opportunities not yet included in the five-year capital plan include: further expansion of liquefied natural gas infrastructure in British Columbia; the fully permitted, cross-border, Lake Erie connector electric transmission project in Ontario; and the acceleration of cleaner energy goals in Arizona.

**THE INDUSTRY**

The North American energy industry continues to transform. There is a heightened focus on the impacts of climate change and the need for cleaner energy and energy conservation initiatives to preserve the environment for future generations. The effects of climate change, coupled with technological advancements, have rapidly shifted customer expectations for cleaner energy. The trend toward renewables and natural gas as a key part of the energy mix, as well as the increasing affordability of cleaner energy, is driving opportunity in the utility sector.

Changing energy policies at the federal, state and provincial levels are creating volatility in certain jurisdictions by introducing uncertainty around environmental, tax and trade regulation. The regulatory and compliance operating environment is also evolving and becoming increasingly complex. These changes are creating additional opportunities to expand investment in new generation sources, including natural gas, solar and wind, as well as infrastructure to interconnect renewable energy sources to the grid. Investment opportunities in storage are also growing with the proliferation of variable renewable generation sources and decreasing costs of storage technology. The Corporation's utilities are well positioned and actively involved in pursuing these opportunities.

New technology is driving change across all service territories. Energy delivery systems are being upgraded with advanced meters, improved controls and more capable operational technology, providing utilities with detailed usage data. Energy management capabilities are expanding through emerging storage and demand response systems, and customers have been enabled with options to manage and reduce energy usage and access more affordable distributed generation technology.

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

Meaningful customer engagement is increasingly important for utilities as customer expectations change and competition for customer attention becomes more intense. Customers want to make informed energy choices and become active participants in the delivery of their energy services. They also expect personalized service, customized service offerings and more real-time, digital communication.

Fortis is well positioned to capitalize on evolving industry opportunities. Its decentralized structure and customer-focused business culture support the efforts required to meet changing customer expectations and to work with policy makers and regulators on energy and service solutions that are financially sustainable. Fortis is also a strategic partner in the Energy Impact Partners utility coalition, which is a strategic private entity fund that invests in emerging technologies, products, services and business models across the full electricity supply chain.

By leveraging these strengths and partnerships, Fortis expects to remain at the forefront of this ever-changing industry.

## OPERATING RESULTS

(\$ millions)	2019	2018	Variance	
			FX	Other
Revenue	8,783	8,390	113	280
Energy Supply Costs	2,520	2,495	30	(5)
Operating Expenses	2,452	2,287	34	131
Depreciation and Amortization	1,350	1,243	14	93
Gain on Disposition	577	—	—	577
Other Income, Net	138	60	1	77
Finance Charges	1,035	974	10	51
Income Tax Expense	289	165	4	120
Net Earnings	1,852	1,286	22	544
Net Earnings Attributable to:				
Non-Controlling Interests	130	120	2	8
Preference Equity Shareholders	67	66	—	1
Common Equity Shareholders	1,655	1,100	20	535
Net Earnings	1,852	1,286	22	544

### Revenue

The increase was due primarily to: (i) Rate Base growth at the regulated utilities, led by ITC; (ii) overall higher flow-through costs in customer rates; (iii) favourable foreign exchange of \$113 million; and (iv) a \$91 million favourable adjustment associated with the November 2019 FERC Order (see "Regulatory Highlights" on page 13). The increase was partially offset by: (i) lower revenue contribution from the Energy Infrastructure segment due primarily to the disposition of the Waneta Expansion and reduced hydroelectric production in Belize due to lower rainfall; and (ii) lower retail sales at UNS Energy due to weather.

### Energy Supply Costs

Energy supply costs were comparable to 2018. A reclassification of finance lease costs of \$29 million from energy supply costs to finance charges, due to the adoption of a new lease standard (see "Accounting Matters - New Accounting Policies" on page 33), was offset by overall higher commodity costs.

### Operating Expenses

The increase was due primarily to general inflationary and employee-related cost increases, including higher stock-based compensation costs driven by an increase in the Corporation's share price and overall performance.

### Depreciation and Amortization

The increase was due primarily to continued investment in energy infrastructure at the Corporation's regulated utilities.

### Gain on Disposition

See "Significant Items" on page 3.

### Other Income, Net

The increase was due primarily to: (i) favourable foreign exchange contracts; (ii) higher AFUDC equity earnings at UNS Energy; and (iii) an \$11 million gain on the repayment of US\$400 million of debt via tender offer (see "Significant Items" on page 3).

### Finance Charges

The increase was due primarily to: (i) overall higher operating utility debt levels to support the capital plan; and (ii) the reclassification of finance lease interest of \$29 million to finance charges from energy supply costs. The increase was partially offset by: (i) lower finance charges due to the repayment of debt (see "Significant Items" on page 3); and (ii) the reversal of interest of \$16 million as a result of the November 2019 FERC Order (see "Regulatory Highlights" on page 13).

### Income Tax Expense

The increase was driven by: (i) tax on the disposition of the Waneta Expansion (see "Significant Items" on page 3); (ii) \$44 million of favourable deferred income tax liability remeasurements in 2018 arising from an election to file a consolidated state income tax return and the designation of net assets related to the Waneta Expansion as held for sale; and (iii) the recognition of income tax expense of \$12 million in 2019 related to the finalization of US tax reform regulations associated with base-erosion and anti-abuse tax, partially offset by higher valuation allowances released in 2019 compared to 2018.

### Net Earnings

See "Performance at a Glance - Earnings and EPS" on page 3.

## BUSINESS UNIT PERFORMANCE

Common Equity Earnings		Variance		
Years Ended December 31			FX <sup>(1)</sup>	Other
(\$ millions)	2019	2018		
<b>Regulated Utilities</b>				
ITC	471	361	9	101
UNS Energy	292	293	6	(7)
Central Hudson	85	74	2	9
FortisBC Energy	165	155	—	10
FortisAlberta	131	120	—	11
FortisBC Electric	54	56	—	(2)
Other Electric <sup>(2)</sup>	106	105	1	—
	<b>1,304</b>	<b>1,164</b>	<b>18</b>	<b>122</b>
<b>Non-Regulated</b>				
Energy Infrastructure	18	72	1	(55)
Corporate and Other	333	(136)	1	468
<b>Common Equity Earnings</b>	<b>1,655</b>	<b>1,100</b>	<b>20</b>	<b>535</b>

<sup>(1)</sup> The reporting currency of ITC, UNS Energy, Central Hudson, Caribbean Utilities, FortisTCI and BECOL is the US dollar. The reporting currency of Belize Electricity is the Belizean dollar, which is pegged to the US dollar at BZ\$2.00=US\$1.00. The Corporate and Other segment includes certain transactions denominated in US dollars.

<sup>(2)</sup> Comprised of the utility operations in eastern Canada and the Caribbean: Newfoundland Power; Maritime Electric; FortisOntario; Caribbean Utilities; FortisTCI; and Belize Electricity.

ITC		Variance		
(\$ millions)	2019	2018	FX	Other
Revenue <sup>(1)</sup>	1,761	1,504	35	222
Earnings <sup>(1)</sup>	471	361	9	101

<sup>(1)</sup> 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, net of foreign exchange, was due primarily to a \$91 million favourable adjustment to revenue associated with the November 2019 FERC Order (see "Regulatory Highlights" on page 13). Higher flow-through costs in customer rates and growth in Rate Base also contributed to the increase in revenue, partially offset by a reduction in the ROE incentive adders.

## Earnings

The increase, net of foreign exchange, was due primarily to the November 2019 FERC Order that resulted in a \$63 million increase in earnings, comprised of \$83 million related to the net reversal of liabilities established in prior periods, partially offset by \$20 million related to the 2019 impact of the reduced ROE. Growth in Rate Base, lower business development costs and a lower effective tax rate also contributed to the earnings increase, partially offset by a reduction in the ROE incentive adders and higher non-recoverable expenses.

UNS Energy	2019	2018	Variance	
			FX	Other
Retail electricity sales (GWh)	10,431	10,600	—	(169)
Wholesale electricity sales (GWh) <sup>(1)</sup>	7,923	6,806	—	1,117
Gas sales (PJ)	16	13	—	3
Revenue (\$ millions)	2,212	2,202	46	(36)
Earnings (\$ millions)	292	293	6	(7)

<sup>(1)</sup> Primarily short-term wholesale sales

## Sales

The decrease in retail electricity sales was due to reduced air conditioning load as a result of cooler-than-normal temperatures in the spring and summer months compared to warmer-than-normal temperatures for the same periods in 2018.

The increase in wholesale electricity sales was due primarily to higher short-term wholesale sales reflecting an increase in system capacity related to Gila River Unit 2. Revenue from short-term wholesale sales is primarily returned to customers through regulatory deferral mechanisms and, therefore, does not materially impact earnings.

The increase in gas volumes was due primarily to heating load as a result of cooler temperatures in the winter months.

## Revenue

The decrease, net of foreign exchange, was due primarily to the flow through of lower energy supply costs and lower retail sales. The decrease in revenue was partially offset by higher flow-through costs related to Springerville Units 3 and 4 and higher short-term wholesale sales.

## Earnings

The decrease, net of foreign exchange, was due primarily to higher depreciation and interest expense associated with Rate Base growth not yet reflected in customer rates, and lower retail sales. The decrease was partially offset by higher AFUDC earnings, lower operating costs associated with scheduled outages and maintenance, and a lower effective tax rate.

Central Hudson	2019	2018	Variance	
			FX	Other
Electricity sales (GWh)	4,963	5,118	—	(155)
Gas sales (PJ)	22	24	—	(2)
Revenue (\$ millions)	917	924	24	(31)
Earnings (\$ millions)	85	74	2	9

### Sales

The decrease in electricity sales was due primarily to lower average consumption as a result of warmer temperatures in winter months that decreased heating load and cooler temperatures in summer months that decreased air conditioning load. Gas volumes were comparable to 2018.

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

### Revenue

The decrease, net of foreign exchange, was due primarily to the flow through of lower energy supply costs and lower electricity sales, partially offset by Rate Base growth.

### Earnings

The increase, net of foreign exchange, was primarily due to Rate Base growth and higher storm restoration costs in 2018.

<b>FortisBC Energy</b>	<b>2019</b>	2018	Variance
Gas sales ( <i>PJ</i> )	227	212	15
Revenue ( <i>\$ millions</i> )	1,331	1,187	144
Earnings ( <i>\$ millions</i> )	165	155	10

### Sales

The increase was due primarily to higher average residential and commercial consumption as a result of colder temperatures in 2019 that increased heating load and higher consumption by transportation customers.

### Revenue

The increase was due primarily to a higher cost of natural gas and other flow-through costs recovered from customers, the recovery of gas storage and transportation costs related to a third-party pipeline incident that occurred in the fourth quarter of 2018, and Rate Base growth.

### Earnings

The increase 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 the delivery. Due to regulatory deferral mechanisms, changes in consumption levels and commodity costs do not materially impact earnings.

<b>FortisAlberta</b>	<b>2019</b>	2018	Variance
Energy deliveries ( <i>GWh</i> )	16,887	17,154	(267)
Revenue ( <i>\$ millions</i> )	598	579	19
Earnings ( <i>\$ millions</i> )	131	120	11

### Deliveries

The decrease was due primarily to lower average consumption by oil and gas customers along with lower average residential consumption as a result of cooler temperatures in 2019 that decreased air conditioning load in the summer months. The decrease in energy deliveries was partially offset by higher average commercial consumption due to customer additions.

As more than 80% of FortisAlberta's revenue is derived from fixed or largely fixed billing determinants, changes in quantities of energy delivered are not entirely correlated with changes in revenue. Revenue is a function of numerous variables, many of which are independent of actual energy deliveries.

### Revenue

The increase was due primarily to Rate Base growth and customer additions, partially offset by a favourable capital tracker revenue true-up in 2018 related to capital expenditures in 2016 and 2017.

### Earnings

The increase was due primarily to lower operating expenses, driven by reduced labour costs, and Rate Base growth. The increase was partially offset by the 2018 capital tracker revenue true-up and a higher effective tax rate.

<b>FortisBC Electric</b>	<b>2019</b>	2018	Variance
Electricity sales (GWh)	<b>3,326</b>	3,250	76
Revenue (\$ millions)	<b>418</b>	408	10
Earnings (\$ millions)	<b>54</b>	56	(2)

### Sales

The increase was due primarily to higher consumption by industrial customers.

### Revenue

The increase was due primarily to higher electricity sales, higher revenue related to a customer load growth regulatory mechanism and overall higher flow-through costs. The increase was partially offset by lower surplus power sales and the loss of revenue associated with the provision of operating, maintenance and management services to the Waneta Expansion (see "Significant Items" on page 3).

### Earnings

The decrease was due primarily to the loss of revenue associated with the Waneta Expansion, partially offset by Rate Base growth.

<b>Other Electric</b>	<b>2019</b>	2018	Variance	
			FX	Other
Electricity sales (GWh)	<b>9,366</b>	9,314	—	52
Revenue (\$ millions)	<b>1,467</b>	1,412	7	48
Earnings (\$ millions)	<b>106</b>	105	1	—

### Sales

The increase was due primarily to overall higher average consumption in the Caribbean and customer additions.

### Revenue

The increase, net of foreign exchange, was due primarily to the flow through of higher energy supply costs and higher electricity sales, partially offset by business interruption insurance proceeds recognized in 2018 at FortisTCI related to Hurricane Irma.

### Earnings

Earnings, net of foreign exchange, were comparable to 2018. Higher electricity sales and Rate Base growth were offset by FortisTCI's insurance proceeds recognized in 2018.

<b>Energy Infrastructure</b>	<b>2019</b>	2018	Variance	
			FX	Other
Electricity sales (GWh)	<b>144</b>	853	—	(709)
Revenue (\$ millions)	<b>82</b>	184	1	(103)
Earnings (\$ millions)	<b>18</b>	72	1	(55)

### Sales

Electricity sales decreased by 541 GWh due to the disposition of the Waneta Expansion (see "Significant Items" on page 3), with the remaining decrease due to lower hydroelectric production in Belize reflecting lower rainfall.

**Revenue and Earnings**

The decreases in revenue and earnings reflected: (i) lower hydroelectric production in Belize; (ii) the disposition of the Waneta Expansion; (iii) lower realized margins at Aitken Creek; and (iv) the unfavourable impact of mark-to-market accounting of natural gas derivatives at Aitken Creek, with unrealized losses of \$15 million during 2019 compared to \$10 million during 2018.

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 resulting earnings volatility can be significant.

Corporate and Other (\$ millions)	2019	2018	Variance	
			FX	Other
Net income (expenses)	333	(136)	1	468

The increase in net income was driven by: (i) a net after-tax gain of \$484 million on the disposition of the Waneta Expansion (see "Significant Items" on page 3); (ii) lower finance charges associated with the disposition, along with a gain on the repayment of debt; (iii) favourable changes associated with foreign exchange contracts in 2019 compared to 2018; and (iv) lower tax expense due to higher valuation allowances released in 2019 compared to 2018, partially offset by the recognition of base-erosion and anti-abuse tax in 2019 as a result of the finalization of the related US tax reform regulations. The increase was also partially offset by lower income tax recovery due to the remeasurement of deferred tax liabilities recognized during 2018: (i) \$30 million resulting from the election to file a consolidated state income tax return; and (ii) \$14 million associated with the designation of the net assets of the Waneta Expansion as held for sale.

**NON-US GAAP FINANCIAL MEASURES**

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

Net earnings attributable to common equity shareholders (i.e., Common Equity Earnings) and basic EPS are the most directly comparable US GAAP measures to Adjusted Common Equity Earnings and Adjusted Basic EPS, respectively. The Actual Payout Ratio calculated using Common Equity Earnings is the most comparable US GAAP measure to the Adjusted Payout Ratio.

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

<b>Non-US GAAP Reconciliation</b>			
Years Ended December 31			
<i>(\$ millions, except as shown)</i>			
	2019	2018	Variance
Common Equity Earnings	1,655	1,100	555
Adjusting items:			
Gain on disposition <sup>(1)</sup>	(484)	—	(484)
November 2019 FERC Order (2)	(83)	—	(83)
US tax reform (3)	12	—	12
Unrealized loss on mark-to-market of derivatives (4)	15	10	5
Consolidated state income tax election (5)	—	(30)	30
Assets held for sale (5)	—	(14)	14
Adjusted Common Equity Earnings	1,115	1,066	49
Adjusted Basic EPS (\$)	2.55	2.51	0.04

<sup>(1)</sup> See "Significant Items" on page 3, included in the Corporate and Other segment

<sup>(2)</sup> See "Regulatory Highlights" below, included in the ITC segment

<sup>(3)</sup> The finalization of US tax reform regulations associated with base-erosion and anti-abuse tax, included in the Corporate and Other segment

<sup>(4)</sup> Represents timing differences related to the accounting of natural gas derivatives at Aitken Creek, included in the Energy Infrastructure segment

<sup>(5)</sup> Remeasurement of deferred income tax liabilities, included in the Corporate and Other segment

## REGULATORY HIGHLIGHTS

### Regulation

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. Under PBR mechanisms, formulae are generally applied that incorporate inflation and assumed productivity improvements for a set term.

The ability to recover prudently incurred costs of providing service and earn the regulator-approved ROE or ROA generally depends on achieving the forecasts established in the rate-setting process. There can be varying degrees of regulatory lag between when costs are incurred and when they are reflected in customer rates.

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

Additional information about regulation and the regulatory matters discussed below is provided in Note 2 in the 2019 Annual Financial Statements. Also refer to "Business Risks - Regulation" on page 25.

### ITC

#### *Incentive Adder Complaint*

In April 2018 a third-party complaint was filed with FERC challenging the independence incentive adders that are included in transmission rates charged by ITC's MISO Subsidiaries. The adder allowed up to 0.50% or 1.00% to be added to the authorized ROE, subject to any ROE cap established by FERC. In October 2018 FERC issued an order reducing the adders to 0.25%, effective April 20, 2018. This equated to a 0.25% decrease in ROE, down from the approximate 0.50% that ITC was earning in rates previously approved by FERC. ITC began reflecting the 0.25% adder in transmission rates in November 2018. ITC's MISO Subsidiaries sought rehearing of this order in 2018, which was denied by FERC. In September 2019 ITC's MISO Subsidiaries filed an appeal in the US Court of Appeal. The final resolution of this matter is not expected to have a material impact on the Corporation's earnings or cash flows.

### *ROE Complaints*

Two third-party complaints requested that the base ROE for MISO transmission owners, including ITC's MISO Subsidiaries, be found to no longer be just or reasonable. The complaints cover two consecutive 15-month periods from November 2013 through February 2015 (the "Initial Refund Period" or "Initial Complaint") and February 2015 through May 2016 (the "Second Refund Period" or "Second Complaint").

In June 2016 the presiding ALJ issued an initial decision on the Second Complaint, recommending a base ROE of 9.70%, up to a maximum of 10.68% with incentive adders. Pending an order from FERC, an estimated regulatory liability of \$206 million (US\$151 million) had been recognized as at December 31, 2018 based on the ALJ's initial decision.

In September 2016 FERC ordered that the base ROE for the Initial Refund Period be set at 10.32%, down from 12.38%, up to a maximum of 11.35% with incentive adders. The resultant rates applied prospectively from September 2016 until an approved ROE was established for the Second Refund Period. The total refund for the Initial Complaint as a result of the September 2016 FERC order was \$158 million (US\$118 million), including interest, and was paid in 2017.

The November 2019 FERC Order determined that the base ROE for the Initial Complaint and from September 2016 onward be 9.88%, up to a maximum of 12.24% with incentive adders. FERC also dismissed the Second Complaint, resulting in a ROE for that period of 12.38% plus incentive adders with no refund required. In addition, as an ROE complaint had not been filed for the period of May 2016 to September 2016, the ROE for that period continued to be 12.38% plus incentive adders with no refund required. The regulated utilities in the MISO region, including ITC, sought rehearing of this order on the basis that it will not allow utilities to earn a reasonable rate of return on investment. In January 2020 FERC issued an order granting the rehearing for further consideration, effectively extending FERC's review.

As at December 31, 2019, a regulatory liability of \$91 million (US\$70 million) was recognized related to the impact of the November 2019 FERC Order on the Initial Refund Period and for the period from September 2016 to December 2019. Additionally, the regulatory liability of \$206 million (US\$151 million) as at December 31, 2018, related to the Second Complaint, was reversed in 2019. The net impact of the November 2019 FERC Order was an increase in revenue and a decrease in interest expense resulting in an increase in net earnings of \$79 million of which Fortis' share was \$63 million. The favourable impact was comprised of: (i) \$83 million related to the net reversal of liabilities established in prior periods; partially offset by (ii) \$20 million related to the 2019 impact of a reduced ROE.

Based on the outcome of the request for rehearing, it is possible the ROE and refunds could materially change from those recognized in 2019.

### *Notices of Inquiry*

In March 2019 FERC issued a NOI seeking comments on whether and how to improve its electric transmission incentives policy. The outcome may impact the existing incentive adders that are included in transmission rates charged by transmission owners, including ITC. Also in March 2019, FERC issued a second NOI seeking comments on whether and how recent policies concerning the determination of the base ROE for electric utilities should be modified. The comment period for both NOI proceedings has ended. The outcome may impact ITC's future ROE and incentive adders.

## **UNS Energy**

### *General Rate Application*

In April 2019 TEP filed a general rate application with the Arizona Corporation Commission requesting an increase in non-fuel revenue of US\$99 million, effective May 1, 2020, with electricity rates based on a 2018 historical test year. Intervenor testimony in relation to TEP's revenue requirement and rate design was filed in October 2019. The application, adjusted for rebuttal testimony filed by TEP in November 2019, includes a request to increase TEP's allowed ROE to 10.00% from 9.75% and the equity component of its capital structure to 53% from 50% on a Rate Base of US\$2.7 billion. Hearings before the ALJ commenced in January and a decision is expected by mid-2020.

## **FortisBC Energy and FortisBC Electric**

In March 2019 FortisBC Energy and FortisBC Electric filed applications with the BCUC requesting approval of a multi-year rate plan and PBR methodology for 2020-2024. A decision is expected in mid-2020.

## FortisAlberta

### *Second-Term Performance-Based Rate-Setting Proceeding*

The AUC has ongoing proceedings to review regulatory applications for rebasing inputs included in PBR rates for 2018-2022, including anomaly-related adjustments and approved changes to depreciation parameters.

In January 2020 the AUC issued two decisions: (i) confirming that changes to depreciation parameters will be incorporated into incremental funding mechanisms; and (ii) establishing new criteria for anomaly-related adjustments. PBR utilities in Alberta are permitted to file depreciation studies by July 2020 and were required to submit their intent to file an anomaly-related adjustment application by February 7, 2020. FortisAlberta does not anticipate filing a depreciation study in 2020 and did notify the AUC of its intent to file an anomaly-related adjustment application.

### *Generic Cost of Capital Proceeding*

In December 2018 the AUC initiated a generic cost of capital proceeding to consider a formula-based approach to setting the allowed ROE beginning in 2021 and whether any process changes are necessary for determining capital structure in years in which a ROE formula is in place. In April 2019 the AUC determined that a traditional non-formulaic approach for assessing ROE and deemed capital structure would be used in 2021, with consideration of a formula-based approach for determining the allowed ROE for 2022 and subsequent years. Expert evidence was filed in January 2020 with an oral hearing scheduled for April 2020. An AUC decision is expected later in 2020.

### *2018 Alberta Independent System Operator Tariff Application*

In September 2019 the AUC issued a decision that addressed, among other things, a proposal to change how the AESO's customer contribution policy is accounted for between distribution facility owners, such as FortisAlberta, and transmission facility owners. The decision prevents any future investment by FortisAlberta under the policy and directs that the unamortized customer contributions of approximately \$400 million as at December 31, 2017, which form part of FortisAlberta's Rate Base, be transferred to the incumbent transmission facility owner in FortisAlberta's service area.

In October 2019 FortisAlberta filed evidence to oppose the decision. Implementation of the order has been suspended and the decision remains under review by the AUC. It is expected that the decision will remain under review through the first quarter of 2020. The likely outcome of this process and potential impacts, if any, cannot be determined at this time.

## FINANCIAL POSITION

Significant Changes between December 31, 2019 and 2018			
Balance Sheet Account	Increase (Decrease)		Explanation
	FX (\$ millions)	Other (\$ millions)	
Assets held for sale	—	(766)	Due to the disposition of the Waneta Expansion.
Regulatory assets (including current and long-term)	(55)	363	Due primarily to the operation of rate stabilization accounts and the normal deferral of derivative losses, energy management costs, income tax expense and employee future benefits.
Property, plant and equipment, net	(974)	2,205	Due primarily to capital expenditures, partially offset by depreciation.
Goodwill	(527)	1	The other increase was not significant.
Short-term borrowings	(2)	454	Due primarily to the issuance of commercial paper at ITC and short-term borrowings at UNS Energy.

Significant Changes between December 31, 2019 and 2018			
Balance Sheet Account	Increase (Decrease)		Explanation
	FX (\$ millions)	Other (\$ millions)	
Other liabilities	(32)	340	Due primarily to higher employee future benefits mainly at FortisBC Energy, and finance lease reclassifications and the balance sheet recognition of operating leases in accordance with the new lease standard (see "New Accounting Policies" on page 33). The increase was also due to higher derivative balances and asset retirement obligations primarily at UNS Energy.
Regulatory liabilities (including current and long-term)	(130)	(138)	Due primarily to the ROE complaints liability at ITC and lower deferred taxes.
Deferred income tax liabilities	(70)	353	Due primarily to the timing differences related to capital expenditures.
Long-term debt (including current portion)	(791)	(1,103)	Due primarily to the repayment of Corporate debt (see "Significant Items" on page 3), partially offset by the issuance of debt at the regulated utilities.
Finance leases (including current portion)	(12)	(193)	Due primarily to the purchase of Gila River Unit 2, partially offset by the recognition of a finance lease for Springerville Common Facilities at TEP. The decrease was also due to reclassifications to other liabilities as noted above.
Shareholders' equity	(585)	2,583	Due primarily to: (i) the issuance of common shares (see "Significant Items" on page 3); and (ii) Common Equity Earnings for 2019, less dividends declared on common shares.
Non-controlling interests	(75)	(266)	Due primarily to the disposition of the Waneta Expansion.

## LIQUIDITY AND CAPITAL RESOURCES

### CASH FLOW REQUIREMENTS

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

Cash required of Fortis to support subsidiary capital expenditures is expected to be derived from borrowings under the Corporation's committed credit facility, proceeds from the DRIP and issuances of common shares, preference shares and long-term debt. Depending on the timing of subsidiary dividend receipts, borrowings under the Corporation's credit facility may be required periodically to support debt servicing and dividend payments.

Within this dynamic, the subsidiaries pay dividends to Fortis and receive equity injections from Fortis when required, and both Fortis and its subsidiaries initially borrow through their committed credit facilities and periodically replace these borrowings with long-term debt. Financing needs also arise periodically for acquisitions.

Credit facilities are syndicated primarily with large banks in Canada and the US, with no one bank holding more than 20% of the total facilities. Approximately \$5.1 billion of the total credit facilities are committed with maturities ranging from 2020 through 2024. Available credit facilities are summarized in the following table.

<b>Credit Facilities</b>				
As at December 31 (\$ millions)	Regulated Utilities	Corporate and Other	2019	2018
Total credit facilities <sup>(1)</sup>	4,209	1,381	5,590	5,165
Credit facilities utilized:				
Short-term borrowings	(512)	—	(512)	(60)
Long-term debt (including current portion)	(640)	—	(640)	(1,066)
Letters of credit outstanding	(64)	(50)	(114)	(119)
Credit facilities unutilized	2,993	1,331	4,324	3,920

<sup>(1)</sup> Additional information about these credit facilities is provided in Note 15 in the 2019 Annual Financial Statements.

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

In December 2018 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 \$2.5 billion. In December 2018 Fortis re-established its ATM Program, which allowed the issuance of up to \$500 million of common shares from treasury to the public at the Corporation's discretion, effective until January 2021.

During 2019 the Corporation issued approximately 4.1 million common shares under its ATM Program at an average price of \$52.16 per share. The gross proceeds of \$212 million (\$209 million net of commissions) were used primarily to fund capital expenditures. Also in 2019, the Corporation issued approximately 22.8 million common shares under a common equity offering at a price of \$52.15 per share for gross proceeds of \$1,190 million (\$1,167 million net of commissions). See "Significant Items" on page 3. Following this issuance, the Corporation terminated the ATM Program. As at December 31, 2019, \$1,098 million remained available under the short-form base shelf prospectus.

As at December 31, 2019: (i) consolidated fixed-term debt maturities/repayments are expected to average \$945 million annually over the next five years; (ii) approximately 80% of the Corporation's consolidated long-term debt, excluding credit facility borrowings, had maturities beyond five years; and (iii) available credit facilities were \$5.6 billion with \$4.3 billion unutilized.

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 expect to continue to have reasonable access to long-term capital in 2020.

Fortis and its subsidiaries were in compliance with debt covenants as at December 31, 2019 and are expected to remain compliant in 2020.

## CASH FLOW SUMMARY

<b>Summary of Cash Flows</b>			
Years ended December 31			
<i>(\$ millions)</i>	2019	2018	Variance
Cash, beginning of year	332	327	5
Cash provided by (used in):			
Operating activities	2,663	2,604	59
Investing activities	(2,768)	(3,252)	484
Financing activities	154	644	(490)
Effect of exchange rate changes on cash and cash equivalents	(26)	24	(50)
Cash and change in cash associated with assets held for sale	15	(15)	30
<b>Cash, end of year</b>	<b>370</b>	<b>332</b>	<b>38</b>

### Operating Activities

See "Performance at a Glance - Operating Cash Flow" on page 5.

### Investing Activities

Cash used in investing activities reflects a higher capital spending level in 2019. See "Performance at a Glance - Capital Expenditures" on page 5 and "Capital Plan" on page 21. Cash used in investing activities was partially offset by proceeds from the disposition of the Waneta Expansion.

### Financing Activities

Cash flows related to financing activities will fluctuate from year to year as a result of changes in the subsidiaries' capital expenditures, the amount of Operating Cash Flows available to fund those capital expenditures and the amount of funding required from debt and common equity issuances.

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

Net proceeds from the disposition of the Waneta Expansion were used to repay credit facility borrowings and repurchase, via a tender offer, US\$400 million of its outstanding 3.055% unsecured senior notes due in 2026.

**Debt Financing**

<b>Long-Term Debt Issuances</b>		<b>Interest</b>				
Year ended December 31, 2019		<b>Month</b>	<b>Rate</b>	<b>Maturity</b>	<b>Amount</b>	<b>Use of</b>
(\$ millions, except %)		<b>Issued</b>	<b>(%)</b>			<b>Proceeds</b>
<b>ITC</b>						
Secured notes	January	4.55	2049	US	50	(1) (2) (3)
Unsecured term loan credit agreement (4)	June	(5)	2021	US	200	(6)
Secured notes	July	4.65	2049	US	50	(1) (2) (3)
First mortgage bonds	August	3.30	2049	US	75	(1) (2) (3)
<b>Central Hudson</b>						
Unsecured notes	October	3.89	2049	US	50	(2) (3) (6)
Unsecured notes	October	3.99	2059	US	50	(2) (3) (6)
<b>FortisBC Energy</b>						
Unsecured debentures	August	2.82	2049		200	(1)
<b>FortisTCI</b>						
Unsecured non-revolving term loan	February	(7)	2025	US	5	(2) (3)
<b>Caribbean Utilities</b>						
Unsecured notes	May	4.14	2049	US	40	(1) (3) (6)
Unsecured notes	August	4.14	2049	US	20	(2) (3) (6)
Unsecured notes	August	3.83	2039	US	20	(2) (3) (6)

(1) Repay credit facility borrowings

(2) Finance capital expenditures

(3) General corporate purposes

(4) Maximum amount of borrowings under this agreement was US\$400 million; in January 2020 the remaining US\$200 million was drawn to repay outstanding commercial paper balances

(5) Floating rate of a one-month LIBOR plus a spread of 0.60%

(6) Repay maturing long-term debt

(7) Floating rate of a one-month LIBOR plus a spread of 1.75%

In January 2020 ITC entered into an unsecured term loan credit agreement, due in January 2021, under which the maximum amount of US\$75 million was borrowed. The proceeds were used to repay credit facility borrowings.

**Common Equity Financing**

<b>Common Equity Issuances and Dividends Paid</b>			
Years Ended December 31			
(\$ millions, except as indicated)	<b>2019</b>	2018	Variance
Number of common shares issued (1) (# millions)	<b>34.8</b>	7.4	27.4
Amount of common shares issued (2)	<b>1,756</b>	307	1,449
Non-cash issuances (3)	<b>(314)</b>	(273)	(41)
Cash proceeds from common shares issued	<b>1,442</b>	34	1,408
Dividends paid per common share (\$)	<b>1.8275</b>	1.7250	0.1025
Total dividends paid	<b>793</b>	731	62
Non-cash DRIP	<b>(299)</b>	(272)	(27)
Cash dividends paid	<b>494</b>	459	35

(1) Mainly related to the Corporation's issuance of shares in the fourth quarter of 2019, DRIP and ATM Program

(2) Net of commissions of \$26 million (2018 - \$nil)

(3) Related to DRIP and stock options

On February 12, 2020, Fortis declared a dividend of \$0.4775 per common share payable on June 1, 2020. The payment of dividends is at the discretion of the Board of Directors and depends on the Corporation's financial condition and other factors.

## CONTRACTUAL OBLIGATIONS

Contractual Obligations As at December 31, 2019 (\$ millions)	Due						
	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Long-term debt:							
Principal <sup>(1)</sup>	22,320	690	872	1,146	1,553	1,106	16,953
Interest	15,483	929	910	879	846	786	11,133
Finance leases <sup>(2)</sup>	1,359	56	121	33	33	33	1,083
Other obligations	450	134	120	94	20	19	63
<b>Other commitments <sup>(3)</sup></b>							
Waneta Expansion capacity agreement	2,628	51	52	53	54	55	2,363
Gas and fuel purchase obligations	2,398	606	424	349	255	140	624
Power purchase obligations	1,743	244	183	168	163	119	866
Renewable PPAs	1,513	104	104	104	103	103	995
Build-transfer agreement - Oso Grande	438	438	—	—	—	—	—
ITC easement agreement	401	13	13	13	13	13	336
Renewables energy credit purchase agreements	124	26	18	17	10	10	43
Debt collection agreement	116	3	3	3	3	3	101
Other	299	36	26	24	25	29	159
	<b>49,272</b>	<b>3,330</b>	<b>2,846</b>	<b>2,883</b>	<b>3,078</b>	<b>2,416</b>	<b>34,719</b>

<sup>(1)</sup> Total is not reduced by unamortized deferred financing and discount costs of \$129 million.

<sup>(2)</sup> Additional information is provided in Note 16 in the 2019 Annual Financial Statements.

<sup>(3)</sup> Additional information is provided in Note 29 in the 2019 Annual Financial Statements.

### Other Contractual Obligations

The Corporation's regulated utilities are obligated to provide service to customers within their respective service territories. Consolidated capital expenditures are forecast to be approximately \$4.3 billion for 2020 and approximately \$18.8 billion over the five-year period from 2020 through 2024. See "Capital Plan" on page 21.

Under a funding framework with the Governments of Ontario and Canada, Fortis will contribute a minimum of approximately \$155 million of equity capital to the Wataynikaneyap Partnership, based on Fortis' proportionate 39% ownership interest and the final regulatory-approved capital cost of the related project. In October 2019 the Wataynikaneyap Partnership entered into loan agreements to finance the project during construction. In the event a lender under such construction 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.

As at December 31, 2019, FortisBC Holdings Inc., a non-regulated holding company, had \$78 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 \$114 million as at December 31, 2019 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.

<b>Consolidated Capital Structure <sup>(1)</sup> (%)</b>		
As at December 31	<b>2019</b>	2018
Debt <sup>(2)</sup>	<b>53.1</b>	57.0
Preference shares	<b>3.8</b>	3.8
Common shareholders' equity and minority interest <sup>(3)</sup>	<b>43.1</b>	39.2
	<b>100.0</b>	100.0

<sup>(1)</sup> Reflects the repayment of debt using proceeds from the disposition of the Waneta Expansion and the \$1.2 billion common equity offering (see "Significant Items" on page 3)

<sup>(2)</sup> Includes long-term debt and finance leases, including current portion, and short-term borrowings, net of cash

<sup>(3)</sup> Includes minority interest of 3.7% as at December 31, 2019 (December 31, 2018 - 4.5%)

#### Outstanding Share Data

As at February 12, 2020, the Corporation had issued and outstanding 463.5 million common shares and the following First Preference Shares: 5.0 million Series F; 9.2 million Series G; 7.0 million Series H; 3.0 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 12, 2020, an additional 3.2 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 level of holding company debt.

<b>Credit Ratings</b>			
As at December 31, 2019	Rating	Type	Outlook
S&P	A-	Corporate	Negative
	BBB+	Unsecured debt	
DBRS Morningstar	BBB (high)	Corporate	Stable
	BBB (high)	Unsecured debt	
Moody's	Baa3	Issuer	Stable
	Baa3	Unsecured debt	

#### CAPITAL PLAN

Capital investment in energy infrastructure is required to ensure the continued and enhanced performance, reliability and safety of the electricity and gas systems, and to meet customer growth. See "Performance at a Glance - Capital Expenditures" on page 5.

<b>2019 Capital Expenditures <sup>(1)</sup></b>											
(\$ millions, except %)	Regulated Utilities							Total Regulated Utilities	Non-Regulated <sup>(2)</sup>	Total	(%)
	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Other Electric				
Generation	—	442	2	—	—	29	57	530	6	536	14
Transmission	951	83	55	194	—	18	146	1,447	—	1,447	38
Distribution	—	255	174	191	385	42	160	1,207	—	1,207	32
Other <sup>(3)</sup>	197	135	86	78	38	17	30	581	47	628	16
<b>Total</b>	1,148	915	317	463	423	106	393	3,765	53	3,818	100
(%)	31	24	8	12	11	3	10	99	1	100	

<sup>(1)</sup> Reflects cash outlay for property, plant and equipment and intangible assets as shown on the consolidated statements of cash flows in the 2019 Annual Financial Statements, as well as Fortis' share of development costs and capital spending for the Wataynikaneyap Transmission Power Project of \$98 million

<sup>(2)</sup> Includes Energy Infrastructure and Corporate and Other segments

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

Planned capital expenditures are based on detailed forecasts of energy demand, labour and material costs, general economic conditions, foreign exchange rates and other factors. These could change and cause actual expenditures to differ from forecast or plan.

Forecast 2020 Capital Expenditures <sup>(1)</sup>											
Regulated Utilities											
(\$ millions, except %)	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Other Electric	Total Regulated Utilities	Non-Regulated	Total	(%)
Generation	—	715	1	—	—	33	120	869	11	880	20
Transmission	914	189	44	221	—	4	254	1,626	—	1,626	37
Distribution	—	274	167	153	365	77	158	1,194	—	1,194	28
Other	62	212	80	133	71	27	34	619	21	640	15
<b>Total</b>	<b>976</b>	<b>1,390</b>	<b>292</b>	<b>507</b>	<b>436</b>	<b>141</b>	<b>566</b>	<b>4,308</b>	<b>32</b>	<b>4,340</b>	<b>100</b>
(%)	22	32	7	12	10	3	13	99	1	100	

<sup>(1)</sup> Excludes the non-cash equity component of AFUDC

Five-Year Capital Plan <sup>(1)</sup>						
(\$ billions)	2020	2021	2022	2023	2024	Total
	4.3	3.8	3.8	3.7	3.2	<b>18.8</b>

<sup>(1)</sup> Excludes the non-cash equity component of AFUDC

The Corporation's five-year 2020-2024 capital plan of \$18.8 billion is \$0.5 billion higher than the \$18.3 billion capital plan disclosed in the Q3 2019 MD&A due to a \$0.5 billion shift in spending to 2020 and 2021 (see "Performance at a Glance - Capital Expenditures" on page 5).

The \$18.8 billion five-year capital plan is \$1.5 billion higher than the \$17.3 billion for 2019-2023, as disclosed in the 2018 annual MD&A, largely due to: (i) expected grid enhancements and cleaner energy resources at ITC and Caribbean Utilities; (ii) expected expansion of the Tilbury LNG site at FortisBC Energy; (iii) an increase in the forecast foreign exchange rate from US\$1.00=CAD\$1.28 to US\$1.00=CAD\$1.32; and (iv) the above-noted shift in spending from 2019 to 2020 and 2021.

The capital plan is low risk and highly executable, with 99% of planned expenditures to occur at the regulated utilities and only 20% related to Major Capital Projects. Geographically, 55% of planned expenditures are expected in the US, including 26% at ITC, with 41% in Canada and the remaining 4% in the Caribbean.

Nature of Capital Expenditures (%)	Actual 2019	Forecast 2020	Five-Year Plan 2020-2024
Growth <sup>(1)</sup>	23	25	28
Sustaining <sup>(2)</sup>	60	62	59
Other <sup>(3)</sup>	17	13	13
<b>Total</b>	<b>100</b>	<b>100</b>	<b>100</b>

<sup>(1)</sup> Relates to the connection of new customers and infrastructure upgrades required to meet load growth, including AESO transmission-related investment at FortisAlberta

<sup>(2)</sup> Relates to the continued and enhanced performance, reliability and safety of generation, transmission and distribution assets

<sup>(3)</sup> Facilities, equipment, vehicles, information technology and other assets

Midyear Rate Base <sup>(1)</sup> (\$ billions)	Actual 2019	Forecast 2020	Forecast 2024
ITC	8.7	9.5	12.0
UNS Energy	5.1	5.8	6.9
Central Hudson	1.9	2.1	2.8
FortisBC Energy	4.5	5.0	6.6
FortisAlberta	3.5	3.7	4.3
FortisBC Electric	1.3	1.4	1.5
Other Electric	3.0	3.2	4.3
<b>Total</b>	<b>28.0</b>	30.7	38.4

<sup>(1)</sup> Simple average of Rate Base at beginning and end of the year

Total midyear Rate Base is forecast to grow to \$38.4 billion by 2024 under the five-year capital plan, representing a CAGR of 6.5%, which is supportive of continuing growth in earnings and dividends.

Major Capital Projects <sup>(1)</sup>		Pre- 2019	Actual 2019	Forecast		
(\$ millions)	Project			2020	2021- 2024	Expected Completion
ITC <sup>(2)</sup>	Multi-Value Regional Transmission Projects	581	44	11	265	2023
	34.5 to 69 kV Transmission Conversion Project	225	127	92	176	Post-2024
UNS Energy	Gila River Unit 2	—	212	—	—	2019
	Southline Transmission Project	—	—	19	373	Post-2024
	Oso Grande Wind Project	—	65	453	—	2020
FortisBC Energy	Lower Mainland Intermediate Pressure System Upgrade	208	180	72	—	2020
	Eagle Mountain Woodfibre Gas Line Project <sup>(3)</sup>	—	—	—	350	2023
	Transmission Integrity Management Capabilities Project	—	13	23	494	Post-2024
	Inland Gas Upgrades Project	3	6	57	262	Post-2024
	Tilbury 1B	—	8	37	315	2024
Other Electric	Wataynikaneyap Transmission Power Project <sup>(4)</sup>	25	98	230	271	2023
<b>Total</b>		1,042	753	994	2,506	

<sup>(1)</sup> Includes applicable AFUDC

<sup>(2)</sup> Pre-2019 capital expenditures are from the date of the ITC acquisition on October 14, 2016

<sup>(3)</sup> Net of forecast customer contributions

<sup>(4)</sup> Fortis' share of estimated capital spending, including deferred development costs. Under the funding framework, Fortis will be funding its equity component only.

### Multi-Value Regional Transmission Projects

Consists of four regional electric transmission projects that have been identified by MISO to address system capacity needs and reliability in various states. Three projects have been completed, one in 2018 and two in 2019. The fourth project is expected to be placed in service in 2023.

### 34.5 to 69kV Transmission Conversion Project

Consists of multiple capital initiatives designed to construct new 69-kV lines, and upgrade existing 34.5-kV lines to 69 kV, with in-service dates ranging from 2019 to post-2024.

### Gila River Unit 2

In 2017 UNS Energy entered into a 20-year tolling PPA that included a three-year option to purchase Gila River Unit 2. The purchase of Gila River Unit 2 was completed in December 2019 and replaces the early retirement of coal-fired generation.

**Southline Transmission Project**

UNS Energy continues to evaluate the cost and timelines associated with the different phases of this project. The first phase, referred to as "Vail-to-Tortolita", is a joint effort between Western Area Power Administration and TEP that will result in new construction and upgrades to connect existing TEP substations. Construction of this phase is expected to commence in 2020.

The second phase of the project relates to the construction of a 600-MW transmission line across southern New Mexico and southern Arizona. The line will improve regional reliability and facilitate the connection of renewable energy resources to the grid, including the Oso Grande Wind Project. UNS Energy expects to purchase a 250-MW ownership in the project. The timing, share and cost of this phase of the project will depend on subscription of the remaining wind available at Oso Grande.

**Oso Grande Wind Project**

Relates to the construction of a 750-MW wind-powered electric generating facility that will complement UNS Energy's existing renewable solar generation portfolio, of which UNS Energy will own 250 MW. Construction on Oso Grande commenced in the third quarter of 2019 and in January 2020 UNS Energy took ownership of its share under a build-transfer contract. Construction is expected to be completed for operation by December 2020.

**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 Burnaby and Coquitlam sections of the project were gasified during 2018 and 2019. A short pipeline segment in South Vancouver will be replaced in 2020. Final allowable project costs are subject to review by the BCUC.

**Eagle Mountain Woodfibre Gas Line Project**

Consists of a pipeline expansion to a proposed LNG site in Squamish, British Columbia. Cost estimates are subject to final project scoping and determination of customer capital contributions. An Order in Council from the Government of British Columbia effectively exempts the project from further regulatory approval. FortisBC Energy and Woodfibre LNG Limited have entered into a pre-execution work agreement enabling FortisBC Energy to incur project feasibility and development costs.

**Transmission Integrity Management Capabilities Project**

Project to improve gas line safety and transmission system integrity, including gas line modifications and looping. In December 2018 a regulatory deferral account was approved by the BCUC to capture approximately \$40 million of development costs to be incurred through 2020 to enable the filing for a CPCN.

**Inland Gas Upgrades Project**

Relates to gas line modifications and replacements to enable in-line integrity inspection capabilities. In January 2020 the CPCN application was approved by the BCUC.

**Tilbury 1B Project**

Consists of construction of additional liquefaction and dispensing in support of optimizing the existing investment in Tilbury Phase 1A Expansion Project. The project has received an Order in Council from the Government of British Columbia. Pre-front-end engineering design and related studies will continue in 2020.

**Wataynikaneyap Transmission Power Project**

Consists of the construction of a \$1.6 billion, 1,800 kilometre, OEB-regulated transmission line to connect 17 remote First Nations communities in Northwestern Ontario to the main electricity grid. FortisOntario is responsible for construction management and operation of the transmission line. The initial phase to connect the Pikangikum First Nation was fully funded by the Canadian government and completed in late 2018. In the fourth quarter of 2019, the project received financial close and a notice to proceed for construction was issued. The project is targeted for completion by the end of 2023.

**Additional Investment Opportunities**

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

*ITC - Lake Erie Connector*

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

*FortisBC Energy - LNG*

Relates to FortisBC's 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. Fortis continues to have discussions with potential export customers.

*Other Opportunities*

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

**BUSINESS RISKS**

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

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

**Regulation**

Regulated utility assets represented approximately 99% of the Corporation's total assets as at December 31, 2019. Regulatory jurisdictions include five Canadian provinces, nine US states and three Caribbean countries, as well FERC regulation for transmission assets in the US.

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

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

For transmission operations, the underlying elements of FERC-established formula rates can be, and have been, challenged by third parties which could result in, and has resulted in, lowered rates and customer refunds. These underlying elements include the assumed ROE and deemed capital structure as well as operating and capital expenditures. These challenges could have a Material Adverse Effect. Recent challenges are described under "Regulatory Highlights - ITC" on page 13.

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

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

### **Climate Change and Physical Risks**

The provision of electric and gas service is subject to customary industry risks, including severe weather and natural disasters, wars, terrorism, critical equipment failure and other catastrophic events within and outside the Corporation's service territories. Resultant service disruption and repair and replacement costs could have a Material Adverse Effect if not resolved in a timely and effective manner and/or mitigated through insurance policies or regulatory cost recovery.

Climate change is predicted to lead to more frequent and intense weather events, changing air temperatures, changing seasonal variations, and regulatory responses (see "Environmental Matters" on page 31), each of which could have a Material Adverse Effect. Severe weather impacts the Corporation's service territories, primarily when thunderstorms, flooding, wildfires, hurricanes and snow or ice storms occur. Increased frequency of extreme weather events could increase the cost of providing service. Changes in precipitation that result in droughts could increase the risk of wildfire caused by the Corporation's electricity assets or may cause water shortages that could adversely affect operations. Extreme weather conditions in general require system backup and can contribute to increased system stress, including service interruptions. Changing air temperatures could also result in system stress and decreased efficiencies over time to operating facilities. Longer-term climate change impacts, such as sustained higher temperatures, higher sea levels and larger storm surges, could result in service disruption, repair and replacement costs, and costs associated with strengthened design standards and systems, each of which could have a Material Adverse Effect if not resolved in a timely and effective manner and/or mitigated through insurance policies or regulatory cost recovery.

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

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

The gas utilities are exposed to operational risks associated with natural gas, including fires, explosions, pipeline corrosion and leaks, accidental damage to mains and service lines, equipment failure, damage and destruction from earthquakes, fires, floods and other natural disasters, and other accidents and issues that can lead to service disruption, spills and commensurate environmental liability, or other liability with a Material Adverse Effect.

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

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

The electricity and gas systems are designed to service customers under various contingencies in accordance with good utility practice. The utilities are responsible for operating and maintaining their assets in a safe manner, including the development and application of appropriate standards, system processes and/or procedures to ensure the safety of employees, contractors and the general public. The impacts of climate change may necessitate the acceleration of these standards, processes and procedures. Failure to do so may disrupt the ability of the utilities to safely provide service, which could cause reputational harm and other impacts with a Material Adverse Effect.

### **Interest Rates**

The market price of the Corporation's common shares is inversely sensitive to interest rate changes.

Additionally, allowed ROEs are exposed to changes in long-term interest rates. A low interest rate environment could reduce allowed ROEs. Alternatively, if interest rates rise, regulatory lag may cause delays in any compensatory ROE increases. Borrowings under variable-rate credit facilities and long-term debt, as well as new debt issuances, are also exposed to interest rate changes.

### **Weather Variability and Seasonality**

Electricity consumption varies significantly in response to climate change and seasonal weather changes. In central and western Canada, Arizona and New York State, cool summers may reduce the use of air conditioning and other cooling equipment, while less severe winters may reduce heating load. Alternatively, severe weather could unexpectedly increase heating and cooling loads, negatively impacting system reliability.

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

Hydroelectric generation is sensitive to rainfall levels.

Regulatory deferral and revenue decoupling mechanisms are in place at certain of the Corporation's utilities to minimize the volatility in earnings that would otherwise be caused by variations in weather conditions. Both the discontinuance of key regulatory mechanisms and their absence at other Fortis entities could result in significant and prolonged weather variations from seasonal norms having a Material Adverse Effect.

### **Growth**

Fortis has a history of growth through acquisitions and organic growth from capital expenditures 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 21. Projects, particularly Major Capital Projects, are subject to risks of delay and cost overruns during construction caused by inflation, supply and labour costs, supplier non-performance, weather, geologic conditions or other factors beyond the Corporation's control. There is no assurance that regulators will approve (i) all of the planned projects or their amounts or timing, (ii) permits in a timely manner, or with reasonable terms and conditions, or (iii) the recovery of 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.

**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 consolidated 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. Although Fortis has a robust talent management program, there is no assurance it will be able to continue to attract sufficient and appropriate talent. Significant failures in these regards could have a Material Adverse Effect.

**Tax Laws**

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

The nature, timing or impact of any future changes in tax laws cannot be predicted. Additionally, certain aspects of US tax reform are still subject to interpretation and clarification, including proposed regulations regarding certain hybrid arrangements.

**Cybersecurity**

As operators of critical energy infrastructure, the Corporation's utilities face the risk of cybercrime, which has increased in frequency, scope and potential impact in recent years. Their ability to operate effectively is dependent upon developing and maintaining complex information systems and infrastructure that support the operation of electric generation, transmission and distribution facilities, including gas facilities; provide customers with billing, consumption and load settlement information, where applicable; and support financial and general operations.

Despite risk-based cybersecurity programs that have been implemented and are continuously monitored for effectiveness, information and operations technology systems may be vulnerable to unauthorized access due to hacking, viruses, acts of war or terrorism, acts of vandalism and other causes. This can result in the disruption of energy service and other business operations, system failures and grid disturbances, property damage, corruption or unavailability of critical data, and the misappropriation and/or disclosure of sensitive, confidential and proprietary business, customer and employee information.

A material breach could adversely affect the financial performance of the Corporation, its reputation and standing with customers, regulators and financial markets, and expose it to claims for third-party damage. The resultant financial impacts may not be fully covered by insurance policies or, in the case of utilities, through regulatory cost recovery, and could have a Material Adverse Effect.

**Technology Advances**

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

New technology developments in distributed generation, particularly solar, and energy efficiency products and services, as well as the implementation of renewable energy and energy efficiency standards, will continue to impact retail sales. Heightened awareness of energy costs and environmental concerns have increased demand for products that reduce energy consumption. The Corporation's utilities are also promoting demand-side management programs.

New technologies include energy derived from renewable sources, customer-owned generation, energy-efficient appliances, battery storage and control systems. Advances in these or other technologies could have a significant impact on retail sales with a potential Material Adverse Effect.

### Foreign Exchange Exposure

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

Fortis has limited this exposure through hedging. As at December 31, 2019, US\$2.2 billion (December 31, 2018 - US\$3.4 billion) of corporately issued US dollar-denominated long-term debt had been designated as an effective hedge of foreign net investments, leaving US\$9.7 billion (December 31, 2018 - US\$8.0 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 flows continue to be impacted by exchange rate fluctuations. On average, Fortis estimates that a five-cent increase or decrease in the US dollar relative to the Canadian dollar exchange rate of US\$1.00=CAD\$1.33 as at December 31, 2019 would increase or decrease annual EPS by approximately 6 cents, which reflects the Corporation's hedging program.

There is no assurance that existing hedging strategies will continue to be effective. They could also have the effect of limiting or reducing the Corporation's total returns if management's expectations concerning future events or market conditions prove to be incorrect, in which case the costs associated with the hedging strategies may outweigh their benefits.

### Natural Gas Competitiveness

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

In British Columbia, which accounts for 79% 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, and leading to further reductions in competitiveness.

Government policy could also impact the competitiveness of natural gas in British Columbia. The provincial government has introduced changes to energy policy, including GHG emission reduction targets and a consumption tax on carbon-based fuels, but has not yet introduced a carbon tax on imported electricity generated through the combustion of carbon-based fuels. The impact of these changes to energy policy may have a material impact on the competitiveness of natural gas relative to non-carbon based energy sources or other energy sources.

In addition, all levels of government have become more active in the development of policies to address climate change. For example, municipal governments have developed policies and bylaws to support the transition to a lower-carbon economy. Government policy may put upward pressure on the cost of natural gas and potentially affect its competitiveness. Government policy may also impose limitations on energy sources permitted to be used in new and existing developments.

### Reliability Standards

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

**General Economic Conditions**

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

**Access to Capital**

Ongoing access to cost-effective capital is required to fund, among other things, capital expenditures and the repayment of maturing debt.

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

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

There is no assurance that sufficient capital will continue to be available on acceptable terms. For further information see "Liquidity and Capital Resources" on page 16.

**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 8); and (ii) price-risk management strategies such as the use of derivative contracts that effectively fix costs (see "Financial Instruments - Derivatives" on page 37).

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

**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 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.

**Purchased Power Supply**

A significant portion of electricity and gas sold by the Corporation's utilities is purchased through the wholesale energy markets or pursuant to contracts with energy suppliers rather than being generated. A disruption in the wholesale energy markets, or a failure on the part of energy or fuel suppliers or operators of energy delivery systems that connect to the Corporation's utilities, could have a Material Adverse Effect.

### **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 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 that may affect the facilities. A divergence in the interests of TEP and those of the joint owners or operators could have a Material Adverse Effect.

Wataynikaneyap Partnership is a partnership, owned 51% by 24 First Nations communities and 49% by a partnership between Fortis (80%) and Algonquin Power & Utilities Corp. (20%), 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.

### **Environmental Matters**

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

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

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

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

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

Some coal-fired generation facilities utilized by UNS Energy have closed before the end of their useful lives due to economic conditions and/or recent or expected changes in environmental regulations, including those relating to GHG emissions. Early closures have necessitated regulatory relief to recover any remaining net book values and decommissioning costs, and potential accelerated depreciation could cause rate pressure. Significant unrecovered costs or rate pressures could have a Material Adverse Effect.

**Insurance**

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

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

**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 and/or third parties. There is no assurance that: (i) all of these 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.

**Reputation, Relationships and Stakeholder Activism**

The Corporation's operations and growth prospects require strong relationships with key stakeholders, including governments and agencies, Indigenous communities, landowners, and environmental organizations. Inadequately managing expectations and issues important to stakeholders, including those arising during construction, could affect the Corporation's reputation as well as have a significant impact on its operations and infrastructure development.

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

**Indigenous Peoples' Land Claims**

The Corporation's British Columbia utilities provide service to customers on Indigenous Peoples' lands and maintain facilities on lands that are subject to Indigenous Peoples' land claims. A treaty negotiation process involving Indigenous Peoples and the Governments of British Columbia and Canada is underway, but the basis for potential settlements is unclear and not all Indigenous Peoples are participating in the process. 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 process 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.

**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.

## Legal, Administrative and Other Proceedings

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

## ACCOUNTING MATTERS

### New Accounting Policies

#### *Leases*

Effective January 1, 2019, the Corporation adopted ASU No. 2016-02, *Leases*, that requires lessees to recognize a right-of-use asset and lease liability for all leases with a lease term greater than 12 months, along with additional disclosures.

At lease inception, 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.

Fortis applied the transition provisions of the new standard as of the adoption date and did not retrospectively adjust prior periods in accordance with the modified retrospective approach. Fortis elected a package of implementation options, referred to as practical expedients, that allowed it to not reassess: (i) whether existing contracts, including land easements, are or contain a lease; (ii) the classification of existing leases; or (iii) the initial direct costs for existing leases. Fortis also utilized the hindsight practical expedient to determine the lease term. Upon adoption, Fortis did not identify or record an adjustment to the opening balance of retained earnings, and there was no impact on net earnings or cash flows.

#### *Hedging*

Effective January 1, 2019, the Corporation adopted ASU No. 2017-12, *Targeted Improvements to Accounting for Hedging Activities*, which better aligns risk management activities and financial reporting for hedging relationships through changes to designation, measurement, presentation and disclosure guidance. Adoption did not have a material impact on the 2019 Annual Financial Statements.

#### *Fair Value Measurement Disclosures*

Effective January 1, 2019, the Corporation adopted ASU No. 2018-13, *Changes to the Disclosure Requirements for Fair Value Measurement*, which improves the effectiveness of financial statement note disclosures by clarifying what is required and important to users of the financial statements. The adoption of this ASU removed the following disclosures for all periods presented: (i) the amount of, and reasons for, transfers between level 1 and level 2 of the fair value hierarchy; (ii) the policy for the timing of transfers between levels; and (iii) the valuation processes for level 3 fair value measurements.

#### *Pensions and Other Post-Retirement Plan Disclosures*

Effective December 31, 2019, the Corporation early adopted, on a retrospective basis, ASU No. 2018-14, *Changes to the Disclosure Requirements for Defined Benefit Plans*, which modifies the disclosure requirements for employers with defined pension or other post-retirement plans and clarifies disclosure requirements. In particular, it removed the following disclosures: (i) the amounts in accumulated other comprehensive income expected to be recognized as components of net period benefit costs over the next fiscal period; and (ii) the effects of a one-percentage-point change on the assumed health care costs and the change in rates on service cost, interest cost and the benefit obligation for post-retirement health care benefits.

**Future Accounting Pronouncements***Income Taxes*

ASU No. 2019-12, *Simplifying the Accounting for Income Taxes*, issued in December 2019, is effective for Fortis January 1, 2021, with early adoption permitted. Principally, it improves consistent application of, and clarifies, existing income tax guidance. Fortis is assessing the impact that adoption will have on its consolidated financial statements.

**Critical Accounting Estimates***General*

The preparation of the 2019 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, 2019, Fortis recognized regulatory assets of \$3.4 billion (December 31, 2018 - \$3.1 billion) and regulatory liabilities of \$3.4 billion (December 31, 2018 - \$3.6 billion).

Regulatory assets represent future revenues and/or receivables associated with incurred costs 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) an obligation 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. Historically, actual settlement amounts and periods have generally not differed materially from those estimated, but there is no assurance that this will always be the case. Differences arising from the regulator's orders would be recognized in accordance with those orders, whereby any amounts disallowed would be immediately recognized in earnings with the remainder recognized in earnings in accordance with their inclusion in customer rates.

**Employee Future Benefits**

Key Estimates and Assumptions	Defined Benefit Pension Plans		OPEB Plans	
	2019	2018	2019	2018
Years Ended December 31				
Funded status <sup>(1)</sup> (\$ millions)				
Benefit obligation <sup>(2)</sup>	(3,632)	(3,207)	(712)	(655)
Plan assets	3,208	2,830	343	293
	(424)	(377)	(369)	(362)
Net benefit cost <sup>(2)</sup> (\$ millions)	65	83	28	34
Key assumptions: (weighted average %)				
Discount rate <sup>(3)</sup>				
During the year	4.05	3.56	4.10	3.57
As at December 31	3.20	4.07	3.25	4.13
Expected long-term rate of return on plan assets <sup>(4)</sup>	5.78	5.80	5.50	5.48
Rate of compensation increase	3.33	3.35	—	—
Health care cost trend increase rate <sup>(5)</sup>	—	—	4.62	4.61

<sup>(1)</sup> Periodic actuarial valuations determine funding contributions for the pension plans and US OPEB plans, while Canadian OPEB plans are unfunded

<sup>(2)</sup> 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

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

<sup>(4)</sup> 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.

<sup>(5)</sup> Actuarially determined, the projected 2020 rate is 6.15% and is assumed to decrease over the next 12 years to the ultimate rate of 4.62% in 2031 and thereafter.

Sensitivity Analysis	Rate of Return - 1% change		Discount Rate - 1% change		Health Care Cost Trend Rate - 1% change	
	Increase	Decrease	Increase	Decrease	Increase	Decrease
Year ended December 31, 2019 (\$ millions)						
Defined benefit pension plans						
Net benefit cost	(25)	23	(29)	55	n/a	n/a
Projected benefit obligation	25	(80)	(482)	612	n/a	n/a
OPEB plans						
Net benefit cost	(3)	3	(7)	10	24	(18)
Accumulated benefit obligation	n/a	n/a	(100)	128	104	(83)

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.

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### **Depreciation and Amortization**

As at December 31, 2019, Fortis recognized property, plant and equipment and intangible assets of \$35.2 billion (December 31, 2018 - \$34.0 billion) representing 66% of total assets (December 31, 2018 - 64%). Depreciation and amortization totalled \$1.4 billion for 2019 (2018 - \$1.2 billion).

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

At the regulated utilities, depreciation rates require regulatory approval and include a provision for estimated future asset removal costs not identified as a legal obligation. Estimates primarily reflect historical experience and expected cost trends. The provision is recognized as a long-term regulatory liability against which actual removal costs are netted when incurred. As at December 31, 2019, this regulatory liability was \$1.2 billion (December 31, 2018 - \$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, 2019, Fortis recognized goodwill of \$12.0 billion (December 31, 2018 - \$12.5 billion), representing 22% of total assets (December 31, 2018 - 24%).

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 for certain reporting units 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. Otherwise, the primary method for estimating fair value of the reporting units is the income approach, whereby net cash flow projections are discounted using an enterprise value method. 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, 2019, deferred income tax liabilities, current income tax receivable included in accounts receivable, deferred income taxes included in regulatory assets, and deferred income taxes included in regulatory liabilities totalled \$3.0 billion, \$35 million, \$1.6 billion and \$1.4 billion, respectively (December 31, 2018 - \$2.7 billion, \$91 million, \$1.5 billion and \$1.6 billion, respectively). Income tax expense was \$289 million in 2019 (2018 - \$165 million).

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

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

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

### **Derivatives**

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

### **Contingencies**

The Corporation and its subsidiaries are subject to various legal proceedings and claims arising in the ordinary course of business, including those generally described under "Business Risks - Indigenous Peoples' Land Claims" on page 32, for which no amounts have been accrued because the outcomes currently cannot be reasonably determined. Further information is provided in Note 29 in the 2019 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, 2019, the carrying value of long-term debt, including the current portion, was \$22.3 billion (December 31, 2018 - \$24.2 billion) compared to an estimated fair value of \$25.3 billion (December 31, 2018 - \$25.1 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**

Fortis generally limits derivative usage to those qualifying as accounting, economic or cash flow hedges, or those that are otherwise 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 and commodity swaps 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/losses associated with changes in the fair value of these energy contracts are deferred as a regulatory asset/liability for recovery from/refund to customers in future rates, as permitted by the regulators. As at December 31, 2019, unrealized losses of \$119 million (December 31, 2018 - \$57 million) were recognized as regulatory assets and unrealized gains of \$2 million (December 31, 2018 - \$9 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 utilizing independent third-party information, where possible.

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/losses associated with changes in the fair value of these energy contracts are recognized in revenue. During 2019 unrealized losses of \$16 million (2018 - unrealized losses of \$12 million) were recognized in revenue.

*Total return swaps*

The Corporation holds total return swaps to manage the cash flow risk associated with forecasted future cash settlements of certain stock-based compensation obligations. The swaps have a combined notional amount of \$111 million and terms of one to three years expiring in January 2020, 2021 and 2022. Fair values are measured using an income valuation approach based on forward pricing curves. During 2019 unrealized gains of \$11 million (2018 - unrealized gains of less than \$1 million) were recognized in other income, net.

*Foreign exchange contracts*

The Corporation holds US dollar foreign exchange contracts to help mitigate exposure to volatility of foreign exchange rates. The contracts expire in 2020 and have a combined notional amount of \$166 million. Fair values are measured using independent third-party information. During 2019 unrealized gains of \$11 million (2018 - unrealized losses of \$11 million) were recognized in other income, net.

*Interest rate swaps*

During 2019 ITC entered into forward-starting interest rate swaps to manage the interest rate risk associated with the refinancing of long-term debt due in June 2021. The swaps have a combined notional value of \$260 million and five-year terms with a mandatory early termination provision. The swaps will be terminated no later than the effective date of November 2020. Fair value was measured using a discounted cash flow method based on LIBOR rates. Unrealized gains and losses associated with 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 2019.

*Other investments*

ITC, UNS Energy and Central Hudson hold investments in trust associated with supplemental retirement benefit plans for select employees. These investments consist of mutual funds and money market accounts, which are recorded at fair value based on quoted market prices in active markets. Gains/losses on these funds are recognized in other income, net and were not material for 2019 and 2018.

<b>Derivative Fair Values</b> (\$ millions)	Level 1 <sup>(1)</sup>	Level 2 <sup>(1)</sup>	Level 3 <sup>(1)</sup>	Total
<b>As at December 31, 2019</b>				
<b>Assets <sup>(2)</sup></b>				
Energy contracts subject to regulatory deferral	—	22	—	22
Energy contracts not subject to regulatory deferral	—	8	—	8
Foreign exchange contracts, interest rate and total return swaps	14	4	—	18
Other investments	121	—	—	121
	<b>135</b>	<b>34</b>	<b>—</b>	<b>169</b>
<b>Liabilities <sup>(3)</sup></b>				
Energy contracts subject to regulatory deferral	(1)	(138)	—	(139)
Energy contracts not subject to regulatory deferral	—	(12)	—	(12)
	<b>(1)</b>	<b>(150)</b>	<b>—</b>	<b>(151)</b>
<b>As at December 31, 2018</b>				
<b>Assets <sup>(2)</sup></b>				
Energy contracts subject to regulatory deferral	—	33	8	41
Energy contracts not subject to regulatory deferral	—	13	3	16
Other investments	155	—	—	155
	<b>155</b>	<b>46</b>	<b>11</b>	<b>212</b>
<b>Liabilities <sup>(3)</sup></b>				
Energy contracts subject to regulatory deferral	—	(86)	(3)	(89)
Energy contracts not subject to regulatory deferral	—	(1)	—	(1)
Foreign exchange contracts, interest rate and total return swaps	(8)	(1)	—	(9)
	<b>(8)</b>	<b>(88)</b>	<b>(3)</b>	<b>(99)</b>

<sup>(1)</sup> 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 measurement. At December 31, 2019, all level 3 assets and liabilities transferred to level 2 because observable market data became available.

<sup>(2)</sup> Current portion is included in accounts receivable and other current assets, with the remainder included in other assets.

<sup>(3)</sup> Current portion is included in accounts payable and other current liabilities, with the remainder included in other liabilities.

<b>Derivative Volumes <sup>(1)</sup></b>	2019	2018
<b>As at December 31</b>		
<b>Energy contracts subject to regulatory deferral</b>		
Electricity swap contracts (GWh)	628	774
Electricity power purchase contracts (GWh)	3,198	651
Gas swap contracts (PJ)	168	203
Gas supply contract premiums (PJ)	241	266
<b>Energy contracts not subject to regulatory deferral</b>		
Wholesale trading contracts (GWh)	1,855	1,440
Gas swap contracts (PJ)	43	37

<sup>(1)</sup> Energy contracts settle on various dates through 2029.

## SELECTED ANNUAL FINANCIAL INFORMATION

Years ended December 31 (\$ millions, except as indicated)	2019	2018	2017
Revenue	8,783	8,390	8,301
Net earnings	1,852	1,286	1,125
Common Equity Earnings	1,655	1,100	963
EPS: (\$)			
Basic	3.79	2.59	2.32
Diluted	3.78	2.59	2.31
Total assets	53,404	53,051	47,822
Long-term debt (excluding current portion)	21,501	23,159	20,691
Dividends declared: (\$)			
Per common share	1.855	1.750	1.650
Per first preference share:			
Series F	1.2250	1.2250	1.2250
Series G <sup>(1)</sup>	1.0983	1.0345	0.9708
Series H	0.6250	0.6250	0.6250
Series I <sup>(2)</sup>	0.7771	0.7116	0.5262
Series J	1.1875	1.1875	1.1875
Series K <sup>(3)</sup>	0.9821	1.0000	1.0000
Series M <sup>(4)</sup>	1.0135	1.0250	1.0250

<sup>(1)</sup> The annual dividend per share was reset from \$0.9708 to \$1.0983 for the five-year period from September 1, 2018 up to but excluding September 1, 2023.

<sup>(2)</sup> 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.

<sup>(3)</sup> The annual dividend per share was reset from \$1.0000 to \$0.9823 for the five-year period from March 1, 2019 up to but excluding March 1, 2024.

<sup>(4)</sup> The annual dividend per share was reset from \$1.0250 to \$0.9783 for the five-year period from December 1, 2019 up to but excluding December 1, 2024.

### 2019/2018

For a discussion of the changes in revenue, net earnings, Common Equity Earnings, EPS, total assets and long-term debt refer to "Performance at a Glance" on page 3, "Operating Results" on page 7, and "Financial Position" on page 15.

### 2018/2017

The 2018/2017 increase in revenue reflects: (i) higher wholesale electricity sales at UNS Energy driven by an increase in system capacity; and (ii) the flow through in 2018 customer rates of higher overall energy supply costs. The increase was partially offset by: (i) the recovery of lower income tax expense due to US tax reform; (ii) mark-to-market accounting adjustments for natural gas derivatives at Aitken Creek; and (iii) a change in presentation of certain revenues to a net basis upon implementation of ASC 606, *Revenue from Contracts with Customers*, in 2018.

The 2018/2017 increase in earnings primarily reflects growth at both the regulated and non-regulated businesses, as well as lower income tax expense, partially offset by one-time favourable adjustments recognized in 2017. Earnings in 2018 were also tempered by the ongoing impact of US tax reform and a lower ROE incentive adder at ITC effective April 2018.

The 2018/2017 increase in EPS reflects the above-noted earnings increases, partially offset by a 9.2 million increase in the weighted average number of common shares outstanding associated with the Corporation's DRIP.

The 2018/2017 increase in total assets was due to the impact of 2018 capital expenditures and foreign exchange on the translation of US dollar-denominated assets.

## FOURTH QUARTER RESULTS

<b>Sales</b>			
Fourth quarters ended December 31	2019	2018	Variance
<b>Regulated utilities</b>			
UNS Energy			
Retail Electricity (GWh)	2,223	2,225	(2)
Wholesale Electricity (GWh)	1,814	2,526	(712)
Gas (PJ)	5	5	—
Central Hudson			
Electricity (GWh)	1,188	1,250	(62)
Gas (PJ)	6	7	(1)
FortisBC Energy (PJ)	71	63	8
FortisAlberta (GWh)	4,279	4,343	(64)
FortisBC Electric (GWh)	888	839	49
Other Electric (GWh)	2,427	2,450	(23)
<b>Non-regulated - Energy Infrastructure (GWh)</b>	<b>14</b>	<b>85</b>	<b>(71)</b>

The decrease in wholesale electricity sales was due primarily to a decrease in system capacity at Gila River Unit 2 resulting from an outage. The increase in gas volumes at FortisBC Energy was due to higher average consumption by residential and commercial customers due to colder temperatures that increased heating load and higher consumption by transportation customers.

<b>Revenue and Common Equity Earnings</b>						
Fourth quarters ended December 31	Revenue			Common Equity Earnings		
<i>(\$ millions, except as indicated)</i>	2019	2018	Variance	2019	2018	Variance
<b>Regulated utilities</b>						
ITC	500	390	110	171	92	79
UNS Energy	510	541	(31)	38	27	11
Central Hudson	226	234	(8)	30	24	6
FortisBC Energy	428	371	57	77	72	5
FortisAlberta	150	140	10	33	22	11
FortisBC Electric	112	111	1	12	13	(1)
Other Electric	381	372	9	22	22	—
<b>Non-regulated</b>						
Energy Infrastructure	19	50	(31)	6	22	(16)
Corporate and Other	—	—	—	(43)	(33)	(10)
Inter-segment eliminations	—	(3)	3	—	—	—
<b>Total</b>	<b>2,326</b>	<b>2,206</b>	<b>120</b>	<b>346</b>	<b>261</b>	<b>85</b>
Weighted average number of common shares outstanding (millions)				447.1	427.5	19.6
Basic EPS (\$)				0.77	0.61	0.16

The increase in revenue was driven by the \$91 million favourable adjustment to revenue at ITC associated with the November 2019 FERC Order (see "Regulatory Highlights" on page 13) and higher revenue at FortisBC Energy due to overall higher flow-through costs. The increase was partially offset by lower revenue at UNS Energy due to lower short-term wholesale sales and lower revenue in the Energy Infrastructure segment due to the disposition of the Waneta Expansion in April 2019 (see "Significant Items" on page 3) and lower hydroelectric production in Belize.

The increase in Common Equity Earnings was due primarily to the November 2019 FERC Order at ITC, along with Rate Base growth at the regulated utilities.

The increase in basic EPS reflects higher Common Equity Earnings, partially offset by a 19.6 million increase in the weighted average number of common shares outstanding associated with the Corporation's common equity offering (see "Significant Items" on page 3), DRIP and ATM Program.

<b>Cash Flows</b>			
Fourth quarters ended December 31			
<i>(\$ millions)</i>	2019	2018	Variance
Cash, beginning of period	228	195	33
Cash provided by (used in):			
Operating activities	634	537	97
Investing activities	(1,104)	(999)	(105)
Financing activities	627	598	29
Foreign exchange	(15)	16	(31)
Cash associated with assets held for sale	—	(15)	15
Cash, end of period	370	332	38

### Operating Activities

The variance was due to higher cash earnings at the regulated subsidiaries, led by ITC, partially offset by unfavourable changes in working capital due primarily to timing differences.

### Investing Activities

The variance reflects higher capital spending, mainly at UNS Energy, in accordance with the Corporation's capital plan.

### Financing Activities

The variance reflects the issuance of common shares and redemption of Corporate debt (see "Cash Flow Summary" on page 18).

## SUMMARY OF QUARTERLY RESULTS

Quarter Ended	Common Equity			
	Revenue <i>(\$ millions)</i>	Earnings <i>(\$ millions)</i>	Basic EPS <i>(\$)</i>	Diluted EPS <i>(\$)</i>
December 31, 2019	2,326	346	0.77	0.77
September 30, 2019	2,051	278	0.64	0.63
June 30, 2019	1,970	720	1.66	1.66
March 31, 2019	2,436	311	0.72	0.72
December 31, 2018	2,206	261	0.61	0.61
September 30, 2018	2,040	276	0.65	0.65
June 30, 2018	1,947	240	0.57	0.57
March 31, 2018	2,197	323	0.77	0.76

Generally, within each calendar year, quarterly results fluctuate primarily in accordance with seasonality. Given the diversified nature of the Corporation's subsidiaries, seasonality varies. Most of the annual earnings of the gas utilities are realized in the first and fourth quarters due to space-heating requirements. Earnings for the electric distribution utilities in the US are generally highest in the second and third quarters due to the use of air conditioning and other cooling equipment.

Generally, from one calendar year to the next, quarterly results reflect: (i) continued organic growth driven by the Corporation's capital plan; (ii) acquisitions and dispositions; (iii) any significant temperature fluctuations from seasonal norms; (iv) the timing and significance of any regulatory decisions; (v) for revenue, the flow through in customer rates of commodity costs; and (vi) for EPS, increases in the weighted average number of common shares outstanding.

**December 2019/December 2018**

See "Fourth Quarter Results" on page 41.

**September 2019/September 2018**

Common Equity Earnings increased by \$2 million and basic EPS decreased by \$0.01, due mainly to Rate Base growth at the regulated utilities, led by ITC, tempered by: (i) the unfavourable impact of the mark-to-market accounting of natural gas derivatives at Aitken Creek; (ii) lower hydroelectric production in Belize; and (iii) for EPS, an 11.8 million increase in the weighted average number of common shares outstanding due to the ATM Program and DRIP.

**June 2019/June 2018**

Common Equity Earnings increased by \$480 million and basic EPS increased by \$1.09, due mainly to: (i) a \$484 million gain on the disposition of the Waneta Expansion; (ii) the favourable impact of the mark-to-market accounting of natural gas derivatives at Aitken Creek; (iii) Rate Base growth at the regulated utilities, led by ITC; and (iv) favourable foreign exchange of \$7 million. The increase was tempered by: (i) lower retail sales, driven by weather, and higher depreciation and interest expense at UNS Energy; (ii) lower earnings contribution from the Energy Infrastructure segment due to lower hydroelectric production in Belize; (iii) lower realized margins at Aitken Creek; and (iv) for EPS, a 9.3 million increase in the weighted average number of common shares outstanding due to the ATM Program and DRIP.

**March 2019/March 2018**

Common Equity Earnings decreased by \$12 million and basic EPS decreased by \$0.05, due mainly to: (i) a favourable \$30 million remeasurement of deferred income tax liabilities in 2018 resulting from an election to file a consolidated state income tax return, which offset earnings growth in 2019. Earnings growth was driven by: (i) strong performance at the regulated utilities due primarily to Rate Base growth; (ii) increased earnings at Central Hudson associated with its rate order effective July 1, 2018; (iii) higher electricity and gas sales at UNS Energy due largely to weather; and (iv) favourable foreign exchange of \$9 million. The increase was tempered by: (i) lower earnings contribution from the Energy Infrastructure segment due to lower realized margins and higher unrealized losses on the mark-to-market accounting of natural gas derivatives at Aitken Creek, along with lower hydroelectric production in Belize; (ii) a lower ROE incentive adder at ITC; and (iii) for EPS, a 7.5 million increase in the weighted average number of common shares outstanding due mainly to the DRIP.

**RELATED-PARTY 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 2019 or 2018. Inter-company balances, transactions and profit are eliminated on consolidation, except for certain inter-company transactions between non-regulated and regulated entities in accordance with accounting standards for rate-regulated entities. These related-party transactions include: (i) the lease of gas storage capacity and gas sales by Aitken Creek to FortisBC Energy; and (ii) the sale of capacity by the Waneta Expansion to FortisBC Electric up to the April 16, 2019 disposition of the Waneta Expansion. These transactions, which are not eliminated on consolidation, did not have a material impact on consolidated earnings, financial position or cash flows.

The Corporation periodically provides short-term financing to subsidiaries to support capital expenditures, acquisitions and seasonal working capital requirements. As at December 31, 2019, there were inter-segment loans outstanding of \$279 million (December 31, 2018 - \$nil), payable on demand with a weighted average interest rate of 2.48%. Total interest charged in 2019 was \$2 million.

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## MANAGEMENT'S EVALUATION OF CONTROLS AND PROCEDURES

### Disclosure Controls and Procedures

DCP are designed to provide reasonable assurance that information required to be disclosed in reports filed with, or submitted to, securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under Canadian and US securities laws. As of December 31, 2019, 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 United States securities laws. Based on that evaluation, the CEO and CFO concluded that such DCP are effective as of December 31, 2019.

### Internal Control over Financial Reporting

ICFR is designed by, or under the supervision of, the Corporation's CEO and CFO and effected by the Corporation's board of directors, management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with US GAAP. Because of its inherent limitations, ICFR may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The Corporation's management, including the Corporation's CEO and CFO, assessed the effectiveness of the Corporation's ICFR as of December 31, 2019, 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, 2019, the Corporation's ICFR was effective.

During the year ended December 31, 2019, 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

Over the long term, Fortis is well positioned 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.

The Corporation's \$18.8 billion five-year capital plan is expected to increase Rate Base from \$28.0 billion in 2019 to \$34.5 billion by 2022 and \$38.4 billion by 2024, translating into three- and five-year CAGRs of 7.2% and 6.5%, respectively. The five-year capital plan reflects the continuation of key industry trends including grid modernization and the delivery of cleaner energy. Beyond the base capital plan, Fortis continues to pursue additional energy infrastructure opportunities. Key opportunities not yet included in the five-year capital plan include: further expansion of LNG infrastructure in British Columbia; the fully permitted, cross-border, Lake Erie connector electric transmission project in Ontario; and the acceleration of cleaner energy goals in Arizona.

Fortis expects long-term growth in Rate Base to support continuing growth in earnings and dividends. Fortis is targeting average annual dividend growth of approximately 6% through 2024. This dividend guidance takes into account many factors, including the expectation of reasonable outcomes for regulatory proceedings at the Corporation's utilities, the successful execution of the five-year capital plan, and management's continued confidence in the strength of the Corporation's diversified portfolio of utilities and record of operational excellence.

## 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 2024; forecast capital expenditures for 2020 and the period 2020 through 2024, and potential funding sources for the capital plan; forecast Rate Base for 2020 and 2024; the expectation that Fortis will remain at the forefront of the industry by leveraging its strengths and partnerships; expected timing, outcome and impact of regulatory filings and decisions; expected or potential funding sources for operating expenses, interest costs and capital plans; the expectation that maintaining the targeted capital structure of the regulated operating subsidiaries will not have an impact on its ability to pay dividends in the foreseeable future; expected consolidated fixed-term debt maturities and repayments over the next five years; the expectation that the Corporation and its subsidiaries will continue to have access to long-term capital and will remain compliant with debt covenants throughout 2020; the nature, timing, benefits and expected costs of certain capital projects including the Multi-Value Regional Transmission Projects, Transmission Conversion Project, Southline Transmission Project, Oso Grande Wind Project, Transmission Integrity Management Capabilities Project, Inland Gas Upgrades Project, Wataynikaneyap Transmission Power Project and additional opportunities beyond the base plan, including the Lake Erie Connector Project; the expectation that the adoption of future accounting pronouncements will not have a material adverse impact; and the expectation that capital investment will support growth in earnings and dividends.*

*Certain material factors or assumptions have been applied in drawing the conclusions contained in the forward-looking information, including, without limitation: reasonable regulatory decisions and the expectation of regulatory stability; the implementation of the five-year capital plan; no material capital project or financing cost overruns; 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.*

*Forward-looking information involves significant risks, uncertainties and assumptions. 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 2020 include, but are not limited to: uncertainty regarding the outcome of regulatory proceedings at the Corporation's utilities; risks associated with climate change and physical risks; the impact of fluctuations in interest rates; the impact of weather variability and seasonality on heating and cooling loads, gas distribution volumes and hydroelectric generation; and risks associated with acquisitions and capital projects.*

*All forward-looking information herein is given as of February 12, 2020. 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

**2019 Annual Financial Statements:** the Corporation's audited consolidated financial statements and notes thereto for the year ended December 31, 2019

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

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

**Adjusted Common Equity Earnings:** net earnings attributable to common equity shareholders adjusted as shown under "Non-US GAAP Financial Measures" on page 12

**Adjusted Payout Ratio:** dividends per common share divided by Adjusted Basic EPS as shown under "Non-US GAAP Financial Measures" on page 12

**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.

**ALJ:** administrative law judge

**ASU:** Accounting Standards Update

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

**AUC:** Alberta Utilities Commission

**BCUC:** British Columbia Utilities Commission

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

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

**CAGR(s):** compound average growth rate of a particular item.  $CAGR = (EV/BV)^{1/N} - 1$ , where: (i) EV is the ending value of the item; (ii) BV is the beginning value of the item; and (iii) N is the number of periods

**Caribbean Utilities:** Caribbean Utilities Company, Ltd., an indirect approximately 60%-owned (as at December 31, 2019) subsidiary of Fortis, together with its subsidiary

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

**CEO:** Chief Executive Officer of Fortis

**CFO:** Chief Financial Officer of Fortis

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

**Corporation:** Fortis Inc.

**COS Regulation:** cost of service regulation

**CPCN:** Certificate of Public Convenience and Necessity

**DBRS Morningstar:** DBRS Limited

**DGP:** 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

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

**GHG:** greenhouse gas

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

**GWh:** gigawatt hour(s)

**ICFR:** internal controls over financial reporting

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

**ITC's MISO Subsidiaries:** International Transmission Company, Michigan Electric Transmission Company, LLC, and ITC Midwest LLC

**LIBOR:** London Interbank Offered Rate

**LNG:** liquefied natural gas

**kV:** kilovolt

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

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

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

**MD&A:** the Corporation's management discussion and analysis for the year ended December 31, 2019

**MISO:** Midcontinent Independent System Operator, Inc.

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

**MW:** megawatt(s)

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

**NOI:** notice of inquiry

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

**November 2019 FERC Order:** a FERC order issued in November 2019 that reduced the base ROE for ITC's MISO Subsidiaries

**NYSE:** New York Stock Exchange

**OEB:** Ontario Energy Board

**OPEB:** other post-employment benefits

**Operating Cash Flows:** cash from operating activities

**PBR:** performance-based rate-setting

**PJ:** petajoule(s)

**PPA:** power purchase agreement

**Q3 2019 MD&A:** interim management discussion and analysis for the three and nine months ended September 30, 2019

**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

**ROA:** rate of return on Rate Base

**ROE:** rate of return on common equity

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

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

**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.

**US:** United States of America

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

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

**Wataynikaneyap Partnership:** Wataynikaneyap Power Limited Partnership