FORTIS BC

FORTISBC ENERGY INC.

MANAGEMENT DISCUSSION & ANALYSIS

For the Year Ended December 31, 2019

February 12, 2020

The following FortisBC Energy Inc. ("FEI" or the "Corporation") Management Discussion & Analysis ("MD&A") has been prepared in accordance with National Instrument 51-102 – Continuous Disclosure Obligations. Financial information for 2019 and comparative periods contained in the following MD&A has been prepared in accordance with accounting principles generally accepted in the United States of America ("US GAAP") and is presented in Canadian dollars. The MD&A should be read in conjunction with the Corporation's Annual Audited Consolidated Financial Statements and notes thereto for the year ended December 31, 2019 and 2018, prepared in accordance with US GAAP.

In this MD&A, FAES refers to FortisBC Alternative Energy Services Inc., FHI refers to the Corporation's parent, FortisBC Holdings Inc., FBC refers to FortisBC Inc., ACGS refers to Aitken Creek Gas Storage ULC, and Fortis refers to the Corporation's ultimate parent, Fortis Inc.

FORWARD-LOOKING STATEMENT

Certain statements in this MD&A contain forward-looking information within the meaning of applicable securities laws in Canada ("forward-looking information"). The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words.

The forward-looking information in this MD&A includes, but is not limited to, statements regarding the Corporation's estimated costs for the current and future phases of the Tilbury Phase 1B Expansion Project; the Lower Mainland Intermediate Pressure System Upgrade Project ("LMIPSU"); the Inland Gas Upgrades Project; and their associated in-service dates; expectations to meet interest payments on outstanding indebtedness from operating cash flows; the Corporation's expected level of capital expenditures and its expectations to finance those capital expenditures through credit facilities, equity injections from FHI and debenture issuances; the Corporation's estimated contractual obligations; the final investment decision, in-service date and estimated costs associated with the pipeline expansion to the proposed Eagle Mountain Woodfibre Liquefied Natural Gas ("Woodfibre LNG") site; and expectations regarding the timing of the BCUC's decision on the Corporation's Multi-year Rate Plan ("MRP") Application.

The forecasts and projections that make up the forward-looking information are based on assumptions, which include but are not limited to: receipt of applicable regulatory approvals and requested rate orders; absence of administrative monetary penalties; the ability to continue to report under US GAAP beyond the Canadian securities regulators exemption to the end of 2023 or earlier; absence of asset breakdown; absence of environmental damage and health and safety issues; absence of climate change impacts on natural gas consumption patterns; absence of adverse weather conditions and natural disasters; ability to maintain and obtain applicable permits; the adequacy of the Corporation's existing insurance arrangements; no adverse affect of the Indigenous peoples' settlement process on the Corporation; the ability to maintain and renew collective bargaining agreements on acceptable terms; no material change in employee future benefit costs; the ability of the Corporation to attract and retain a skilled workforce; absence of information technology infrastructure failure; absence of cyber-security failure; continued energy demand; the ability to arrange sufficient and cost effective financing; no material adverse rating actions by credit rating agencies; the competitiveness of natural gas pricing when compared with alternate sources of energy; continued population growth and new housing starts; the availability of natural gas supply; and the ability to hedge certain risks including no counterparties to derivative instruments failing to meet obligations.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. The factors which could cause results or events to differ from current expectations include, but are not limited to: regulatory approval and rate orders risk (including the risk of imposition of administrative monetary penalties); continued reporting in accordance with US GAAP risk; asset breakdown, operation, maintenance and expansion risk; environment, health and safety matters risk; climate change risk; weather and natural disasters risk; permits risk; underinsured and uninsured losses; risks related to Indigenous rights and engagement; labour relations risk; employee future benefits risk; human resources risk; information technology infrastructure risk; cyber-security risk; interest rates risk; impact of changes in economic conditions risk; capital resources and liquidity risk; competitiveness and commodity price risk; counterparty credit risk; natural gas supply and weather related risks; and other risks described in the Corporation's most recent Annual Information Form ("AIF"). For additional information with respect to these risk factors, reference should be made to the section entitled "Business Risk Management" in this MD&A.

All forward-looking information in this MD&A is qualified in its entirety by this cautionary statement and, except as required by law, the Corporation undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise after the date hereof.

CORPORATE OVERVIEW

The Corporation is the largest distributor of natural gas in British Columbia ("BC"), serving approximately 1,040,700 residential, commercial, industrial, and transportation customers in more than 135 communities. The Corporation provides transmission and distribution services to its customers, and obtains natural gas supplies on behalf of most residential, commercial, and industrial customers. Gas supplies are sourced primarily from northeastern BC and, through the Corporation's Southern Crossing Pipeline, from Alberta.

The Corporation is regulated by the British Columbia Utilities Commission ("BCUC"). Pursuant to the *Utilities Commission Act* (British Columbia), the BCUC regulates such matters as rates, construction, and financing.

The Corporation is an indirect, wholly-owned subsidiary of Fortis, a leader in the North American electric and natural gas utility business. Fortis shares are listed on both the Toronto Stock Exchange and the New York Stock Exchange.

REGULATION

Customer Rates and Deferral Mechanisms

Customer rates include both the delivery charge and the cost of natural gas. The cost of natural gas, consisting of the commodity, storage and transport costs, is passed through to customers without mark-up. The Corporation's customer rates are based on estimates and forecasts. In order to manage the risk of forecast error associated with some of these estimates and to manage volatility in rates, a number of regulatory deferral accounts are in place.

There are two primary deferral mechanisms in place to decrease the volatility in rates caused by such factors as fluctuations in gas supply costs and the significant impacts of weather and other changes on customer use rates.

The first mechanism relates to the recovery of all gas supply costs through deferral accounts that capture variances (overages and shortfalls) from forecasts in costs incurred and amounts recovered through rates. Balances to be either refunded to or recovered from customers are determined via quarterly application and review by the BCUC. Currently under this mechanism, there are two separate deferral accounts: the Commodity Cost Reconciliation Account ("CCRA") and the Midstream Cost Reconciliation Account ("MCRA").

The second mechanism seeks to stabilize delivery revenues from residential and commercial customers through a deferral account that captures variances in the forecast versus actual customer use rate for residential and commercial customers throughout the year. This mechanism is called the Revenue Stabilization Adjustment Mechanism ("RSAM").

The RSAM, MCRA and CCRA accounts are either refunded to or recovered from customers in rates within two years with actual refunds or recoveries dependent upon approved rates and actual gas consumption volumes.

Variances from regulated forecasts used to set rates for natural gas revenue are flowed back to customers in future rates through approved regulatory deferral mechanisms and therefore these variances do not have an impact on net earnings in either 2019 or 2018. As part of the 2014 Performance Based Ratemaking ("PBR") Application decision received in September 2014 and effective through to the end of 2019, the Corporation had a flow-through deferral account that captured variances from regulated forecast items, excluding formulaic operation and maintenance costs, that do not have separately approved deferral mechanisms, and flowed those variances through customer rates in the following year.

Performance Based Ratemaking Plan for 2014 to 2019 ("2014 PBR Application")

In September 2014, the BCUC issued its decision on FEI's 2014 PBR Application. The approved PBR Plan incorporates an incentive mechanism for improving operating and capital expenditure efficiencies. Operation and maintenance expenses and base capital expenditures during the PBR period, 2014 to 2019, are subject to an incentive formula reflecting incremental costs for inflation and half of customer growth, less a fixed productivity adjustment factor of 1.1 per cent each year. The PBR Plan also includes a 50/50 sharing of variances ("Earnings Sharing Mechanism") from the formula-driven operation and maintenance expenses and capital expenditures over the PBR period, and a number of service quality measures designed to ensure FEI maintains service levels. It also sets out the requirements for an annual review process which provides a forum for discussion between FEI and interested parties regarding its current performance and future activities.

In December 2017, the BCUC issued its decision on FEI's 2018 delivery rates. The decision resulted in a 2018 average rate base of approximately $4,370 million (excluding the rate base of approximately $11 million for Fort Nelson) and no increase in customer delivery rates. 2018 rates would have otherwise decreased had there not been approval to defer a revenue surplus for the year. The revenue surplus amounts derived from FEI's 2018 and 2017 delivery rate decisions will be refunded to customers in future rates.

In February 2019, the BCUC issued its decision on FEI's 2019 delivery rates, which incorporates the decision received in January 2019 on FEI's 2019-2022 Demand Side Management Expenditures Application. The decision resulted in a 2019 average rate base of approximately $4,497 million (excluding the rate base of approximately $12 million for Fort Nelson) and an increase to the delivery rate of 1.1 per cent effective January 1, 2019.

Also in January 2019, the BCUC issued its decision approving an increase to FEI's midstream rates to reflect both the recovery of increased costs of procuring additional gas on the open marketplace to replace the gas that was not received through the Westcoast natural gas transmission pipeline during 2018, as well as the forecasted increase in midstream costs over the next twelve months. Combined with the 1.1 per cent delivery rate increase, the pass through of these costs to customers resulted in an approximate 9 per cent increase to residential rates on January 1, 2019.

In addition to the rate base amounts approved in annual regulatory decisions, multi-year projects under construction earn a regulated return through an allowance for funds used during construction ("AFUDC").

Multi-Year Rate Plan for 2020 to 2024

In March 2019, FEI filed an application with the BCUC requesting approval of an MRP for the years 2020 to 2024. The MRP Application proposes a rate-setting framework that includes, amongst other items, a level of operation and maintenance expense per customer indexed for inflation, a similar approach to growth capital, a forecast approach to sustainment capital, a 50/50 sharing between customers and the Corporation of variances from the allowed Return on Equity ("ROE"), targeted incentives for the Corporation related to growth, emissions reductions and customer engagement, and an innovation fund recognizing the need to accelerate investment in clean energy innovation. FEI is also seeking approval of updated depreciation rates and a number of service quality indicators designed to ensure the Corporation maintains service levels. The regulatory process to review this application is ongoing, with a decision expected by mid-2020.

In November 2019, the BCUC approved a rate increase of 2.0 per cent over 2019 rates pursuant to the MRP, on an interim and refundable basis, effective January 1, 2020. Interim rates will remain in place pending a final determination on 2020 rates by the BCUC. When combined with a decrease to FEI's midstream rates that was also approved in November 2019, residential rates decreased by 2.0 per cent effective January 1, 2020.

Directions to the BCUC

In November 2013, the BC Provincial government issued an Order of the Lieutenant Governor in Council ("2013 OIC") directing the BCUC to allow the Corporation to undertake the Tilbury Expansion Project at Tilbury Island in Delta, BC. The 2013 OIC and the subsequent amendments made to the OIC by the BC Provincial government in December 2014 and March 2017 set out a number of requirements for the BCUC as follows:

- to exempt the Tilbury Expansion Project from a Certificate of Public Convenience and Necessity ("CPCN") process (a CPCN process is typically required when a utility seeks approval for a major capital project and the utility must provide information related to the project needs and justifications, cost estimates, alternatives and customer impacts);
- to allow the Tilbury Expansion Project to proceed in two phases (Phase 1A and Phase 1B, respectively);
- to impose an upper limit of $425 million on capital costs before development costs and construction carrying costs related to the Tilbury Phase 1A Expansion Project;

- to impose an upper limit of $400 million on capital costs before development costs and construction carrying costs related to the Tilbury Phase 1B Expansion Project;
- to allow for recovery of the costs of the Tilbury Expansion Project from customers;
- to amend the tariff rates for LNG customers served from FEI's LNG facilities;
- to exempt from a CPCN process the pipeline and compression facilities that would supply the Woodfibre LNG facility near Squamish, BC should such facility proceed;
- to exempt from a CPCN process certain transmission projects, including one to increase the transmission line capacity to the Corporation's Tilbury LNG Facility; and
- to provide the methodologies for regulatory treatment of certain of the costs of these various projects.

Prior to 2017, the Provincial government allowed $170 million of FEI investment in incentives and infrastructure funding under the Greenhouse Gas Reductions Regulations ("GGRR") for FEI natural gas for transportation ("NGT") programs. During 2017, the Provincial government amended the GGRR, allowing an additional $160 million of FEI investment in incentives and infrastructure funding to further expand the FEI NGT programs, for a total of $330 million under the GGRR. Specifically, the additional incentives provide for the following to be included in FEI's regulated rate base, if certain conditions are met:

- incremental expenditures of $70 million toward incenting LNG powered marine and rail;
- incremental expenditures of $40 million toward incenting NGT customers that consumed natural gas procured from biomass or biogas sources; and
- investments of $50 million in related LNG bunkering infrastructure and assets required to enable the development of LNG bunkering capability to fuel LNG powered marine vessels calling at ports in BC.

In addition, in the same GGRR amendment, the Provincial government authorized the utility to acquire Renewable Natural Gas ("RNG") of up to 5 per cent of its non-bypass supply portfolio provided the RNG costs are no more than $30 per gigajoule.

FEI's opportunities under the GGRR to further expand its investments in NGT and LNG for domestic use, as well as expand its source of RNG, support the transition to a lower carbon economy pursuant to policies established by various levels of government.

CONSOLIDATED RESULTS OF OPERATIONS

	Quarter			**Year**		
Periods Ended December 31	**2019**	2018	Variance	**2019**	2018	Variance
Gas sales (petajoules)	**71**	63	8	**227**	212	15
($ millions)						
Revenue	**427**	371	56	**1,330**	1,187	143
Cost of natural gas	**149**	106	43	**437**	322	115
Operation and maintenance	**76**	74	2	**265**	245	20
Property and other taxes	**17**	14	3	**68**	63	5
Depreciation and amortization	**60**	55	5	**240**	223	17
Total expenses	**302**	249	53	**1,010**	853	157
Operating income	**125**	122	3	**320**	334	(14)
Add: Other income	**27**	37	(10)	**94**	144	(50)
Less: Finance charges	**56**	67	(11)	**213**	271	(58)
Earnings before income taxes	**96**	92	4	**201**	207	(6)
Income taxes	**14**	12	2	**18**	17	1
Net earnings	**82**	80	2	**183**	190	(7)
Net earnings attributable to non-controlling interests	**-**	-	-	**1**	1	-
Net earnings attributable to controlling interest	**82**	80	2	**182**	189	(7)

The following table outlines net earnings and the significant variances in the Consolidated Results of Operations for the three months ended December 31, 2019 as compared to December 31, 2018:

Quarter		
Item	**Increase (Decrease)** ($ millions)	**Explanation**
Net earnings attributable to controlling interest	**2**	Net earnings for the quarter ended December 31, 2019 were $82 million compared to $80 million for the same period in 2018. The increase was primarily due to: • a higher investment in regulated assets, and • lower operating costs excluded for rate-setting purposes, partially offset by • a $3 million lower income tax benefit as a result of the Corporation having a tax loss utilization plan ("TLUP") with a lower interest rate than a similar TLUP in place in 2018, and due to unwinding the TLUP earlier in the fourth quarter of 2019 compared to 2018, as well as • higher operation and maintenance expenses for the quarter, net of the regulated Earnings Sharing Mechanism, as compared to operating costs allowed in rates under the PBR formula, and the timing of incurring such costs throughout the year. Both 2019 and 2018 net earnings are based on an allowed return on equity of 8.75 per cent and a deemed equity component of capital structure of 38.5 per cent.
Revenue	**56**	The increase in total revenue was primarily due to: • a higher cost of natural gas recovered from customers, as approved by the BCUC, • a decrease in current year flow-through deferral amounts to be refunded to customers in future rates, • a decrease in the refund of the MCRA gas storage and transport cost regulatory liability, and • an increase in revenue approved for rate-setting purposes resulting from higher investment in regulated assets. Gas sales volumes were higher for the quarter primarily due to higher average consumption by residential and commercial customers as a result of colder weather, and an increase in the number of customers compared to the prior year, as well as higher consumption by transportation customers. The variance between revenue associated with actual consumption and revenue forecasted for rate-setting purposes is captured either in the RSAM deferral account or the flow-through deferral account, for which the income statement offsets are recognized in alternative revenue and other revenue, resulting in no impact on total revenue.
Cost of natural gas	**43**	The increase in the cost of natural gas was primarily due to: • a higher storage and transport cost, approved by the BCUC, of $1.485 per gigajoule for the fourth quarter of 2019, as compared to $1.064 per gigajoule for the same quarter in 2018, • a decrease in the refund of the MCRA gas storage and transport cost regulatory liability, during the quarter, and • higher gas sales consumption compared to the same period in 2018.
Depreciation and amortization	**5**	The increase was primarily due to a higher depreciable asset base compared to the prior year, including depreciation on the Tilbury Expansion Project and the Vancouver portion of the LMIPSU Project, both beginning January 1, 2019, partially offset by lower amortization of regulatory assets.
Other income	**(10)**	Other income primarily consists of dividend income from TLUP structures, the equity component of AFUDC, and the non-service cost component of pension and other post-employment benefits ("OPEB"), which was recognized as a credit to other income. As part of the TLUP, the Corporation received dividend income from FHI relating to a $2,500 million (2018 - $2,500 million) investment in preferred shares. The decrease in other income was primarily due to lower dividend income due to FEI having a TLUP in place in 2018 at a higher dividend rate, compared to a similar TLUP in place in 2019 which was also wound-up earlier in the fourth quarter of 2019 compared to the prior year TLUP. The decrease was partially offset by an increase in the non-service cost component of pension and OPEB and a higher equity component of AFUDC in 2019 associated with the construction of the LMIPSU Project.

Quarter		
Item	**Increase (Decrease)** ($ millions)	**Explanation**
Finance charges	**(11)**	The decrease in finance charges was primarily due to FEI having a TLUP in place in 2018 at a higher interest rate, compared to a similar TLUP in place in 2019 which was also wound-up earlier in the fourth quarter of 2019 compared to the prior year TLUP, partially offset by higher interest from a higher level of debt used to finance the increased investment in regulated assets, and the issuance of long-term debentures in December 2018 and August 2019, which were used to repay credit facilities carrying lower interest rates.
Income taxes	**2**	The increase in income tax expense was primarily due to a lower TLUP tax recovery and higher taxable temporary differences, partially offset by lower taxable temporary differences.

The following table outlines net earnings and the significant variances in the Consolidated Results of Operations for the year ended December 31, 2019 as compared to December 31, 2018:

Year		
Item	**Increase (Decrease)** ($ millions)	**Explanation**
Net earnings attributable to controlling interest	**(7)**	Net earnings for the year ended December 31, 2019 were $182 million compared to $189 million for the same period in 2018. The decrease was primarily due to: • a $16 million lower income tax benefit as a result of the Corporation having a TLUP with a lower interest rate than a similar TLUP in place in 2018, and due to implementing the TLUP later in 2019 compared to 2018, and • higher operation and maintenance expenses, net of the regulated Earnings Sharing Mechanism, as compared to operating costs allowed in rates under the PBR formula, partially offset by • a higher investment in regulated assets, and • higher net earnings as result of the operations excluded for rate-setting purposes.
Revenue	**143**	The increase in total revenues were primarily due to: • a higher cost of natural gas recovered from customers, as approved by the BCUC, • a decrease in the refund of the MCRA gas storage and transport cost regulatory liability, • a decrease in current year flow-through deferral amounts to be refunded to customers in future rates, and • an increase in revenue approved for rate-setting purposes resulting from higher investment in regulated assets. Gas sales volumes were higher primarily due to the same reasons identified in the quarter. The higher consumption compared to what is approved in rates resulted in increased revenue from contracts with customers, and was offset by equal alternative revenue and other revenue amounts resulting in no impact on total revenue.
Cost of natural gas	**115**	The increase was primarily due to the same reasons identified in the quarter.
Operation and maintenance	**20**	The increase in operation and maintenance expense was primarily due to higher labour and contracting costs, higher electricity costs to operate the Tilbury LNG facility, and higher employee benefit costs.
Property and other taxes	**5**	The increase in property and other taxes was primarily due to an increase in the assessed values of land and other assets owned by the utility.
Depreciation and amortization	**17**	The increase was primarily due to the same reasons identified in the quarter.
Other income	**(50)**	The decrease was primarily due to the same reasons identified in the quarter, as well as lower dividend income from having a TLUP in place in 2018 at a higher dividend rate, compared to a similar TLUP in place in 2019 which was also implemented later in 2019 compared to the prior year TLUP.

Year		
Item	**Increase (Decrease)** ($ millions)	**Explanation**
Finance charges	**(58)**	The decrease in finance charges was primarily due to the same reasons identified in the quarter, as well as lower interest expense from having a TLUP in place in 2018 at a higher interest rate, compared to a similar TLUP in place in 2019 which was also implemented later in 2019 compared to the prior year TLUP.
Income taxes	**1**	The increase in income taxes was primarily due to a lower TLUP tax recovery, partially offset by higher deductible temporary differences primarily as a result of the June 2019 enactment of new enhanced Capital Cost Allowance rules, lower earnings before tax, lower taxable temporary differences, and decreases in flow-through deferral amounts to be refunded to customers in future rates.

SUMMARY OF QUARTERLY RESULTS

The following table sets forth unaudited quarterly information for each of the eight quarters ended March 31, 2018 through December 31, 2019. The information has been obtained from the Corporation's Unaudited Condensed Consolidated Interim Financial Statements. Past operating results are not necessarily indicative of results for any future period and should not be relied upon to predict future performance.

Quarter Ended	**Revenue**	**Net Earnings (Loss)** [1]
($ millions)		
December 31, 2019	427	82
September 30, 2019	183	(15)
June 30, 2019	235	16
March 31, 2019	485	99
December 31, 2018	371	80
September 30, 2018	161	(10)
June 30, 2018	227	18
March 31, 2018	428	101

[1] Net earnings (loss) attributable to controlling interest

A summary of the past eight quarters reflects the seasonality associated with the Corporation's business. Due to the seasonal nature of natural gas consumption patterns, the natural gas transmission and distribution operations of FEI normally generate higher net earnings in the first and fourth quarters and lower net earnings in the second quarter, which are partially offset by net losses in the third quarter. As a result of the seasonality, interim net earnings are not indicative of net earnings on an annual basis.

December 2019/2018 – Net earnings were higher due to higher investment in regulated assets and lower operating costs excluded for rate-setting purposes, partially offset by a $3 million lower income tax benefit from the TLUP and higher regulated operation and maintenance expenses in part due to the timing of incurring such costs throughout the year. The lower income tax benefit from the TLUP was a result of a lower interest rate than a similar TLUP in place in 2018, as well as the Corporation unwinding the TLUP earlier in the fourth quarter of 2019 compared to 2018.

September 2019/2018 – Net loss was higher primarily due to a $3 million lower income tax benefit from the TLUP and higher operation and maintenance expenses for the quarter, net of the regulated Earnings Sharing Mechanism, as compared to operating costs allowed in rates under the PBR formula, in part due to the timing of incurring such costs throughout the year, partially offset by higher investment in regulated assets.

June 2019/2018 – Net earnings were lower primarily due to a $6 million lower income tax benefit from the TLUP, partially offset by higher operation and maintenance expense savings for the quarter, net of the regulated Earnings Sharing Mechanism, as compared to operating costs allowed in rates under the PBR formula, primarily due to the timing of incurring such costs throughout the year, and higher investment in regulated assets. The lower income tax benefit from the TLUP was a result of the Corporation having a TLUP in place in 2018 with a higher interest rate, effective earlier in 2018 compared to the TLUP in place in 2019.

March 2019/2018 – Net earnings were lower primarily due to lower income tax benefit as a result of the Corporation having a TLUP in place during the first quarter of 2018, compared to no TLUP implemented in the first quarter of 2019, and lower operation and maintenance expense savings for the quarter, net of the regulated

Earnings Sharing Mechanism, as compared to operating costs allowed in rates under the PBR formula primarily due to the timing of incurring such costs throughout the year, partially offset by higher investment in regulated assets.

CONSOLIDATED FINANCIAL POSITION

The following table outlines the significant changes in the Consolidated Balance Sheets between December 31, 2019 and December 31, 2018:

Balance Sheet Account	**Increase (Decrease)** ($ millions)	**Explanation**
Accounts receivable	**23**	The increase was primarily due to: • higher tariff-based trade receivables as a result of an increase in customer rates and increased consumption due to colder weather and customer additions, • higher gas cost mitigation receivables, and • the change in the fair value of natural gas derivatives, which are offset by a regulatory asset, partially offset by • a lower tax receivable due to a recovery of corporate income tax paid in prior years partially offset by expected tax refund for the current year, and • lower cash collateral paid for natural gas contracts.
Regulatory assets (current and long-term)	**172**	The increase was primarily due to: • an increase in the deferred income tax liability and an increase in unrecognized actuarial losses and past service costs for pension and OPEB, the offsets of which were deferred as a regulatory asset, • increased expenditures on Demand Side Management ("DSM") expenditures and GGRR programs, • increased pre-development expenditures for capital projects, and • a higher RSAM deferral balance, which captures variances in gas use for residential and commercial customers, partially offset by • the change in the fair market value of natural gas derivatives.
Property, plant and equipment, net	**301**	The increase was primarily due to capital expenditures of $448 million incurred during the year ended December 31, 2019, which included sustainment and growth capital as well as major project expenditures discussed further under "Projected Capital Expenditures", a $39 million increase in accrued capital expenditures, and $8 million in equity AFUDC, partially offset by: • depreciation expense, excluding net salvage provision, of $173 million, • costs of removal of $15 million incurred, the offset of which has been recognized in regulatory liabilities, and • contributions in aid of construction of $6 million.
Credit facility	**(61)**	The decrease was primarily a result of net repayment of the credit facility with the cash flows provided by operations, proceeds received from the $140 million share issuance in the second quarter of 2019, and the $200 million debt issuance in the third quarter of 2019, partially offset by borrowing to finance the debt component of FEI's capital expenditure program.
Accounts payable and other current liabilities	**32**	The increase was primarily due to: • higher capital accruals, primarily related to LMIPSU project expenditures, • cash deposits received relating to development expenditures incurred for the Eagle Mountain Woodfibre Gas Pipeline Project, which are recognized as a liability until applied against spending, and • higher goods and services tax and carbon tax payable, partially offset by • the change in the fair market value of natural gas derivatives, which are offset by a regulatory asset, and • a decrease in natural gas midstream payables which were higher at the end of 2018 due to a natural gas transmission pipeline incident.

Balance Sheet Account	Increase (Decrease) ($ millions)	Explanation
Regulatory liabilities (current and long-term)	**34**	The increase was primarily due to the build-up of the net salvage provision, as well as a higher MCRA regulatory liability primarily due to higher natural gas midstream costs and payments made by FEI during the first quarter of 2019 to secure long-term natural gas pipeline capacity, partially offset by mitigation activities.
Long-term debt	**199**	The increase was due to the issuance of $200 million of unsecured Medium Term Note Debentures ("MTN Debentures") during the third quarter of 2019, net of debt issuance costs. The proceeds were used to repay existing credit facilities in support of the debt component of FEI's capital expenditure program.
Deferred income taxes	**48**	The increase was primarily due to higher deductible temporary differences associated with property, plant, and equipment that includes $12 million resulting from the June 2019 enactment of new enhanced CCA rules, and higher net deductible temporary differences in regulatory deferral accounts.
Other liabilities (long-term)	**77**	The increase was primarily due to an increase in the unfunded status of the Corporation's defined benefit pension and OPEB plans, which was primarily driven by a decrease in the discount rate used to measure the projected benefit obligation.
Common shares	**140**	The increase is due to a $140 million FEI equity issuance during the second quarter of 2019. The proceeds were used to repay existing credit facilities in support of the equity component of FEI's capital expenditure program.

LIQUIDITY AND CAPITAL RESOURCES

Summary of Consolidated Cash Flows

Years Ended December 31	**2019**	2018	Variance
($ millions)			
Cash flows provided by (used for)			
Operating activities	**408**	356	52
Investing activities	**(514)**	(517)	3
Financing activities	**109**	161	(52)
Net change in cash	**3**	-	3

Operating Activities

Cash provided by operating activities was $52 million higher compared to the same period in 2018. The increase was primarily due to an increase of $33 million related to changes in working capital, which was primarily related to higher gas costs payable and a recovery of corporate income tax paid in prior years partially offset by an income tax receivable in respect of 2019. Increases in cash provided by operating activities were also due to higher depreciation and amortization expense of $17 million, which was primarily due to a higher depreciable asset base compared to the prior year, and a higher net change to regulatory assets and liabilities. The increases in cash provided by operating activities were partially offset by lower net earnings.

Investing Activities

Cash used for investing activities was $3 million lower in 2019 compared to the same period in 2018 primarily due to lower capital expenditures that resulted from the timing of accrued capital expenditures, partially offset by changes in other assets and liabilities due to higher investment in DSM expenditures and GGRR programs.

Financing Activities

Cash provided by financing activities was $52 million lower in 2019 compared to the same period in 2018. The change was primarily driven by higher repayments of credit facilities during 2019 as compared to net proceeds provided by credit facilities during 2018. These repayments were funded by cash provided by operating activities, as well as a $140 million issuance of common shares in the second quarter of 2019 as compared to a $40 million issuance of common shares in the second quarter of 2018. FEI received proceeds from a $200 million debt issuance in the third quarter of 2019 and a $200 million debt issuance during the fourth quarter of 2018.

During 2019, FEI paid common share dividends of $150 million (2018 - $142 million) to its parent company, FHI.

Contractual Obligations

The following table sets forth the Corporation's estimated contractual obligations due in the years indicated:

As at December 31, 2019	Total	Due Within 1 Year	Due in Year 2	Due in Year 3	Due in Year 4	Due in Year 5	Due After 5 Years
($ millions)							
Interest obligations on long-term debt	2,670	136	136	136	136	136	1,990
Long-term debt [1]	2,795	-	-	-	-	-	2,795
Gas purchase obligations (a)	1,506	389	277	238	174	76	352
Capital lease and finance obligations (b)	47	6	38	3	-	-	-
Other (c)	22	18	2	1	1	-	-
Totals	7,040	549	453	378	311	212	5,137

[1] Excludes unamortized debt issuance costs.

(a) The Corporation enters into contracts to purchase natural gas and natural gas transportation and storage services from various suppliers. These contracts are used to ensure that there is an adequate supply of natural gas to meet the needs of customers and to minimize exposure to market price fluctuations. The gas purchase obligations are based on gas commodity indices that vary with market prices. The amounts disclosed reflect index prices that were in effect at December 31, 2019.

(b) Between 2000 and 2005, the Corporation entered into arrangements whereby certain natural gas distribution assets were leased to certain municipalities and then leased back by the Corporation from the municipalities. The natural gas distribution assets are not accounted for as a sale-leaseback, and instead are accounted for as financing transactions. The proceeds from these transactions have been recorded as a finance obligation. Lease payments made, less the portion considered to be interest expense, decrease the finance obligation. On November 30, 2019, the Corporation exercised an early termination payment option in the amount of $12 million on one of these financing transactions.

(c) Included in other contractual obligations are building leases and defined benefit pension plan funding obligations.

During the fourth quarter of 2019, the Electricity Supply Agreement ("ESA") with British Columbia Hydro and Power Authority ("BC Hydro") that provided for supply of electrical service for the Tilbury Expansion Project Phase 1A, and was previously disclosed as a contractual obligation, was terminated. In its place, the Corporation purchases power as an industrial customer under a standard industrial tariff, based on the energy needs of the facility.

In addition to the items in the table above, the Corporation has issued commitment letters to customers who may meet the criteria to obtain DSM funding under the DSM Program approved by the BCUC. As at December 31, 2019, the Corporation had issued $22 million (2018 - $16 million) of commitment letters to these customers.

In January 2012, two unrelated parties collectively purchased a 15 per cent equity interest in the MHLP, which at the time was a wholly owned limited partnership of the Corporation. These non-controlling interest owners hold a put option which, if exercised, would oblige the Corporation to purchase the non-controlling interest owners' 15 per cent voting share in MHLP for cash. For rate-making purposes, these non-controlling interests are considered equity and if FEI was required to purchase these non-controlling interests, FEI would fund the transaction with an equity issuance. Accordingly, the Corporation has presented these redeemable non-controlling interests as equity. During 2019, MHLP underwent a re-organization which didn't impact the consolidation of the partnership in FEI or the put option held by the non-controlling interest owners.

Capital Structure

The Corporation's principal business of regulated natural gas transmission and distribution requires ongoing access to capital in order to allow the Corporation to fund the maintenance, replacement and expansion of infrastructure. The Corporation maintains a capital structure in line with the deemed regulatory capital structure approved by the BCUC at 38.5 per cent equity and 61.5 per cent debt. This capital structure excludes the financing of goodwill and other non-regulated items that do not impact the deemed capital structure. As part of its 2016 decision on FEI's application to review the benchmark utility ROE and common equity component of capital structure, the BCUC determined that the common equity component of capital structure and ROE for FEI will remain in effect until otherwise determined by the Commission.

Credit Ratings

Debentures issued by the Corporation are rated by DBRS Morningstar and Moody's Investors Service ("Moody's"). The ratings assigned to the debentures issued by the Corporation are reviewed by these agencies on an ongoing basis.

The table below summarizes the ratings assigned to the Corporation's debentures as at December 31, 2019:

Rating Agency	Credit Rating	Type of Rating	Outlook
DBRS Morningstar	A	Unsecured Debentures	Stable
Moody's	A3	Unsecured Debentures	Stable

During 2019, DBRS Morningstar and Moody's issued updated credit rating reports confirming the Corporation's debenture rating and outlook.

Projected Capital Expenditures and Other Investments

The Corporation continually updates its capital expenditure programs and assesses current and future operating, maintenance, replacement, expansion and removal expenditures that will be incurred in the ongoing operation of its business.

The initial approval from the BCUC to proceed with capital projects can occur through a number of processes, including revenue requirement applications and CPCNs. Once the projects are approved, the regulatory process allows for capital project costs to be reviewed by the BCUC subsequent to the capital project being completed and in service to confirm that all costs are recoverable in customer rates.

The 2020 projected capital expenditures are approximately $510 million, inclusive of AFUDC and excluding customer contributions in aid of construction, and are necessary to provide service, public and employee safety, and reliability of supply of natural gas to the Corporation's customer base. Included in these projected capital expenditures are more significant projects further described below.

LMIPSU Project

In December 2014, the Corporation filed a CPCN application to replace certain sections of intermediate pressure gas line segments within the Greater Vancouver area. In October 2015, the BCUC approved the CPCN substantially as filed, which included an estimate of the project costs of approximately $250 million. In the course of its project development activities, FEI conducted further detailed engineering work and evaluated construction bids and other costs which resulted in a revised cost estimate of approximately $500 million. This estimate was provided to the BCUC during the first quarter of 2018 in a compliance filing for their information. The Vancouver, Burnaby and Coquitlam segments of the project were completed and gasified during 2018 and 2019. A short segment in South Vancouver will be replaced in 2020 as planned. After the project is complete and in service, the final project costs remain subject to the BCUC's review process.

Inland Gas Upgrades

In December 2018, FEI filed a CPCN application to implement cost effective integrity management solutions to mitigate the potential integrity issues within the interior region of BC. The cost of the capital project is estimated at $360 million to be incurred primarily between 2020 and 2024. The CPCN application was approved by the BCUC in January 2020.

Transmission Integrity Management Capabilities ("TIMC") Project

The multi-year TIMC Project is focused on improving gas line safety and the integrity of the transmission system, including gas line modifications and looping. As part of the BCUC's December 2018 decision on FEI's 2019 delivery rates, a regulatory deferral account was approved to capture approximately $40 million of development costs to be incurred through to mid-2020 to enable the filing of a CPCN.

Demand Side Management ("DSM") Expenditures Plan

In January 2019, the BCUC issued its decision and accepted FEI's 2019-2022 DSM Expenditures Plan to incur approximately $325 million of expenditures from 2019 through 2022 and include such expenditures as rate base additions. This plan delivers a cost-effective portfolio of DSM programs and activities which align with BC's energy objectives and meets the requirements of the Demand-Side Measures Regulations, and responds to government policy encouraging an increase in DSM program incentives and support.

Tilbury Phase 1B Expansion Project

This project consists of construction of additional liquefaction and dispensing, including on-shore piping, 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 that allows for investment of up to $400 million of capital costs before development costs and construction carrying costs. During 2020 FEI will continue to proceed with its pre-Front-End Engineering Design (“FEED”) and FEED studies.

Other Major Capital Projects

Beyond 2020, the Corporation has received BCUC or OIC approval for further major capital projects discussed below.

LNG Infrastructure

The Corporation continues to pursue additional LNG infrastructure investment opportunities in BC, including a gas line expansion to the proposed Woodfibre LNG site near Squamish, BC, and a further expansion of Tilbury that would help position BC as a vital domestic and international LNG provider to lower global greenhouse gas emissions. The OIC granted FEI exemptions from the requirement to seek BCUC CPCN approvals for the pipeline expansion to the LNG site and certain further expansions at the Tilbury site, subject to certain conditions.

The anticipated capital expenditures, net of the forecasted customer contributions, of FEI’s potential gas line expansion are $350 million, conditional on Woodfibre LNG proceeding with its LNG export facility. The current estimate of FEI’s investment in the project may be updated for final scoping, detailed construction estimates and scheduling, and final determination of the customer contributions. Woodfibre LNG holds an export license from the National Energy Board and has received environmental assessment approvals from the Squamish Indigenous peoples, the BC Environmental Assessment Office and the Canadian Environmental Assessment Agency. In November 2016, Woodfibre LNG’s parent company announced they had authorized the funds necessary to proceed with the project. During the fourth quarter of 2018, FEI and Woodfibre LNG entered into a pre-execution work agreement that establishes the funding requirements to be provided by Woodfibre LNG for FEI to incur ongoing project feasibility and development costs. In July 2019, Woodfibre LNG received a permit from the BC Oil and Gas Commission to construct, operate, and maintain an LNG facility, one of the key permits for advancement of the project.

FEI has also received environmental assessment approvals for the gas line expansion from the BC Environmental Assessment Office and the Squamish Indigenous peoples. FEI’s proposed gas line expansion remains contingent on Woodfibre LNG making a final decision to proceed with construction of its LNG export facility. At this time, should the project proceed, it is not expected to be in service before 2023.

Cash Flow Requirements

The Corporation’s cash flow requirements fluctuate seasonally based primarily on natural gas consumption. The Corporation maintains an adequate committed credit facility.

It is expected that operating expenses and interest costs will generally be paid out of operating cash flows, with varying levels of residual cash available for capital expenditures and/or dividend payments. Cash required to complete capital expenditure programs, pre-development capital costs and investments in Energy Efficiency and Conservation and GGRR programs, is also expected to be financed from a combination of borrowings under credit facility, equity injections from FHI and debenture issuances.

The Corporation’s ability to service its debt obligations and pay dividends on its common shares is dependent on the financial results of the Corporation. Depending on the timing of cash payments, borrowings under the Corporation’s credit facility may be required from time to time to support the servicing of debt and payment of dividends. The Corporation may have to rely upon the proceeds of new debenture issuances to meet its principal debt obligations when they become due.

Credit Facility and Debentures

Credit Facility

As at December 31, 2019, the Corporation had a $700 million syndicated credit facility available which matures in August 2024.

The following summary outlines the Corporation's credit facility as at December 31:

($ millions)	**2019**	2018
Credit facility	**700**	700
Draws on credit facility	**(138)**	(199)
Letters of credit outstanding	**(47)**	(48)
Credit facility available	**515**	453

Debentures

On August 7, 2019, FEI entered into an agreement with certain affiliates of a group of Canadian Chartered Banks to sell $200 million of unsecured Medium Term Note ("MTN") Debentures Series 32. The MTN Debentures Series 32 bear interest at a rate of 2.82 per cent to be paid semi-annually and mature on August 9, 2049. The closing of the issuance occurred on August 9, 2019, with net proceeds being used to repay existing credit facilities.

Dividend Restrictions

As part of its approval of the acquisition of FHI by Fortis, the BCUC imposed the continuation of a number of conditions intended to ring-fence the Corporation from FHI. These restrictions included a prohibition on the payment of dividends unless the Corporation has in place at least as much common equity as that deemed by the BCUC for rate-making purposes. In 2019 and 2018, none of these restrictions constrained the distribution of FEI earnings not otherwise needed for reinvestment.

OFF-BALANCE SHEET ARRANGEMENTS

As at December 31, 2019, the Corporation had no material off-balance sheet arrangements, with the exception of letters of credit outstanding of $47 million (2018 - $48 million) primarily to support the Corporation's unfunded supplemental pension benefit plans.

RELATED PARTY TRANSACTIONS

In the normal course of business, the Corporation transacts with its parent, FHI, ultimate parent, Fortis, and other related companies under common control, including FBC and ACGS, in financing transactions and to provide or receive services and materials. The following transactions were measured at the exchange amount unless otherwise indicated.

Related Party Recoveries

The amounts charged to the Corporation's parent and other related parties under common control for the years ended December 31 were as follows:

($ millions)	**2019**	2018
Operation and maintenance expense charged to FBC (a)	**7**	6
Operation and maintenance expense charged to FHI (b)	**1**	1
Other income received from FHI (c)	**77**	137
Operation and maintenance expense charged to ACGS (d)	**1**	1
Total related party recoveries	**86**	145

(a) The Corporation charged FBC for natural gas sales, office rent, management services and other labour.

(b) The Corporation charged FHI for office rent and management services.

(c) As part of a TLUP implemented in the second quarter of 2019, the Corporation received dividend income from FHI relating to a $2,500 million (2018 - $2,500 million) investment in preferred shares. The TLUP was unwound in December, 2019.

(d) The Corporation charged ACGS for management services and other labour.

Related Party Costs

The amounts charged by the Corporation's parent and other related parties under common control for the years ended December 31 were as follows:

($ millions)	2019	2018
Operation and maintenance expense charged by FBC (a)	**8**	8
Operation and maintenance expense charged by FHI (b)	**13**	12
Finance charges paid to FHI (c)	**77**	137
Gas storage and purchases charged by ACGS (d)	**23**	25
Total related party costs	**121**	182

(a) FBC charged the Corporation for electricity purchases, management services and other labour.

(b) FHI charged the Corporation for management services, labour and materials and governance costs.

(c) As part of a TLUP implemented in the second quarter of 2019, the Corporation paid FHI interest on $2,500 million (2018 - $2,500 million) of intercompany subordinated debt. The TLUP was unwound in December, 2019.

(d) ACGS charged the Corporation for the lease of natural gas storage capacity and natural gas purchases.

Balance Sheet Amounts

The amounts due from related parties as at December 31 included in accounts receivable on the Consolidated Balance Sheets, and the amounts due to related parties, included in accounts payable and other current liabilities on the Consolidated Balance Sheets, were as follows:

	2019		2018	
($ millions)	**Amount Due From**	**Amount Due To**	Amount Due From	Amount Due To
FHI	**1**	**-**	-	(2)
ACGS	**-**	**(2)**	-	(2)
Total due from (due to) related parties	**1**	**(2)**	-	(4)

During the fourth quarter of 2019, $1 million was transferred from FEI's tax instalment account to FHI's tax instalment account at the Canada Revenue Agency ("CRA"). The transfer resulted in a decrease to FEI's income tax receivable balance and a decrease to FHI's income taxes payable balance as permitted by the CRA for associated entities.

BUSINESS RISK MANAGEMENT

The Corporation is subject to a variety of risks and uncertainties that may have a material adverse effect on the Corporation's results of operations and financial position.

Regulatory Approval and Rate Orders

The regulated operations of the Corporation are subject to the uncertainties faced by regulated companies. These uncertainties include the approval by the BCUC of customer rates that permit a reasonable opportunity to recover on a timely basis the estimated costs of providing services, including a fair return on and of rate base. The ability of the Corporation to recover the actual costs of providing services and to earn the approved rates of return is impacted by achieving the forecasts established in the rate-setting process. The cost for upgrading existing facilities and adding new facilities requires the approval of the BCUC for inclusion in the rate base. There is no assurance that capital projects perceived as required by the management of the Corporation will be approved or that conditions to such approval will not be imposed.

Through the regulatory process, the BCUC approves the ROE that the Corporation is allowed to earn and the deemed capital structure. Fair regulatory treatment that allows the Corporation a reasonable opportunity to earn a fair risk adjusted rate of return comparable to that available on alternative, similar risk investments is essential for maintaining service quality as well as on-going capital attraction and growth. There can be no assurance that the rate orders issued by the BCUC will permit the Corporation to recover all costs actually incurred and to earn the expected or fair rate of return.

Rate applications that reflect cost of service and establish revenue requirements are subject to either a public hearing process which may be oral or written, or a negotiated settlement. The BCUC has approved a PBR rate-setting methodology for the Corporation for a term of 2014 through 2019, after an extensive public hearing process. Rates during this term were determined through a review process which occurred on an annual basis. Rates for 2020 through 2024 are dependent on the outcome of the MRP. There can be no assurance that the rate orders issued will permit the Corporation to recover all costs actually incurred and to earn the expected rate of return.

A failure to obtain rates that recover the costs of providing service or provide a reasonable opportunity to earn an appropriate ROE and capital structure as applied for may adversely affect the business carried on by the Corporation, the undertaking or timing of proposed upgrades or expansion projects, ratings assigned by rating agencies, the issue and sale of securities, and other matters which may, in turn, have a material adverse effect on the Corporation's results of operations and financial position.

There is legislation in BC which enables the BCUC to impose administrative monetary penalties on the Corporation, upon finding contravention of a BCUC order, rule, or standard. The penalty amount varies depending on the nature of the violation and it is not recoverable from customers.

Continued Reporting in Accordance with US GAAP

In December 2017, the Ontario Securities Commission ("OSC") approved the extension of the Corporation's exemptive relief order which permits the Corporation to continue reporting in accordance with US GAAP, until the earliest of: (i) January 1, 2024; (ii) the first day of the financial year that commences after the Corporation ceases to have activities subject to rate regulation; or (iii) the effective date prescribed by the International Accounting Standards Board ("IASB") for the mandatory application of a standard within International Financial Reporting Standards ("IFRS") specific to entities with activities subject to rate regulation.

The IASB has released an interim, optional standard on Regulatory Deferral Accounts and continues to work on a project focusing on accounting specific to rate-regulated activities. It is not yet known when this project will be completed or whether IFRS will, as a result, include a permanent mandatory standard to be applied by entities with activities subject to rate regulation.

The Corporation continues to closely monitor the efforts of the IASB to issue a permanent standard specific to entities with activities subject to rate regulation. In the event that such a standard will not be issued before, or issued with an effective date after, the expiry of the OSC relief order, the Corporation will consider seeking an extension to the OSC relief order. If the OSC relief does not continue as detailed above, the Corporation would then be required to become a United States Securities and Exchange Commission ("SEC") registrant in order to continue reporting under US GAAP or adopt IFRS.

In the absence of a permanent standard for rate-regulated activities or continued OSC relief, adopting IFRS could result in volatility in the Corporation's earnings as compared to what would otherwise be recognized under US GAAP.

Asset Breakdown, Operation, Maintenance and Expansion

The Corporation's assets require ongoing maintenance, replacement and expansion. Accordingly, to ensure the continued performance of the physical assets, the Corporation determines expenditures that should be made to maintain, replace and expand the assets. The Corporation could experience service disruptions and increased costs if it is unable to maintain, replace or expand its asset base. The inability to recover, through approved rates, the costs of capital expenditures that the Corporation believes are necessary to maintain, replace, expand and remove its assets, the failure by the Corporation to properly implement or complete approved capital expenditure programs or the occurrence of significant unforeseen equipment failures could have a material adverse effect on the Corporation's results of operations and financial position.

The Corporation continually updates its capital expenditure programs and assesses current and future operating, maintenance, replacement, expansion and removal expenses that will be incurred in the ongoing operation of its business. Management's analysis is based on assumptions as to costs of services and equipment, regulatory requirements, revenue requirement approvals, and other matters, which involve some degree of uncertainty. It is uncertain whether capital expenditures will, in all cases, receive regulatory approval for recovery in future customer rates. The inability to recover capital expenditures could have a material adverse effect on the Corporation's results of operations and financial position.

Environment, Health and Safety Matters

The Corporation is subject to numerous laws, regulations and guidelines governing the management, transportation and disposal of hazardous substances and other waste materials and otherwise relating to the protection of the environment and health and safety, for which the Corporation incurs compliance costs. The process of obtaining environmental permits and approvals, including any necessary environmental assessment, can be lengthy, contentious and expensive. This process could lead to delays in project approvals and lengthier construction timelines, which could adversely affect the Corporation through increased operating and capital costs. Potential environmental damage and costs could arise due to a variety of events, including severe weather and other natural disasters, human error or misconduct, or equipment failure. However, there can be no assurance that such costs will be recoverable through rates and, if substantial, unrecovered costs could have a material adverse effect on the Corporation’s results of operations and financial position.

The Corporation is exposed to environmental risks that owners and operators of properties in BC generally face. These risks include the responsibility of any current or previous owner or operator of a contaminated site for remediation of the site, whether or not such person actually caused the contamination. In addition, environmental and safety laws make owners, operators and persons in charge of management and control of facilities subject to prosecution or administrative action for breaches of environmental and safety laws, including the failure to obtain certificates of approval. It is not possible to predict with absolute certainty the position that a regulatory authority will take regarding matters of non-compliance with environmental and safety laws. Changes in environmental, health and safety laws could also lead to significant increases in costs to the Corporation.

The trend in environmental regulation has been to impose more restrictions and limitations on activities that may impact the environment, including the generation and disposal of wastes, the use and handling of chemical substances, environmental management for sensitive species and their habitat, and conducting environmental impact assessments and remediation. It is possible that other developments may lead to increasingly strict environmental and safety laws, regulations and enforcement policies and claims for damages to property or persons resulting from the Corporation’s operations, any one of which could result in substantial costs or liabilities to the Corporation. Any regulatory changes that impose additional environmental restrictions or requirements on the Corporation or its customers could adversely affect the Corporation through increased operating and capital costs.

The Corporation is exposed to various operational risks, such as pipeline leaks; accidental damage to mains and service lines; corrosion in pipes; pipeline or equipment failure; other issues that can lead to outages and/or leaks or spills; and any other accidents involving natural gas, that could result in significant operational disruptions and/or environmental liability. The Corporation responds to spills and leaks and takes remedial steps in accordance with environmental regulations and standards and sound industry practice; however, there can be no assurance that the Corporation will not be obligated to incur further expenses in connection with changes in environmental regulations and standards or as a result of historical contamination.

Natural gas transmission, distribution and storage has inherent potential risks and there can be no assurance that substantial costs and liabilities will not be incurred. Potential environmental damage and costs could materialize due to some type of severe weather event or major equipment failure and there can be no assurance that such costs would be recoverable. Unrecovered costs could have a material adverse effect on the Corporation’s results of operations and financial position.

While the Corporation maintains insurance, the insurance is subject to coverage limits as well as time sensitive claims discovery and reporting provisions which could result in delays between the occurrence of an insured loss and recovery through insurance proceeds. In addition, there can be no assurance that the possible types of liabilities that may be incurred by the Corporation will be covered by insurance. See “Underinsured and Uninsured Losses” below.

Climate Change

In addition to the seasonality of the Corporation’s business, climate change may affect the temperature variability in the Corporation's service territory and cause changes in the consumption pattern of natural gas by the Corporation's customers, which in turn could have an impact on customer rates.

As further described in the “Competitiveness and Commodity Price Risk” section 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 in new and existing developments.

Climate change may also have the effect of increasing the severity and frequency of weather-related events that could affect the Corporation's operations and system reliability, explained further under "Weather and Natural Disasters" below. Responding to these changes in weather events could lead to increased costs associated with the strengthening of infrastructure to ensure system reliability and resiliency. An increase in the severity and frequency of weather-related events could impact future operating, maintenance, replacement, expansion and removal costs that will be incurred in the ongoing operation of its business.

Weather and Natural Disasters

The facilities of the Corporation could be exposed to the effects of severe weather conditions and other natural events, some of which could be caused by climate change. A major natural disaster, such as an earthquake, could severely damage the Corporation's natural gas transmission, distribution and storage systems. Although the Corporation's facilities have been constructed, operated and maintained to withstand severe weather, there is no assurance that they will successfully do so in all circumstances. Furthermore, many of these facilities are located in remote areas which make it more difficult to perform maintenance and repairs if such assets are damaged by weather conditions or other natural events. The Corporation operates facilities in remote and mountainous terrain with a risk of loss or damage from forest fires, floods, washouts, landslides, avalanches and similar natural events.

The Corporation has limited insurance against storm damage and other natural disasters. In the event of a large uninsured loss caused by severe weather conditions, changes in climate, or other natural disasters, application would be made to the BCUC for the recovery of these costs through higher rates to offset any loss. However, there can be no assurance that the BCUC would approve any such application. Losses resulting from repair costs and lost revenues could substantially exceed insurance coverage and any increased rates. Furthermore, the Corporation could be subject to claims from its customers for damages caused by the failure to transmit or distribute natural gas to them in accordance with the Corporation's contractual obligations. Thus, any major damage to the Corporation's facilities could result in lost revenues, repair costs and customer claims that are substantial in amount, and could, therefore, have a material adverse effect on the Corporation's results of operations and financial position.

Permits

The acquisition, ownership and operation of natural gas businesses and assets require numerous permits, approvals and certificates from federal, provincial and local government agencies and Indigenous Peoples. For various reasons, including increased stakeholder participation, the Corporation may not be able to obtain or maintain all required regulatory approvals. If there is a delay in obtaining any required regulatory approval or if the Corporation fails to maintain or obtain any required approval or fails to comply with any applicable law, regulation or condition of an approval, the Corporation's ability to properly implement or complete approved capital expenditure programs could become limited and the operation of its assets and the distribution of natural gas could be prevented or become subject to additional costs, any of which could have a material adverse effect on the Corporation's results of operations and financial position.

Underinsured and Uninsured Losses

The Corporation maintains insurance coverage with respect to potential liabilities and the accidental loss of value of certain of its assets, in amounts and with such insurers as is considered appropriate, taking into account all relevant factors, including the practices of owners of similar assets and operations. It is anticipated that such insurance coverage will be maintained. However, there can be no assurance that the Corporation will be able to obtain or maintain adequate insurance in the future at rates it considers reasonable. Further, there can be no assurance that available insurance will cover all losses or liabilities that might arise in the conduct of the Corporation's business. The occurrence of a significant uninsured claim or a claim in excess of the insurance coverage limits maintained by the Corporation or a claim that falls within a significant self-insured retention could have a material adverse effect on the Corporation's results of operations and financial position.

In the event of an uninsured loss or liability, the Corporation would apply to the BCUC to recover the loss (or liability) through an increased tariff. However, there can be no assurance that the BCUC would approve any such application, in whole or in part. Additionally, delays between the occurrence of an uninsured loss (or liability) and recovery through an increased tariff could result in variability of results between periods. Any major damage to the Corporation's facilities could result in repair costs and customer claims that are substantial in amount and which could have a material adverse effect on the Corporation's results of operations and financial position.

FORTIS BC

Indigenous Rights and Indigenous Engagement

The Corporation provides service to customers on Indigenous Peoples' lands and maintains gas facilities on lands that are subject to land claims by various Indigenous Peoples. There are various treaty negotiation processes involving Indigenous Peoples and the Governments of BC and Canada that are underway, but the basis upon which settlements might be reached in the Corporation's service areas is not clear. Furthermore, not all Indigenous Peoples are participating in the processes. To date, the policy of the Government of BC has been to endeavour to structure settlements without prejudicing existing rights held by third parties such as the Corporation. However, there can be no certainty that the settlement processes will not have a material adverse effect on the Corporation's results of operations and financial position.

Before issuing approvals for the addition of new infrastructure, the BCUC will consider whether the Crown has a duty to consult Indigenous Peoples and to accommodate, if necessary, and if so whether the consultation and accommodation by the Crown have been adequate. The Crown's duty to consult and accommodate may also be triggered before other permits and authorizations are issued to the Corporation such as those under the *Oil and Gas Activities Act*. If engagement and consultation with Indigenous groups are not addressed upfront, this may affect the timing, cost and likelihood of regulatory approval of certain of the Corporation's capital projects and result in higher costs to implement projects in the longer term.

The Province's *Declaration on the Rights of Indigenous Peoples Act* ("DRIPA") sets out a process by which the Province will review its laws to ensure they are consistent with the United Nations Declaration on the Rights of Indigenous Peoples. This review may result in amendments to provincial legislation which may affect the Corporation. DRIPA also empowers the Government of BC to enter into agreements with Indigenous governing bodies to provide for joint-decision making or to require consent of an Indigenous governing body before certain decisions are made.

Labour Relations

The Corporation employs members of labour unions that have entered into collective bargaining agreements with the Corporation. The provisions of such collective bargaining agreements affect the flexibility and efficiency of the business carried on by the Corporation. There can be no assurance that current relations will continue in future negotiations or that the terms under the present collective bargaining agreements will be renewed.

The inability to maintain, or to renew, the collective bargaining agreements on acceptable terms could result in increased labour costs or service interruptions arising from labour disputes, that are not provided for in approved rates and that could have a material adverse effect on the Corporation's results of operations and financial position.

Employee Future Benefits

The Corporation maintains defined benefit pension plans and supplemental pension arrangements. There is no certainty that the plan assets will be able to earn the assumed rate of returns. Market driven changes impacting the performance of the plan assets may result in material variations in actual return on plan assets from the assumed return on the assets causing material changes in net benefit costs. Net benefit cost is impacted by, among other things, the discount rate, changes in the expected mortality rates of plan members, the amortization of experience and actuarial gains or losses, and expected return on plan assets. Market driven changes impacting other assumptions, including the assumed discount rate, may also result in future contributions to pension plans that differ significantly from current estimates as well as causing material changes in net benefit cost.

There is also measurement uncertainty associated with net benefit cost, future funding requirements, the net accrued benefit asset and projected benefit obligation due to measurement uncertainty inherent in the actuarial valuation process.

Net benefit cost variances from forecast for rate-setting purposes are recovered through future rates using regulatory deferral accounts approved by the BCUC. There can be no assurance that such deferral mechanisms will exist in the future as they are dependent on future regulatory decisions and orders. An inability to flow through these costs could have a material adverse effect on the Corporation's results of operations and financial position.

Human Resources

The ability of the Corporation to deliver service in a cost-effective manner is dependent on the ability of the Corporation to attract, develop and retain skilled workforces. Like other utilities across Canada, the Corporation is faced with demographic challenges relating to such skilled workforces. The inability to attract, develop and retain skilled workforces could have a material adverse effect on the Corporation.

Information Technology Infrastructure

The ability of the Corporation to operate effectively is dependent upon managing and maintaining information systems and infrastructure that support the operation of distribution, transmission and storage facilities; provide customers with billing and consumption information; and support the financial and general operating aspects of the business. The reliability of the communication infrastructure and supporting systems are also necessary to provide important safety information. System failures could have a material adverse effect on the Corporation.

Cyber-Security

The Corporation operates critical energy infrastructure in its service territory and, as a result, is exposed to the risk of cyber-security violations. Unauthorized access to corporate and information technology systems due to hacking, viruses and other causes could result in service disruptions and system failures. In addition, in the normal course of operation, the Corporation requires access to confidential customer data, including personal and credit information, which could be exposed in the event of a security breach. A security breach could have a material adverse effect on the Corporation's results of operations and financial position.

Interest Rates

The Corporation is exposed to interest rate risks associated with floating rate debt and refinancing of its long-term debt. Regulated interest expense variances from forecast for rate-setting purposes are recovered through future rates using a regulatory deferral account approved by the BCUC. There can be no assurance that such deferral mechanisms will exist in the future as they are dependent on future regulatory decisions and orders. An inability to flow through these costs could have a material adverse effect on the Corporation's results of operations and financial position.

Impact of Changes in Economic Conditions

A general and extended decline in BC's economy or in that of the Corporation's service area in particular, would be expected to have the effect of reducing demand for energy over time. Energy sales are influenced by economic factors such as changes in employment levels, personal disposable income, energy prices, housing starts and customer growth. New customer additions at the Corporation are typically a result of population growth and new housing starts, which are affected by the state of the provincial economy. The Corporation is also affected by changes in trends in housing starts from single family dwellings to multi-family dwellings, for which natural gas has a lower penetration rate. The growth of new multi-family housing starts continues to significantly outpace that of new single-family housing starts. Natural gas and crude oil prices are closely correlated with natural gas and crude oil exploration and production activity in certain of the Corporation's service territories. The level of these activities can influence energy demand which could have a material adverse effect on the Corporation.

Capital Resources and Liquidity

The Corporation's financial position could be adversely affected if it fails to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and the repayment of maturing debt. The Corporation's ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the regulatory environment in BC, regulatory decisions regarding capital structure and ROE, the results of operations and financial position of the Corporation, conditions in the capital and bank credit markets, ratings assigned by rating agencies and general economic conditions. Funds generated from operations after payment of expected expenses (including interest payments on any outstanding debt) may not be sufficient to fund the repayment of all outstanding liabilities when due and anticipated capital expenditures. There can be no assurance that sufficient capital will be available on acceptable terms to fund capital expenditures and to repay existing debt.

Generally, the Corporation is subject to financial risk associated with changes in the credit ratings assigned by credit rating agencies. Credit ratings impact the level of credit risk spreads on new long-term debt issues and on the Corporation's credit facility. A change in the credit ratings could potentially affect access to various sources of capital and increase or decrease the Corporation's finance charges. Also, a significant downgrade in the Corporation's credit ratings could trigger margin calls and other cash requirements under the Corporation's natural gas purchase and natural gas derivative contracts. Global financial crises have placed scrutiny on rating agencies and rating agency criteria that may result in changes to credit rating practices and policies.

Volatility in the global financial and capital markets may increase the cost of and affect the timing of issuance of long-term capital by the Corporation.

Competitiveness and Commodity Price Risk

In the Corporation's utility service territory, natural gas primarily competes for space and hot water heating load with electricity. In addition to other price comparisons, the upfront capital cost differences between electricity and natural gas equipment for hot water and space heating applications continue to present a challenge for the competiveness of natural gas on a fully-costed basis.

In the future, if natural gas becomes less competitive due to price or other factors such as the public perception of natural gas as an energy source, the Corporation's ability to add new customers could be impaired, and existing customers could reduce their consumption of natural gas or eliminate its usage altogether as furnaces, water heaters and other appliances are replaced. This may result in higher rates and, in an extreme case, could ultimately lead to an inability to fully recover the Corporation's cost of service in rates charged to customers.

Government policy has also impacted the competitiveness of natural gas in BC. The Government of BC has introduced changes to energy policy including greenhouse gas emission reduction targets and a consumption tax on carbon-based fuels. However, the Government of BC has yet to introduce carbon tax on imported electricity generated through the combustion of carbon-based fuels. The impact of these changes in energy policy may have a material impact on the competitiveness of natural gas relative to non-carbon based energy sources or other energy sources.

There are other competitive challenges that are impacting the penetration of natural gas into new housing stock such as green attributes of the energy source, and type of housing stock being built. In addition, municipal and other government policy may impose limitations on energy sources permitted in new and existing developments.

A severe and prolonged increase in commodity costs could materially affect the Corporation despite regulatory measures available for compensating for changes in commodity costs. There can be no assurance that the current BCUC approved flow through mechanisms in place allowing for the flow through of the natural gas supply costs, will continue in the future as they are dependent on future regulatory decisions and orders. An inability to flow through the full cost of natural gas could have a material adverse effect on the Corporation's results of operations and financial position.

Counterparty Credit Risk

The Corporation is exposed to credit risk in the event of non-performance by counterparties. The Corporation deals with reasonable credit-quality institutions in accordance with established credit approval practices. To date the Corporation has not experienced any material counterparty defaults and does not expect any counterparties to fail to meet their obligations; however, the credit quality of counterparties, can change rapidly. In the event of non-performance by counterparties, there could be a material adverse effect on the Corporation's results of operations and financial position.

Natural Gas Supply Risk

The Corporation is dependent on a limited selection of pipeline and storage providers. Regional market prices, particularly at the Sumas market hub, have been higher than prices elsewhere in North America during peak winter periods when regional pipeline and storage resources become constrained to serve the demand for natural gas in BC and the US Pacific Northwest. Fluctuations in the amount of natural gas used by customers can vary significantly in response to seasonal changes in weather and longer term changes in climate.

In addition, the Corporation is highly dependent on a single source transmission pipeline. In the event of a prolonged service disruption on the Westcoast transmission system, the Corporation's customers could experience outages, thereby affecting revenues and incurring costs to safely relight customers. The Corporation uses LNG peak shaving facilities to mitigate this risk by providing short-term on-system supply during cold weather spells or emergency situations.

Developments are occurring in the region that may increase the demand for gas supply from BC. These include an increase in pipeline capacity to deliver gas from BC to markets outside of BC and the potential development of large scale LNG facilities to export gas. BC has significant natural gas resources that are expected to be sufficient to meet incremental demand requirements and to continue to supply existing markets. It is uncertain at this time, however, how the pace and location of infrastructure development to connect production to new and existing markets could impact the Corporation's access to supply or the price of that supply.

There can be no assurance that the current BCUC approved flow through mechanisms in place allowing for the flow through of the natural gas supply costs, will continue in the future, as they are dependent on future regulatory decisions and orders. An inability to flow through the full cost of natural gas could have a material adverse effect on the Corporation's results of operations and financial position.

FINANCIAL INSTRUMENTS

Financial Instruments Measured at Fair Value on a Recurring Basis

The following table presents the Corporation's assets and liabilities as at December 31 accounted for at fair value on a recurring basis, all of which are Level 2 of the fair value hierarchy:

($ millions)	**2019**	2018
Assets		
Current		
Natural gas contracts subject to regulatory deferral [1]	**11**	5
Long-term		
Natural gas contracts subject to regulatory deferral [1]	**2**	9
Total assets	**13**	14
Liabilities		
Current		
Natural gas contracts subject to regulatory deferral [1]	**(11)**	(22)
Long-term		
Natural gas contracts subject to regulatory deferral [1]	**(1)**	(1)
Total liabilities	**(12)**	(23)
Total assets (liabilities), net	**1**	(9)

[1] Derivative contracts that are "in the money" are included in accounts receivable or other assets, and "out of the money" are included in accounts payable and other current liabilities or other liabilities.

The Corporation has elected gross presentation for its derivative contracts under master netting agreements, which applies only to its natural gas derivatives. The table below presents the potential offset of counterparty netting and cash collateral:

		Gross Amount Not Offset in the Balance Sheet		
December 31, 2019	**Gross Amount Recognized in the Balance Sheet**	**Counterparty Netting of Natural Gas Contracts [1]**	**Cash Collateral Posted**	**Net Amount**
($ millions)				
Natural gas contracts subject to regulatory deferral:				
Accounts receivable	**11**	**(8)**	**10**	**13**
Other assets	**2**	**(1)**	**-**	**1**
Accounts payable and other current liabilities	**(11)**	**8**	**-**	**(3)**
Other liabilities	**(1)**	**1**	**-**	**-**

[1] Positions, by counterparty, are netted where the intent and legal right to offset exists.

		Gross Amount Not Offset in the Balance Sheet		
December 31, 2018	Gross Amount Recognized in the Balance Sheet	Counterparty Netting of Natural Gas Contracts [1]	Cash Collateral Posted	Net Amount
($ millions)				
Natural gas contracts subject to regulatory deferral:				
Accounts receivable	5	(4)	16	17
Other assets	9	(1)	-	8
Accounts payable and other current liabilities	(22)	4	-	(18)
Other liabilities	(1)	1	-	-

[1] Positions, by counterparty, are netted where the intent and legal right to offset exists.

Derivative Instruments

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

FEI enters into physical natural gas supply contracts and financial commodity swaps to fix the effective purchase price of natural gas, as the majority of the natural gas supply contracts have floating, rather than fixed, prices. Swap contracts are agreements between two parties to exchange streams of payments over time according to specified terms. Swap contracts require receipt of payment for the notional quantity of the commodity based on the difference between a fixed price and the market price on the settlement date. The fair value of the natural gas derivatives is calculated using the present value of cash flows based on published market prices and forward curves for natural gas.

Natural gas contracts held by FEI are subject to regulatory recovery through rates. As at December 31, 2019 and 2018, these natural gas contracts were not designated as hedges and any unrealized gains or losses associated with changes in the fair value of the derivatives were deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the BCUC, and as shown in the following table:

($ millions)	**2019**	2018
Unrealized net gain (loss) recorded to current regulatory liabilities (assets)	**1**	(9)

Cash inflows and outflows associated with the settlement of all derivative instruments are included in operating cash flows on the Corporation's Consolidated Statements of Cash Flows.

Financial Instruments Not Measured At Fair Value

The fair value of a financial instrument is the market price to sell an asset or transfer a liability at the measurement date. The Corporation uses the following methods and assumptions for estimating the fair value of financial instruments:

- The carrying values of cash, accounts receivable, accounts payable, other current assets and liabilities and borrowings under the credit facility on the Consolidated Balance Sheets of the Corporation approximate their fair values due to the short-term nature of these financial instruments. These items have been excluded from the table below.
- For long-term debt, the Corporation uses quoted market prices when available. When quoted market prices are not available, the fair value is determined by discounting the future cash flows of the specific debt instrument at an estimated yield to maturity equivalent to benchmark government bonds or treasury bills, with similar terms to maturity, plus a market credit risk premium equal to that of issuers of similar credit quality. Since the Corporation does not intend to settle the long-term debt prior to maturity, the fair value estimate does not represent an actual liability and, therefore, does not include exchange or settlement costs.

The use of different estimation methods and market assumptions may yield different estimated fair value amounts. The following table includes the carrying value and estimated fair value of the Corporation's long-term debt as at December 31:

		2019		2018	
($ millions)	**Fair Value Hierarchy**	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Long-term debt [1]	Level 2	**2,795**	**3,527**	2,595	2,994

[1] Carrying value excludes unamortized debt issuance costs.

NEW ACCOUNTING POLICIES

Standard	Effective Date	Description	Effect on FEI
Leases	January 1, 2019	ASU No. 2016-02, *Leases* (ASC 842), 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 quantitative and qualitative disclosures. When a contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration, a right-of-use asset and lease liability are recognized. At 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. 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. Leases with a term of twelve months or less are not recorded on the balance sheet but are recognized as lease expense straight-line over the lease term.	FEI applied the transition provisions as of the adoption date and did not retrospectively adjust prior periods. FEI 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 lease classification of existing leases; or (iii) the initial direct costs for existing leases. 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 FEI accounts for as a single lease component. Also, the Corporation utilized the hindsight practical expedient to determine the lease term. Upon adoption, the Corporation 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. As at December 31, 2019, the Corporation recognized $6 million of right-of-use assets and lease liabilities related to office facilities.

FUTURE ACCOUNTING PRONOUNCEMENTS

FEI considers the applicability and impact of all ASUs issued by the Financial Accounting Standards Board ("FASB"). Any ASUs issued by FASB, but not yet adopted by FEI, that are not included below were assessed and determined to be either not applicable to the Corporation or not expected to have a material impact on the Consolidated Financial Statements.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Corporation's consolidated financial statements in accordance with US GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances. Additionally, certain estimates and judgments are necessary since the regulatory environment in which the Corporation operates often requires amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. Due to changes in facts and circumstances and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are recognized in the period in which they become known. The Corporation's critical accounting estimates are discussed below.

Regulation

Generally, the accounting policies used by the Corporation in its regulated operations are subject to examination and approval by the regulatory authority, the BCUC. These accounting policies may differ from those used by entities not subject to rate regulation. The timing of the recognition of certain assets, liabilities, revenues and expenses, as a result of regulation, may differ from that otherwise expected using US GAAP for entities not subject to rate regulation. Regulatory assets and regulatory liabilities arise as a result of the rate-setting process and have been recognized based on previous, existing or expected regulatory orders or decisions. Certain estimates are necessary since the regulatory environment in which the Corporation operates often requires amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. The final amounts approved by the regulatory authority for deferral as regulatory assets and regulatory liabilities and the approved recovery or settlement periods may differ from those originally expected. Any resulting adjustments to original estimates are recognized in earnings in the period in which they become known. In the event that a regulatory decision is received after the balance sheet date but before the consolidated financial statements are issued, the facts and circumstances are reviewed to determine whether or not it is a recognized subsequent event. As at December 31, 2019, the Corporation recognized $1,003 million in current and long-term regulatory assets (2018 - $831 million) and $223 million in current and long-term regulatory liabilities (2018 - $189 million).

Depreciation, Amortization and Removal Costs

Depreciation and amortization are estimates based primarily on the useful life of assets. Estimated useful lives are based on current facts and historical information and take into consideration the anticipated physical life of the assets. As at December 31, 2019, the Corporation's property, plant and equipment and intangible assets were $5,076 million, or approximately 69 per cent of total assets, compared to $4,777 million, or approximately 70 per cent of total assets, as at December 31, 2018. Changes in depreciation and amortization rates may have a significant impact on the Corporation's consolidated depreciation and amortization expense.

As approved by the BCUC, the net salvage provision is collected as a component of depreciation on an accrual basis, with actual removal costs incurred drawing down the accrual balance. Removal costs are the direct costs incurred by the Corporation in taking assets out of service, whether through actual removal of the asset or through disconnection from the transmission or distribution system.

As part of the customer rate-setting process, appropriate depreciation, amortization and net salvage provision rates are approved by the BCUC for the Corporation's regulated operations. The rates are reviewed on an ongoing basis to ensure they continue to be appropriate. From time to time, independent third-party depreciation studies are performed for the regulated operations. Based on the results of these independent third party studies, the impact of any over-or-under collection, as a result of actual experience differing from that expected and provided for in previous rates, is generally reflected in future rates and expense.

Assessment for Impairment of Goodwill

The Corporation is required to perform, at least on an annual basis, an impairment test for goodwill, and any impairment provision has to be charged to earnings. In addition, the Corporation also performs an impairment test if any event occurs or if circumstances change that would indicate that the fair value was below its carrying value. No such event or change in circumstances occurred during 2019 or 2018.

As at December 31, 2019, goodwill totaled $913 million (2018 - $913 million).

During 2019, the Corporation performed an annual assessment of goodwill and concluded that it is more likely than not that the fair value of the reporting unit was greater than the carrying value and that goodwill was not impaired.

Employee Future Benefits

The Corporation's defined benefit pension plans, supplemental pension arrangements and OPEB plans are subject to judgments utilized in the actuarial determination of the net benefit cost and related obligation. The main assumptions utilized by management in determining the net benefit cost and obligation are the discount rate for the projected benefit obligation and the expected long-term rate of return on plan assets.

The assumed long-term rate of return on the defined benefit pension plan assets, for the purpose of determining pension net benefit cost for 2019, was 6.00 per cent, which was consistent with 2018. As one of the Corporation's defined benefit pension plans has excess interest indexing provision where a portion of investment returns are allocated to provide for indexing of pension benefits, the projected benefit obligations for this plan may vary based on the expected long-term rate of return on plan assets.

The assumed discount rate, used to measure the projected pension benefit obligations on the measurement date of December 31, 2019, and to determine the pension net benefit cost for 2020, is 3.00 per cent. This is a decrease from the 3.75 per cent assumed discount rate used to measure the projected benefit obligations as at December 31, 2018, and to determine the pension net benefit cost for 2019.

The long-term rate of return is based on the expected average return of the assets over a long period given the relative asset mix. The discount rate is determined with reference to the current market rate of interest on high quality debt instruments with cash flows that match the time and amount of expected benefit payments.

The Corporation expects net benefit cost for 2020 related to its defined benefit pension plans, prior to regulatory adjustments, to be $22 million, an increase of $14 million compared to 2019, which is primarily due to an increase of amortization of actuarial losses and increases in current service costs and interest costs due to the decline in discout rates.

The following table provides the sensitivities associated with a 100 basis point change in the expected long-term rate of return on pension plan assets and discount rate on 2019 net benefit pension cost, and the related projected benefit obligations recognized in the Corporation's Consolidated Financial Statements:

Increase (decrease) ($ millions)	**Net Benefit Cost**	**Projected Benefit Obligation**
1% increase in the expected rate of return	**(5)**	**11**
1% decrease in the expected rate of return	**3**	**(55)**
1% increase in the discount rate	**(6)**	**(127)**
1% decrease in the discount rate	**14**	**166**

The above table reflects the changes before the effect of any regulatory deferral mechanism approved by the BCUC. The Corporation currently has in place a BCUC approved mechanism to defer variations in pension net benefit costs from forecast net benefit costs, used to set customer rates, as a regulatory asset or liability.

Other significant assumptions applied in measuring the pension net benefit cost and/or the projected benefit obligation include the average rate of compensation increase, average remaining service life of the active employee group, and employee and retiree mortality rates.

The Corporation's OPEB plans are also subject to judgments utilized in the actuarial determination of the OPEB net benefit cost and related projected benefit obligation. Except for the assumption of the expected long-term rate of return on plan assets, the above assumptions, along with health care cost trends, were also utilized by management in determining OPEB plan net benefit cost and projected benefit obligation. The Corporation currently has in place a BCUC approved mechanism to defer variations in OPEB net benefit costs from forecast OPEB net benefit costs, used to set customer rates, as a regulatory asset or liability.

As at December 31, 2019, the Corporation had a pension projected benefit net liability of $135 million (2019 - $80 million) and an OPEB projected benefit liability of $123 million (2018 - $111 million). The increase in the projected pension benefit liability during 2019 was primarily a result of the 0.75 per cent decrease in the assumed discount rate used to measure the projected benefit liability. The increase in the OPEB projected benefit liability was a result of the change in the discount rate, partially offset by the elimination of British Columbia Medical Services Premiums effective January 1, 2020. During 2019, the Corporation recorded pension and OPEB net benefit cost, inclusive of regulatory adjustments, of $18 million (2018 - $19 million).

Asset Retirement Obligations ("AROs")

The measurement of the fair value of AROs requires making reasonable estimates concerning the method of settlement and settlement dates associated with the legally obligated asset retirement costs. There are also uncertainties in estimating future asset-retirement costs due to potential external events, such as changing legislation or regulations and advances in remediation technologies. The Corporation does not have any AROs for which amounts have been recorded as at December 31, 2019 and 2018.

The nature, amount and timing of costs associated with land and environmental remediation and/or removal of assets cannot be reasonably estimated at this time as the natural gas transmission and distribution systems are reasonably expected to operate in perpetuity due to the nature of their operation; and applicable licenses and permits are reasonably expected to be renewed or extended indefinitely to maintain the integrity of the related assets and ensure the continued provision of service to customers. In the event that environmental issues are known and identified, assets are decommissioned or the applicable licenses, permits, or agreements are terminated, AROs will be recognized at that time provided the costs can be reasonably estimated and are material.

Revenue Recognition

The Corporation recognizes revenue on an accrual basis. Recording revenue on an accrual basis requires use of estimates and assumptions. Customer bills are issued throughout the month based on meter readings or estimates that establish natural gas consumption by customers since the last meter reading. The unbilled revenue accrual for the period is based on estimated natural gas sales to customers for the period since the last meter reading at the approved rates. The development of the sales estimates requires analysis of consumption on a historical basis in relation to key inputs, such as the current price of natural gas, population growth, economic activity, weather conditions and system losses. The estimation process for accrued unbilled natural gas consumption will result in adjustments to natural gas revenue in the periods they become known, when actual results differ from the estimates. As at December 31, 2019 the amount of accrued unbilled revenue recorded in accounts receivable was $102 million (2018 - $89 million) on annual natural gas revenues of $1,290 million (2018 - $1,136 million).

Income Taxes

Income taxes are determined based on estimates of the Corporation's current income taxes and estimates of deferred income taxes resulting from temporary differences between the carrying value of assets and liabilities in the consolidated financial statements and their tax values. 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. Deferred income tax assets are assessed for the likelihood that they will be recovered from future taxable income. To the extent recovery is not considered more likely than not, a valuation allowance is recognized against earnings in the period when the allowance is created or revised. Estimates of the provision for current income taxes, deferred income tax assets and liabilities, and any related valuation allowance, might vary from actual amounts incurred.

SELECTED ANNUAL FINANCIAL INFORMATION

The following table sets forth information derived from audited financial statements for the years ended December 31, 2019, 2018 and 2017. These results are not necessarily indicative of results for any future period and should not be relied upon to predict future performance.

Years Ended December 31	**2019**	2018	2017
($ millions)			
Revenue	**1,330**	1,187	1,199
Net earnings attributable to controlling interest	**182**	189	185
Total assets	**7,351**	6,866	6,511
Long-term debt, excluding current portion	**2,774**	2,575	2,376
Dividends on common shares	**150**	142	126

2019/2018 – Revenue increased $143 million over 2018 and net earnings decreased $7 million over 2018. For a discussion of the reasons for the increase in revenues and decrease in net earnings, refer to the "Consolidated Results of Operations" section of this MD&A. The increase in total assets was mainly due to capital expenditures, which included sustainment and growth capital as well as major project expenditures discussed further under "Projected Capital Expenditures and Other Investments". Long-term debt increased due to the long-term debt issuance of $200 million in August 2019.

2018/2017 – Revenue decreased $12 million over 2017 and net earnings increased $4 million over 2017. The decrease in revenue was primarily due to a lower cost of natural gas recovered from customers, as approved by the BCUC, and an increase in the refund of the MCRA gas storage and transport cost regulatory liability, which decreased revenues, partially offset by an increase in revenues approved for rate setting purposes resulting from higher investment in regulated assets, and $10 million in amortization of certain revenue related regulatory liabilities, that qualify as alternative revenue programs and therefore have been recognized in revenues during 2018 as a result of adopting ASC Topic 606. Net earnings increased due to higher investment in regulated assets, and higher income tax benefit as a result of the Corporation having a TLUP in place for a longer duration in 2018, as compared to the TLUP in place in 2017, partially offset by lower operation and maintenance expense savings year to date, net of the regulated Earnings Sharing Mechanism, and lower interest savings. The increase in total assets was mainly due to capital expenditures (including those related to LMIPSU, Tilbury Phase 1A Expansion Project, Inland Gas Upgrades, and TIMC). Long-term debt increased due to the long-term debt issuance of $200 million in December 2018.

From 2017 to 2019, dividends were paid to assist in maintaining the BCUC approved capital structure of 38.5 per cent equity.

OTHER DEVELOPMENTS

Collective Agreements

The collective agreement between the Corporation and Local 213 of the International Brotherhood of Electrical Workers ("IBEW") expired on March 31, 2019 and bargaining between FEI and IBEW continues. The IBEW represents employees in specified occupations in the areas of transmission and distribution.

There are two collective agreements between the Corporation and Local 378 of the Canadian Office and Professional Employees Union now referred to as MoveUP. The first collective agreement representing customer service employees expires on March 31, 2022. The second collective agreement representing employees in specified occupations in the areas of administration and operations support expires on June 30, 2023.

OUTSTANDING SHARE DATA

As at the filing date of this MD&A, the Corporation had issued and outstanding 338,944,220 common shares, all of which are owned by FHI, a directly wholly-owned subsidiary of Fortis.

ADDITIONAL INFORMATION

Additional information about FEI, including its AIF, can be accessed at www.fortisbc.com or www.sedar.com. The information contained on, or accessible through, either of these websites is not incorporated by reference into this document.

For further information, please contact:

Ian Lorimer
Vice President, Finance and Chief Financial Officer
Tel: 250-469-8013
Email: ian.lorimer@fortisbc.com

FortisBC Energy Inc.
10th Floor, 1111 West Georgia Street
Vancouver, British Columbia V6E 4M3

Website: www.fortisbc.com