FORTISBC ENERGY INC.

MANAGEMENT DISCUSSION & ANALYSIS

For the Year Ended December 31, 2018

February 14, 2019

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 2018 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, 2018 and 2017, 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 Liquefied Natural Gas Facility Expansion Project ("Tilbury Expansion Project"), the Lower Mainland Intermediate Pressure System Upgrade Project ("LMIPSU"), the Inland Gas Upgrades Project ("IGU") 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 the effect of the Westcoast Energy Inc. ("Westcoast") natural gas transmission pipeline incident.

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 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; weather and natural disasters risk; permits risk; underinsured and uninsured losses; risks involving Indigenous peoples; 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 1,029,500 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 operates primarily under a cost of service regulation as prescribed by the BCUC. The Corporation applies to the BCUC for approval of annual revenue requirements based on forecast costs of service, including, but not limited to, natural gas supply costs, operating expenses, depreciation and amortization, income taxes, interest on debt and a return on equity ("ROE"). From 2014 through 2019, the regulatory framework includes some performance-based rate-setting attributes.

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").

In 2018, the MCRA deferral account captured the increased cost of procuring additional gas on the open marketplace to replace the gas that was not received during the fourth quarter of 2018 due to an incident that took place on October 9, 2018. The incident affected Westcoast's natural gas transmission pipeline, near Prince George, BC, which provides supply of natural gas to FEI for distribution to its customers in various locations across BC. Westcoast is a wholly-owned subsidiary of Enbridge Inc. FEI declared a force majeure under several of its rate schedules. No FEI infrastructure was damaged as a result of this incident. FEI communicated to its customers during the fourth quarter of 2018 the importance of conserving gas consumption to ensure adequate supply was available during the period of reduced capacity on Westcoast's natural gas transmission pipeline.

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 2018 or 2017. As part of the 2014 Performance Based Ratemaking ("PBR") Application decision received in September 2014 and effective through to the end of the PBR term, the Corporation has a flow-through deferral account that captures variances from regulated forecast items, excluding formulaic operation and maintenance costs, that do not have separately approved deferral mechanisms, and flows those variances through customer rates in the following year.

Multi-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.

Price Risk Management Application

In June 2016, the BCUC approved the Corporation's Price Risk Management Application to implement specific price risk management tools and strategies to limit the exposure to fluctuations in natural gas prices for customers who receive commodity supply from FEI. These included enhancements to the commodity rate setting mechanism as well as the use of derivative instruments based on pre-defined market price targets and maximum volume limits. Since July 2016, FEI's future commodity rate setting has incorporated the rate setting enhancements and FEI implements derivative instruments if the market price targets are reached for terms out to March 2019. Since the first quarter of 2017, there were occasions when the market price targets approved by the BCUC were reached and the Company entered into fixed price financial swaps to hedge against the physical natural gas contracts. These fixed price financially settled natural gas commodity swaps were recognized as derivative instruments. The Corporation has filed the 2018 Price Risk Management Plan with the BCUC requesting further enhancements to its price risk management strategies and is awaiting a decision.

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 the Coastal Transmission System ("CTS") project, which will increase the Corporation's pipeline capacity on three transmission line segments, and 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.

During the first quarter of 2017, the Provincial government amended the Greenhouse Gas Reductions Regulation ("GGRR") providing an additional $160 million of incentives and infrastructure funding to further expand the FEI natural gas for transportation ("NGT") programs. Specifically, the additional incentives provide for the following to be potentially included in FEI's 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.

CONSOLIDATED RESULTS OF OPERATIONS

	Quarter			Year		
Periods Ended December 31	**2018**	2017	Variance	**2018**	2017	Variance
Gas sales (petajoules)	**63**	69	(6)	**212**	221	(9)
($ millions)						
Total revenues [1]	**371**	366	5	**1,187**	1,199	(12)
Cost of natural gas	**106**	119	(13)	**322**	411	(89)
Operation and maintenance [2]	**74**	74	-	**245**	234	11
Property and other taxes	**14**	14	-	**63**	63	-
Depreciation and amortization	**55**	51	4	**223**	203	20
Total expenses	**249**	258	(9)	**853**	911	(58)
Operating income	**122**	108	14	**334**	288	46
Add: Other income [2]	**37**	41	(4)	**144**	153	(9)
Less: Finance charges	**67**	65	2	**271**	248	23
Earnings before income taxes	**92**	84	8	**207**	193	14
Income tax expense	**12**	11	1	**17**	7	10
Net earnings	**80**	73	7	**190**	186	4
Net earnings attributable to non-controlling interest	**-**	-	-	**1**	1	-
Net earnings attributable to controlling interest	**80**	73	7	**189**	185	4

[1] 2018 total revenues have been presented pursuant to adopting Accounting Standards Codification ("ASC") Topic 606, *Revenue from Contracts with Customers,* using the modified retrospective method which does not require restatement of prior periods and therefore did not affect the revenue or net earnings comparison for the periods ended December 31.

[2] The components of 2018 and 2017 operating costs and other income have been presented pursuant to adopting Accounting Standards Update ("ASU") No. 2017-07*, Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost,* which requires restatement of 2017 comparatives for presentation purposes. This did not have a material impact on three months ended December 31, 2017 and resulted in a retrospective $2 million reclassification from operating costs to other income for the year ended December 31, 2017. There was no effect on the net earnings comparison for the periods ended December 31.

The following table outlines net earnings and the significant variances in the Consolidated Results of Operations for the three months ended December 31, 2018 as compared to December 31, 2017:

Quarter		
Item	**Increase (Decrease)** ($ millions)	**Explanation**
Net earnings attributable to controlling interest	**7**	Net earnings for the quarter ended December 31, 2018 were $80 million compared to $73 million for the same period in 2017 primarily due to: • higher investment in regulated assets, and • 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. Both 2018 and 2017 net earnings are based on allowed ROE of 8.75 per cent and a deemed equity component of capital structure of 38.5 per cent.
Total revenues	**5**	Total revenues include revenue from contracts with customers, which includes tariff revenues, fees charged for tariff-based customer connections, and revenue from agreements with customers to provide transportation of natural gas over utility owned infrastructure. Also included in total revenues is alternative revenue, which includes the Corporation's Earnings Sharing Mechanism, RSAM, and flow-through variances related to industrial and other customer revenue. Lastly, total revenues include other revenue, which is primarily comprised of regulatory deferral adjustments that capture variances from regulated forecast items, excluding formulaic operation and maintenance costs. If such regulatory deferral adjustments recognized in the current period are owed to, or recoverable from,

Quarter		
Item	**Increase (Decrease)** ($ millions)	**Explanation**
		customers in future rates, they are recognized as either other expense or other revenue, respectively. The increase in total revenues was primarily due to: • an increase in revenues approved for rate-setting purposes resulting from higher investment in regulated assets, • $2 million in amortization of certain revenue related to 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, and • a decrease in the refund of the MCRA gas storage and transport cost regulatory liability, which increased revenues, partially offset by • a lower cost of natural gas recovered from customers, as approved by the BCUC. There were lower gas sales volumes compared to the same period in 2017 primarily due to lower average consumption by residential, commercial and transportation customers as a result of warmer weather and focused conservation efforts relating to reduced gas supply. The variance between revenues associated with actual average consumption and those revenues forecast for rate-setting purposes are captured in either the RSAM deferral account or the flow-through deferral account, for which the income statement offsets are recognized in alternative revenues. The lower consumption resulted in lower revenue from contracts with customers, but was offset by an equal alternative revenue amount resulting in no impact on total revenues.
Cost of natural gas	**(13)**	The cost of natural gas includes commodity, storage and transport, as well as the storage and transport variances captured in the MCRA deferral account, all of which are passed through to customers with no impact to the margin on gas sales or net earnings. Changes in consumption levels of customers and changes in the commodity cost of natural gas from those approved by the BCUC do not materially impact earnings as a result of regulatory deferral accounts. The decrease in the cost of natural gas was primarily due to: • a lower commodity cost, approved by the BCUC, of $1.549 per gigajoule for the quarter ended December 31, 2018, as compared to $2.050 per gigajoule for the same quarter in 2017, and • lower gas sales consumption compared to the same period in 2017, partially offset by • a lower amount of MCRA gas storage and transport cost regulatory liability refunded to customers, which decreases the cost of natural gas, during the quarter.
Depreciation and amortization	**4**	The increase was primarily due to higher depreciable asset base compared to the prior year. In addition, $2 million in amortization of certain revenue related regulatory liabilities have been recognized in revenues during the fourth quarter of 2018 as a result of adopting ASC Topic 606 requirements around alternative revenues, while $2 million for the same period of 2017 was recognized as a reduction to amortization expense.
Other income	**(4)**	Other income primarily consists of the equity component of allowance for funds used during construction ("AFUDC") as well as the non-service cost component of pension and other post-employment benefits. The decrease in other income was primarily due to a higher equity component of AFUDC recognized in the fourth quarter of 2017 associated with the Tilbury Phase 1A project under construction at that time, which has now been included in rate base for 2018, and lower dividend income due to FEI winding-up a tax loss utilization plan ("TLUP") earlier in the fourth quarter in 2018, as compared to the TLUP in place in 2017. As part of the TLUP, the Corporation received dividend income from FHI relating to a $2,500 million (2017 - $2,500 million) investment in preferred shares. A TLUP is a series of transactions, whereby the Corporation sets up an investment in an affiliate's preferred shares and issues subordinated debt to that affiliate; these two financial instruments are shown on a net basis. The Corporation receives non-taxable dividend income on the preferred shares and pays tax deductible interest on the debt. The effect of this transaction is to transfer tax losses between affiliated entities.

The following table outlines net earnings and the significant variances in the Consolidated Results of Operations for the year ended December 31, 2018 as compared to December 31, 2017:

Year		
Item	**Increase (Decrease)** ($ millions)	**Explanation**
Net earnings attributable to controlling interest	**4**	Net earnings for the year ended December 31, 2018 were $189 million compared to $185 million for the same period in 2017 primarily 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, effective March 1, 2018 to December 12, 2018, as compared to the TLUP in place in 2017, effective March 15, 2017 to December 14, 2017, partially offset by • lower operation and maintenance expense savings year to date, net of the regulated Earnings Sharing Mechanism, as compared to operating costs allowed in rates under the PBR formula primarily due to a non-recurring benefits refund received during the third quarter of 2017 for which there was no comparable amount received in the same period of 2018, and • lower interest savings.
Total revenues	**(12)**	The lower total revenues were 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. For rate setting purposes, there was an overall increase in the forecasted 2018 cost of service primarily due to an increase in regulated investment, which would normally be expected to increase revenues. However, this increase in cost of service was more than offset by forecasted growth in number of customers and gas volume throughput for 2018. For the year ended December 31, 2018, there were lower gas sales volumes compared to the same period in 2017 primarily due to lower average consumption by residential, commercial and transportation customers as a result of warmer weather. The quarterly revenue discussion explains how the changes in consumption are captured in regulatory deferral mechanisms. The lower consumption resulted in lower revenue from contracts with customers, but was offset by an equal alternative revenue amount resulting in no impact on total revenues.
Cost of natural gas	**(89)**	The decrease in the cost of natural gas was primarily due to: • a lower commodity cost, approved by the BCUC, of $1.549 per gigajoule for the year ended December 31, 2018, as compared to $2.050 per gigajoule for the same period in 2017, • a higher amount of MCRA gas storage and transport cost regulatory liability refunded to customers, which decreases the cost of natural gas, and • lower gas sales consumption compared to the same period in 2017.
Operation and maintenance	**11**	The higher operating and maintenance expense was primarily due to higher labour and contracting costs, inflationary increases and a non-recurring benefits refund received during the third quarter of 2017 for which there was no comparable amount received in the same period of 2018.
Depreciation and amortization	**20**	The increase was primarily due to the same reasons as identified in the quarter. For the year ended December 31, 2018, $10 million in amortization of certain revenue related regulatory liabilities have been recognized in revenues as a result of adopting ASC Topic 606, while $9 million for the same period of 2017 was recognized as a reduction to amortization expense.
Other income	**(9)**	Other income primarily consists of the equity component of AFUDC as well as the non-service cost component of pension and other post-employment benefits. The decrease in other income was primarily due to a higher equity component of AFUDC recognized in 2017 associated with Tilbury Phase 1A project under construction at that time, which has

Year		
Item	**Increase (Decrease)** ($ millions)	**Explanation**
		now been included in rate base for 2018. The decrease was partially offset by higher dividend income from FEI having a TLUP in place earlier in the first quarter in 2018, as compared to the TLUP in place in 2017.
Finance charges	**23**	The increase in finance charges was primarily due to FEI having a TLUP in place earlier in the first quarter of 2018, as compared to the TLUP in place in 2017, a higher level of debt used to finance the increased investment in regulated assets, and the issuance of long-term debentures in October 2017 and December 2018, which were used to repay credit facilities carrying lower interest rates.
Income tax expense	**10**	The increase in income taxes was primarily due to lower tax deductions associated with property, plant and equipment, higher earnings before tax, and the 1% increase in the BC provincial statutory tax rate effective January 1, 2018, partially offset by higher TLUP tax recovery and higher temporary tax differences related to regulatory deferral accounts.

SUMMARY OF QUARTERLY RESULTS

The following table sets forth unaudited quarterly information for each of the eight quarters ended March 31, 2017 through December 31, 2018. 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	**Revenues**	**Net Earnings (Loss)** [1]
($ millions)		
December 31, 2018	371	80
September 30, 2018	161	(10)
June 30, 2018	227	18
March 31, 2018	428	101
December 31, 2017	366	73
September 30, 2017	156	(4)
June 30, 2017	228	17
March 31, 2017	449	99

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

Due to the seasonal nature of the Corporation's natural gas transmission and distribution operations and its impact on 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 2018/2017 – Net earnings were higher primarily due to higher investment in regulated assets and higher operation and maintenance expense savings, 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.

September 2018/2017 – Net loss was higher primarily due to lower operating and maintenance expense savings, 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 a non-recurring benefits refund received during the third quarter of 2017 for which there was no comparable amount received in the same period of 2018, and lower interest savings, partially offset by higher investment in regulated assets.

June 2018/2017 – Net earnings were higher primarily due to higher investment in regulated assets.

March 2018/2017 – Net earnings were higher primarily due to higher investment in regulated assets, higher income tax benefit as a result of the Corporation having a TLUP in place earlier in the first quarter in 2018, as compared to the TLUP in place in 2017, partially offset by lower operation and maintenance expense savings, net of the regulated Earnings Sharing Mechanism, as compared to operating costs allowed in rates under the PBR formula.

CONSOLIDATED FINANCIAL POSITION

The following table outlines the significant changes in the Consolidated Balance Sheets between December 31, 2018 and December 31, 2017:

Balance Sheet Account	**Increase (Decrease)** ($ millions)	**Explanation**
Accounts receivable	**46**	The increase was primarily due to: • higher income taxes receivable, • 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 • lower trade and unbilled receivables due to warmer weather and a lower commodity cost approved by the BCUC in customer rates. Net income taxes moved from a payable of $15 million at December 31, 2017 to a receivable of $51 million at December 31, 2018 due to higher tax instalments, a higher TLUP tax recovery, and a reduction in the MCRA gas storage and transport cost regulatory liability account that resulted in lower taxable income.
Property, plant and equipment, net	**302**	The increase was primarily due to capital expenditures of $473 million incurred during the year ended December 31, 2018, which included sustainment and growth capital as well as major project expenditures discussed further under "Projected Capital Expenditures", and $5 million in non-cash equity component of AFUDC, partially offset by: • depreciation expense, excluding net salvage provision, of $154 million, • costs of removal of $17 million incurred, the offset of which has been recognized in regulatory liabilities, and • contributions in aid of construction of $5 million.
Credit facility	**88**	The increase was primarily due to higher borrowings partially to finance the debt portion of FEI's 2018 capital expenditure program.
Accounts payable and other current liabilities	**61**	The increase was primarily due to: • higher gas cost payables, driven in part by higher natural gas midstream costs, and • a cash deposit received in 2018 related to development expenditures incurred for the Eagle Mountain Woodfibre Gas Pipeline Project, partially offset by • the change in the fair value of natural gas derivatives, which are offset by a regulatory asset, and • the change in income taxes discussed as part of the changes in accounts receivable above.
Capital lease and finance obligations (current and long-term)	**(33)**	The decrease was primarily due to a decrease in finance obligations resulting from an early termination payment option exercised in October 2018 in the amount of $27 million on one of the lease-in, lease-out arrangements with a municipality FEI operates in.
Regulatory liabilities (current and long-term)	**(61)**	The decrease was primarily due to a lower MCRA regulatory liability, which was drawn down primarily due to higher natural gas midstream costs, lower CCRA regulatory liability, and lower RSAM deferral which decreased due to warmer weather, partially offset by increases in net salvage provision and regulatory flow-through deferral account.
Long-term debt	**199**	The increase was due to proceeds received from the December 2018 long-term debt issuance of $200 million, less debt issuance costs.
Deferred income taxes	**53**	The increase was primarily due to higher deductible temporary differences on regulatory deferral liabilities owing back to customers in future rates and an increase in taxable temporary differences associated with property, plant and equipment. A comparable adjustment has been recognized in regulatory assets since the related income tax amounts are expected to be recovered from customers in future rates.

Balance Sheet Account	Increase (Decrease) ($ millions)	Explanation
Other liabilities	**(39)**	The decrease was primarily due to a decrease in the unfunded status of defined benefit pension and other post-employment benefit plans, primarily due to higher discount rates, recognized in other liabilities.
Common shares	**40**	The increase was due to a $40 million equity issuance in the second quarter of 2018.

LIQUIDITY AND CAPITAL RESOURCES

Summary of Consolidated Cash Flows

Years Ended December 31	**2018**	2017	Variance
($ millions)			
Cash flows provided by (used for)			
Operating activities	**356**	471	(115)
Investing activities	**(517)**	(427)	(90)
Financing activities	**161**	(44)	205
Net change in cash	**-**	-	-

Operating Activities

Cash provided by operating activities was $115 million lower compared to 2017. The decrease was primarily due to:

- changes in long-term regulatory assets and liabilities did not provide cash in 2018 and were a source of cash in 2017 primarily due to changes in FEI's rate stabilization regulatory deferral accounts, as well as a higher amount of revenue surplus collected in 2017 compared to 2018 pursuant to the annual rate filings with the BCUC, and
- changes in non-cash working capital of $84 million are related to the change in income taxes, resulting from higher tax instalments and lower taxable income in 2018 compared to 2017, and an increase in midstream costs incurred in 2018 due to the Westcoast pipeline incident to be recovered from customers during 2019, partially offset by
- higher depreciation and amortization expense of $20 million primarily due to higher depreciable asset base compared to the prior year and amortization of certain revenue related regulatory liabilities that have been recognized in revenues as a result of adopting ASC Topic 606 in 2018, while $9 million for the same period of 2017 was recognized as a reduction to amortization expense, and
- lower equity component of AFUDC.

Investing Activities

Cash used for investing activities was $90 million higher in 2018 compared to 2017 primarily due to increased capital expenditures, which included sustainment and growth capital and the LMIPSU project, and changes in other assets and liabilities due to higher investment in Energy Efficiency and Conservation and GGRR programs.

Financing Activities

Due to lower cash flows from operating activities and higher cash used for investing activities in 2018 compared to 2017, there was a requirement for increased cash provided by financing activities. The increase in cash provided by financing activities of $205 million was primarily due to:

- net proceeds from credit facilities of $88 million, compared to net credit facility repayments of $83 million in 2017,
- a cash deposit received in 2018 related to development expenditures incurred by FEI for the Woodfibre LNG Project of $11 million,
- higher proceeds from the $200 million long-term debt issuance in 2018, compared to the $175 million long-term debt issuance in 2017, and
- the issuance of 2,982,928 common shares in the amount of $40 million, compared to no common share issuance in 2017, partially offset by
- the early termination payment option in the amount of $27 million exercised in 2018 on one of the lease-in, lease-out arrangements with a municipality FEI operates in, and

- higher common share dividends paid.

During 2018, FEI paid common share dividends of $142 million (2017 - $126 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, 2018	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	2,637	131	131	131	131	131	1,982
Long-term debt [1]	2,595	-	-	-	-	-	2,595
Gas purchase obligations (a)	1,219	317	269	223	184	129	97
Capital lease and finance obligations (b)	67	20	7	37	3	-	-
Power purchase obligations (c)	522	4	6	8	9	12	483
Other (d)	24	16	3	2	1	1	1
Totals	7,064	488	416	401	328	273	5,158

[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, 2018.

(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 October 31, 2018, the Corporation exercised an early termination payment option in the amount of $27 million on one of these financing transactions. In addition, another early termination payment could potentially be due in 2019 and as such, it has been included as due within one year and recognized in current liabilities as at December 31, 2018.

(c) In March 2015, FEI entered into an Electricity Supply Agreement ("ESA") with British Columbia Hydro and Power Authority ("BC Hydro") which provides for BC Hydro to supply electrical service for the Tilbury Expansion Project Phase 1A. The energy purchased under the ESA does not relate to a specific plant and the output being purchased does not constitute a significant portion of the output of a specific plant.

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

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, 2018, the Corporation had issued $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 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.

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 Limited ("DBRS") 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, 2018:

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

During 2018, Moody's and DBRS 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 2019 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 has since conducted further detailed engineering work and evaluated construction bids and other costs which resulted in a revised cost estimate of the project of approximately $500 million. This estimate was provided to the BCUC during the first quarter of 2018 as a compliance filing for their information. The project is expected to be constructed primarily during 2018 and 2019. During 2018, FEI completed a significant portion of the Vancouver section of the project which was then gasified in December 2018. Construction of the remaining portion of the project has resumed in the first quarter of 2019. After the project is complete and in service, the final project costs remain subject to the BCUC's review process.

Tilbury Phase 1A Expansion Project

In October 2014, FEI began construction of the expansion of its Tilbury LNG Facility in Delta, BC as approved in the 2013 OIC and the subsequent amendments made to the OIC by the BC Provincial government in December 2014 and March 2017. The cost of construction of the Tilbury Phase 1A Expansion is approximately $400 million, prior to including AFUDC and development costs, and includes a new LNG storage tank and liquefier. The construction is substantially complete and FEI started the commissioning process of the facility and achieved LNG production in late 2018. Full LNG production of the facility is expected in the first quarter of 2019.

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 between 2019 and 2024. The CPCN application is still subject to the regulatory process for review and approval by the BCUC, which in turn could affect the estimated project costs and timing of incurring such costs.

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 between 2018 and mid-2020 to enable the filing of a CPCN.

Demand Side Management ("DSM") Expenditures Plan

In June 2018, FEI filed its 2019-2022 DSM Expenditures Plan which delivers a cost-effective portfolio of DSM programs and activities which align with BC's energy objectives and FEI's long-term resource plan, meets the requirements of the Demand-Side Measures Regulations and respond to government policy encouraging an increase in DSM program incentives and support. 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.

Other Major Capital Projects

Beyond 2019, 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. The 2013 OIC as amended, granted FEI exemptions from the requirement to seek BCUC CPCN approvals for the pipeline expansion to the Woodfibre 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.

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, 2018, the Corporation had a $700 million syndicated credit facility available which matures in August 2023.

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

($ millions)	2018	2017
Credit facility	**700**	700
Draws on credit facility	**(199)**	(111)
Letters of credit outstanding	**(48)**	(56)
Credit facility available	**453**	533

Debentures

On October 20, 2017, the Corporation filed a short form base shelf prospectus to establish a Medium Term Note Debenture ("MTN Debentures") Program and entered into a Dealers Agreement with certain affiliates of a group of Canadian Chartered Banks. The Corporation may, from time to time during the 25 month life of the shelf prospectus, issue MTN Debentures in an aggregate principal amount of up to $650 million. The establishment of the MTN Debenture Program has been approved by the BCUC.

On October 26, 2017, FEI entered into an agreement with the dealers listed in the Dealers Agreement to sell $175 million of unsecured MTN Debentures Series 30. The MTN Debentures Series 30 bear interest at a rate of 3.69 per cent to be paid semi-annually and mature on October 30, 2047. The closing of the issuance occurred on October 30, 2017, with net proceeds being used to repay existing credit facilities.

On December 4, 2018, FEI entered into an agreement with the dealers listed in the Dealers Agreement to sell $200 million of unsecured MTN Debentures Series 31. The MTN Debentures Series 31 bear interest at a rate of 3.85 per cent to be paid semi-annually and mature on December 7, 2048. The closing of the issuance occurred on December 7, 2018, with net proceeds being used to repay existing credit facilities.

As at December 31, 2018, $275 million remains available under the MTN Debenture Program.

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 2018 and 2017, none of these restrictions constrained the distribution of FEI earnings not otherwise needed for reinvestment.

OFF-BALANCE SHEET ARRANGEMENTS

As at December 31, 2018, the Corporation had no material off-balance sheet arrangements, with the exception of letters of credit outstanding of $48 million (2017 - $56 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)	**2018**	2017
Operation and maintenance expense charged to FBC (a)	**6**	5
Operation and maintenance expense charged to FHI (b)	**1**	1
Other income received from FHI (c)	**137**	131
Operation and maintenance expense charged to ACGS (d)	**1**	1
Total related party recoveries	**145**	138

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

(b) The Corporation charged FHI for management services, labour and materials.

(c) As part of a TLUP, the Corporation received dividend income from FHI relating to a $2,500 million (2017 - $2,500 million) investment in preferred shares.

(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)	**2018**	2017
Operation and maintenance expense charged by FBC (a)	**8**	8
Operation and maintenance expense charged by FHI (b)	**12**	13
Finance charges paid to FHI (c)	**137**	131
Gas storage and purchases charged by ACGS (d)	**25**	24
Total related party costs	**182**	176

(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, the Corporation paid FHI interest on $2,500 million (2017 - $2,500 million) of intercompany subordinated debt.

(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, 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 as at December 31:

	2018		2017	
($ millions)	**Amount Due From**	**Amount Due To**	Amount Due From	Amount Due To
FHI	**-**	**(2)**	-	(3)
FBC	**-**	**-**	1	(1)
ACGS	**-**	**(2)**	-	(2)
Total due from (due to) related parties	**-**	**(4)**	1	(6)

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 will be determined through a review process which occurs on an annual basis. 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. 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 and 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.

Weather and Natural Disasters

A major natural disaster, such as an earthquake, could severely damage the Corporation’s natural gas transmission, distribution and storage systems. In addition, the facilities of the Corporation could be exposed to the effects of severe weather conditions and other natural events. 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 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. 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.

Indigenous Peoples

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. A treaty negotiation process involving various Indigenous Peoples and the Governments of BC and Canada is 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 process. 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 process will not have a material adverse effect on the Corporation's results of operations and financial position.

The Supreme Court of Canada decided in 2010 that before issuing approvals for the addition of new facilities, the BCUC must 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. This may affect the timing, cost and likelihood of the BCUC's approval of certain of the Corporation's capital projects.

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, 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 regulate or restrict the energy source 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 and Weather Related Risks

The Corporation is dependent on a limited selection of pipeline and storage providers, particularly in the Lower Mainland, Interior and Vancouver Island. 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.

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)	2018	2017
Assets		
Current		
Natural gas contracts subject to regulatory deferral [1]	**5**	2
Long-term		
Natural gas contracts subject to regulatory deferral [1]	**9**	4
Total assets	**14**	6
Liabilities		
Current		
Natural gas contracts subject to regulatory deferral [1]	**(22)**	(47)
Long-term		
Natural gas contracts subject to regulatory deferral [1]	**(1)**	(7)
Total liabilities	**(23)**	(54)
Total liabilities, net	**(9)**	(48)

[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, 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.

		Gross Amount Not Offset in the Balance Sheet		
December 31, 2017	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	2	(1)	7	8
Other assets	4	(1)	-	3
Accounts payable and other current liabilities	(47)	1	-	(46)
Other liabilities	(7)	1	-	(6)

[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, 2018 and 2017, 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)	**2018**	2017
Unrealized net loss recorded to current regulatory assets	**9**	48

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 Carried 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:

		2018		2017	
($ millions)	**Fair Value Hierarchy**	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Long-term debt [1]	Level 2	**2,595**	**2,994**	2,395	2,955

[1] Carrying value excludes unamortized debt issuance costs.

NEW ACCOUNTING POLICIES

Standard	Effective Date	Description	Effect on FEI
Revenue from Contracts with Customers	January 1, 2018	ASC Topic 606, *Revenue from Contracts with Customers*, supersedes the revenue recognition requirements in ASC Topic 605, *Revenue Recognition*, including most industry-specific revenue recognition guidance throughout the codification. This standard clarifies the principles for recognizing revenue and enables users of financial statements to better understand and consistently analyze an entity's revenues across industries and transactions.	The Corporation adopted the new revenue recognition guidance using the modified retrospective transition method, under which comparative periods are not restated and the cumulative impact of applying the standard is recognized at the date of initial adoption supplemented by additional disclosures. Upon adoption, there were no adjustments to the opening balance of the Corporation's retained earnings as there were no changes to the timing of how revenue is recognized. The Corporation elected three practical expedients in implementing ASC 606, *Revenue from Contracts with Customers*. The Corporation applied a portfolio approach in evaluating consideration from residential and commercial customers. The Corporation also applied a practical expedient to consideration received from certain customers on a tariff schedule and did not adjust the promised amount of consideration for the effect of a significant financing component because FEI expects that the period between the transfer of natural gas to the customer and the customer's payment for that service will be one year or less. Finally, FEI elected to recognize revenue in the amount to which FEI has a right to invoice the customer. The adoption of this standard did not materially change the Corporation's accounting policy for recognizing revenue.
Improving The Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost	January 1, 2018	ASU No. 2017-07, *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost,* requires current service costs to be disaggregated and grouped in the statement of earnings with other employee compensation costs arising from services rendered. The other components of net benefit costs must be presented separately and outside of operating income. Additionally, only the service cost component is eligible for capitalization.	On adoption, the Corporation applied the presentation guidance retrospectively and the capitalization guidance prospectively. This resulted in a retrospective $2 million reclassification from operation and maintenance expense to other income for the year ended December 31, 2017.
Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract	January 1, 2020	ASU No. 2018-15, *Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract,* aligns the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal use software. Accordingly, the amendments in this update require a customer in a hosting arrangement that is a service contract to follow the guidance in ASC 350, *Intangibles - Goodwill and Other*, to determine whether implementation costs should be capitalized or expensed.	The Corporation early adopted this ASU during the third quarter of 2018 using the retrospective approach, which did not have a material impact on the Consolidated Financial Statements for the years ended December 31, 2018 and 2017.

FUTURE ACCOUNTING PRONOUNCEMENTS

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

Standard	Effective Date	Description	Expected Effect on FEI
Leases	January 1, 2019	ASU No. 2016-02, Leases (ASC Topic 842), issued in February 2016, is effective for FEI January 1, 2019, and is to be applied using a modified retrospective approach or an optional transition method with implementation options, referred to as practical expedients. Principally, it requires balance sheet recognition of a right-of-use asset and a lease liability by lessees for those leases that are classified as operating leases along with additional disclosures.	FEI has selected the optional transition method which allows entities to continue to apply the current lease guidance in the comparative periods presented in the year of adoption and apply the transition provisions of the new guidance on the effective date of the new guidance. FEI elected a package of practical expedients that allowed it to not reassess the lease classification of existing leases or whether existing contracts, including land easements, are or contain a lease. Upon adoption, FEI will recognize right-of-use assets and corresponding lease liabilities for operating leases primarily related to office facilities. FEI has not identified an adjustment to opening retained earnings, and there will be no impact on earnings or cash flows. The Corporation is continuing to assess the presentation and disclosure requirements of ASC 842.

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, 2018, the Corporation recognized $831 million in current and long-term regulatory assets (2017 - $825 million) and $189 million in current and long-term regulatory liabilities (2017 - $250 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, 2018, the Corporation's property, plant and equipment and intangible assets were $4,777 million, or approximately 70 per cent of total assets, compared to $4,480 million, or approximately 69 per cent of total assets, as at December 31, 2017. 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 2018 or 2017.

As at December 31, 2018, goodwill totaled $913 million (2017 - $913 million).

During 2018, 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 other post-employment benefit 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 2018, was 6.00 per cent, which is consistent with the 6.00 per cent assumed long-term rate of return used for 2017. As one of the Corporation's defined benefit pension plans has excess interest indexing provisionwhere 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 assumption.

The assumed discount rate, used to measure the projected pension benefit obligations on the measurement date of December 31, 2018, and to determine net pension cost for 2019, is 3.75 per cent, which is an increase from the 3.50 per cent assumed discount rate used to measure the projected benefit obligations as at December 31, 2017, and to determine net pension cost for 2018.

The long-term rate of return on plan assets 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 pension cost for 2019 related to its defined benefit pension plans, prior to regulatory adjustments, to be $8 million, a decrease of $3 million compared to 2018, which is due to an increase in the expected return on plan assets assumption offset by increases in current service costs and interest costs.

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 2018 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	**(4)**	**15**
1% decrease in the expected rate of return	**3**	**(45)**
1% increase in the discount rate	**(9)**	**(99)**
1% decrease in the discount rate	**15**	**128**

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 net benefit pension 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, 2018, the Corporation had a pension projected benefit net liability of $80 million (2017 - $88 million) and an OPEB projected benefit liability of $111 million (2017 - $128 million). During 2018, the Corporation recorded pension and OPEB net benefit cost, inclusive of regulatory adjustments, of $19 million (2017 - $20 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, 2018 and 2017.

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, 2018 the amount of accrued unbilled revenue recorded in accounts receivable was $89 million (2017 - $114 million) on annual natural gas revenues of $1,136 million (2017 - $1,193 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.

During the year ended December 31, 2017, the Province of BC enacted a corporate income tax rate increase of 1.00 per cent effective January 1, 2018. As a result, the combined Federal and BC provincial corporate tax rate increased from 26.00 per cent to 27.00 per cent in 2018.

SELECTED ANNUAL FINANCIAL INFORMATION

The following table sets forth information derived from audited financial statements for the years ended December 31, 2018, 2017 and 2016. 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	**2018**	2017	2016
($ millions)			
Revenues	**1,187**	1,199	1,151
Net earnings attributable to controlling interest	**189**	185	170
Total assets	**6,866**	6,511	6,300
Long-term debt, excluding current portion	**2,575**	2,376	2,205
Dividends on common shares	**142**	126	120

2018/2017 – Revenues decreased $12 million over 2017 and net earnings increased $4 million over 2017. For a discussion of the reasons for the decrease in revenues and the increase 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". Long-term debt increased due to the long-term debt issuance of $200 million in December 2018.

2017/2016 – Revenues increased $48 million over 2016 and net earnings increased $15 million over 2016. The increase in revenues was primarily due to higher gas sales volumes and a higher cost of natural gas, as approved by the BCUC, partially offset by lower revenues resulting from certain gas cost deferrals being refunded to customers. Net earnings increased due to a lower income tax expense as a result of the Corporation having a TLUP in place since the first quarter of 2017, with a higher investment in preferred shares in 2017, as compared to the TLUP in place since the second quarter of 2016, and higher investment in regulated assets, partially offset by a decrease in the variance between the operating and maintenance expense incurred as compared to the operating costs forecasted in rates and recognized in revenues. The increase in total assets was mainly due to capital expenditures (including those related to the CTS, Tilbury Expansion Phase 1A, and LMIPSU projects). Long-term debt increased due to the long-term debt issuance of $175 million in October 2017.

From 2016 to 2018, 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") expires on March 31, 2019. 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 ("COPE") 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 328,928,792 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.

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