
FORTISBC ENERGY INC.

MANAGEMENT DISCUSSION & ANALYSIS

For the Three and Nine Months Ended September 30, 2018

November 1, 2018

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 Unaudited Condensed Consolidated Interim Financial Statements and notes thereto for the three and nine months ended September 30, 2018, prepared in accordance with US GAAP and the Corporation's Annual Audited Consolidated Financial Statements and notes thereto together with the MD&A for the year ended December 31, 2017, with 2016 comparatives, 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 Tilbury Liquefied Natural Gas Facility Expansion Project ("Tilbury Expansion Project") and the Lower Mainland Intermediate Pressure System Upgrade ("LMIPSU") project, and their associated in-service dates; expectations to meet interest payments on outstanding indebtedness from operating cash flows; the Corporation's expected level of capital expenditures and its expectations to finance those capital expenditures through credit facilities, equity injections from FHI and debenture issuances; the Corporation's estimated contractual obligations; the final investment decision, in-service date and estimated costs associated with the pipeline expansion to the proposed Eagle Mountain Woodfibre Liquefied Natural Gas ("LNG") site; and the effect of the Enbridge 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; the Indigenous peoples' settlement process does not adversely affect 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 ratings 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 risk including risks relating to the Enbridge natural gas transmission pipeline incident; 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 Corporation's MD&A and AIF for the year ended December 31, 2017.

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 1,021,000 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 an indirect, wholly-owned subsidiary of Fortis, a leader in the North American electric and gas utility business, serving customers across Canada, the United States and the Caribbean.

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.

Variations 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 variations do not have an impact on net earnings in either 2018 or 2017. As part of the Performance Based Ratemaking ("PBR") 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 variations from regulated forecast items, excluding formulaic operation and maintenance costs, that do not have separately approved deferral mechanisms, and flows those variations through customer rates in the following year.

In addition to annual delivery rate changes, the Corporation reviews natural gas and propane charges every three months with the British Columbia Utilities Commission ("BCUC") in order to ensure the rates charged to customers are sufficient to cover the cost of purchasing natural gas and contracting for third-party pipeline and storage capacity.

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 2016, the BCUC issued its decision on FEI's 2017 delivery rates. The decision resulted in a 2017 average rate base of approximately \$3,705 million (excluding the rate base of approximately \$11 million for Fort Nelson) and no increase in customer delivery rates. 2017 rates would have otherwise decreased had there not been approval to defer a revenue surplus for the year ("2017 revenue surplus").

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 August 2018, FEI filed its application for approval of 2019 delivery rates under the PBR Plan. The 2019 application includes a forecast average rate base of approximately \$4,491 million (excluding the rate base of approximately \$12 million for Fort Nelson). FEI has requested an interim delivery rate increase of 1.1 per cent effective 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 Eagle Mountain Woodfibre LNG ("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

| Periods Ended September 30 | Quarter | | | Year to Date | | |
|---|-------------|------|----------|--------------|------|----------|
| | 2018 | 2017 | Variance | 2018 | 2017 | Variance |
| Gas sales (petajoules) | 30 | 27 | 3 | 149 | 152 | (3) |
| (\$ millions) | | | | | | |
| Total revenues ¹ | 161 | 156 | 5 | 816 | 833 | (17) |
| Cost of natural gas | 31 | 38 | (7) | 216 | 292 | (76) |
| Operation and maintenance ² | 54 | 48 | 6 | 171 | 160 | 11 |
| Property and other taxes | 15 | 15 | - | 49 | 49 | - |
| Depreciation and amortization | 56 | 50 | 6 | 168 | 152 | 16 |
| Total expenses | 156 | 151 | 5 | 604 | 653 | (49) |
| Operating income | 5 | 5 | - | 212 | 180 | 32 |
| Add: Other income ² | 46 | 49 | (3) | 107 | 112 | (5) |
| Less: Finance charges | 78 | 73 | 5 | 204 | 183 | 21 |
| (Loss) Earnings before income taxes | (27) | (19) | (8) | 115 | 109 | 6 |
| Income tax (recovery) expense | (18) | (16) | (2) | 5 | (4) | 9 |
| Net(loss) earnings | (9) | (3) | (6) | 110 | 113 | (3) |
| Net earnings attributable to non-controlling interest | 1 | 1 | - | 1 | 1 | - |
| Net (loss) earnings attributable to controlling interest | (10) | (4) | (6) | 109 | 112 | (3) |

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 did not affect the net earnings comparison for the periods ended September 30.

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 to restate 2017 comparatives for presentation purposes. This resulted in a retrospective nil and \$2 million reclassification from operating costs to other income for the three and nine months ended September 30, 2017, respectively. There was no effect on the net earnings comparison for the periods ended September 30.

The following table outlines net loss and the significant variances in the Consolidated Results of Operations for the three months ended September 30, 2018 as compared to September 30, 2017:

| Quarter | | |
|---|-----------------------------------|---|
| Item | Increase (Decrease) (\$ millions) | Explanation |
| Net loss attributable to controlling interest | (6) | <p>Net loss for the quarter ended September 30, 2018 was \$10 million compared to the \$4 million net loss for the same period in 2017 primarily due to:</p> <ul style="list-style-type: none"> lower operation and maintenance expense savings for the quarter, net of the regulated Earnings Sharing Mechanism, as compared to operating costs allowed in rates under the PBR formula primarily due to the timing of incurring such costs throughout the year 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. <p>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.</p> |

| Quarter | | |
|-------------------------------|--|--|
| Item | Increase (Decrease) (\$ millions) | Explanation |
| Revenues | 5 | <p>Included in revenues are revenues from contracts with customers, which include 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.</p> <p>Also included in revenues are alternative revenues, which include the Corporation's Earnings Sharing Mechanism, Revenue Stabilization Adjustment Mechanism ("RSAM"), flow-through variances related to industrial customer revenue, and other revenue, which is 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, customers in future rates, they are recognized as either other expense or other revenue, respectively.</p> <p>The increase in total revenues was primarily due to:</p> <ul style="list-style-type: none"> • an increase in revenues approved for rate-setting purposes resulting from higher investment in regulated assets, and • \$3 million in amortization of certain revenue related regulatory liabilities that have been recognized in revenues during 2018 as a result of adopting ASC Topic 606, partially offset by • a lower cost of natural gas recovered from customers, as approved by the BCUC, and • an increase in the refund of certain gas cost deferrals to customers which decreased revenues. <p>There were higher gas sales volumes compared to the same period in 2017 primarily due to higher average consumption by residential, commercial and transportation customers as a result of colder weather. 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 higher consumption resulted in higher revenue from contracts with customers, but was offset by an equal alternative revenue amount resulting in no impact on total revenues.</p> |
| Cost of natural gas | (7) | <p>Included in revenue and the cost of natural gas are certain variances between actual and forecasted amounts for setting customer rates, 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.</p> <p>The decrease in the cost of natural gas was primarily due to:</p> <ul style="list-style-type: none"> • a lower cost of commodity, approved by the BCUC, of \$1.549 per gigajoule for the quarter ended September 30, 2018, as compared to \$2.050 per gigajoule for the same period in 2017, and • certain gas cost deferrals refunded to customers, partially offset by • higher gas sales consumption compared to the same period in 2017. |
| Operation and maintenance | 6 | <p>The increase in operating and maintenance expense was primarily due to the timing of incurring such costs throughout the year, 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.</p> |
| Depreciation and amortization | 6 | <p>The increase was primarily due to higher depreciable asset base compared to the prior year. In addition, \$3 million in amortization of certain revenue related regulatory liabilities have been recognized in revenues during the third 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.</p> |
| Other income | (3) | <p>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 third quarter of 2017 associated with Tilbury Phase 1A project under construction at that time, which has now been included in rate base for 2018.</p> |
| Finance charges | 5 | <p>The increase in finance charges was primarily due to a higher level of debt used to finance the increased investment in regulated assets and the issuance of long-term debentures in October 2017, which were used to repay credit facilities carrying lower interest rates.</p> |

| Quarter | | |
|----------------|--|---|
| Item | Increase (Decrease) (\$ millions) | Explanation |
| Income taxes | (2) | The increase in income tax recoveries was primarily due to higher loss before tax and the 1.0 percent increase in the BC provincial statutory tax rate effective January 1, 2018. |

The following table outlines net earnings and the significant variances in the Consolidated Results of Operations for the nine months ended September 30, 2018 as compared to September 30, 2017:

| Year to Date | | |
|---|--|---|
| Item | Increase (Decrease) (\$ millions) | Explanation |
| Net earnings attributable to controlling interest | (3) | <p>Net earnings for the nine months ended September 30, 2018 were \$109 million, a decrease of \$3 million compared to the same period in 2017, primarily due to:</p> <ul style="list-style-type: none"> • 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 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, and • higher income tax benefit as a result of the Corporation having a tax loss utilization plan ("TLUP") in place earlier in 2018, effective March 1, 2018, as compared to the TLUP in place in 2017, effective March 15, 2017. <p>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.</p> |
| Revenues | (17) | <p>The lower total revenues were primarily due to:</p> <ul style="list-style-type: none"> • a lower cost of natural gas recovered from customers, as approved by the BCUC, and • an increase in the refund of certain gas cost deferrals to customers which decreased revenues, partially offset by • an increase in revenues approved for rate setting purposes resulting from higher investment in regulated assets, and • \$8 million in amortization of certain revenue related regulatory liabilities that have been recognized in revenues during 2018 as a result of adopting ASC Topic 606. <p>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.</p> <p>For the nine months ended September 30, 2018, there were lower gas sales volumes compared to the same period in 2017 primarily due to lower average consumption by residential and commercial 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.</p> |
| Cost of natural gas | (76) | <p>The decrease in the cost of natural gas was primarily due to:</p> <ul style="list-style-type: none"> • a lower cost of commodity, approved by the BCUC, of \$1.549 per gigajoule for the nine months ended September 30, 2018, as compared to \$2.050 per gigajoule for the same period in 2017, • a higher amount of certain gas cost deferrals refunded to customers, and • lower gas sales consumption compared to the same period in 2017. |

| Year to Date | | |
|-------------------------------|--|--|
| Item | Increase (Decrease) (\$ millions) | Explanation |
| Operation and maintenance | 11 | The higher operating and maintenance expense was primarily due to the timing of incurring such costs throughout the year, 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 | 16 | The increase in depreciation and amortization was primarily due to the same reasons as identified in the quarter. For the nine months ended September 30, 2018, \$8 million in amortization of certain revenue related regulatory liabilities have been recognized in revenues as a result of adopting ASC Topic 606, while \$7 million for the same period of 2017 was recognized as a reduction to amortization expense. |
| Other income | (5) | 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 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 | 21 | The increase in finance charges was primarily due to FEI having a TLUP in place earlier in 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, which were used to repay credit facilities carrying lower interest rates. |
| Income taxes | 9 | The increase in income taxes was primarily due to higher earnings before tax, lower deductible temporary differences, and the 1.0 percent increase in the BC provincial statutory tax rate effective January 1, 2018, partially offset by higher TLUP tax recovery. |

SUMMARY OF QUARTERLY RESULTS

The following table sets forth unaudited quarterly information for each of the eight quarters ended December 30, 2016 through September 30, 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) |
|----------------------|-----------------|----------------------------|
| (\$ millions) | | |
| 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 |
| December 31, 2016 | 394 | 77 |

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.

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.

December 2017/2016 – Net earnings were lower primarily due to 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, the timing of incurring operating and maintenance expenses, including operating costs allowed in rates under the PBR formula, which were more favourable in the first half of 2017; partially offset by a higher investment in regulated assets and a lower income tax expense as a result of the Corporation having a TLUP in place with a higher investment in preferred shares in 2017, as compared to the TLUP in place in 2016.

CONSOLIDATED FINANCIAL POSITION

The following table outlines the significant changes in the Consolidated Balance Sheets between September 30, 2018 and December 31, 2017:

| Balance Sheet Account | Increase (Decrease) (\$ millions) | Explanation |
|---|--|--|
| Accounts receivable | (112) | The decrease was primarily due to seasonality of natural gas tariff sales, partially offset by increased gas cost mitigation activity volumes and the change in the fair value of natural gas derivatives, which are offset by a regulatory liability. |
| Net income taxes receivable | 38 | The increase was primarily due to tax instalments for 2018 in excess of 2018 tax expense as well as the payment of prior year taxes payable in the current year. |
| Regulatory assets (current and long-term) | (35) | The decrease was primarily due to changes in fair market value of natural gas derivative instruments, partially offset by a higher regulated deferred income tax liability, the offset of which was deferred as a regulatory asset, and increased expenditures on energy efficiency and conservation programs. As at September 30, 2018 and December 31, 2017, the unrealized gains and losses associated with changes in the fair value of the derivatives were \$10 million unrealized gain and \$48 million unrealized loss, respectively. These unrealized gains and losses were deferred as a regulatory liability and asset for refund to, or recovery from, customers in future rates. |
| Property, plant and equipment, net | 209 | The increase was primarily due to capital expenditures of \$309 million incurred during the nine months ended September 30, 2018, which includes sustainment and growth capital as well as major project expenditures discussed further under "Projected Capital Expenditures", \$28 million in changes in non-cash working capital and \$3 million related to the equity component of AFUDC, partially offset by: <ul style="list-style-type: none"> • depreciation expense, excluding net salvage provision, of \$116 million, • costs of removal incurred of \$12 million, the offset of which has been recognized in regulatory liabilities, and • contributions in aid of construction of \$3 million. |
| Credit facility | 71 | The increase was primarily due to higher borrowings to finance the debt portion of FEI's 2018 capital expenditure program. |
| Accounts payable and other current liabilities | (19) | The decrease was primarily due to lower liabilities associated with the fair market value of natural gas derivatives, described in the above variance for regulatory assets, partially offset by: <ul style="list-style-type: none"> • higher capital accruals related to LMIPSU project expenditures, and • seasonal increase in credit balances related to customer payment plan arrangements. |
| Other taxes payable | (18) | The decrease was primarily due to lower carbon tax payable which decreased as a result of seasonality of sales. |
| Regulatory liabilities (current and long-term) | 25 | The increase was due to the build-up of the net salvage provision, higher regulatory flow-through deferral accounts owing to customers and changes in fair market value of natural gas derivative instruments, partially offset by a |

| Balance Sheet Account | Increase (Decrease) (\$ millions) | Explanation |
|-----------------------|---|--|
| | | lower RSAM deferral balance, which captures gas throughput related variances in delivery revenue for residential and commercial customers. |
| Common shares | 40 | The increase is due to a \$40 million FEI equity issuance in the second quarter of 2018. |

LIQUIDITY AND CAPITAL RESOURCES

Summary of Consolidated Cash Flows

| Nine Months Ended September 30 (\$ millions) | 2018 | 2017 | Variance |
|---|--------------|-------|----------|
| Cash flows provided by (used for) | | | |
| Operating activities | 308 | 348 | (40) |
| Investing activities | (317) | (320) | 3 |
| Financing activities | 14 | (24) | 38 |
| Net change in cash | 5 | 4 | 1 |

Operating Activities

Cash flows provided by operating activities were \$40 million lower compared to the same period in 2017. The decrease was primarily due to changes in long-term regulatory assets and liabilities, partially offset by higher depreciation and amortization expense and lower equity component of AFUDC.

Investing Activities

Cash used for investing activities was \$3 million lower for the nine months ended September 30, 2018 compared to the same period in 2017. This was primarily due to the timing of incurring capital expenditures, including the LMIPSU project, partially offset by changes in other assets and liabilities.

Financing Activities

Cash flows provided by financing activities were \$14 million compared to 2017 when cash used for financing activities was \$24 million. The increase in cash provided by financing activities was primarily due to \$40 million issuance of common shares in the second quarter of 2018 for which there was no comparative issuance in 2017 and higher net proceeds from credit facilities, partially offset by higher dividends.

During the nine months ended September 30, 2018, FEI paid a common share dividend of \$95 million (2017 - \$84 million) to its parent company, FHI. No dividend was paid during the three months ended September 30, 2018 or 2017 due to the seasonal nature of the business described in "Summary of Quarterly Results" section of this MD&A.

Contractual Obligations

The Corporation's contractual obligations have not changed materially from those disclosed in the MD&A for the year ended December 31, 2017.

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

As at September 30, 2018, the Corporation's debentures were rated by DBRS Limited at A, outlook stable and by Moody's Investors Service at A3, outlook stable. There have been no changes to the Corporation's credit ratings from those reported in the Corporation's 2017 annual MD&A.

Projected Capital Expenditures

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 2018 projected capital expenditures are approximately \$490 million, which 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 the third quarter of 2018, FEI completed a significant portion of the Vancouver section of the project. 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 the portion of the Tilbury Phase 1A Expansion Project currently under construction is approximately \$400 million, prior to including AFUDC and development costs, and will include a new LNG storage tank and liquefier. The commissioning process of the facility was interrupted in the third quarter of 2017 and restarted in the third quarter of 2018 with LNG production anticipated to commence during the fourth quarter of 2018. Subject to the commissioning process going as planned during 2018, the project will be completed in 2019.

Other Major Capital Projects

Beyond 2018, the Corporation has identified and received BCUC or OIC approval of further major capital projects as discussed below.

LNG Infrastructure

The Corporation continues to pursue additional LNG infrastructure investment opportunities in British Columbia, including a gas line expansion to the proposed Woodfibre LNG site near Squamish, BC, and a further expansion of Tilbury. The 2014 and amendments to the 2013 OIC grant 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 is \$350 million and is 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 British Columbia 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.

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 2022.

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 flow available for capital expenditures and/or dividend payments. Cash required to complete capital expenditure 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 come due.

Credit Facility and Debentures

Credit Facility

As at September 30, 2018, the Corporation had a \$700 million syndicated credit facility available. The credit facility matures in August 2023.

The following summary outlines the Corporation's credit facility:

| (\$ millions) | September 30, 2018 | December 31, 2017 |
|-------------------------------|--------------------|-------------------|
| Credit facility | 700 | 700 |
| Draws on credit facility | (182) | (111) |
| Letters of credit outstanding | (53) | (56) |
| Credit facility available | 465 | 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.

As of September 30, 2018, \$475 million remains available under the MTN Debenture Program.

OFF-BALANCE SHEET ARRANGEMENTS

As at September 30, 2018, the Corporation had no material off-balance sheet arrangements, with the exception of letters of credit outstanding of \$53 million (December 31, 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 three and nine months ended September 30 were as follows:

| (\$ millions) | Three months ended September 30 | | Nine months ended September 30 | |
|---|------------------------------------|------|-----------------------------------|------|
| | 2018 | 2017 | 2018 | 2017 |
| Operation and maintenance expense charged to FBC (a) | 1 | 1 | 3 | 3 |
| Operation and maintenance expense charged to FHI (b) | - | - | 1 | 1 |
| Other income received from FHI (c) | 44 | 44 | 103 | 96 |
| Operation and maintenance expense charged to ACGS (d) | 1 | 1 | 1 | 1 |
| Total related party recoveries | 46 | 46 | 108 | 101 |

(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 three and nine months ended September 30 were as follows:

| (\$ millions) | Three months ended September 30 | | Nine months ended September 30 | |
|--|------------------------------------|------|-----------------------------------|------|
| | 2018 | 2017 | 2018 | 2017 |
| Operation and maintenance expense charged by FBC (a) | 1 | 1 | 5 | 5 |
| Operation and maintenance expense charged by FHI (b) | 3 | 3 | 9 | 9 |
| Finance charges paid to FHI (c) | 44 | 44 | 103 | 96 |
| Gas storage and purchases charged by ACGS (d) | 6 | 5 | 19 | 18 |
| Total related party costs | 54 | 53 | 136 | 128 |

(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:

| (\$ millions) | September 30, 2018 | | December 31, 2017 | |
|---|--------------------|---------------|-------------------|---------------|
| | Amount Due From | Amount Due To | Amount Due From | Amount Due To |
| FHI | - | (1) | - | (3) |
| FBC | - | - | 1 | (1) |
| ACGS | - | (2) | - | (2) |
| Total due from (due to) related parties | - | (3) | 1 | (6) |

FINANCIAL INSTRUMENTS

Financial Instruments Measured at Fair Value on a Recurring Basis

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

| (\$ millions) | September 30, 2018 | December 31, 2017 |
|---|--------------------|-------------------|
| Assets | | |
| <i>Current</i> | | |
| Natural gas contracts subject to regulatory deferral ¹ | 11 | 2 |
| <i>Long-term</i> | | |
| Natural gas contracts subject to regulatory deferral ¹ | 3 | 4 |
| Total assets | 14 | 6 |
| Liabilities | | |
| <i>Current</i> | | |
| Natural gas contracts subject to regulatory deferral ¹ | (4) | (47) |
| <i>Long-term</i> | | |
| Natural gas contracts subject to regulatory deferral ¹ | - | (7) |
| Total liabilities | (4) | (54) |
| Total assets (liabilities), net | 10 | (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:

| September 30, 2018 | Gross Amount Recognized in the Balance Sheet | Gross Amount Not Offset in the Balance Sheet | | Net Amount |
|---|--|--|------------------------|------------|
| | | Counterparty Netting of Natural Gas Contracts ¹ | Cash Collateral Posted | |
| (\$ millions) | | | | |
| Natural gas contracts subject to regulatory deferral: | | | | |
| Accounts receivable | 11 | (3) | 6 | 14 |
| Other assets | 3 | - | - | 3 |
| Accounts payable and other current liabilities | (4) | 3 | - | (1) |

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

| | Gross Amount Recognized in the Balance Sheet | Gross Amount Not Offset in the Balance Sheet | | Net Amount |
|---|---|---|------------------------------|---------------|
| | | Counterparty Netting of Natural Gas Contracts ¹ | Cash Collateral Posted | |
| December 31, 2017 (\$ 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 September 30, 2018, these natural gas contracts were not designated as hedges and any unrealized gains or losses associated with changes in the fair value of the derivatives were deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the BCUC, and as shown in the following table:

| (\$ millions) | September 30, 2018 | December 31, 2017 |
|--|--------------------|-------------------|
| Unrealized net gain (loss) recorded to current regulatory liabilities (assets) | 10 | (48) |

Cash inflows and outflows associated with the settlement of all derivative instruments are included in operating cash flows on the Corporation's Condensed 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 Condensed 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:

| (\$ millions) | Fair Value Hierarchy | September 30, 2018 | | December 31, 2017 | |
|-----------------------------|----------------------|--------------------|----------------------|-------------------|----------------------|
| | | Carrying Value | Estimated Fair Value | Carrying Value | Estimated Fair Value |
| Long-term debt ¹ | Level 2 | 2,395 | 2,822 | 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, <i>Revenue from Contracts with Customers</i> , supersedes the revenue recognition requirements in ASC Topic 605, <i>Revenue Recognition</i> , 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. | <p>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.</p> <p>The adoption of this standard did not materially change the Corporation's accounting policy for recognizing revenue. The Corporation's revenue recognition policy, effective January 1, 2018, is as follows:</p> <p>The majority of the Corporation's revenue is derived from natural gas sales to residential, commercial, industrial, and transportation customers. Most of the Corporation's contracts have a single performance obligation, the delivery of natural gas. Substantially all of the Corporation's performance obligations are satisfied over time as natural gas is delivered because of the continuous transfer of control to the customer, generally using an output measure of progress, gigajoules delivered. The billing of natural gas sales is based on the reading of customer meters, which occurs on a systematic basis throughout the month.</p> <p>The Corporation disaggregates revenue by type of customer, as disclosed in the Condensed Consolidated Interim Financial Statements for the three and nine months ended September 30, 2018 and 2017.</p> |
| Improving The Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost | January 1, 2018 | ASU No. 2017-07, <i>Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost</i> , 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, both of which did not have a material impact on the three months ended September 30, 2017 and resulted in a retrospective \$2 million reclassification from operation and maintenance expense to other income for the nine months ended September 30, 2017 in the Condensed Consolidated Interim Financial Statements. |

| Standard | Effective Date | Description | Effect on FEI |
|--|-----------------------|---|--|
| Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract | January 1, 2020 | ASU No. 2018-15, <i>Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract</i> , which 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, <i>Intangibles - Goodwill and Other</i> , 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 Condensed Consolidated Interim Financial Statements for the three and nine months ended September 30, 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, <i>Leases</i> (ASC Topic 842), was issued in February 2016, is effective for FEI January 1, 2019 with earlier adoption permitted, 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. | <p>The Corporation expects to elect 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 will elect a package of practical expedients that allows it to not reassess whether any expired or existing contract is a lease or contains a lease, the lease classification of any expired or existing leases, and the initial direct costs for any existing leases. The Corporation also will elect an additional practical expedient that permits entities to not evaluate existing land easements that were not previously accounted for as leases.</p> <p>Based on the Corporation's assessment to date, leasing activities accounted for as operating leases primarily relate to office facilities. Ongoing implementation efforts include the evaluation of business processes and controls to support recognition under the new standard and preparation of expanded disclosures. FEI continues to assess the impact of adoption and monitor standard-setting activities that may affect transition requirements.</p> |

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Corporation's Condensed Consolidated Interim 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 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.

Interim financial statements may also employ a greater use of estimates than the annual financial statements. There were no material changes in the nature of the Corporation's critical accounting estimates during the third quarter of 2018 from those disclosed in the Corporation's 2017 annual MD&A.

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"). 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.

Enbridge natural gas transmission pipeline incident

On October 10, 2018, FEI issued a press release relating to an incident that took place affecting a natural gas transmission pipeline near Prince George, BC on October 9, 2018. This pipeline provides supply of natural gas which FEI then distributes to its customers in various locations across BC. FEI declared a force majeure under several of its rate schedules. Both the duration and amount of reduced capacity from the disrupted pipe will determine the effect on FEI and its customers. FEI has regulatory deferral mechanisms in place for changes in usage, gas costs and material costs incurred which are beyond the control of the Corporation. No FEI infrastructure has been damaged as a result of this incident.

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 Annual Information Form, 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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