FORTISBC ENERGY INC.

MANAGEMENT DISCUSSION & ANALYSIS

For the Three and Six Months Ended June 30, 2018

July 30, 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 six months ended June 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; and the Corporation's estimated contractual obligations; and the final investment decision, in-service date and estimated costs associated with the pipeline expansion to the proposed Eagle Mountain Woodfibre Liquified Natural Gas ("LNG") site.

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 First Nations' 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 First Nations; 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; 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 1,017,000 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.

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 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 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.

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. While there was an overall increase in the forecasted 2018 cost of service, primarily due to a higher investment in regulated assets, this was more than offset by forecasted growth in customers and throughput for 2018. As a result, 2018 rates would have otherwise decreased had there not been approval to defer a revenue surplus for the year ("2018 revenue surplus"). The revenue surplus amounts derived from FEI's 2018 and 2017 delivery rate decisions are expected to be refunded to customers in future rates.

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. During the year ended December 31, 2017 and quarter ended March 31, 2018, 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. This application is under review by the BCUC.

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 no more than $30 per gigajoule.

CONSOLIDATED RESULTS OF OPERATIONS

	Quarter			Year to Date		
Periods Ended June 30	**2018**	2017	Variance	**2018**	2017	Variance
Gas sales (petajoules)	**39**	42	(3)	**119**	125	(6)
($ millions)						
Total revenues [1]	**227**	228	(1)	**655**	677	(22)
Cost of natural gas	**51**	73	(22)	**185**	254	(69)
Operation and maintenance [2]	**59**	56	3	**117**	112	5
Property and other taxes	**17**	17	-	**34**	34	-
Depreciation and amortization	**56**	51	5	**112**	102	10
Total expenses	**183**	197	(14)	**448**	502	(54)
Operating income	**44**	31	13	**207**	175	32
Add: Other income [2]	**45**	50	(5)	**61**	63	(2)
Less: Finance charges	**78**	73	5	**126**	110	16
Earnings before income taxes	**11**	8	3	**142**	128	14
Income tax (recovery) expense	**(7)**	(9)	2	**23**	12	11
Net earnings	**18**	17	1	**119**	116	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 June 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 $1 million and $2 million reclassification from operating costs to other income for the three and six months ended June 30, 2017, respectively. There was no effect on the net earnings comparison for the periods ended June 30.

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

Quarter		
Item	**Increase (Decrease)** ($ millions)	**Explanation**
Net earnings	**1**	Net earnings for the quarter ended June 30, 2018 were $18 million, an increase of $1 million compared to the same period in 2017 primarily due to higher investment in regulated assets. 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.

Quarter		
Item	**Increase (Decrease)** ($ millions)	**Explanation**
Revenues	**(1)**	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. 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. The decrease in total revenues was primarily due to: • a lower cost of natural gas recovered from customers, as approved by the BCUC, and • an increase in the refund of 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. 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 customers and throughput for 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 variance between revenues associated with actual average consumption and those revenues forecast for rate-setting purposes are captured in the RSAM deferral account for which the income statement offset is recognized in alternative revenues.
Cost of natural gas	**(22)**	Included in revenue and the cost of natural gas are certain variances between actual and forecast 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. The decrease in the cost of natural gas was primarily due to: • a lower cost of commodity, approved by the BCUC, of $1.549 per Gigajoule for the quarter ended June 30, 2018, as compared to $2.050 per Gigajoule for the same period in 2017, • certain gas cost deferrals refunded to customers, and • lower gas sales consumption compared to the same period in 2017.
Operation and maintenance	**3**	The increase in operating and maintenance expense was primarily due to higher labour and contracting costs.
Depreciation and amortization	**5**	The increase was primarily due to higher depreciation which is based on the prior year's depreciable asset base which has increased from the prior year. In addition, the amortization of certain revenue related regulatory liabilities have been recognized in revenues during 2018 as a result of adopting ASC Topic 606, *Revenue from Contracts with Customers*, while the equivalent balances for the same period of 2017 were recognized as a credit to amortization.
Other income	**(5)**	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 OPEB expense. The decrease in other income for the second quarter of 2018 was primarily due to a lower equity component of AFUDC.
Finance charges	**5**	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.

Quarter		
Item	**Increase (Decrease)** ($ millions)	**Explanation**
Income taxes	**2**	The decrease in income tax recoveries for the second quarter of 2018 was primarily due to lower deductible temporary differences and higher earnings before tax.

The following table outlines the significant variances in the Consolidated Results of Operations for the six months ended June 30, 2018 as compared to June 30, 2017:

Year to Date		
Item	**Increase (Decrease)** ($ millions)	**Explanation**
Net earnings	**3**	Net earnings for the six months ended June 30, 2018 were $119 million, an increase of $3 million compared to 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 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, 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. 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.
Revenues	**(22)**	The lower total revenues for the six months ended June 30, 2018 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 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. The quarterly revenue explanation explains the effect of forecasted growth in customers and throughput, as well as regulatory deferral mechanisms, on revenues for 2018.
Cost of natural gas	**(69)**	The decrease in the cost of natural gas for the six months ended June 30, 2018 was primarily due to the same reasons as identified in the quarter.
Operation and maintenance	**5**	The higher operating and maintenance expense for the six months ended June 30, 2018 was primarily due to higher labour and contracting costs.
Depreciation and amortization	**10**	The increase in depreciation and amortization for the six months ended June 30, 2018 was primarily due to the same reasons as identified in the quarter.
Finance charges	**16**	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	**11**	The increase in income taxes for the six months ended June 30, 2018 was primarily due to lower deductible temporary differences, higher earnings before tax, and the 1.0 per cent increase in the BC provincial statutory tax rate effective January 1, 2018, partially offset by higher TLUP tax recovery in 2018.

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SUMMARY OF QUARTERLY RESULTS

The following table sets forth unaudited quarterly information for each of the eight quarters ended September 30, 2016 through June 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)		
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
September 30, 2016	151	(11)

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.

June 2018/2017 – Net earnings for the quarter ended June 30, 2018 were slightly higher than the same period in 2017 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.

September 2017/2016 – Net loss was lower primarily due to higher operating and maintenance expense savings, net of the regulated Earnings Sharing Mechanism, as compared to operating costs allowed in rates under the PBR formula, higher investment in regulated assets, and higher income tax recovery 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 for 2016.

CONSOLIDATED FINANCIAL POSITION

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

Balance Sheet Account	Increase (Decrease) ($ millions)	Explanation
Accounts receivable	**(103)**	The decrease was primarily due to lower tariff based receivables as a result of seasonality of sales and a decrease in the cost of the natural gas commodity, partially offset by increased gas cost mitigation activity volumes and higher receivables related to natural gas derivatives.
Inventories	**(22)**	The decrease was primarily due to the drawdown of natural gas in storage during the winter months and a decrease in the average cost of purchasing natural gas.
Property, plant and equipment, net	**111**	The increase was primarily due to capital expenditures of $194 million incurred during the six months ended June 30, 2018, which includes sustainment and growth capital as well as major project expenditures discussed further under "Projected Capital Expenditures", and $4 million in changes in non-cash working capital, partially offset by: • depreciation expense, excluding net salvage provision, of $77 million, • cost of removal of $8 million, the offset of which has been recognized in regulatory liabilities, and • contributions in aid of construction of $2 million.
Regulatory assets (current and long-term)	**(40)**	The decrease was primarily due to lower unrealized losses related to changes in fair market value of natural gas derivative instruments deferred as a regulatory asset, partially offset by a higher regulated deferred income tax liability, the offset of which was deferred as a regulatory asset.
Credit facility	**(56)**	The decrease was primarily a result of net repayment of the credit facility with seasonal cash flows provided by operations.
Accounts payable and other current liabilities	**(68)**	The decrease was primarily due to a decrease in liabilities associated with the fair market value of natural gas derivatives, described in the above variance for regulatory assets, and the seasonal decrease in credit balances related to customer payment plan arrangements.
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

Six Months Ended June 30	2018	2017	Variance
($ millions)			
Cash flows provided by (used for)			
Operating activities	**314**	326	(12)
Investing activities	**(200)**	(189)	(11)
Financing activities	**(110)**	(134)	24
Net change in cash	**4**	3	1

Operating Activities

Cash flows provided by operating activities were $12 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 an increase in net earnings, depreciation and amortization expense and changes in non-cash working capital.

Investing Activities

Cash used for investing activities was $11 million higher compared to the same period in 2017 primarily due to a higher level of capital expenditures incurred during 2018.

Financing Activities

Cash used for financing activities was $24 million lower compared to the same period in 2017 primarily due to $40 million issuance of common shares in the second quarter of 2018 for which there was no comparative issuance in 2017, partially offset by higher dividends and net repayments of credit facilities.

During the three and six months ended June 30, 2018, FEI paid a common share dividend of $48 million (2017 - $42 million) and $95 million (2017 - $84 million), respectively, to its parent company, FHI.

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 June 30, 2018, the Corporation's debentures were rated by DBRS Limited at A stable and by Moody's Investors Service at A3 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 initial approval is received, the regulatory process allows for capital project costs to be reviewed by the BCUC subsequent to completion and in service to determine if any portion of the cost of the project should not be allowed for recovery in customer rates.

The 2018 projected capital expenditures are approximately $490 million which includes the more significant projects further described below.

LMIPSU Project

In December 2014, the Corporation filed a CPCN application to replace certain sections of intermediate pressure pipeline 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. 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 on 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. The restart of commissioning and LNG production is anticipated to commence during the last half of 2018. Based on the commissioning process going as planned during 2018, the project will be completed in 2019.

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Other Major Capital Projects

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

LNG Infrastructure

The Corporation continues to pursue additional LNG infrastructure investment opportunities in British Columbia, including a pipeline expansion to the proposed Woodfibre LNG site near Squamish, BC, and a further expansion of Tilbury. The 2014 OIC and 2017 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 First Nation, 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 First Nation. FEI's proposed pipeline 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 for 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 June 30, 2018, the Corporation had a $700 million syndicated credit facility available. The credit facility matures in August 2022.

The following summary outlines the Corporation's credit facility:

($ millions)	**June 30, 2018**	December 31, 2017
Credit facility	**700**	700
Draws on credit facility	**(55)**	(111)
Letters of credit outstanding	**(52)**	(56)
Credit facility available	**593**	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 June 30, 2018, $475 million remains available under the MTN Debenture Program.

OFF-BALANCE SHEET ARRANGEMENTS

As at June 30, 2018, the Corporation had no material off-balance sheet arrangements, with the exception of letters of credit outstanding of $52 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 six months ended June 30 were as follows:

	Three months ended June 30		**Six months ended June 30**	
($ millions)	**2018**	2017	**2018**	2017
Operation and maintenance expense charged to FBC (a)	**1**	1	**2**	2
Operation and maintenance expense charged to FHI (b)	**1**	1	**1**	1
Other income received from FHI (c)	**44**	44	**59**	52
Total related party recoveries	**46**	46	**62**	55

(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.

Related Party Costs

The amounts charged by the Corporation's parent and other related parties under common control for the three and six months ended June 30 were as follows:

	Three months ended June 30		**Six months ended June 30**	
($ millions)	**2018**	2017	**2018**	2017
Operation and maintenance expense charged by FBC (a)	**2**	2	**4**	4
Operation and maintenance expense charged by FHI (b)	**3**	3	**6**	6
Finance charges paid to FHI (c)	**44**	44	**59**	52
Gas storage and purchases charged by ACGS (d)	**6**	5	**13**	13
Total related party costs	**55**	54	**82**	75

(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, which are included in accounts receivable on the Consolidated Balance Sheets, and the amounts due to related parties which are included in accounts payable and other current liabilities on the Consolidated Balance Sheets, were as follows:

	June 30, 2018		December 31, 2017	
($ millions)	**Amount Due From**	**Amount Due To**	Amount Due From	Amount Due To
FHI	**-**	**-**	-	(3)
FBC	**1**	**(1)**	1	(1)
ACGS	**-**	**(2)**	-	(2)
Total due from (due to) related parties	**1**	**(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)	**June 30, 2018**	December 31, 2017
Assets		
Current		
Natural gas contracts subject to regulatory deferral [1]	**12**	2
Long-term		
Natural gas contracts subject to regulatory deferral [1]	**3**	4
Total assets	**15**	6
Liabilities		
Current		
Natural gas contracts subject to regulatory deferral [1]	**(14)**	(47)
Long-term		
Natural gas contracts subject to regulatory deferral [1]	**-**	(7)
Total liabilities	**(14)**	(54)
Total liabilities, net	**1**	(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		
June 30, 2018	**Gross Amount Recognized in the Balance Sheet**	**Counterparty Netting of Natural Gas Contracts [1]**	**Cash Collateral (Received) /Posted**	**Net Amount**
($ millions)				
Natural gas contracts subject to regulatory deferral:				
Accounts receivable	**12**	**(3)**	**6**	**15**
Other assets	**3**	**-**	**-**	**3**
Accounts payable and other current liabilities	**(14)**	**3**	**-**	**(11)**

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

December 31, 2017	Gross Amount Recognized in the Balance Sheet	Gross Amount Not Offset in the Balance Sheet: Counterparty Netting of Natural Gas Contracts [1]	Gross Amount Not Offset in the Balance Sheet: Cash Collateral (Received)/ 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 June 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)	**June 30, 2018**	December 31, 2017
Unrealized net gain (loss) recorded to current regulatory liabilities (assets)	**1**	(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 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	June 30, 2018 Carrying Value	June 30, 2018 Estimated Fair Value	December 31, 2017 Carrying Value	December 31, 2017 Estimated Fair Value
Liabilities					
Long-term debt [1]	Level 2	**2,395**	**2,902**	2,395	2,955

[1] Carrying value excludes unamortized debt issuance costs.

NEW ACCOUNTING POLICIES

Standard	Effective Date	Description	Applied to 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 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: 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. The Corporation disaggregates revenue by type of customer, as disclosed in note 9 of Condensed Consolidated Interim Financial Statements for the three and six months ended June 30, 2018.
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 periodic 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 $1 million and $2 million reclassification from operation and maintenance expense to other income for the three and six months ended June 30, 2017, respectively, in the Condensed Consolidated Interim Financial Statements for the three and six months ended June 30, 2018 and 2017 (note 5).

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	Applied to FEI
Leases	January 1, 2019	ASU No. 2016-02, *Leases* (ASC Topic 842), was issued in February 2016, is effective January 1, 2019 with earlier adoption permitted, and is to be applied using a modified retrospective approach with practical expedient options. 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 expects to elect a package of practical expedients that will allow 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. FEI also expects to elect an additional practical expedient that permits entities to not evaluate existing land easements that were previously not accounted for as leases. FEI continues to assess the impact of adoption and monitor standard-setting activities that may affect the transition requirements.

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 second 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.

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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