FortisBC Energy Inc.
Management Discussion & Analysis
For the Three and Nine Months Ended September 30, 2017
Dated November 3, 2017

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 2017 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, 2017, 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, 2016, with 2015 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"), the Lower Mainland Intermediate Pressure System Upgrade ("LMIPSU") project, the Coastal Transmission System ("CTS") 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 expectations for employee future benefit costs; 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 2018 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 skilled workforces; 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. For additional information with respect to these risk factors, reference should be made to the section entitled "Business Risk Management" in this MD&A and the Corporation's MD&A for the year ended December 31, 2016.

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 999,000 residential, commercial and 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 Inc. ("Fortis"). Fortis is 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 and 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 2017 or 2016. As part of the 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 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.

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 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 incremental incentives and infrastructure funding to further expand the FortisBC natural gas for transportation (NGT) programs. Specifically, the additional incentives and investments include:

- 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.

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 2015, the BCUC issued its decision on FEI's 2016 delivery rates. The decision resulted in a 2016 average rate base of approximately $3,693 million (excluding the rate base of approximately $11 million for Fort Nelson) and a customer delivery rate increase of 1.79 per cent over 2015 rates.

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.

In September 2017, FEI filed its application for approval of 2018 delivery rates under the PBR Plan. The 2018 application includes a forecast average rate base of approximately $4,370 million (excluding the rate base of approximately $11 million for Fort Nelson) and requests no increase in customer delivery rates. 2018 rates would have otherwise decreased had FEI not requested in the application to defer a revenue surplus for the year.

In addition to the rate base amounts approved in the 2016 and 2017 regulatory decisions, assets under construction earn a regulated return. Included in assets under construction are significant capital projects such as the Tilbury 1A Expansion Project. The cost for the scope of this project currently under construction is approximately $400 million, before development costs and allowance for funds used during construction ("AFUDC"), and is expected to be in service by the end of 2017 or in the first quarter of 2018.

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 nine months ended September 30, 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. In June 2017, the Corporation filed the 2017 Price Risk Management Plan with the BCUC requesting further enhancements to its price risk management tools.

CONSOLIDATED RESULTS OF OPERATIONS

	Quarter			Year to Date		
Periods Ended September 30	**2017**	2016	Variance	**2017**	2016	Variance
Gas sales (petajoules)	**27**	28	(1)	**152**	130	22
($ millions)						
Natural gas revenue	**151**	144	7	**828**	737	91
Other revenue	**5**	7	(2)	**5**	20	(15)
Total revenues	**156**	151	5	**833**	757	76
Cost of natural gas	**38**	29	9	**292**	204	88
Operation and maintenance	**48**	53	(5)	**158**	161	(3)
Property and other taxes	**15**	16	(1)	**49**	48	1
Depreciation and amortization	**50**	50	-	**152**	152	-
Total expenses	**151**	148	3	**651**	565	86
Operating income	**5**	3	2	**182**	192	(10)
Other income	**49**	42	7	**110**	71	39
Finance charges	**73**	71	2	**183**	156	27
(Loss) earnings before income taxes	**(19)**	(26)	7	**109**	107	2
Income tax (recovery) expense	**(16)**	(16)	-	**(4)**	13	(17)
Net (loss) earnings	**(3)**	(10)	7	**113**	94	19
Net earnings attributable to non-controlling interest	**1**	1	-	**1**	1	-
Net (loss) earnings attributable to controlling interest	**(4)**	(11)	7	**112**	93	19

Net (Loss) Earnings

Net loss for the third quarter of 2017 was $4 million, a decrease of $7 million as compared to the $11 million loss for the third quarter of 2016. On a year-to-date basis, net earnings were $112 million, an increase of $19 million as compared to the same period in 2016.

For the third quarter of 2017, the lower net loss was primarily due to:

- higher operation and maintenance expense savings, net of the regulated Earnings Sharing Mechanism, as compared to operation and maintenance costs allowed in rates under the PBR formula,
- higher investment in regulated assets, and
- a higher income tax recovery as a result of the Corporation having a tax loss utilization plan ("TLUP") in place with a higher investment in preferred shares in 2017, as compared to the TLUP in place in 2016. Excluding the effects of the TLUP, the income tax recovery for the third quarter of 2017 would have been lower compared to the same period of 2016 due to a lower quarterly net loss before income taxes. Other income tax variances compared to income taxes allowed in rates under the PBR formula are subject to a flowthrough deferral mechanism and therefore do not affect net earnings.

On a year-to-date basis, the higher net earnings were primarily due to:

- higher income tax recovery as a result of the Corporation having a TLUP in place since the first quarter of 2017, with a higher investment in preferred shares in 2017, as compared to the TLUP in place since the second quarter of 2016, and
- higher investment in regulated assets.

As part of the TLUP, the Corporation received dividend income from FHI relating to a $2,500 million (2016 - $1,900 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.

In both 2017 and 2016 the allowed ROE and deemed equity component of capital structure approved by the BCUC in setting delivery rates were 8.75 per cent and 38.5 per cent, respectively.

Gas Sales

Gas sales volumes for the third quarter of 2017 were comparable with the third quarter of 2016. On a year-to-date basis, the increase in gas sales volumes was primarily due to customer growth, higher average consumption by residential and commercial customers as a result of colder weather, and higher gas volumes for transportation customers due to certain transportation customers switching to natural gas compared to alternative fuel sources.

Natural Gas Revenue and Cost of Natural Gas

The increase in natural gas revenue for the third quarter of 2017 was primarily due to a higher cost of natural gas as a result of higher natural gas prices. On a year-to-date basis, the increase in natural gas revenue was primarily due to higher gas sales volumes and a higher cost of natural gas as a result of higher natural gas prices. Changes in consumption levels of customers and changes in the commodity cost of natural gas do not materially impact earnings as a result of regulatory deferral accounts.

Other Revenue

Other revenue consists of the Earnings Sharing Mechanism, certain flow-through adjustments for variances from the forecast used to set rates, and other miscellaneous operating revenue items.

Other revenue for the third quarter of 2017 was comparable with the third quarter of 2016. On a year-to-date basis, the decrease in other revenue was primarily due to an increase in regulatory deferral adjustments owing to customers in future rates, including the 2017 revenue surplus for which the offset has been recognized in regulatory liabilities.

Operation and Maintenance

The decrease in operating and maintenance expense for the third quarter of 2017 was primarily due to lower pension and other post-employment benefit costs and lower labour and contracting costs. On a year-to-date basis, the lower pension and other post-employment benefit costs were partially offset by higher labour and contracting costs.

Property and Other Taxes

Property and other taxes were comparable between periods.

Depreciation and Amortization

Depreciation and amortization was comparable between periods due to an increase in the net salvage collected in depreciation, offset by an increase in amortization of regulatory liabilities.

Other Income

Other income primarily consists of dividend income from TLUPs and the equity component of AFUDC.

The increase in other income for the third quarter of 2017 was primarily due to higher dividend income from FEI having a TLUP in place with a higher investment in preferred shares in 2017, as compared to the TLUP in place in 2016. On a year-to-date basis, the increase in other income was primarily due to FEI having a TLUP in place since the first quarter of 2017, with a higher investment in preferred shares in 2017, as compared to the TLUP in place since the second quarter of 2016, and a higher equity component of AFUDC.

Finance Charges

The increase in finance charges for the third quarter of 2017 was primarily due to higher finance charges from FEI having a TLUP in place with a higher level of subordinated debt, as compared to the TLUP in place in 2016. On a year-to-date basis, the increase in finance charges was primarily due to FEI having a TLUP in place since the first quarter of 2017, with a higher level of subordinated debt in 2017, as compared to the TLUP in place since the second quarter of 2016. The increase for both comparable periods was partially offset by a lower average cost of debt, which resulted from the repayment of higher interest-bearing Purchase Money Mortgages that matured in September 2016 and were replaced with the issuance of lower interest-bearing debentures in April 2016 and December 2016.

Income Taxes

For the third quarter of 2017, income tax expense was comparable between periods primarily due to an increase in the current year's TLUP tax recovery and a decrease in taxable permanent differences offset by a decrease in deductible temporary differences and lower loss before tax.

On a year-to-date basis, the decrease in income tax expense was primarily due to an increase in the current year's TLUP tax recovery, an increase in deductible temporary differences and a decrease in taxable permanent differences.

CONSOLIDATED FINANCIAL POSITION

The following table outlines the significant changes in the consolidated balance sheets between September 30, 2017 and December 31, 2016:

Balance Sheet Account	Increase (Decrease) ($ millions)	Explanation
Accounts receivable	**(115)**	The decrease was primarily due to the seasonality of natural gas tariff sales, partially offset by higher off-system sales volumes.
Regulatory assets - current and long-term	**(57)**	The decrease was primarily due to a lower Revenue Stabilization Adjustment Mechanism ("RSAM") deferral balance, which captures the variances in delivery revenue for residential and commercial customers; a decrease in the fair value of certain derivative instruments deferred as a regulatory asset with the offset recorded in accounts payable and other long-term liabilities; and a lower regulated deferred income tax liability, the offset of which has been deferred as a regulatory asset, partially offset by an increase in the costs relating to the Energy Efficiency and Conservation program.
Property, plant and equipment, net	**200**	The increase was primarily due to capital expenditures of $317 million incurred during the period, less: • depreciation expense, excluding net salvage provision, of $109 million, • contributions in aid of construction of $2 million, and • changes in non-cash working capital of $6 million.
Credit facility	**66**	The increase was primarily due to an increase in borrowings to finance the debt portion of FEI's 2017 capital expenditure program.
Accounts payable and other current liabilities	**(39)**	The decrease was primarily due to lower gas cost payables as a result of lower gas prices and lower accruals for natural gas for transportation incentives, partially offset by an increase in credit balances related to customer payment plan arrangements.
Other taxes payable	**(21)**	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	**28**	The increase was primarily due to increases in the Midstream Cost Reconciliation Account ("MCRA") deferral balance, net salvage provision, and other deferral adjustments owing to customers in future rates, including the 2017 revenue surplus, partially offset by decreases in the Commodity Cost Reconciliation Account ("CCRA") and Rate Stabilization Deferral Account ("RSDA") deferral balances.

LIQUIDITY AND CAPITAL RESOURCES

Summary of Consolidated Cash Flows

Nine Months Ended September 30	**2017**	2016	Variance
($ millions)			
Cash flows provided by (used for)			
Operating activities	**348**	265	83
Investing activities	**(320)**	(245)	(75)
Financing activities	**(24)**	(18)	(6)
Net increase in cash and cash equivalents	**4**	2	2

Operating Activities

Cash flows provided by operating activities were $83 million higher compared to the same period in 2016. The increase was primarily due to an increase in net earnings, changes in long-term regulatory assets and liabilities, and non-cash working capital.

Investing Activities

Cash used for investing activities was $75 million higher compared to the same period in 2016. The increase was primarily due to increased property, plant and equipment expenditures during 2017, which were primarily related to the CTS project.

Financing Activities

Cash used for financing activities was $6 million higher compared to the same period in 2016.

During the nine months ended September 30, 2017, net proceeds from credit facilities were used to fund property, plant and equipment expenditures.

During the nine months ended September 30, 2016, net proceeds from the issuance of $300 million of Medium Term Note Debentures in April 2016 were used to repay existing credit facilities and finance the debt portion of FEI's capital expenditure program.

In September 2016, FEI also repaid the $200 million Series B Purchase Money Mortgage using proceeds from credit facilities.

During the third quarter of 2016, FEI received cash of approximately $63 million as security for development expenditures incurred on the Eagle Mountain Woodfibre Gas Pipeline Project, which replaced a letter of credit that was previously held.

In July 2016, the Corporation issued 2,024,150 common shares to FHI for total proceeds of $30 million.

During the three and nine months ended September 30, 2017, the Corporation paid a common share dividend of nil (2016 - nil) and $84 million (2016 - $80 million), respectively, to its parent company, FHI.

CONTRACTUAL OBLIGATIONS

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

As at September 30, 2017	Total	Due Within 1 Year	Due in Year 2	Due in Year 3	Due in Year 4	Due in Year 5	Due After 5 Years
($ millions)							
Interest obligations on long-term debt	2,365	116	116	116	116	116	1,785
Long-term debt [1]	2,220	-	-	-	-	-	2,220
Gas purchase obligations	1,082	304	206	177	130	100	165
Capital lease and finance obligations	110	8	37	19	10	33	3
Power purchase obligations	482	5	6	8	9	12	442
Other	8	4	2	2	-	-	-
Totals	6,267	437	367	322	265	261	4,615

[1] Excludes unamortized debt issuance costs of $15 million.

The gas purchase obligations are based on gas commodity indices that vary with market prices. The amounts disclosed reflect index prices that were in effect at September 30, 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 effects of goodwill and other items that do not impact the deemed capital structure.

Credit Ratings

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

The table below summarizes the ratings assigned to the Corporation's debentures as at September 30, 2017:

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

During July 2017 Moody's issued an updated credit rating report confirming the Corporation's debenture rating and outlook.

Projected Capital Expenditures

The 2017 projected capital expenditures are approximately $480 million which include the CTS project of approximately $130 million and the Tilbury Expansion Project Phase 1A of approximately $30 million.

CTS Project

The CTS project, approved in the 2014 OIC, is estimated to cost approximately $170 million and involves the installation of 11 kilometers of pipeline in the cities of Surrey and Coquitlam. The project is intended to increase security of supply by reducing the number of single points of failure. Construction is expected to be primarily completed by the end of 2017.

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 Corporation is preparing to restart the commissioning process on the facility, which was interrupted in the third quarter of 2017. The storage tank and liquefier are both expected to be in service by the end of 2017 or in the first quarter of 2018.

Other Major Capital Projects

Beyond 2017, the Corporation has identified and received BCUC or OIC approval on further major capital projects as discussed 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. The anticipated cost of the project is approximately $250 million with expenditures incurred primarily during 2018.

LNG Infrastructure

The Corporation continues to pursue additional LNG infrastructure investment opportunities in British Columbia, including a pipeline expansion to the proposed Eagle Mountain Woodfibre LNG ("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 pipeline 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 has obtained an export license from the National Energy Board, which was recently extended from 25 to 40 years, and 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 the necessary environmental assessment approvals for the pipeline expansion from the Squamish First Nation and provincial environmental assessment office. FEI's potential pipeline expansion remains contingent on Woodfibre LNG making a final decision to proceed with construction of its LNG export facility. Should the project proceed, it is not expected to be in service before 2021.

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 facilities, 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, 2017, the Corporation had a $700 million syndicated credit facility available. In July 2017, the credit facility was amended such that it now matures in August 2022.

The following summary outlines the Corporation's credit facility:

($ millions)	September 30, 2017	December 31, 2016
Credit facility	**700**	700
Draws on credit facility	**(260)**	(194)
Letters of credit outstanding	**(56)**	(52)
Credit facility available	**384**	454

Debentures

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

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

OFF-BALANCE SHEET ARRANGEMENTS

As at September 30, 2017 the Corporation had no material off-balance sheet arrangements, with the exception of letters of credit outstanding of $56 million (December 31, 2016 - $52 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:

	Three months ended September 30		Nine months ended September 30	
($ millions)	**2017**	2016	**2017**	2016
Operation and maintenance expense charged to FBC (a)	**1**	1	**3**	3
Operation and maintenance expense charged to FHI (b)		1	**1**	1
Other income received from FHI (c)	**44**	38	**96**	59
Operation and maintenance expense charged to ACGS (d)	**1**	-	**1**	-
Total related party recoveries	**46**	40	**101**	63

(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 the TLUP, the Corporation received dividend income from FHI relating to a $2,500 million (2016 - $1,900 million) investment in preferred shares. A TLUP is a series of transactions, whereby the Corporation sets up an investment in an affiliate's preferred shares and issues subordinated debt to that affiliate; these two financial instruments are shown on a net basis. The Corporation receives non-taxable dividend income on the preferred shares and pays tax deductible interest on the debt. The effect of this transaction is to transfer tax losses between affiliated entities. The dividend income associated with the TLUP was previously recognized in other revenue for the three and nine months ended September 30, 2016 and was subsequently reclassified to other income for the year ended December 31, 2016 and for the three and nine months ended September 30, 2017.

(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:

	Three months ended September 30		**Nine months ended September 30**	
($ millions)	**2017**	2016	**2017**	2016
Operation and maintenance expense charged by FBC (a)	**1**	2	**5**	5
Operation and maintenance expense charged by FHI (b)	**3**	3	**9**	10
Finance charges paid to FHI (c)	**44**	38	**96**	59
Gas storage and purchases charged by ACGS (d)	**5**	4	**18**	9
Total related party costs	**53**	47	**128**	83

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

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

(c) As part of a TLUP, the Corporation paid FHI interest on $2,500 million (2016 - $1,900 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, are as follows:

	September 30, 2017		December 31, 2016	
($ millions)	**Amount Due From**	**Amount Due To**	Amount Due From	Amount Due To
FHI	**-**	**(3)**	-	-
FBC	**1**	**(1)**	-	(1)
ACGS	**-**	**(2)**	-	(3)
Total due from (due to) related parties	**1**	**(6)**	-	(4)

BUSINESS RISK MANAGEMENT

The business risks of the Corporation remain substantially unchanged from those outlined in the Corporation's 2016 annual MD&A, other than as noted below:

Continued Reporting in Accordance with US GAAP

In October 2017 an application was filed by Fortis, on behalf of its subsidiaries, including FEI, with the Ontario Securities Commission ("OSC") to grant the Corporation permanent exemptive relief from the application of International Financial Reporting Standards ("IFRS"). This application, if approved, would allow FEI to continue to prepare its financial statements in accordance with US GAAP until either (i) Fortis ceases to be an United States Securities and Exchange Commission ("SEC") issuer, (ii) Fortis ceases to prepare its consolidated financial statements in accordance with US GAAP, (iii) FEI ceases to have activities subject to rate regulation, or (iv) FEI ceases to be a subsidiary of Fortis. This application would replace the current relief order issued by the OSC in January 2014 which permits FEI to continue to prepare its financial statements in accordance with US GAAP, until the earliest of: (i) January 1, 2019; (ii) the first day of the financial year that commences after FEI ceases to have activities subject to rate regulation; or (iii) the effective date prescribed by the International Accounting

Standards Board ("IASB") for the mandatory application of a standard within IFRS specific to entities with activities subject to rate regulation.

NEW ACCOUNTING POLICIES

Simplifying the Test for Goodwill Impairment

Effective January 1, 2017, the Corporation adopted Accounting Standards Update ("ASU") No. 2017-04, *Simplifying the Test for Goodwill Impairment*. The amendments in this update simplify the subsequent measurement of goodwill by eliminating step two in the current two-step goodwill impairment test. An entity will apply a one-step quantitative test and record the amount of goodwill impairment as the excess of a reporting unit's carrying amount over its fair value, not to exceed the total amount of goodwill allocated to the reporting unit. The new guidance does not amend the optional qualitative assessment of goodwill impairment. The above-noted ASU was applied prospectively and did not impact the Corporation's condensed consolidated interim financial statements for the three and nine months ended September 30, 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. There have been no changes to the disclosure of the ASUs discussed in the Corporations' 2016 MD&A with the exception of the following updates described below.

Revenue from Contracts with Customers

ASU No. 2014-09 was issued in May 2014 and the amendments in this update create Accounting Standards Codification ("ASC") Topic 606, *Revenue from Contracts with Customers*, and supersede 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 can be applied consistently across various transactions, industries and capital markets. In 2016, a number of additional ASUs were issued that clarify implementation guidance in ASC Topic 606. This standard, and all related ASUs, is effective for annual and interim periods beginning after December 15, 2017. Early adoption is permitted for annual and interim periods beginning after December 15, 2016. The Corporation has elected not to early adopt.

The new guidance permits two methods of adoption: (i) the full retrospective method, under which comparative periods would be restated, and the cumulative impact of applying the standard would be recognized as at January 1, 2017, the earliest period presented; and (ii) the modified retrospective method, under which comparative periods would not be restated and the cumulative impact of applying the standard would be recognized at the date of initial adoption, January 1, 2018. The Corporation expects to adopt the guidance using the modified retrospective method.

The majority of the Corporation's revenue is generated from natural gas sales to customers based on published tariff rates, as approved by the BCUC, and is considered to be in scope of ASU No. 2014-09. FEI has assessed tariff revenue and expects that the adoption of this standard will not change the Corporation's accounting policy for recognizing retail and wholesale tariff revenue and therefore, will not have an impact on earnings. FEI continues to assess whether this standard will have an impact on its remaining revenue streams. The Corporation has not disclosed the expected impact of the adoption of this standard on its consolidated financial statements as it is not expected to be material.

Alternative revenue programs of rate regulated utilities are outside the scope of this standard as they are not considered contracts with customers. Revenues arising from alternative revenue programs will be presented separately from revenues in scope of the new guidance. The Corporation also expects to add additional disclosures to address the requirements to provide more information regarding the nature, amount, timing and uncertainty of revenue and cash flows. FEI is in the process of drafting these required disclosures.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost

ASU No. 2017-07, *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*, was issued in March 2017 and the amendments in this update require that an employer disaggregate the current service costs component of net benefit cost and present it in the same statement of earnings line item as other employee compensation costs arising from services rendered. The other components of net benefit cost are required to be presented separately from the service cost component and outside of operating income. Additionally, the amendments allow only the service cost component to be eligible for capitalization when applicable. This update is effective for annual and interim periods beginning after December 15, 2017. Early adoption is permitted, however, early adoption must be within the first interim period of a reporting year. The amendments in this update should be applied retrospectively for the presentation of the net periodic benefit costs and prospectively, on and after the effective date, for the capitalization in assets of only the service cost component of net periodic benefit costs. FEI is assessing the impact that the adoption of this update will have on its consolidated financial statements and related disclosures.

FINANCIAL INSTRUMENTS

Fair Value Estimates

The following table summarizes the fair value measurements of the Corporation's long-term debt, natural gas supply contracts, commodity swaps and foreign exchange forward contracts as of September 30, 2017 and December 31, 2016, all of which are Level 2 of the fair value hierarchy and recorded on the consolidated balance sheets at their carrying value or fair value:

	September 30, 2017		December 31, 2016	
($ millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Assets				
Current				
Foreign exchange forward contracts [1]	**1**	**1**	-	-
Liabilities				
Current				
Natural gas supply contracts [1]	**3**	**3**	10	10
Natural gas commodity swaps [1]	**5**	**5**	-	-
Long-term				
Long-term debt [2]	**2,220**	**2,664**	2,220	2,687
Natural gas supply contracts [1]	**1**	**1**	4	4

1 Natural gas supply contracts, commodity swaps and foreign exchange forward 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.

2 Carrying value excludes unamortized debt issuance costs of $15 million (2016 - $14 million).

The fair values of the Corporation's financial instruments, including derivatives, reflect a point-in-time estimate based on current and relevant market information about the instruments as at the balance sheet dates. The estimates cannot be determined with precision as they involve uncertainties and matters of judgment.

At September 30, 2017, the Corporation's outstanding derivative balances, which consisted of physically-settled natural gas supply contracts, financially-settled natural gas commodity swaps and foreign exchange forward contracts, were as follows:

($millions)	**Gross Derivatives Balance [1]**	**Gross Amounts Not Offset in the Balance Sheet [2]**	**Total Net Derivatives Balance**
Natural gas supply contracts and commodity swaps:			
Accounts payable and other current liabilities	**8**	**-**	**8**
Other liabilities	**1**	**-**	**1**
Foreign exchange forward contracts:			
Accounts receivable	**1**	**-**	**1**

1 See the September 30, 2017 unaudited condensed consolidated interim financial statements for a discussion of the valuation techniques used to calculate the fair value of these instruments.

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

At December 31, 2016, the Corporation's outstanding derivative balances, which consisted of physically-settled natural gas supply contracts, were as follows:

($millions)	Gross Derivatives Balance [1]	Gross Amounts Not Offset in the Balance Sheet [2]	Total Net Derivatives Balance
Natural gas supply contracts:			
Accounts payable and other current liabilities	10	-	10
Other liabilities	4	-	4

[1] See the December 31, 2016 consolidated financial statements for a discussion of the valuation techniques used to calculate the fair value of these instruments.

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

The following table shows the cumulative unrealized losses at September 30, 2017 and December 31, 2016, with respect to all derivative instruments:

($ millions)	**September 30, 2017**	December 31, 2016
Unrealized loss on natural gas supply contracts and commodity swaps[1]	**9**	14
Unrealized gain on foreign exchange forward contracts[1]	**(1)**	-

[1] Unrealized gains and losses on derivative instruments are recorded to current regulatory assets or liabilities rather than being recorded to the consolidated statement of earnings. Accordingly, net earnings were not impacted by unrealized amounts on these instruments.

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 involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are recognized in the period in which they become known.

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 2017 from those disclosed in the Corporation's 2016 annual MD&A.

SUMMARY OF QUARTERLY RESULTS

The following table sets forth unaudited quarterly information for each of the eight quarters ended December 31, 2015 through September 30, 2017. The information has been obtained from the Corporation's unaudited condensed consolidated interim financial statements, which have been prepared in accordance with US GAAP. 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, 2017	156	(4)
June 30, 2017	228	17
March 31, 2017	449	99
December 31, 2016	394	77
September 30, 2016	151	(11)
June 30, 2016	200	13
March 31, 2016	406	91
December 31, 2015	411	76

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 earnings are not indicative of net earnings on an annual basis.

December 2016/2015 – Net earnings were higher primarily due to higher investment in regulated assets, higher operating and maintenance expense savings, net of the regulated Earnings Sharing Mechanism, and the timing of recognizing revenue versus the incurrence of the related expenses, which was more pronounced in the fourth quarter of 2016 versus the same period of 2015, partially offset by lower income tax recovery as a result of the Corporation having a TLUP in place for a shorter duration in the fourth quarter of 2016 as compared to the same period of 2015.

March 2017/2016 – Net earnings were higher due to the timing of recognizing revenue versus the incurrence of the related expenses, which was more pronounced in the first quarter of 2017 compared to the same period of 2016, higher income tax recovery as a result of the Corporation having a TLUP in place in the first quarter of 2017 and higher investment in regulated assets, partially offset by lower operating and maintenance expense savings, net of the regulated Earnings Sharing Mechanism, as compared to the operating costs allowed in the rates under the PBR formula.

June 2017/2016 - Net earnings were higher primarily due to the Corporation having a TLUP in place since the first quarter of 2017, with a higher investment in preferred shares in 2017, as compared to having a similar TLUP in place for part of the second quarter of 2016, which generated lower tax expense, higher investment in regulated assets, partially offset by the timing of incurring operating costs, in particular operating and maintenance expenses, and lower savings on the operating costs compared to operating costs allowed in rates under the PBR formula.

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.

BUSINESS OUTLOOK

Collective Agreements

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 was ratified during the first quarter of 2017 and expires on March 31, 2022. The second collective agreement representing employees in specified occupations in the areas of administration and operations support was renewed for a three year term which expires on March 31, 2018.

OUTSTANDING SHARE DATA

As at the filing date of this MD&A the Corporation had issued and outstanding 325,945,864 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, is available on SEDAR at www.sedar.com.

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