FortisBC Energy Inc.
Management Discussion & Analysis
For the Year Ended December 31, 2015
Dated February 18, 2016

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 2015 and comparative periods contained in the following MD&A has been prepared in accordance with accounting principles generally accepted in the United States ("US GAAP") and is presented in Canadian dollars unless otherwise specified. The MD&A should be read in conjunction with the Corporation's annual audited consolidated financial statements and notes thereto for the year ended December 31, 2015, with 2014 comparatives, prepared in accordance with US GAAP.

In this MD&A, FEVI refers to FortisBC Energy (Vancouver Island) Inc., FEW refers to FortisBC Energy (Whistler) Inc., TGHI refers to Terasen Gas Holdings Inc., FAES refers to FortisBC Alternative Energy Services Inc., FHI refers to the Corporation's parent, FortisBC Holdings Inc., FBC refers to FortisBC Inc., 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 associated in-service date; estimated costs and in-service date of the Lower Mainland Intermediate Pressure System upgrade ("LMIPSU"); 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; the Corporation's belief that changes in consumption levels of sales customers and changes in the commodity cost of natural gas do not materially impact earnings as a result of regulatory deferral accounts; and the Corporation's estimated contractual obligations.

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; no significant decline in interest rates; 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.

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 AMALGAMATION AND OVERVIEW

In February 2014, the British Columbia Utilities Commission ("BCUC") approved the amalgamation of FEI, FEVI, FEW and TGHI, subject to the consent of the Lieutenant Governor in Council. The BCUC approved the adoption of common rates for natural gas delivery to all customers except those in the Fort Nelson service area and approved the phase-in to common rates over a three year period. The amalgamation received the consent of the Lieutenant Governor in Council in May 2014 and was effected on December 31, 2014.

The Corporation is the resulting corporation from the amalgamation on December 31, 2014 of FEI, FEVI, FEW and TGHI. Prior to the amalgamation FEI, FEVI, FEW and TGHI were under common control and therefore the amalgamation has been presented on a pooling-of-interest basis, as if the historical financial position and operating results of these corporations had always been amalgamated. Prior period financial and operating information has been restated to present the results of the amalgamated Corporation.

The Corporation is the largest distributor of natural gas in British Columbia ("BC"), serving approximately 982,000 residential, commercial and industrial and transportation customers in more than 135 communities. Major areas served by the Corporation are the Lower Mainland, Vancouver Island and Whistler regions of BC. The Corporation provides transmission and distribution services to its customers, and obtains natural gas supplies on behalf of most residential, commercial and industrial customers. Gas supplies are sourced primarily from northeastern BC and, through the Corporation's Southern Crossing Pipeline, from Alberta.

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

The Corporation operates primarily under a cost of service regulation as prescribed by the BCUC. The Corporation applies to the BCUC for approval of annual revenue requirements based on forecast costs of service, including, but not limited to, natural gas supply costs, operating expenses, depreciation and amortization, income taxes, interest on debt and a return on equity ("ROE"). Starting in 2014, through 2019, the regulatory framework includes some performance-based rate-setting attributes.

The Corporation is an indirect, wholly-owned subsidiary of 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 Quarterly Gas Cost Changes

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, to manage volatility in rates, and to match costs with benefits, a number of regulatory deferral accounts are in place.

For FEI and FEW prior to the amalgamation on December 31, 2014 and for the amalgamated FEI, there are two primary deferral mechanisms in place to decrease the volatility in rates caused by such factors as fluctuations in gas supply costs and the significant impacts of weather and other changes on use rates. The first mechanism relates to the recovery of all gas supply costs through deferral accounts that capture variances (overages and shortfalls) from forecasts in costs incurred. Balances are either refunded to or recovered from customers via quarterly application and review by the BCUC. Currently under this mechanism, there are two separate deferral accounts; the Commodity Cost Reconciliation Account ("CCRA") and the Midstream Cost Reconciliation Account ("MCRA"). The second mechanism seeks to stabilize revenues from residential and commercial customers through a deferral account that captures variances in the forecast versus actual customer use rate for residential and commercial customers throughout the year. This mechanism is called the Revenue Stabilization Adjustment Mechanism ("RSAM"). The RSAM and MCRA accounts are either refunded to or recovered from customers in rates over 2 years with actual refunds or recoveries dependent upon annually approved rates and actual gas consumption volumes. The CCRA account is anticipated to be fully refunded to or recovered from customers within the next fiscal year.

Beginning in 2010, a Rate Stabilization Deferral Account ("RSDA") was created for FEVI. Until the end of 2014, the RSDA accumulated the difference between the revenues received from FEVI customers and the actual cost of service to FEVI customers, excluding operation and maintenance cost variances from forecast. FEVI, prior to the amalgamation also had a Gas Cost Variance Account ("GCVA") that accumulated variances between the actual and forecast gas costs, which were flowed through future customer rates. As approved by the BCUC, the ending 2014 GCVA balance was transferred to the RSDA effective January 1, 2015. The RSDA account is being returned to customers (excluding those residing on Vancouver Island and the Sunshine Coast and in Whistler) over a period of three years.

For 2014, the pre-amalgamation FEI, and for 2015 through 2019 the amalgamated FEI, has a BCUC approved 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 to customers in the following year. This deferral account replaced a number of deferral accounts that existed prior to then, that captured such items as variances in interest rates, insurance and factors affecting income taxes. In addition, the flow-through deferral account captures variances in margin related to customer growth and industrial margin, and certain other items that previously were not subject to flow through treatment.

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.

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.

The table below shows the residential rate changes since January 1, 2014 for a typical residential customer in FEI's Lower Mainland service area:

	2014					**2015**			
	Jan 1	April 1	July 1	Oct 1	Nov 1	**Jan 1**	**April 1**	**Aug 1**	**Oct 1**
Effective rate per gigajoule	$9.69	$11.06	$11.06	$10.20	$10.22	**$10.16**	**$8.86**	**$8.88**	**$8.88**
Percentage change in rate	3.5%	14.1%	-	(7.8%)	0.2%	**(0.6%)**	**(12.8%)**	**0.2%**	**-**

When comparing December 31, 2015 to December 31, 2014, an average bill for a Lower Mainland residential customer decreased by approximately 13.1 per cent, primarily due to a decrease in natural gas costs.

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 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 will provide a forum for discussion between FEI and interested parties regarding its current performance and future activities.

The BCUC's PBR Decision resulted in a 2014 average rate base for pre-amalgamation FEI of approximately $2,765 million (excluding rate base for Fort Nelson) and a 2014 delivery rate increase of approximately 1.8 per cent.

In May and June 2015, the BCUC issued its decisions on FEI's 2015 delivery rates and on the inclusion of the Vancouver Island and Whistler service areas under the PBR Plan. The decisions result in an amalgamated rate base of approximately $3,661 million (excluding the separately approved rate base of approximately $11 million for Fort Nelson) and a customer delivery rate increase of approximately 0.7 per cent over 2014 rates.

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

Allowed ROE and Capital Structure

A Generic Cost of Capital ("GCOC") Proceeding to establish the allowed ROE and capital structures for BC regulated utilities occurred from 2012 to 2014. FEI was designated as the benchmark utility and a BCUC decision established that the ROE for the benchmark utility would be set at 8.75 per cent with a 38.5 per cent common equity component of capital structure, both effective January 1, 2013. The benchmark utility ROE and common equity component of capital structure remained in effect through December 31, 2015.

As a result of the second stage of the GCOC Proceeding decision which was received in March 2014, pre-amalgamation FEVI and FEW were approved for a common equity component of capital structure of 41.5 per cent and an ROE of 9.25 per cent and 9.5 per cent respectively, effective January 1, 2013. Effective January 1, 2015, the ROE and common equity component of capital structure for the amalgamated FEI was set to equal the benchmark utility, at 8.75 per cent and 38.5 per cent, respectively.

The BCUC decision on the first stage of the GCOC Proceeding, received in May 2013, directed FEI to file an application to review the 2016 benchmark utility ROE and common equity component of capital structure by no later than November 30, 2015.

In October 2015, FEI filed its application to review the 2016 benchmark utility ROE and common equity component of capital structure. In December 2015, the BCUC determined that FEI's existing common equity component of capital structure and ROE will remain the benchmark on an interim basis, effective January 1, 2016. A decision on the application is expected in mid-2016.

US GAAP

In January 2014, the Ontario Securities Commission ("OSC") issued a relief order which permits the Corporation 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 the Corporation ceases to have activities subject to rate regulation; or (iii) the effective date prescribed by the International Accounting Standards Board ("IASB") for the mandatory application of a standard within International Financial Reporting Standards ("IFRS") specific to entities with activities subject to rate regulation. The OSC relief order effectively replaces and extends the OSC's previous relief order, which expired January 1, 2015.

The BCUC had previously approved the Corporation's request to adopt US GAAP for regulatory purposes until December 31, 2014. In May 2014, FEI applied for approval to continue the use of US GAAP for regulatory purposes effective January 1, 2015. In July 2014, the BCUC granted the requested approval, until such time as FEI no longer has an OSC exemption to use US GAAP or is no longer reporting under US GAAP for financial reporting purposes, whichever is earlier.

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 expand its Tilbury LNG Facility ("Tilbury Expansion Project") at Tilbury Island in Delta, BC. The 2013 OIC 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;
- to impose an upper limit of $400 million on capital costs related to the Tilbury Expansion Project; and
- to allow for recovery of the costs of the Tilbury Expansion Project from customers.

In December 2014, the BC Provincial government issued an Order of the Lieutenant Governor in Council ("2014 OIC") amending directions to the BCUC in the 2013 OIC. The 2014 OIC sets out a number of requirements for the BCUC as follows:

- to allow the Tilbury Expansion Project to proceed in two phases (Phase 1A and Phase 1B respectively), with Phase 1B proceeding if the Corporation obtains long-term sales contracts, taking a minimum 70 per cent of the liquefaction capacity of the Phase 1B, on average, for the first 15 years of its operation;

- to impose an upper limit of $400 million of capital costs plus construction carrying costs on each phase of the Tilbury Expansion Project;
- to exempt from a CPCN process the pipeline and compression facilities that would supply a third party operated LNG facility near Squamish, BC should such facility proceed;
- to exempt from a CPCN process the Coastal Transmission System ("CTS") projects which consist of four transmission line projects, three of which increase the Corporation's pipeline capacity within the Lower Mainland and one to increase the capacity to the Corporation's Tilbury LNG Facility;
- to provide the methodologies for regulatory treatment of certain of the costs of these various projects; and
- to provide clarifications on certain items in the 2013 OIC.

LMIPSU CPCN

In December 2014, the Corporation filed a CPCN application to replace certain sections of intermediate pressure pipeline segments within the Greater Vancouver area. The anticipated cost of the project is approximately $250 million with an expected in-service date of 2018. In October 2015, the BCUC approved the CPCN substantially as filed.

CONSOLIDATED RESULTS OF OPERATIONS

	Quarter			Year		
Periods Ended December 31	**2015**	2014	Variance	**2015**	2014	Variance
Gas sales (petajoules)	**62**	59	3	**186**	195	(9)
($ millions)						
Revenue	**456**	452	4	**1,353**	1,489	(136)
Expenses						
Cost of natural gas	**160**	208	(48)	**497**	646	(149)
Operation and maintenance	**72**	60	12	**231**	224	7
Depreciation and amortization	**48**	48	-	**194**	193	1
Property and other taxes	**15**	14	1	**61**	60	1
	295	330	(35)	**983**	1,123	(140)
Operating income	**161**	122	39	**370**	366	4
Finance charges	**73**	53	20	**181**	189	(8)
Earnings before income taxes	**88**	69	19	**189**	177	12
Income taxes	**12**	12	-	**38**	35	3
Net earnings	**76**	57	19	**151**	142	9
Net earnings attributable to non-controlling interests	**-**	-	-	**1**	1	-
Net earnings attributable to controlling interest	**76**	57	19	**150**	141	9

Net Earnings Attributable to Controlling Interest

The Corporation reported net earnings of $76 million for the three months ended December 31, 2015 and net earnings of $150 million for the twelve months ended December 31, 2015, compared to net earnings of $57 million and net earnings of $141 million in the corresponding periods of 2014.

Prior to 2015, the pre-amalgamation net earnings of FEVI were subject to the use of the RSDA as discussed above under Regulation. Effective January 1, 2015, the use of the RSDA ceased and net earnings are now subject to quarterly seasonal consumption differences which results in higher net earnings being recognized in the first and fourth quarters offset by lower net earnings in the second and third quarters. As a result of the discontinuance of the RSDA mechanism, net earnings for the three months ended December 31, 2015 were higher by approximately $9 million.

Pre-amalgamation FEVI and FEW net earnings in 2014 were based on a deemed equity component of capital structure of 41.5 per cent and an allowed ROE of 9.25 per cent for FEVI and 9.5 per cent for FEW. Effective January 1, 2015, the deemed equity component of capital structure and ROE reverted to that of FEI at 38.5 per cent and 8.75 per cent, respectively. As a result of this change, net earnings for the three and twelve months ended December 31, 2015 were $1 million and $4 million lower, respectively, compared to the corresponding periods in 2014, on an amalgamated basis.

In the first quarter of 2014, the Corporation recognized the one time retroactive effect to January 1, 2013 of the second stage of the GCOC decision which resulted in an additional $1 million of net earnings in that quarter.

In addition to the above, net earnings were higher for the three months ended December 31, 2015 due to a higher allowance for funds used during construction ("AFUDC"), the effects of the flow-through deferral amounts and higher tax savings from the current year's tax loss utilization plan ("TLUP"). Also, net earnings for the three months ended December 31, 2015 were higher due to the curving of revenue versus the incurrence of the related expenses, which was more pronounced in the fourth quarter of 2015 versus the same period in 2014. Expenses are generally incurred evenly throughout the year while revenue is recognized based on seasonal gas volumes. The increase is partially offset by lower operation and maintenance savings, net of the regulated Earnings Sharing Mechanism prescribed by the PBR Decision.

The increase in net earnings for the twelve months ended December 31, 2015 was primarily due to a higher AFUDC, the effects of the flow-through deferral amounts and higher operation and maintenance savings, net of the regulated Earnings Sharing Mechanism prescribed by the PBR Decision.

As part of the TLUP, the Corporation received dividend income from FHI relating to a $2,100 million (2014 - $1,400 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.

Gas Sales

For the three months ended December 31, 2015, gas sales volumes were higher compared to the corresponding period in 2014 primarily due to higher gas volumes for transportation customers due to certain transportation customers switching to natural gas compared to alternative fuel sources.

For the twelve months ended December 31, 2015, gas sales volumes were lower compared to the corresponding period in 2014 primarily due to lower average consumption in the first quarter by residential, commercial and transportation customers as a result of warmer weather.

Revenue and Cost of Natural Gas

For the three months ended December 31, 2015, revenues increased by $4 million, while for the twelve months ended December 31, 2015 revenues decreased by $136 million, respectively, compared to the corresponding periods in 2014.

Higher revenues for the three months ended December 31, 2015 were primarily due to higher revenue from the current year's TLUP, higher gas sales, the Earnings Sharing Mechanism, the discontinuance of the RSDA, a higher equity component of AFUDC and the effects of flow-through deferral amounts. This is partially offset by lower natural gas costs.

Lower revenues for the twelve months ended December 31, 2015 were primarily due to lower natural gas costs, lower gas sales and lower revenue from the current year's TLUP partially offset by a higher equity component of AFUDC.

For the three months ended December 31, 2015, cost of natural gas decreased by $48 million compared to the corresponding period in 2014. The decrease was primarily due to lower costs for natural gas partially offset by higher gas sales.

For the twelve months ended December 31, 2015, cost of natural gas decreased by $149 million compared to the corresponding period in 2014. The decrease was primarily due to lower costs for natural gas and lower gas sales.

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.

Operation and Maintenance Expense

For the three months and twelve months ended December 31, 2015, operation and maintenance expense increased by $12 million and $7 million, respectively, compared to the corresponding periods in 2014.

The increase for the three months was primarily due to higher contracting costs related to the operation of the natural gas pipelines, higher materials and supplies costs related to natural gas pipeline materials and higher information technology costs.

The increase for the twelve months was primarily due to higher facilities costs and higher contracting costs related to the operation of the natural gas pipelines and higher materials and supplies costs related to natural gas pipeline materials. This is partially offset by lower labour costs and lower bad debts.

Depreciation and Amortization

For the three months ended December 31, 2015, depreciation and amortization expense was comparable to the corresponding period in 2014, as higher depreciation expense due to the increase in the depreciable asset base of the Corporation was offset by lower amortization of regulatory asset deferral accounts.

For the twelve months ended December 31, 2015, depreciation and amortization expense increased by $1 million compared to the corresponding period in 2014. The increase was due to higher depreciation expense due to the increase in the depreciable asset base of the Corporation partially offset by lower amortization of regulatory asset deferral accounts.

Finance Charges

For the three months ended December 31, 2015, finance charges increased by $20 million compared to the corresponding period in 2014. The increase was primarily a result of the current year's TLUP generating higher interest expense in the fourth quarter of 2015 compared to the same period in 2014. This is partially offset by a higher debt component of AFUDC.

For the twelve months ended December 31, 2015, finance charges decreased by $8 million compared to the corresponding period in 2014. The decrease was primarily due to a higher debt component of AFUDC and the current year's TLUP generating lower interest expense compared to the same period in 2014.

Income Taxes

For the three months ended December 31, 2015, income tax expense was comparable to the corresponding period in 2014, as higher pre-tax earnings and higher taxable temporary differences were offset by higher income tax recovery from the current year's TLUP and lower taxable permanent differences.

For the twelve months ended December 31, 2015, income tax expense increased by $3 million compared to the corresponding period in 2014. The increase was primarily due to higher pre-tax earnings and higher taxable temporary differences partially offset by lower taxable permanent differences.

Net Earnings Attributable to Non-Controlling Interests

The Corporation, through its wholly owned subsidiary Mt. Hayes (GP) Ltd., owns an 85 per cent interest in the Mt. Hayes Storage Limited Partnership ("MHLP").

For the three and twelve months ended December 31, 2015 the net earnings attributable to non-controlling interest were comparable to the corresponding periods in 2014.

CONSOLIDATED FINANCIAL POSITION

The following table outlines the significant changes in the consolidated balance sheets between December 31, 2015 and December 31, 2014:

Balance Sheet Account	Increase (Decrease) ($ millions)	Explanation
Property, plant and equipment	**282**	The increase was primarily due to $439 million in capital expenditures incurred during the period partially offset by depreciation expense of $138 million and changes in non-cash capital accruals of $40 million. The increase was also due to a $13 million non-cash elimination of a contribution in aid of construction between FEVI and FEW.
Short-term notes	**90**	The increase was primarily due to an increase in the borrowings to finance the ongoing capital program and repay the Series A Purchase Money Mortgages partially offset by proceeds from the issuance of long-term debt and proceeds from the FEI equity issuance.
Common shares	**85**	The increase was due to the FEI equity issuance in the second quarter of 2015.
Long-term debt	**49**	The increase was primarily due to borrowings to finance the ongoing capital program partially offset by the repayment of the Series A Purchase Money Mortgages.
Accounts payable and other current liabilities	**(62)**	The decrease was primarily due to a reduction in capital accruals related to the Tilbury Expansion Project and a decrease in gas costs payable.

LIQUIDITY AND CAPITAL RESOURCES

Summary of Consolidated Cash Flows

Years Ended December 31,	**2015**	2014	Variance
($ millions)			
Cash flows provided by (used for):			
Operating activities	**365**	251	114
Investing activities	**(449)**	(321)	(128)
Financing activities	**77**	72	5
Net (decrease) increase in cash and cash equivalents	**(7)**	2	(9)

Operating Activities

Cash flows provided by operating activities were $114 million higher in 2015 compared to 2014 primarily due to changes in working capital partially offset by changes in long-term regulatory assets and liabilities.

Investing Activities

Cash used for investing activities was $128 million higher in 2015 compared to 2014 primarily due to increased property, plant and equipment expenditures related to the Tilbury Expansion Project.

Financing Activities

Cash provided by financing activities was $5 million higher in 2015 compared to 2014. The increase was primarily due to the issuance of long-term debt and the FEI equity issuance in the second quarter of 2015 partially offset by lower short-term notes borrowings, the repayment of long-term debt, and an increase in dividends paid.

On May 21, 2015, the Corporation issued 10,483,702 common shares to FHI for total proceeds of $85 million. The proceeds from the issuance were used to finance capital expenditures.

During 2015, the Corporation paid common share dividends of $134 million (2014 - $95 million) to its parent company, FHI. The year-to-date dividends include a one-time dividend to reduce the common equity component of the pre-amalgamation FEVI and FEW regulated capital structure from 41.5 per cent to 38.5 per cent.

Contractual Obligations

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

As at December 31, 2015	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	2,200	122	101	101	101	101	1,674
Long-term debt[1]	1,975	205	-	-	-	-	1,770
Gas purchase obligations (a)	1,333	321	228	205	139	126	314
Capital lease and finance obligations (b)	105	6	6	34	17	4	38
Power purchase obligations (c)	513	1	10	12	13	13	464
Defined benefit pension funding contributions (d)	14	14	-	-	-	-	-
Operating lease obligations (e)	12	3	3	3	2	1	-
Totals	6,152	672	348	355	272	245	4,260

[1] Excludes debt issuance costs of $13 million.

(a) The Corporation enters into contracts to purchase natural gas and natural gas transportation and storage services from various suppliers. These contracts are used to ensure that there is an adequate supply of natural gas to meet the needs of customers and to minimize exposure to market price fluctuations. The natural gas supply contract obligations are based on gas commodity indices that vary with market prices. The amounts disclosed reflect index prices that were in effect at December 31, 2015.

(b) Between 2000 and 2005, the Corporation entered into leasing arrangements whereby certain natural gas distribution assets were leased to certain municipalities and then leased back by the Corporation from the municipalities. The natural gas distribution assets are considered to be integral equipment to real estate assets and as such these transactions have been accounted for as financing transactions. The proceeds from these transactions have been recorded as a financial liability included in capital lease and finance obligations. Lease payments less the portion considered to be interest expense decrease the financial liability. The transactions have implicit interest rates between 6.82 per cent and 8.66 per cent and are being repaid over a 35 year period. Each of the arrangements allow the Corporation, at its option, to terminate the lease arrangements early, after 17 years. If the Corporation exercises this option, the Corporation would pay the municipality an early termination payment which is equal to the carrying value of the obligation on the Corporation's financial statements at that point in time.

(c) In March 2015, FEI entered into an Electricity Supply Agreement ("ESA") with British Columbia Hydro and Power Authority ("BC Hydro") which provides for BC Hydro to supply electrical service for the Tilbury Expansion Project Phase 1A. FEI's estimated contractual obligations under the ESA are disclosed in the table above as power purchase obligations.

(d) The Corporation sponsors defined benefit pension plans. Under the terms of these plans, the Corporation is required to provide pension funding contributions, including current service, solvency and special funding amounts. The contributions are based on estimates provided under the latest completed actuarial valuations. If the actuarial valuation falls in the next twelve months, then the Corporation has provided for an estimate of the contributions for the upcoming year. Employee defined benefit pension plan contributions beyond the date of the next actuarial valuation cannot be accurately estimated.

(e) The Corporation has entered into operating leases for certain building space.

In addition to the items in the table above, the Corporation has issued commitment letters to customers to provide Energy Efficiency and Conservation ("EEC") funding under the EEC Program approved by the BCUC. As at December 31, 2015, the Corporation had issued $33 million of commitment letters to customers.

In January 2012, two unrelated parties collectively purchased a 15 per cent equity interest in the MHLP, which at the time was a wholly owned limited partnership of FEVI. These non-controlling interest owners hold a put option which, if exercised, would oblige the Corporation to purchase the non-controlling interest owners' 15 per cent share in MHLP for cash. For rate-making purposes, this non-controlling interest is considered equity and if FEI was required to purchase this non-controlling interest, FEI would fund the transaction with an equity issuance. Accordingly, the Corporation has presented this redeemable non-controlling interest as equity.

Capital Structure

The Corporation's principal business of regulated natural gas transmission and distribution requires ongoing access to capital in order to allow the Corporation to fund the maintenance, replacement and expansion of infrastructure. The amalgamated Corporation effective January 1, 2015 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. Prior to the amalgamation and effective for 2014 the capital structure was: FEI – 38.5 per cent equity and 61.5 per cent debt, FEVI and FEW – 41.5 per cent equity and 58.5 per cent debt. This capital structure excludes the effects of goodwill and other items that do not impact the deemed capital structure.

Credit Ratings

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

The table below summarizes the ratings assigned to the Corporation's securities as at December 31, 2015:

Credit Ratings	**DBRS**	**Moody's**
Commercial paper	R-1 (Low), Stable Trend	-
Secured long-term debt	A, Stable Trend	A1, Stable Outlook
Unsecured long-term debt	A, Stable Trend	A3, Stable Outlook

Projected Capital Expenditures

The Corporation has estimated 2016 capital expenditures before contributions in aid of construction and including cost of removal of approximately $350 million. Capital expenditures include forecast 2016 costs associated with the Tilbury Expansion Project Phase 1A of approximately $100 million. The 2016 capital expenditures are necessary to provide service, public and employee safety and reliable transmission and distribution of natural gas to the Corporation's customer base.

Tilbury Expansion Project Phase 1A

In October 2014, FEI began construction on the expansion of its Tilbury LNG Facility in Delta, BC. The Tilbury Expansion Project Phase 1A is estimated to cost approximately $440 million including AFUDC and will include a new LNG storage tank and liquefier, both expected to be in service around the end of 2016. During the fourth quarter of 2015, project progress included the LNG storage tank roof air raise milestone, the liquefaction process area piping assembly and the beginning of equipment delivery to the site. The Tilbury Expansion Project is further discussed in the "Regulation - Directions to the BCUC" section of this MD&A.

Cash Flow Requirements

The Corporation's cash flow requirements fluctuate seasonally based 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 December 31, 2015, the Corporation had a $700 million syndicated credit facility available of which $256 million was unused. Prior to August 2015, FEI had two credit facilities in the amounts of $500 million and the legacy FEVI credit facility of $200 million. In August 2015, the principal amount of FEI's $500 million credit facility was increased to $700 million and the credit facility was extended by two years to mature in August 2018. The $200 million credit facility due to mature in December 2015 was cancelled in August 2015.

The following summary outlines the Corporation's credit facility:

($ millions)	**December 31, 2015**	December 31, 2014
Total credit facility	**700**	700
Short-term notes	**(391)**	(301)
Letters of credit outstanding	**(53)**	(50)
Credit facility available	**256**	349

Debentures

On April 1, 2015, 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 $1 billion. The establishment of the MTN Debenture Program has been approved by the BCUC.

On April 8, 2015, FEI entered into an agreement with the dealers listed in the Dealers Agreement to sell $150 million of unsecured MTN Debentures Series 26. The MTN Debentures Series 26 bear interest at a rate of 3.375 per cent to be paid semi-annually and mature on April 13, 2045. The closing of the issuance occurred on April 13, 2015, with net proceeds being used to repay existing short-term note indebtedness.

In September 2015, FEI's $75 million Series A Purchase Money Mortgages due September 30, 2015 were repaid with proceeds from short-term notes.

Dividend Restrictions

As part of its approval of the acquisition of FHI by Fortis, the BCUC imposed a number of conditions intended to ring-fence the Corporation from FHI. These restrictions included a prohibition on the payment of dividends unless the Corporation has in place at least as much common equity as that deemed by the BCUC for rate-making purposes. As a result of the decision issued by the BCUC, the Corporation must maintain a percentage of common equity to total capital that is at least as much as that determined by the BCUC from time to time for rate-setting purposes. In 2015 and 2014, none of these restrictions constrained the distribution of FEI earnings not otherwise needed for reinvestment.

OFF-BALANCE SHEET ARRANGEMENTS

As at December 31, 2015, the Corporation had no material off-balance sheet arrangements, with the exception of letters of credit outstanding of $53 million (2014 - $50 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, ultimate parent and other related companies under common control to provide or receive services and materials. The following transactions were measured at the exchange amount unless otherwise indicated.

Related Party Recoveries

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

($ millions)	**2015**	2014
Operation and maintenance expense charged to FBC (a)	**4**	4
Operation and maintenance expense charged to FHI (b)	**1**	1
Dividend income received from FHI (c)	**47**	50
	52	55

(a) The Corporation charged FBC for office rent and management services.

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

(c) As part of a TLUP, the Corporation received dividend income from FHI relating to a $2,100 million (2014 - $1,400 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 years ended December 31 were as follows:

($ millions)	**2015**	2014
Operation and maintenance expense charged by FBC (a)	**6**	5
Operation and maintenance expense charged by FHI (b)	**13**	13
Finance charges paid to FHI (c)	**-**	1
Finance charges paid to FHI (d)	**47**	50
	66	69

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

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

(c) FHI charged the Corporation interest expense on a $20 million promissory note. During 2014, FEW had promissory notes due to FHI bearing interest at 5.108 per cent. The notes were repaid in January 2015.

(d) As part of a TLUP, the Corporation paid FHI interest on $2,100 million (2014 - $1,400 million) of inter-company subordinated debt.

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 and current portion of long-term debt on the consolidated balance sheets, are as follows:

	2015		2014	
($ millions)	**Amount Due From**	**Amount Due To**	Amount Due From	Amount Due To
FHI	**1**	**1**	-	1
Debt due to FHI (a)	**-**	**-**	-	20
FBC	**-**	**-**	-	1
	1	**1**	-	22

(a) During 2014, FEW had a promissory note due to FHI bearing interest at 5.108 per cent. The note was repaid in January 2015.

In the fourth quarter of 2014, subject to a regulatory order from the BCUC, FEI transferred the thermal energy services deferral account to FAES, for net proceeds of approximately $12 million. The recovery has been shown as a reduction in long-term regulatory assets.

During the year ended December 31, 2014, FEVI borrowed demand notes from Fortis. The demand notes were unsecured, due on demand and FEVI was charged interest that approximated FEVI's cost of short-term borrowing. Final payment of the demand notes occurred during the fourth quarter of 2014.

In October 2014, FBC loaned $53 million by way of a demand note to FEVI. The demand note was unsecured, due on demand and FEVI was charged interest that approximated FEVI's cost of short-term borrowing. The demand note was repaid in November 2014.

BUSINESS RISK MANAGEMENT

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

Regulatory Approval and Rate Orders

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

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

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

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

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

Continued Reporting in Accordance with US GAAP

In January 2014, the OSC issued a relief order which permits the Corporation 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 the Corporation ceases to have activities subject to rate regulation; or (iii) the effective date prescribed by the IASB for the mandatory application of a standard within IFRS specific to entities with activities subject to rate regulation. In July 2014, the BCUC approved the Corporation's request to continue to use US GAAP for regulatory purposes effective January 1, 2015. This regulatory approval is granted until such time that the Corporation no longer has an OSC exemption to use US GAAP or is no longer reporting under US GAAP for financial reporting purposes, whichever is earlier. If the OSC relief does not continue as detailed above, the Corporation would then be required to become a United States Securities and Exchange Commission ("SEC") registrant in order to continue reporting under US GAAP or adopt IFRS.

The IASB has released an interim, optional standard on Regulatory Deferral Accounts and continues to work on a project focusing on accounting specific to rate-regulated activities. It is not yet known when this project will be completed or whether IFRS will, as a result, include a permanent mandatory standard to be applied by entities with activities subject to rate regulation. In the absence of a permanent standard for rate-regulated activities, adopting IFRS could result in volatility in the Corporation's earnings as compared to that which would otherwise be recognized under US GAAP.

Asset Breakdown, Operation, Maintenance and Expansion

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

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

Environment, Health and Safety Matters

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

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

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

The Corporation is exposed to various operational risks, such as pipeline leaks; accidental damage to mains and service lines; corrosion in pipes; pipeline or equipment failure; other issues that can lead to outages and/or leaks; and any other accidents involving natural gas, that could result in significant operational disruptions and/or environmental liability.

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

While the Corporation maintains insurance, the insurance is subject to coverage limits as well as time sensitive claims discovery and reporting provisions and there can be no assurance that the possible types of liabilities that may be incurred by the Corporation will be covered by insurance. See "Underinsured and Uninsured Losses" below.

Weather and Natural Disasters

A major natural disaster, such as an earthquake, could severely damage the Corporation's natural gas transmission, distribution and storage systems. In addition, the facilities of the Corporation could be exposed to the effects of severe weather conditions and other natural events. Although the Corporation's facilities have been constructed, operated and maintained to withstand severe weather, there is no assurance that they will successfully do so in all circumstances. Furthermore, many of these facilities are located in remote areas which make it more difficult to perform maintenance and repairs if such assets are damaged by weather conditions or other natural events. The Corporation operates facilities in remote and mountainous terrain with a risk of loss or damage from forest fires, floods, washouts, landslides, avalanches and similar natural events. The Corporation has limited insurance against storm damage and other natural disasters. In the event of a large uninsured loss caused by severe weather conditions or other natural disasters, application would be made to the BCUC for the recovery of these costs through higher rates to offset any loss. However, there can be no assurance that the BCUC would approve any such application. Losses resulting from repair costs and lost revenues could substantially exceed insurance coverage and any increased rates. Furthermore, the Corporation could be subject to claims from its customers for damages caused by the failure to transmit or distribute natural gas to them in accordance with the Corporation's contractual obligations. Thus, any major damage to the Corporation's facilities could result in lost revenues, repair costs and customer claims that are substantial in amount, and could, therefore, have a material adverse effect on the Corporation's results of operations and financial position.

Permits

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

Underinsured and Uninsured Losses

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

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

First Nations

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

The Supreme Court of Canada decided in 2010 that before issuing approvals for the addition of new facilities, the BCUC must consider whether the Crown has a duty to consult First Nations and to accommodate, if necessary, and if so whether the consultation and accommodation by the Crown have been adequate. This may affect the timing, cost and likelihood of the BCUC’s approval of certain of the Corporation’s capital projects.

Labour Relations

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

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

Employee Future Benefits

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

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

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

Human Resources

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

Information Technology Infrastructure

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

Cyber-Security

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

Interest Rates

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

While the current determination of the allowed ROE was set for the Corporation, until December 31, 2015, future proceedings to determine its ROE may consider the general level of interest rates as a factor for setting the ROE. If interest rates continue to remain at historically low levels, the allowed ROE may also decrease. The continuation of a low interest rate environment could adversely affect the Corporation's ability to earn a reasonable ROE, which in turn, could have a material adverse effect on the Corporation's results of operations and financial position.

Impact of Changes in Economic Conditions

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

Capital Resources and Liquidity

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

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

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

Competitiveness and Commodity Price Risk

In the Corporation's utility service territory natural gas primarily competes for space and hot water heating load with electricity. More recently there has been upward pressure on electricity rates in BC largely due to new investment required in the electric generation and transmission sector. In addition, the growth in North American natural gas supply, primarily from shale gas production, has resulted in a lower natural gas price environment. These factors have helped to improve natural gas competiveness on an operating basis. Nevertheless, upfront capital cost differences between electricity and natural gas equipment for hot water and space heating applications continue to present a challenge for the competiveness of natural gas on a fully-costed basis.

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

There are other competitive challenges that are impacting the penetration of natural gas into new housing stock such as green attributes of the energy source, and type of housing stock being built. In recent years, the Corporation has experienced a decline in the percentage of new homes installing natural gas compared with the total number of dwellings being built throughout BC.

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

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

Counterparty Credit Risk

The Corporation is exposed to credit risk in the event of non-performance by counterparties. The Corporation deals with reasonable credit-quality institutions in accordance with established credit approval practices. To date the Corporation has not experienced any material counterparty defaults and does not expect any counterparties to fail to meet their obligations; however, the credit quality of counterparties, can change rapidly.

Natural Gas Supply

The Corporation is dependent on a limited selection of pipeline and storage providers, particularly in the Lower Mainland, Interior and Vancouver Island. Regional market prices, particularly at the Sumas market hub, have been higher than prices elsewhere in North America during peak winter periods when regional pipeline and storage resources become constrained to serve the demand for natural gas in BC and the US Pacific Northwest.

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

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

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

NEW ACCOUNTING POLICIES

Simplifying the Presentation of Debt Issuance Costs

Effective October 1, 2015, the Corporation early adopted Accounting Standard Update ("ASU") No. 2015-03 that requires debt issuance costs to be presented on the consolidated balance sheet as a direct deduction from the carrying amount of debt liability, consistent with debt discounts or premiums. The adoption of this update was applied retrospectively and resulted in the reclassification of debt issuance costs of approximately $12 million from long-term other assets to long-term debt on the Corporation's consolidated balance sheet as at December 31, 2014. Additionally, the Corporation early adopted ASU No. 2015-15 that clarifies the presentation and subsequent measurement of debt issuance costs associated with line-of-credit arrangements. The update permits an entity to defer and present debt issuance costs as an asset and subsequently amortize the deferred debt issuance costs ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement. The adoption of this update was applied retrospectively and did not have a material impact on the Corporation's consolidated financial statements.

Balance Sheet Classification of Deferred Taxes

Effective October 1, 2015, the Corporation early adopted ASU No. 2015-17 that requires deferred tax assets and liabilities to be classified and presented as long-term on the consolidated balance sheet. The adoption of this update was applied retrospectively and resulted in the reclassification of current deferred income tax assets of approximately $1 million to long-term deferred income tax liability on the consolidated balance sheet as at December 31, 2014. As a result, the Corporation also reclassified current regulatory assets of $12 million and current regulatory liabilities of $12 million to long-term regulatory assets on the consolidated balance sheet as at December 31, 2014, all associated with regulatory deferred income taxes.

FUTURE ACCOUNTING PRONOUNCEMENTS

FEI considers the applicability and impact of all ASU's 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.

Revenue from Contracts with Customers

ASU No. 2014-09 was issued in May 2014 and the amendments in this update create Accounting Standard 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 completes a joint effort by FASB and the IASB to improve financial reporting by creating common revenue recognition guidance for US GAAP and IFRS that clarifies the principles for recognizing revenue and that can be applied consistently across various transactions, industries and capital markets. This standard was originally effective for annual and interim periods beginning after December 15, 2016 and is to be applied on a full retrospective or modified retrospective basis. ASU No. 2015-14 was issued in August 2015 and the amendments in this update defer the effective date of ASU No. 2014-09 by one year to annual and interim periods beginning after December 15, 2017. Early adoption is permitted as of the original effective date. The majority of FEI's revenue is generated from natural gas sales to customers based on published tariff rates, as approved by the BCUC, and is expected to be in the scope of ASU No. 2014-09. FEI has not yet selected a transition method and is assessing the impact that the adoption of this standard will have on its consolidated financial statements and related disclosures. FEI plans to have this assessment substantially complete by the end of 2016.

Amendments to the Consolidation Analysis

ASU No. 2015-02 was issued in February 2015 and the amendments in this update change the analysis that a reporting entity must perform to determine whether it should consolidate certain types of legal entities. Specifically, the amendments note the following with regard to limited partnerships: (i) modify the evaluation of whether limited partnerships and similar legal entities are variable interest entities or voting interest entities; and (ii) eliminate the presumption that a general partner should consolidate a limited partnership. This update is effective for annual and interim periods beginning after December 15, 2015 and may be applied using a modified retrospective approach or retrospectively. The adoption of this update is not expected to materially impact FEI's consolidated financial statements.

FINANCIAL INSTRUMENTS

Fair Value Estimates

The following table summarizes the fair value measurements of the Corporation's long-term debt and natural gas derivative contracts as of December 31, 2015 and 2014, all of which are Level 2 of the fair value hierarchy and recorded on the consolidated balance sheets at their carrying value:

	2015		2014	
($ millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Long-term debt, including current portion[1]	**1,975**	**2,393**	1,925	2,461
Natural gas supply contract premiums[2]	**17**	**17**	11	11

1 Carrying value excludes unamortized debt issuance costs of $13 million (2014 - $12 million). For the purposes of this disclosure, carrying value is used to approximate fair value for the promissory note and the repayable government loan.
2 Included in accounts payable and other current liabilities as at December 31, 2015 and 2014.

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 December 31, 2015, the Corporation's outstanding derivative balances, which consisted of natural gas supply contract premiums, were as follows:

($ millions)	**Gross Derivatives Balance[1]**	**Netting[2]**	**Cash Collateral**	**Total Derivatives Balance**
Natural gas supply contract premiums:				
Accounts payable and other current liabilities	**17**	**-**	**-**	**17**

1 See the December 31, 2015 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.

At December 31, 2014, the Corporation's outstanding derivative balances, which consisted of natural gas supply contract premiums, were as follows:

($ millions)	Gross Derivatives Balance[1]	Netting[2]	Cash Collateral	Total Derivatives Balance
Natural gas supply contract premiums:				
Accounts payable and other current liabilities	11	-	-	11

1 See the December 31, 2014 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 December 31, 2015 and 2014, with respect to all natural gas derivative contracts:

($ millions)	**2015**	2014
Unrealized loss on natural gas supply contract premiums [1,2]	**17**	11

1 Unrealized gains and losses on commodity risk-related derivative instruments are recorded in current regulatory assets or liabilities rather than being recorded to the consolidated statement of earnings.
2 These amounts are fully passed through to customers in rates. Accordingly, net earnings were not impacted by realized amounts on these instruments.

CRITICAL ACCOUNTING ESTIMATES

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

Regulation

Generally, the accounting policies of the Corporation's regulated operations are subject to examination and approval by the regulatory authority, the BCUC. These accounting policies may differ from those used by entities not subject to rate regulation. The timing of the recognition of certain assets, liabilities, revenues and expenses, as a result of regulation, may differ from that otherwise expected using US GAAP for entities not subject to rate regulation. Regulatory assets and regulatory liabilities arise as a result of the rate-setting process and have been recognized based on previous, existing or expected regulatory orders or decisions. Certain estimates are necessary since the regulatory environment in which the Corporation operates often requires amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. The final amounts approved by the regulatory authority for deferral as regulatory assets and regulatory liabilities and the approved recovery or settlement periods may differ from those originally expected. Any resulting adjustments to original estimates are recognized in earnings in the period in which they become known. In the event that a regulatory decision is received after the balance sheet date but before the consolidated financial statements are issued, the facts and circumstances are reviewed to determine whether or not it is a recognized subsequent event. As at December 31, 2015, the Corporation recognized $794 million in current and long-term regulatory assets (2014 - $786 million) and $186 million in current and long-term regulatory liabilities (2014 - $150 million).

Depreciation, Amortization and Removal Costs

Depreciation and amortization are estimates based primarily on the useful life of assets. Estimated useful lives are based on current facts and historical information and take into consideration the anticipated physical life of the assets. As at December 31, 2015, the Corporation's property, plant and equipment and intangible assets were $4,084 million, or approximately 67 per cent of total assets, compared to $3,814 million, or approximately 65 per cent of total assets, as at December 31, 2014. Changes in depreciation and amortization rates may have a significant impact on the Corporation's consolidated depreciation and amortization expense.

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

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

Capitalized Overhead

As required by the BCUC, the Corporation capitalizes overhead costs that may not be directly attributable to specific items of property, plant and equipment, but which relate to the overall capital expenditure program. These capitalized overheads are allocated over constructed property, plant and equipment and amortized over their estimated service lives. The methodology for calculating and allocating these general expenses to property, plant and equipment is established by the BCUC. In 2015, capitalized overhead totaled $33 million

(2014 - $33 million). Any change in the methodology of calculating and allocating general overhead costs to property, plant and equipment could have a significant impact on the amounts recorded as operating expenses and property, plant and equipment.

Assessment for Impairment of Goodwill and Indefinite-Lived Intangible Assets

The Corporation is required to perform, at least on an annual basis, an impairment test for goodwill, and any impairment provision is charged to earnings. The annual impairment test is performed as at October 1. In addition the Corporation also performs an impairment test if any event occurs or if circumstances change that would indicate that the fair value was below its carrying value. No such event or change in circumstances occurred during 2015 or 2014.

As at December 31, 2015, goodwill totaled $913 million (2014 - $913 million).

The Corporation performs an annual internal quantitative assessment and fair value is estimated by an independent external consultant when: (i) management's assessment of quantitative and qualitative factors indicates that fair value is not 50 per cent or more likely to be greater than carrying value; or (ii) the excess of estimated fair value compared to carrying value, as determined by an independent external consultant as of the date of the immediately preceding goodwill impairment test, was not significant. Irrespective of the above noted approach, the Corporation may have fair value estimated by an independent external consultant, as at the annual impairment date, at a minimum once every three years.

As at October 1, 2015, the Corporation chose to perform internal quantitative and qualitative assessments for goodwill and concluded that fair value was 50 per cent or more likely to be greater than carrying value. It was concluded that goodwill of the Corporation was not impaired.

Indefinite-lived intangible assets, not subject to amortization, consist of land and certain other transmission rights and totaled $51 million as at December 31, 2015 (2014 - $54 million).

Intangible assets with indefinite useful lives are tested for impairment annually or more frequently if events or changes in circumstances indicate the asset may be impaired.

The useful life of an intangible asset with an indefinite useful life is reviewed annually to determine whether the indefinite life assessment continues to be supportable. If not, the change in the useful life assessment from indefinite to finite is made on a prospective basis.

Based on the Corporation's assessment it was concluded the indefinite-lived intangible assets of the Corporation were not impaired.

Employee Future Benefits

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

The assumed long-term rate of return on the defined benefit pension plan assets, for the purpose of determining pension net benefit cost for 2015, was 6.41 per cent, which is comparable to the 6.40 per cent assumed long-term rate of return used for 2014.

The assumed discount rate, used to measure the projected pension benefit obligations on the measurement date of December 31, 2015, and to determine net pension cost for 2016, is 4.00 per cent, which is consistent with the assumed discount rate used to measure the projected benefit obligations as at December 31, 2014, and to determine net pension cost for 2015.

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

The Corporation expects net benefit pension cost for 2016 related to its defined benefit pension plans, prior to regulatory adjustments, to be approximately $7 million lower than in 2015. The lower net benefit pension cost is primarily due to an improvement in the funded status of the plans due to a combination of asset related gains and past service contributions being remitted to the plans.

The following table provides the sensitivities associated with a 100 basis point change in the expected long-term rate of return on pension plan assets and discount rate on 2015 net benefit pension cost, and the related projected benefit obligations recognized in the Corporation's consolidated financial statements:

Increase (decrease) ($ millions)	**Net Benefit Cost**	**Projected Benefit Obligation**
1% increase in the expected rate of return	(4)	-
1% decrease in the expected rate of return	3	(31)
1% increase in the discount rate	(13)	(105)
1% decrease in the discount rate	15	136

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

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

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

As at December 31, 2015, the Corporation had a pension projected benefit net liability of $86 million (2014 - $97 million) and an OPEB projected benefit liability of $118 million (2014 - $135 million). During 2015, the Corporation recorded pension and OPEB net benefit cost, inclusive of regulatory adjustments, of $32 million (2014 - $30 million).

Asset Retirement Obligations ("AROs")

The measurement of the fair value of AROs requires making reasonable estimates concerning the method of settlement and settlement dates associated with the legally obligated asset retirement costs. There are also uncertainties in estimating future asset-retirement costs due to potential external events, such as changing legislation or regulations and advances in remediation technologies. The Corporation does not currently have any identified AROs for which amounts have been recorded as at December 31, 2015 and 2014.

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

Revenue Recognition

The Corporation recognizes revenue on an accrual basis. Recording revenue on an accrual basis requires use of estimates and assumptions. Customer bills are issued throughout the month based on meter readings or estimates that establish natural gas consumption by customers since the last meter reading. The unbilled revenue accrual for the period is based on estimated natural gas sales to customers for the period since the last meter reading at the approved rates. The development of the sales estimates requires analysis of consumption on a historical basis in relation to key inputs, such as the current price of natural gas, population growth, economic activity, weather conditions and system losses. The estimation process for accrued unbilled natural gas consumption will result in adjustments to natural gas revenue in the periods they become known, when actual results differ from the estimates. As at December 31, 2015 the amount of accrued unbilled revenue recorded in accounts receivable was approximately $97 million (2014 - $102 million) on annual natural gas transmission and distribution revenues of $1,295 million (2014 - $1,435 million).

Income Taxes

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

Contingencies

Contingencies are described in the "Business Outlook" section of this MD&A.

SELECTED ANNUAL FINANCIAL INFORMATION

The following table sets forth audited financial information for the years ended December 31, 2015, 2014 and 2013. The financial information has been prepared in accordance with US GAAP. These results are not necessarily indicative of results for any future period and should not be relied upon to predict future performance.

Years Ended December 31	**2015**	2014	2013
($ millions)			
Revenues	**1,353**	1,489	1,428
Net earnings attributable to controlling interest	**150**	141	135
Total assets[2]	**6,084**	5,882	5,607
Long-term debt, excluding current portion[1,2]	**1,757**	1,808	1,882
Dividends on common shares	**134**	95	150

1 Excludes short-term notes.
2 2013 restated for reclassification of debt issuance costs of $13 million from long-term other assets to long-term debt.

2015/2014 – Revenues decreased $136 million over 2014 and net earnings increased $9 million over 2014. For a discussion of the reasons for the decrease in revenues and the increase in net earnings, refer to the "Consolidated Results of Operations" section of this MD&A. The increase in total assets was mainly due to capital expenditures (including those related to the Tilbury Expansion Project). Long-term debt decreased due the Series B Purchase Money Mortgages being classified as current long-term debt in 2015, the repayment of the Series A Purchase Money Mortgages, promissory note payable to FHI and the government loan repayable partially offset by the issuance of long-term debt. Dividends in 2015 include a one-time dividend to reduce the common equity component of the pre-amalgamation FEVI and FEW regulated capital structure from 41.5 per cent to 38.5 per cent.

2014/2013 – Revenues increased $61 million over 2013 and net earnings increased $6 million over 2013. Revenues increased primarily due to higher commodity costs and delivery rates in 2014 compared to 2013, higher revenue from the TLUP in 2014 and higher equity component of AFUDC. Net earnings increased primarily due to 2014 reflecting the GCOC stage two decision which increased the FEVI and FEW common equity component of capital structure, higher equity component of AFUDC and higher tax savings from the current year's TLUP. The increase in total assets was mainly due to capital expenditures (including those related to the Tilbury Expansion Project) and increased regulatory assets relating to deferred income taxes and defined benefit pension plans and OPEBs. Long-term debt is comparable to the prior year. Dividends in 2013 included a one-time dividend to reduce the common equity component of the pre-amalgamation FEI capital structure to 38.5 per cent from 40.0 per cent as a result of the BCUC decision on the first stage of the GCOC Proceeding.

SUMMARY OF QUARTERLY RESULTS

The following table sets forth unaudited quarterly information for each of the eight quarters ended March 31, 2014 through December 31, 2015. The information has been obtained from the Corporation's unaudited interim consolidated 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	**Revenue**	**Net Earnings (Loss)**
($ millions)		
December 31, 2015	456	76
September 30, 2015	177	(18)
June 30, 2015	229	6
March 31, 2015	491	87
December 31, 2014	452	57
September 30, 2014	238	(5)
June 30, 2014	286	12
March 31, 2014	513	78

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.

March 2015/2014 - Net earnings were higher primarily due to the discontinuance of the FEVI RSDA mechanism partially offset by a lower amalgamated ROE and deemed equity component of capital structure and the retroactive effect to January 1, 2013 of the GCOC decision stage two decision reflected in the first quarter of 2014.

June 2015/2014 – Net earnings were lower primarily due to the discontinuance of the FEVI RSDA mechanism, the curving of revenue versus the incurrence of the related expenses which was more pronounced in the second quarter of 2015 versus the same period in 2014, a lower amalgamated ROE and deemed equity component of capital structure and FEI having a TLUP in place in the second quarter of 2014 which generated lower tax expense, partially offset by operation and maintenance expense savings, net of the regulated Earnings Sharing Mechanism prescribed by the PBR Decision, and higher AFUDC.

September 2015/2014 – The higher net loss was primarily due to the discontinuance of the FEVI RSDA mechanism, lower tax savings from the current year's TLUP, and a lower amalgamated ROE and deemed equity component of capital structure, partially offset by operation and maintenance expense savings, net of the regulated Earnings Sharing Mechanism prescribed by the PBR Decision and higher AFUDC.

December 2015/2014 – Net earnings were higher primarily due to the discontinuance of the FEVI RSDA mechanism, higher tax savings from the current year's TLUP, the curving of revenue versus the incurrence of the related expenses which was more pronounced in the fourth quarter of 2015 versus the same period in 2014, higher AFUDC and the effects of the flow-through deferral amounts, partially offset by lower operation and maintenance savings, net of the regulated Earnings Sharing Mechanism prescribed by the PBR Decision and a lower amalgamated ROE and deemed equity component of capital structure.

BUSINESS OUTLOOK

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, 2017. 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 323,921,714 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.

For further information, please contact:

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