FortisBC Energy Inc.
Management Discussion & Analysis
For the Year Ended December 31, 2014
Dated February 19, 2015

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 2014 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, 2014, with 2013 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 ("LNG") Facility Expansion Project and associated in-service date; estimated costs and in-service date of the Lower Mainland Intermediate Pressure System upgrade; 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 and changes in the commodity cost of natural gas do not materially impact earnings as a result of regulatory deferral accounts; and the forecast average rate base for 2015.

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 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 benefits 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 ratings 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 rate risk; impact of changes in economic conditions risk; capital resources and liquidity risk; competiveness 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 (unless otherwise specified).

The Corporation is the largest distributor of natural gas in British Columbia ("BC"), serving approximately 967,000 residential, commercial and industrial and transportation customers in more than 125 communities. Major areas served by the Corporation are the Greater Vancouver, Fraser Valley, Thompson, Okanagan, Kootenay, North Central Interior, Vancouver Island, Sunshine Coast 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, a diversified, international distribution utility holding corporation having investments in distribution, transmission and generation utilities, as well as commercial real estate and hotel operations.

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 review and application to 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").

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 and the actual cost of service, 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.

The RSAM and MCRA accounts are either refunded to or recovered from customers in rates over 2 years with actual refunds dependent upon annually approved rates and actual gas consumption volumes. The CCRA account is anticipated to be fully recovered within the next fiscal year. As approved by the BCUC, the ending 2014 GCVA balance was transferred to the RSDA effective January 1, 2015 and the RSDA account will be 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 new 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 customer rates in the following year. This new deferral account replaced a number of other deferral accounts that existed prior to then, that captured such items as variances in interest rates, insurance and factors affecting income taxes. In addition to those items, 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 commodity and midstream charges. The commodity cost of natural gas and midstream costs are passed through to customers without mark-up.

In addition to annual delivery rate changes, the Corporation reviews natural gas and propane commodity and midstream 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 midstream resources such as third-party pipeline or storage capacity.

The table below shows the residential rate changes since January 1, 2013 for a typical Lower Mainland residential customer:

	2013				**2014**				
	Jan 1	April 1	July 1	Oct 1	**Jan 1**	**April 1**	**July 1**	**Oct 1**	**Nov 1**
Effective rate per gigajoule	$9.36	$9.36	$10.00	$9.36	**$9.69**	**$11.06**	**$11.06**	**$10.20**	**$10.22**
Percentage change in rate	1.6%	-	6.8%	(6.4%)	**3.5%**	**14.1%**	-	**(7.8%)**	**0.2%**

When comparing December 31, 2014 to December 31, 2013, an average bill for a Lower Mainland residential customer increased by approximately 9.2 per cent, due to an increase in natural gas and midstream costs and an increase in delivery rates.

Until December 31, 2014, FEVI customers had a bundled rate that had remained unchanged since January 1, 2010.

Application for Multi-year Performance Based Ratemaking Plan for 2014 to 2018 ("2014 PBR Application")

In June 2013, pre-amalgamation FEI filed its 2014 PBR Application with the BCUC. Pursuant to an Evidentiary Update filed in February 2014, the application assumed a forecast average rate base of approximately $2,778 million for 2014 and requested approval of a delivery rate increase for 2014 of 0.6 per cent determined under a formula approach for operation and maintenance costs and capital costs, and a continuation of this rate setting methodology for a further four years. Effective January 1, 2014, the BCUC provided approval for an interim refundable delivery rate increase of 1.4 per cent as determined in the Evidentiary Update filed in September 2013.

In September 2014, the BCUC issued its PBR Decision on FEI's 2014 PBR Application. As part of the PBR Decision the term of the PBR was extended to 2019. 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 approved 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.

In October 2014, pre-amalgamation FEI filed a PBR Decision Compliance Filing ("Compliance Filing") with the BCUC which updated the 2014 revenue requirements and rates based on the PBR Decision. The Compliance Filing updated the 2014 average rate base to approximately $2,765 million and the 2014 delivery rate increase to 1.8 per cent, compared to the existing interim delivery rate increase of 1.4 per cent discussed above. FEI has implemented permanent 2014 delivery rates, effective November 1, 2014, to reflect the additional delivery rate increase compared to interim rates. FEI will recover the January 2014 to October 2014 revenue deficiency between interim and permanent rates through a deferral mechanism.

In January 2015, FEI filed for approval of its 2015 rates under the PBR Decision. This filing assumes a forecast average rate base of approximately $3,656 million (excluding the separately approved rate base of approximately $12 million for Fort Nelson) and requests approval of a customer delivery rate increase of approximately 2 per cent determined under the PBR Plan formula approach for operation and maintenance costs, and capital costs. The regulatory process to review the application will continue through 2015, with a decision on the final rate increase expected in the second quarter of 2015.

Allowed ROE and Capital Structure

In February 2012, the BCUC established that a Generic Cost of Capital ("GCOC") Proceeding would occur.

The BCUC also determined that a second, subsequent stage be added to the GCOC proceeding to determine an appropriate ROE and capital structure for all other regulated utilities in BC, once the benchmark has been established in the first stage of the GCOC Proceeding. FEI has been designated as the benchmark utility. FEVI and FEW had their ROE risk premium and capital structure determined in the second stage.

Pursuant to a BCUC order released in December 2012, effective January 1, 2013, the approved 2012 ROE and capital structure for pre-amalgamation FEI, FEVI and FEW and all other regulated entities in BC that rely on the benchmark utility to establish rates, were to be maintained and made interim. In May 2013, the BCUC issued its decision on the first stage of the GCOC Proceeding. The decision determined that the ROE of the benchmark utility would be set at 8.75 per cent with a 38.5 per cent common equity component, both effective January 1, 2013. The common equity component of capital structure will remain in effect through December 31, 2015. Effective January 1, 2014, the BCUC has also introduced an Automatic Adjustment Mechanism ("AAM") to set the ROE on an annual basis for the benchmark utility. The AAM will take effect when the actual long-term Government of Canada bond yield exceeds 3.8 per cent. The AAM will be in effect until December 31, 2015. In January and December 2014, the BCUC confirmed that the necessary conditions for the AAM to be triggered for the 2014 and 2015 ROE respectively had not been met, therefore the benchmark ROE remains at 8.75 per cent for 2015.

Prior to the GCOC Proceeding, both FEVI and FEW had been approved for a common equity component of capital structure of 40 per cent and a ROE risk premium of 50 basis points over the benchmark utility. As a result of the BCUC's decision on the first stage of the GCOC Proceeding, which reduced the ROE of the benchmark utility by 75 basis points, the interim allowed ROE of FEVI and FEW decreased from 10 per cent to 9.25 per cent effective January 1, 2013, while the common equity component of the capital structure remained unchanged at 40 per cent. The 2013 interim allowed ROE and capital structure for FEVI and FEW was subject to potential further change as a result of the second stage of the GCOC Proceeding.

In March 2013, the BCUC initiated the second stage of the GCOC Proceeding. FEVI and FEW filed risk premium and equity ratio evidence in July 2013. In March 2014, the BCUC issued its decision on the second stage of the GCOC Proceeding, setting the common equity component of capital structure for FEVI and FEW at 41.5 per cent effective January 1, 2013. The BCUC reaffirmed for FEVI a ROE risk premium of 50 basis points over the benchmark utility and for FEW set its ROE risk premium at 75 basis points (25 basis points higher than the ROE risk premium that was in place prior to the decision) over the benchmark utility.

The resulting ROE for FEVI of 9.25 per cent and for FEW of 9.5 per cent was effective for 2013 and 2014.

Effective January 1, 2015, the ROE and common equity component of capital structure for the amalgamated FEI will be 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 ROE and common equity component of capital structure by no later than November, 30, 2015.

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 was due to expire effective 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 Corporations 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.

Lower Mainland Intermediate Pressure System Upgrade 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. The BCUC has established a regulatory preliminary review process for this application.

CONSOLIDATED RESULTS OF OPERATIONS

	Quarter			Year		
Periods Ended December 31	**2014**	2013	Variance	**2014**	2013	Variance
Gas sales (petajoules)	**59**	68	(9)	**195**	200	(5)
($ millions)						
Revenue	**452**	475	(23)	**1,489**	1,428	61
Expenses						
Cost of natural gas	**208**	214	(6)	**646**	600	46
Operation and maintenance	**60**	71	(11)	**224**	231	(7)
Depreciation and amortization	**48**	46	2	**193**	185	8
Property and other taxes	**14**	17	(3)	**60**	63	(3)
	330	348	(18)	**1,123**	1,079	44
Operating income	**122**	127	(5)	**366**	349	17
Finance charges	**53**	63	(10)	**189**	189	-
Earnings before income taxes	**69**	64	5	**177**	160	17
Income taxes	**12**	8	4	**35**	24	11
Net earnings	**57**	56	1	**142**	136	6
Net earnings attributable to non-controlling interest	**-**	**-**	-	**1**	1	-
Net earnings attributable to controlling interest	**57**	56	1	**141**	135	6

Gas Sales

For the three and twelve months ended December 31, 2014, gas sales volumes were lower compared to the corresponding period in 2013 primarily due to lower consumption by residential, commercial and transportation customers as a result of warmer weather.

Net Earnings Attributable to Controlling Interest

The Corporation reported net earnings of $57 million for the three months ended December 31, 2014 and net earnings of $141 million for the twelve months ended December 31, 2014, compared to net earnings of $56 million and net earnings of $135 million in the corresponding periods of 2013.

Pre-amalgamation FEI earnings for 2014 and 2013 were based on an allowed ROE of 8.75 per cent and a deemed equity component of capital structure of 38.5 per cent, which resulted from the BCUC decision on the first stage of the GCOC Proceeding received in May 2013.

FEVI and FEW were previously approved for a risk premium of 50 basis points over the benchmark utility. As a result of the BCUC's decision on the first stage of the GCOC Proceeding received in May 2013, which reduced the ROE of the benchmark utility by 75 basis points, the interim allowed ROE for FEVI and FEW correspondingly deceased by 75 basis points to 9.25 per cent effective January 1, 2013, while the deemed equity component of the capital structure remained unchanged. The allowed ROE and capital structure for FEVI and FEW was subject to further change as a result of the second stage of the GCOC Proceeding. As a result of the BCUC's decision on the second stage of the GCOC Proceeding received in the first quarter of 2014, the allowed ROE for 2013 and 2014 for FEVI was set at 9.25 per cent and for FEW was set at 9.5 per cent, effective January 1, 2013. The deemed equity component for FEVI and FEW increased to 41.5 per cent effective January 1, 2013 from 40.0 per cent previously.

The FEVI and FEW negative effect of the first stage of the GCOC decision was reflected in the second, third and fourth quarters of 2013, while the positive effect of the second stage of the GCOC decision retroactive back to January 1, 2013 was reflected in 2014.

The increase in net earnings of $1 million for the three months ended December 31, 2014, as compared to December 31, 2013, was primarily due to operation and maintenance expense savings, net of the regulated Earnings Sharing Mechanism as prescribed by the PBR Decision, and higher allowance for funds used during construction ("AFUDC"), partially offset by the effects of the flow-through deferral amounts and lower tax savings from the current year's tax loss utilization plan ("TLUP"). The TLUP in 2014 was wound-up in November 2014 whereas the TLUP in 2013 was wound-up in December 2013.

The increase in net earnings of $6 million for the twelve months ended December 31, 2014, as compared to December 31, 2013, was primarily due to 2014 reflecting the GCOC stage one and two decisions compared to 2013 reflecting only the GCOC stage one decision, higher AFUDC and higher tax savings from the current year's TLUP.

As part of the TLUP, the Corporation received dividend income from FHI relating to a $1,400 million (2013 - $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.

Revenue and Cost of Natural Gas

For the three months ended December 31, 2014, revenues decreased by $23 million, while for the twelve months ended December 31, 2014 revenues increased by $61 million, respectively, compared to the corresponding periods in 2013.

Lower revenues for the three months ended December 31, 2014 are primarily due to lower gas sales, the effects of flow-through deferral amounts, including the Earnings Sharing mechanism, and lower revenue from the current year's TLUP, partially offset by higher commodity costs and delivery rates and higher equity component of AFUDC.

Higher revenues for the twelve months ended December 31, 2014 are primarily due to higher commodity costs and delivery rates, higher revenue from the current year's TLUP and higher equity component of AFUDC, partially offset by lower gas sales and the effects of flow-through deferral amounts, including the Earnings Sharing mechanism.

For the three months ended December 31, 2014, cost of natural gas decreased by $6 million compared to the corresponding period in 2013 primarily due to lower gas sales, partially offset by higher costs for natural gas.

For the twelve months ended December 31, 2014, cost of natural gas increased by $46 million compared to the corresponding period in 2013 primarily due to higher costs for natural gas, partially offset by lower gas sales.

Operation and Maintenance Expense

For the three months and twelve months ended December 31, 2014, operation and maintenance expense decreased by $11 million and $7 million, respectively, compared to the corresponding periods in 2013. The decrease in operation and maintenance expense was primarily due to lower contracting costs and lower wage expense, partially offset by higher pension and other post-employment costs and a reduction in the allowed regulated rate of overhead capitalization as a result of the PBR Decision.

Depreciation and Amortization

For the three and twelve months ended December 31, 2014, depreciation and amortization expense increased by $2 million and $8 million, respectively, compared with the corresponding periods in 2013. The increase was due to higher amortization of regulatory asset deferral accounts and higher depreciation expense due to the increase in the depreciable asset base of the Corporation.

As approved by the BCUC, effective January 1, 2014, depreciation of property, plant and equipment and amortization of intangible assets commences the year after the asset is available for use. Prior to January 1, 2014, depreciation and amortization commenced in the month after the asset was available for use.

Finance Charges

For the three months ended December 31, 2014, finance charges decreased by $10 million compared to the corresponding period in 2013. The decrease was primarily a result of the timing of the current year's TLUP which generated lower interest expense in the fourth quarter of 2014 compared to the same period in 2013.

For the twelve months ended December 31, 2014, finance charges were comparable with the corresponding period in 2013, as higher interest expense from the current year's TLUP was offset by higher debt component of AFUDC and lower interest expense for pre-amalgamation FEVI due to lower short-term interest rates in the current year compared to 2013.

Income Taxes

For the three and twelve months ended December 31, 2014, income tax expense increased by $4 million and $11 million, respectively, compared to the corresponding periods in 2013.

The increase in income tax expense for the three months was mainly due to the current year's TLUP which generated a lower income tax recovery in the fourth quarter of 2014 compared to the fourth quarter of 2013.

The increase in income tax expense for the twelve months was mainly due to lower deductible temporary differences, higher pre-tax earnings and higher taxable permanent differences, partially offset by the current year's TLUP which generated a higher income tax recovery in 2014 compared to the TLUP that was in place during 2013.

Net Earnings Attributable to Non-Controlling Interest

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

For the three and twelve months ended December 31, 2014, the net earnings attributable to non-controlling interest was comparable with the corresponding periods in 2013.

CONSOLIDATED FINANCIAL POSITION

The following table outlines the significant changes in the consolidated balance sheets as at December 31, 2014 compared to December 31, 2013:

Balance Sheet Item	Increase ($ millions)	Explanation
Property, plant and equipment	**219**	The increase was primarily due to $302 million in capital expenditures incurred during 2014, changes in non-cash capital accruals of $47 million, and changes in non-cash contributions in aid of construction accruals of $8 million, partially offset by depreciation expense of $134 million.
Short-term notes	**174**	The increase was primarily due to an increase in the borrowings for investment in property, plant and equipment.
Regulatory assets	**86**	The increase in regulatory assets was primarily due to an increase in the US GAAP funded status deferral amount relating to the difference between the carrying value and the funded status of the Corporation's defined benefit plans and other post-employment benefit ("OPEB") plans due to a lower discount rate used in 2014, the offset of which is recognized in other liabilities, and a higher regulated asset for deferred income taxes due to an increase in temporary timing differences.
Other liabilities	**48**	See regulatory assets explanation above.
Accounts payable and other current liabilities	**44**	The increase was primarily due to an accrual for costs related to the Tilbury Expansion Project.

LIQUIDITY AND CAPITAL RESOURCES

Summary of Consolidated Cash Flows

Years Ended December 31	**2014**	2013	Variance
($ millions)			
Cash flows provided by (used for):			
Operating activities	**251**	293	(42)
Investing activities	**(321)**	(194)	(127)
Financing activities	**72**	(121)	193
Net increase (decrease) in cash and cash equivalents	**2**	(22)	24

Operating Activities

Cash flows provided by operating activities were $42 million lower in 2014 compared to 2013 primarily due to changes in long-term regulatory assets and liabilities and working capital.

Investing Activities

Cash used for investing activities was $127 million higher in 2014 compared to 2013 primarily due to increased property, plant and equipment expenditures.

Financing Activities

Cash provided by financing activities was $72 million in 2014, compared to cash used for financing activities of $121 million in 2013. The variance of $193 million was primarily due to an increase in short-term notes to finance the increased investment in property, plant and equipment which was partially offset by a decrease in dividends paid in 2014 as compared to 2013. 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 as a result of the BCUC decision on the first stage of the GCOC Proceeding.

During 2014, the Corporation paid common share dividends of $95 million (2013 - $150 million) to its parent company, FHI.

Contractual Obligations

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

As at December 31, 2014	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 on long-term debt	2,176	126	117	96	96	96	1,645
Debt retirement [1]	1,925	105	200	-	-	-	1,620
Natural gas supply contract obligations	194	194	-	-	-	-	-
Capital lease and finance obligations	112	6	6	6	7	33	54
Defined benefit pension plan funding contributions	30	17	13	-	-	-	-
Operating leases	15	3	3	3	3	2	1
Government loan	5	-	5	-	-	-	-
Totals	4,457	451	344	105	106	131	3,320

1. Included in debt retirement is $10 million of the FEVI government loan that was reclassed to current portion of long-term debt as it is due within 1 year.

The natural gas supply contract obligations as at December 31, 2014, which fix the price of natural gas, are based on current market rates. The measurement of these natural gas supply contract obligations will change based on the change in the value of the derivative which vary with market prices.

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 7.17 per cent and 8.76 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.

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.

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

In prior years, FEVI received non-interest bearing, repayable loans from the Federal and BC Provincial governments of $50 million and $25 million respectively, in connection with the construction and operation of the Vancouver Island natural gas pipeline. As approved by BCUC, these loans have been recorded as government grants and have reduced the amounts reported for utility capital assets. The Federal government loan was fully repaid in 2013. As at December 31, 2014, $15 million remains outstanding on the BC Provincial government loan, of which $10 million has been recognized in current portion of long term debt and $5 million has been charged against property, plant and equipment.

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, 2014, the Corporation had issued $26 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 will maintain a capital structure in line with the deemed 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 2013 and 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.

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 various securities as at December 31, 2014:

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

In June 2014, Moody's affirmed the long-term credit ratings of the Corporation of A1 for secured long-term debt and A3 for unsecured long-term debt and changed the ratings outlook to stable from negative.

In January 2015, DBRS affirmed the long-term credit ratings of the Corporation after the completion of the amalgamation on December 31, 2014.

Projected Capital Expenditures

The Corporation has estimated 2015 capital expenditures before contributions in aid of construction and including cost of removal of approximately $400 million. Capital expenditures include forecast 2015 costs associated with the Tilbury Expansion Project Phase 1A of approximately $170 million. The 2015 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 $400 million plus construction carrying costs and will include a second LNG tank and a new liquefier, both expected to be in service by the end of 2016. 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 working capital requirements fluctuate seasonally based on natural gas consumption. Given the regulated nature of its business, the Corporation is able to maintain negative working capital balances. The Corporation maintains adequate committed credit facilities.

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 Facilities

As at December 31, 2014, the Corporation had $700 million in syndicated credit facilities available of which $349 million was unused. The $500 million credit facility matures in August 2016 and the $200 million credit facility matures in December 2015.

The following summary outlines the Corporation's credit facilities:

($ millions)	**December 31, 2014**	December 31, 2013
Total credit facility	**700**	700
Short-term notes	**(301)**	(127)
Letters of credit outstanding	**(50)**	(50)
Credit facility available	**349**	523

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 2014 and 2013, none of these restrictions constrained the distribution of FEI earnings not otherwise needed for reinvestment.

OFF-BALANCE SHEET ARRANGEMENTS

As at December 31, 2014, the Corporation had no material off-balance sheet arrangements, with the exception of letters of credit outstanding of $50 million (2013 - $50 million).

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)	**2014**	2013
Operation and maintenance expense charged to FBC (a)	**4**	3
Operation and maintenance expense charged to FHI (b)	**1**	1
Other income recovered from FHI (c)	**50**	47
	55	51

(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 $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)	**2014**	2013
Operation and maintenance expense charged by FBC (a)	**5**	4
Operation and maintenance expense charged by FHI (b)	**13**	12
Finance charges paid to FHI (c)	**1**	1
Finance charges paid to FHI (d)	**50**	47
	69	64

(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 2013 and 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 $1,400 million (2013 - $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:

As at December 31	**2014**		2013	
($ millions)	**Amount Due From**	**Amount Due To**	Amount Due From	Amount Due To
FHI	**-**	**1**	2	-
Debt due to FHI	**-**	**20**	-	20
FBC	**-**	**1**	-	1
	-	**22**	2	21

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 late 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 late 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 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") Issuer in order to continue reporting under US GAAP or adopt IFRS.

The IASB has recently 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 would 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 or 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 endeavor 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 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

While the current determination of the allowed ROE is 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 facilities. 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

Prior to 2000, natural gas consistently enjoyed a substantial competitive advantage when compared with alternative sources of energy in BC. However, since the majority of electricity prices in BC were set based on the historical average cost (primarily hydroelectric dams) of production, rather than based on market forces, natural gas' competitive advantage was substantially eroded during the next decade. 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.

The Corporation employs various strategies to mitigate the exposure of customers' commodity rates to natural gas price volatility including supply diversity, natural gas storage, deferral account and rate setting mechanisms, and rate structures. The Corporation has also in the past used hedging tools involving derivative instruments. In 2011 the BCUC directed the Corporation to discontinue its hedging program while any pre-existing hedges were managed to expiry ending in 2014. The absence of such financial hedging tools may result in the Corporation's customers being more exposed to market price volatility on a go forward 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 to Asian markets. 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.

CHANGE IN ACCOUNTING ESTIMATE

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 plan. These capitalized overheads are allocated over constructed property, plant and equipment and are amortized over their estimated services lives. The methodology for calculating and allocating these general expenses to property, plant and equipment is established by the BCUC. As approved in the 2014 PBR Decision and effective January 1, 2014, on a prospective basis, the Corporation's capitalized overhead decreased from 14 per cent to 12 per cent of gross regulated operation and maintenance costs. This change was reflected as an approximately $5 million decrease in property, plant and equipment during 2014 and a corresponding increase to operation and maintenance costs and revenues approved to be collected from customers.

CHANGE IN ACCOUNTING POLICY

As approved in the PBR Decision and effective January 1, 2014, on a prospective basis, depreciation of property, plant and equipment and amortization of intangible assets commences at the beginning of the year following when the asset is available for use. Prior to January 1, 2014, depreciation and amortization commenced in the month after the asset was available for use.

FUTURE ACCOUNTING PRONOUNCEMENTS

Revenue from Contracts with Customers

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standard Update ("ASU") No. 2014-09, *Revenue from Contracts with Customers*. 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 update is effective for annual and interim periods beginning on or after December 15, 2016 and is to be applied on a full retrospective or modified retrospective basis. Early adoption is not permitted. FEI is assessing the impact that the adoption of this standard will have on its consolidated financial statements.

Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern

In August 2014, FASB issued ASU No. 2014-15, *Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern*. The amendments in this update are intended to provide guidance about management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and provide related disclosures. This update is effective for annual and interim periods beginning on or after December 15, 2016. Early adoption is permitted. FEI is assessing the impact that the adoption of this standard will have on its 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, 2014 and December 31, 2013, all of which are Level 2 of the fair value hierarchy and recorded on the consolidated balance sheets at their carrying value:

	2014		2013	
($ millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Long-term debt, including current portion[1]	**1,925**	**2,461**	1,925	2,279
Natural gas commodity swaps, options, basis swaps and supply contract premiums[2]	**11**	**11**	15	15

1. Includes unsecured debentures, purchase money mortgages, promissory notes and the current portion of the repayable government loans for which the carrying value is measured at cost and excludes credit facilities. For the purposes of this disclosure, carrying value is used to approximate fair value for the promissory note and the repayable government loans.
2. Included in accounts payable and other current liabilities as at December 31, 2014 and 2013.

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 31,2014, 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.

At December 31, 2013, the Corporation's outstanding derivative balances, which consisted of natural gas supply contract premiums and other natural gas derivative contracts, including commodity swaps, options and basis swaps, were as follows:

($ millions)	Gross Derivatives Balance[1]	Netting[2]	Cash Collateral	Total Derivatives Balance
Natural gas commodity swaps, options, basis swaps and supply contract premiums:				
Accounts payable and other current liabilities	15	-	-	15

1. See the December 31, 2013 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 losses at December 31, 2014 and 2013, with respect to all natural gas derivative contracts:

($ millions)	**2014**	2013
Unrealized loss on natural gas commodity swaps, options, basis swaps and supply contract premiums [1,2]	**11**	15

1. Unrealized gains and losses on commodity risk-related derivative instruments are recorded to 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 in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are recorded in the period they become known.

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 recorded 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 reported in earnings in the period in which they become known. As at December 31, 2014, the Corporation recorded $798 million in current and long-term regulatory assets (2013 - $712 million) and $162 million in current and long-term regulatory liabilities (2013 - $188 million).

Depreciation and Amortization

Depreciation property, plant and equipment and amortization of intangibles, by their nature, are an estimate 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, 2014, the Corporation's property, plant and equipment and intangible assets were $3,814 million, or approximately 65 per cent of total assets, compared to $3,598 million, or approximately 64 per cent of total assets, as at December 31, 2013. Changes in depreciation and amortization rates can have a significant impact on the Corporation's depreciation and amortization expense.

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

Goodwill and Indefinite-Lived Intangible Assets Impairment Assessment

Goodwill represents the excess, at the dates of acquisition, of the purchase price over the fair value of the net amounts assigned to individual assets acquired and liabilities assumed relating to business acquisitions. Goodwill is carried at initial cost less any write-down for impairment. As at December 31, 2014, goodwill totaled $913 million (2013 - $913 million).

To test goodwill for impairment, 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 criteria, the Corporation will have fair value estimated by an independent external consultant, as at the annual impairment date, at a minimum once every three years.

In addition to the annual impairment test, 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.

As at October 1, 2014, the fair value of the Corporation was estimated by an independent external consultant and estimated fair value was determined to be in excess of 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 $54 million as at December 31, 2014 (2013 - $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 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 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 2014, was 6.40 per cent, which is comparable to the 6.39 per cent assumed long-term rate of return used for 2013.

The assumed discount rate, used to measure the Corporation's projected pension benefit obligations on the measurement date of December 31, 2014, was 4.00 per cent, down from 4.75 per cent used on December 31, 2013. The decrease in discount rates reflects the decreased credit spreads and cost of capital on investment grade corporate bonds.

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 2015 related to its defined benefit pension plans, prior to regulatory adjustments, to be approximately $4 million higher than in 2014. The higher net benefit pension cost is primarily due to the effect of the decrease in the discount rates effective December 31, 2014, partially offset by increased investment returns.

The following table provides the sensitivities associated with a 100 basis point change in the expected long-term rate of return on plan assets and discount rate on 2014 net benefit pension cost and the projected pension benefit obligation recorded 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	2	(21)
1% increase in the discount rate	(10)	(111)
1% decrease in the discount rate	13	132

The above table reflects the changes before the effect of any regulatory deferral mechanism approved by the BCUC. The Corporation currently has in place BCUC approved mechanisms 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 pension net benefit cost and/or the projected pension benefit obligation were the average rate of compensation increase, assumed rates of retirement and assumed rates of mortality. 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.

As at December 31, 2014, the Corporation had a pension projected benefit net liability of $97 million (2013 - $71 million) and an OPEB projected benefit liability of $135 million (2013 - $112 million). During 2014, the Corporation recorded pension and OPEB net benefit cost, inclusive of regulatory adjustments, of $30 million (2013 - $20 million).

Asset Retirement Obligations ("AROs")

In measuring the fair value of AROs, the Corporation is required to make reasonable estimates concerning the method of settlement and settlement dates associated with the legally obligated asset retirement costs. The Corporation does not currently have any identified AROs for which amounts have been recorded as at December 31, 2014 and 2013. The nature, amount and timing of costs associated with land and environmental remediation and/or removal of assets cannot be reasonably estimated due to the nature of their operation; and applicable licenses, permits and laws are reasonably expected to be renewed or extended indefinitely to maintain the integrity of the related assets and to ensure the continued provision of service to customers. In the event that environmental issues are identified, or the applicable licenses, permits, laws or agreements are terminated, AROs will be recorded at that time provided the costs can be reasonably estimated.

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, 2014, the amount of accrued unbilled revenue recorded in accounts receivable was approximately $102 million (2013 - $111 million) on annual natural gas transmission and distribution revenues of $1,435 million (2013 - $1,378 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 the future tax rates that are expected to be in effect and management's assumptions regarding the expected timing of the reversal of such temporary differences. 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 recorded and charged against earnings in the period that the allowance is created or revised. Estimates of the provision for 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, 2014, 2013 and 2012. 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	**2014**	2013	2012
($ millions)			
Revenues	**1,489**	1,428	1,475
Net earnings attributable to controlling interest	**141**	135	145
Total assets	**5,907**	5,620	5,609
Current and long-term debt[1]	**1,925**	1,925	1,939
Common dividends paid	**95**	150	95

1. Excludes short term notes

2014/2013 – Revenues increased $61 million over 2013 and net earnings increased $6 million over 2013. For a discussion of the reasons for the increase in revenues and 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) and increased regulatory assets relating to deferred income taxes and defined benefit pension plans and OPEBs. Current and 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 as a result of the BCUC decision on the first stage of the GCOC Proceeding.

2013/2012 – Revenues decreased $47 million over 2012 and net earnings decreased $10 million over 2012. Revenues decreased due to lower cost of natural gas in 2013 compared to 2012. Revenue and earnings decreased due to the decrease in the allowed ROE and deemed equity component of capital structure for 2013 compared to 2012. Total assets and current and long-term debt are 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 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, 2013 through December 31, 2014. The information has been obtained from the Corporation's unaudited interim consolidated financial statements which, in the opinion of management, 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) Attributable to Controlling Interest**
($ millions)		
December 31, 2014	452	57
September 30, 2014	237	(6)
June 30, 2014	287	12
March 31, 2014	513	78
December 31, 2013	475	56
September 30, 2013	214	(11)
June 30, 2013	246	6
March 31, 2013	493	84

Due to the seasonal nature of the Corporation's natural gas transmission and distribution operations and its impact on, natural gas consumption patterns, the natural gas transmission and distribution operations of FEI normally generate higher net earnings in the first and fourth quarters and lower net earnings in the second quarter, which are partially offset by net losses in the third quarter. As a result of the seasonality, interim earnings are not indicative of earnings on an annual basis.

March 2014/2013 - Net earnings were lower primarily due to a lower allowed ROE and equity component of the capital structure and higher income taxes. The GCOC stage one decision reducing the allowed ROE and equity component of capital structure although effective January 1, 2013, was received in May 2013.

June 2014/2013 - Net earnings were higher primarily due to the retroactive negative impact of the GCOC stage one decision reflected in the second quarter of 2013 relating to the first quarter of 2013.

September 2014/2013 - The lower net loss was primarily due to the higher tax savings from the current year's TLUP. The TLUP in 2014 was put in place in the second quarter whereas the TLUP in 2013 was put in place in the third quarter.

December 2014/2013 – Net earnings were higher primarily due to operation and maintenance expense savings, net of the regulated Earnings Sharing Mechanism and higher AFUDC partially offset by the effects of the flow-through deferral amounts and lower tax savings from the current year's TLUP. The TLUP in 2014 was wound-up in November 2014 whereas the TLUP in 2013 was wound-up in December 2013.

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 employees in specified occupations in the areas of administration and operations support expires March 31, 2015. The second collective agreement representing customer service employees expires on March 31, 2017.

Contingencies

The Corporation was the plaintiff in a BC Supreme Court action against the City of Surrey ("Surrey") in which the Corporation sought the court's determination on the manner in which costs related to the relocation of a natural gas transmission pipeline would be shared between itself and Surrey. The relocation was required due to the development and expansion of Surrey's transportation infrastructure. The Corporation claimed that the parties had an agreement that dealt with the allocation of costs. In turn, Surrey advanced counterclaims including an allegation that the Corporation breached the agreement and that Surrey suffered damage as a result. In December 2013, the Court issued a decision which ordered the Corporation and Surrey to share equally the cost of the pipeline relocation. The Court also decided that Surrey was successful in its counterclaim that the Corporation breached the agreement. In December 2014, the Corporation and Surrey reached a settlement, resolving all pending claims and relief sought.

OUTSTANDING SHARE DATA

As at the filing date of this MD&A the Corporation had issued and outstanding 313,438,012 common shares, all of which are owned by FHI, a directly wholly-owned subsidiary of Fortis.

The Corporation is an indirect wholly-owned subsidiary of Fortis.

ADDITIONAL INFORMATION

Additional information about FortisBC Energy Inc., including its Annual Information Form, is available on SEDAR at www.sedar.com.

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