FortisBC Energy Inc.
Management Discussion & Analysis
For the Year Ended December 31, 2013
Dated February 6, 2014

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 2013 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 annual audited consolidated financial statements and notes thereto for the year ended December 31, 2013, with 2012 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., 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 LNG Facility Expansion Project and associated in-service date; 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 issues; 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 2014.

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; 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, operating, maintenance and expansion risk; environment, health and safety matters risk; weather and natural disasters risk; permits risk; underinsured and uninsured losses; risks involving First Nations; labour relations risk; employee future benefits risk; human resources risk; information technology infrastructure risk; cyber-security risk; interest rates risk; impact of changes in economic conditions risk; capital resources and liquidity risk; 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 OVERVIEW

The Corporation is the largest distributor of natural gas in British Columbia ("BC"), serving approximately 850,000 residential, commercial and industrial and transportation customers in more than 100 communities. Major areas served by the Corporation are Greater Vancouver, the Fraser Valley and the Thompson, Okanagan, Kootenay and North Central Interior 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 British Columbia Utilities Commission ("BCUC"). Pursuant to the *Utilities Commission Act* (British Columbia), the BCUC regulates such matters as tariffs, rates, construction, operations, financing and accounting.

FEI 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. In the past, the regulatory framework included 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, Quarterly Gas Cost Changes and Regulatory Applications

The Corporation's rates are based on estimates of several items, such as natural gas sales volumes, cost of natural gas, certain operating expenses and interest rates. 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.

The Corporation currently employs deferral accounts to address certain uncontrollable or non-routine items and to match costs incurred to the periods that the costs benefit. Two primary deferral mechanisms currently in place 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 throughout the year. This mechanism is called the Revenue Stabilization Adjustment Mechanism ("RSAM").

An interest rate deferral account is also in place to absorb interest rate fluctuations. The interest rate deferral account effectively fixed the interest rate on short-term funds attributable to the Corporation's regulated assets at 3.5 per cent during 2013 and 2.5 per cent for 2012.

In addition, the Corporation has other deferral accounts related to energy efficiency and conservation expenditures, certain operating expenses, such as property taxes, pension and other post-employment benefits ("OPEB") expenses and insurance, factors affecting income taxes, gains and losses on asset disposals, and certain other items.

Customer rates include both the delivery charge, and the commodity and midstream charges. The commodity cost of natural gas and midstream costs are flowed 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.

Overall, residential rates increased in 2013 as compared to 2012. The table below shows the rate changes since January 1, 2012 for a typical Lower Mainland residential customer:

	2012					**2013**			
	Jan 1	April 1	June 1	July 1	Oct 1	**Jan 1**	**April 1**	**July 1**	**Oct 1**
Effective rate per gigajoule	$10.39	$9.36	$9.21	$9.21	$9.21	**$9.36**	**$9.36**	**$10.00**	**$9.36**
Percentage change in rate	3.3%	(9.9%)	(1.6%)	-	-	**1.6%**	**-**	**6.8%**	**(6.4%)**

When comparing December 31, 2013 to December 31, 2012, an average bill for a FEI residential customer increased by approximately 1.6 per cent, due to increases in both the commodity cost of natural gas and the January 1, 2013 increase in delivery rates partially offset by a refund relating to the Generic Cost of Capital ("GCOC") decision described below.

In April 2012, the BCUC issued its decision on FEI, FEVI and FEW's 2012/2013 Revenue Requirements Application ("2012/2013 RRA"). For the Corporation the final approved delivery rate increase effective January 1, 2013 was 5.9 per cent (January 1, 2012 – 4.2 per cent).

In August 2011, the Corporation received a decision from the BCUC on the use of Energy Efficiency and Conservation ("EEC") funds as incentives for Natural Gas Vehicles ("NGV"). FEI had made these funds available to assist large customers to purchase NGV in lieu of vehicles fueled by diesel. The decision determined that it was not appropriate to use EEC funds for this purpose and the BCUC requested that FEI provide further submissions to determine the prudency of the EEC incentives at a future time. An application was filed with the BCUC to review the prudency of the EEC incentives and a decision was received on April 30, 2013 in which the BCUC determined the EEC incentives for NGV were prudently incurred and can be recovered from natural gas ratepayers, as part of the incentive program funding under the Greenhouse Gas Reductions (Clean Energy) Regulation ("GGRR") under the *Clean Energy Act* ("CEA") that was promulgated in May 2012.

In February 2012, the BCUC approved a general tariff for FEI to provide compressed natural gas ("CNG") and liquefied natural gas ("LNG") refueling services for transportation vehicles. FEI has received either permanent or interim rate approval for four refueling projects. In addition, FEI has received BCUC approval for rate treatment of expenditures under the GGRR. FEI has also received approval for one of two refueling stations applied for under the GGRR with a decision pending on the second refueling station.

The Corporation received a BCUC decision on changing its LNG sales and dispensing service rate schedule from a pilot program to a permanent program in June 2013. The decision did not approve the program as permanent, but extended the pilot program until the end of 2020, and set out the rate to be charged.

In November 2013, the Province signed an Order in Council ("Special Direction") setting out a number of requirements for the BCUC as follows:

- to allow FEI to provide CNG and LNG service as part of its natural gas service;
- to exempt the expansion of FEI's Tilbury LNG Facilities from a Certificate of Public Convenience and Necessity ("CPCN") process; and
- to approve a permanent LNG sales and dispensing service for FEI at the rate set out in the Special Direction.

In April 2012, the Corporation, together with FEVI and FEW, applied to the BCUC for the necessary approvals to amalgamate and implement postage stamp rates across the service territories served by the amalgamated entity for 2014. The evidentiary portion of the proceeding was closed in October 2012 and a decision was received in February 2013. In its decision, the BCUC denied the request to implement postage stamp rates. On March 27, 2013, the Corporation filed a Notice of Application for Leave to Appeal the decision with the BC Court of Appeal, and on April 26, 2013, the Corporation filed an Application for

Reconsideration with the BCUC. In June 2013, the BCUC determined that the reconsideration application would be heard. The regulatory process to review the reconsideration application was completed in November 2013 and a decision is expected in early 2014.

In June 2013, FEI filed an application for a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018. Pursuant to an Evidentiary Update filed on September 6, 2013, the application assumes a forecast average rate base for FEI of approximately $2,789 million for 2014 and requests approval of a delivery rate increase for 2014 of 1.4 per cent determined under a formula approach for operating and capital costs, and a continuation of this rate setting methodology for a further four years. Effective January 1, 2014, the BCUC has provided approval for a 1.4 per cent interim refundable rate increase. The regulatory process to review the application will continue through 2014, with a decision expected in the third quarter of 2014.

Allowed Return on Equity ("ROE") and Capital Structure

In February 2012, the BCUC established that a GCOC Proceeding would occur and in April 2012, issued a final scoping document identifying specific items that would be reviewed as part of the GCOC Proceeding.

Pursuant to a BCUC order released in December 2012, effective January 1, 2013, the approved 2012 ROE and capital structure for the Corporation and all other regulated entities in BC that rely on the benchmark utility, which was determined to be FEI, 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 in capital structure will remain in effect through December 31, 2015. Effective January 2014, the BCUC is also introducing an Automatic Adjustment Mechanism ("AAM") to set the ROE on an annual basis for the Corporation. 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 2014, the BCUC confirmed that the necessary conditions for the AAM to be triggered for the 2014 ROE have not been met, therefore the benchmark ROE remains at 8.75 per cent for 2014.

CONSOLIDATED RESULTS OF OPERATIONS

	Quarter Ended December 31			**Year Ended December 31**		
	2013	2012[1]	Variance	**2013**	2012	Variance
Gas sales (Petajoules (PJs))	**61**	55	6	**180**	179	1
($ millions)						
Revenue	**409**	388	21	**1,211**	1,266	(55)
Expenses						
Cost of natural gas	**190**	176	14	**531**	605	(74)
Operation and maintenance	**61**	63	(2)	**200**	196	4
Depreciation and amortization	**38**	32	6	**148**	128	20
Property and other taxes	**12**	13	(1)	**51**	50	1
	301	284	17	**930**	979	(49)
Operating income	**108**	104	4	**281**	287	(6)
Finance charges	**56**	57	(1)	**163**	164	(1)
Earnings before income taxes	**52**	47	5	**118**	123	(5)
Income taxes	**5**	1	4	**14**	11	3
Net earnings	**47**	46	1	**104**	112	(8)

[1] Certain comparative figures have been reclassified to conform to the current year's presentation.

Gas Sales

For the three months ended December 31, 2013, gas sales volumes were higher compared to the corresponding period in 2012 primarily due to higher consumption by residential, commercial and transportation customers as a result of colder weather.

For the twelve months ended December 31, 2013, gas sales volumes were higher compared to the corresponding period in 2012 primarily due to higher consumption by residential customers as a result of colder weather in the winter months partially offset by lower gas volumes for transportation customers due to certain transportation customers switching to alternative fuel sources compared to natural gas.

Net Earnings

As a result of the BCUC's decision on stage one of the GCOC Proceeding received in May of 2013, the allowed ROE for 2013 for the Corporation decreased to 8.75 per cent effective January 1, 2013 from 9.5 per cent in 2012. The deemed equity component for the Corporation decreased to 38.5 per cent effective January 1, 2013 from 40 per cent in 2012. The decision decreased net earnings for the three and twelve months ended December 31, 2013 by approximately $5 million and $12 million, respectively.

The Corporation reported net earnings of $47 million for the three months ended December 31, 2013 and net earnings of $104 million for the year ended December 31, 2013, compared to net earnings of $46 million and net earnings of $112 million, respectively, in the corresponding periods of 2012.

For the three months ended December 31, 2013, net earnings were higher primarily due to higher margin due to the timing of the recognition of customer demand, lower than forecasted finance charges, higher rate base and a higher allowance for funds used during construction partially offset by a lower allowed ROE in 2013 compared to 2012, a decrease in the equity component of the capital structure and higher income taxes.

For the twelve months ended December 31, 2013, net earnings were lower primarily due to a lower allowed ROE in 2013 compared to 2012, a decrease in the equity component of the capital structure, lower margin for transportation customers as compared to forecast and higher income taxes partially offset by lower than forecasted finance charges, lower operation and maintenance expense, higher rate base and a higher allowance for funds used during construction.

Revenue and Cost of Natural Gas

For the three months ended December 31, 2013, revenues increased by $21 million while for the twelve months ended December 31, 2013 revenues decreased by $55 million compared to the corresponding periods in 2012. For the three months ended December 31, 2013, cost of natural gas increased by $14 million while for the twelve months ended December 31, 2013 cost of natural gas decreased by $74 million compared to the corresponding periods in 2012.

Higher revenues and cost of natural gas for the three months reflect higher gas sales primarily due to colder weather. The higher revenues for the three months are also due to a higher delivery rate in 2013 compared to 2012 partially offset by the decrease in the allowed ROE and deemed equity component for 2013 compared to 2012.

Lower revenues and cost of natural gas for the twelve months is mainly due to a lower cost of natural gas in 2013 compared to the same period in 2012. Also, lower revenues for the twelve months is due to the decrease in the allowed ROE and deemed equity component for 2013 compared to 2012 partially offset by a higher delivery rate in 2013 compared to 2012.

Margin for the three and twelve months ended December 31, 2013 was higher compared to the comparable periods in 2012 mainly due to an increase in delivery rates which recognizes a higher rate base and higher allowance for funds used during construction partially offset by a lower allowed ROE and deemed equity component. The margin increase for the three months was also due to the timing of the recognition of customer demand. The margin increase for the twelve months is partially offset by lower margin for transportation customers as compared to forecast.

Changes in consumption levels of sales customers and changes in the commodity cost of natural gas do not materially impact earnings as a result of regulatory deferral accounts.

Operation and Maintenance Expense

For the three months ended December 31, 2013, operation and maintenance expense decreased by $2 million, while for the twelve months ended December 31, 2013 operation and maintenance expense increased by $4 million, respectively, compared to the corresponding periods in 2012. The decrease in operation and maintenance expense for the three months was mainly due to the timing of expenditures partially offset by higher contracting costs. The increase in operation and maintenance expense for the twelve months was mainly due to higher contracting costs and higher information technology support costs.

Depreciation and Amortization

As part of the 2012/2013 RRA decision, the BCUC ordered the Corporation to capture differences between actual depreciation and forecast depreciation in a deferral account.

For the three and twelve months ended December 31, 2013, depreciation and amortization expense increased by $6 million and $20 million, respectively, as compared with the corresponding periods in 2012. The increase was primarily due to higher amortization of regulatory deferral accounts and higher depreciation expense in 2013 as approved by the BCUC.

Finance Charges

For the three and twelve months ended December 31, 2013, finance charges decreased by $1 million in both periods, respectively, as compared with the corresponding periods in 2012. The decrease was primarily a result of a higher debt component of allowance for funds used during construction in 2013 compared to 2012.

Income Taxes

In the third quarter of 2013, the Corporation revised its estimated year-to-date income tax expense to reflect a change in the Canadian federal and BC provincial combined statutory rate from 25.0 per cent to 26.0 per cent effective April 1, 2013, resulting from legislation enacted in July 2013. Income tax expense reported for both the fourth quarter and year ended December 31, 2013 reflect the change in the statutory tax rate.

For the three and twelve months ended December 31, 2013, income tax expense increased by $4 million and $3 million, respectively, compared to the corresponding periods in 2012. The increase in income tax expense for the three months was primarily due to higher pre-tax earnings and higher taxable permanent differences offset by higher deductible temporary differences. The increase in income tax expense for the twelve months was mainly due to higher taxable permanent differences offset by lower pre-tax earnings and higher deductible temporary differences.

CONSOLIDATED FINANCIAL POSITION

The following table outlines the significant changes in the consolidated balance sheets as at December 31, 2013 compared to December 31, 2012:

Balance Sheet Item	**Increase (Decrease)** ($ millions)	**Explanation**
Property, plant and equipment	47	The increase was primarily due to approximately $143 million in capital expenditures incurred during the period, changes in non-cash capital accruals of $6 million and changes in non-cash contributions in aid of construction accruals of $3 million partially offset by depreciation expense of $106 million.
Short-term notes	54	The increase was primarily due to an increase in the borrowings to finance the ongoing capital program.
Other long-term liabilities	(27)	The decrease was primarily due to a decrease in pension and OPEB liabilities driven by increased investment returns and an increase in discount rates partially offset by changes in assumed rates of mortality.

LIQUIDITY AND CAPITAL RESOURCES

Summary of Consolidated Cash Flows

Years ended December 31	**2013**	2012[1]	Variance
($ millions)			
Cash flows provided by (used for):			
Operating activities	**230**	234	(4)
Investing activities	**(171)**	(173)	2
Financing activities	**(81)**	(56)	(25)
Net (decrease) increase in cash and cash equivalents	**(22)**	5	(27)

[1] Certain comparative figures have been reclassified to conform to the current year's presentation.

Operating Activities

Cash flow provided by operating activities which included the impact of changes in non-cash working capital, was $4 million lower in 2013 compared to 2012. The decrease was primarily due to changes in long-term regulatory assets and liabilities and changes in non-cash working capital partially offset by higher net earnings adjusted for non-cash items.

Investing Activities

Cash used in investing activities was $2 million lower in 2013 compared to 2012. The decrease was primarily due to a decrease in intangible asset and cost of removal expenditures partially offset by increased property, plant and equipment expenditures.

Financing Activities

Cash used for financing activities was $25 million higher in 2013 compared to 2012. The variance was primarily due to an increase in dividends paid during 2013 compared to 2012 and in the second quarter of 2012 there were proceeds from the issuance of common shares, with no comparable equity issuance in 2013. The increase was partially offset by increased short-term note borrowings in 2013.

During 2013, the Corporation paid common share dividends of $131 million (2012 - $85 million) to its parent companies.

In April 2012, the Corporation issued 1,900,000 common shares to its parent companies for total proceeds of $65 million.

Contractual Obligations

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

As at December 31, 2013	**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	1,791	105	105	97	76	76	1,332
Debt retirement and capital lease and finance obligations	1,664	7	82	207	7	34	1,327
Operating leases	16	3	3	3	2	2	3
Gas purchase obligations	292	244	48	-	-	-	-
Employee defined benefit pension plans	20	14	6	-	-	-	-
Totals	3,783	373	244	307	85	112	2,662

Gas purchase contract commitments are based on gas commodity indices that vary with market prices. The amounts disclosed reflect index prices that were in effect at December 31, 2013.

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 valuation.

If the actuarial valuation falls in the next 12 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.

In addition to the items in the table above, the Corporation has issued commitment letters to customers to provide EEC and NGV funding under the EEC and NGV programs approved by the BCUC. As at December 31, 2013, the Corporation had issued $23 million of commitment letters to customers.

The Corporation and FEVI have a 35 year storage and delivery agreement related to the Mt. Hayes storage facility located on Vancouver Island. Under the agreement, the Corporation will contract for at least two-thirds of the storage capacity and deliverability provided by the storage facility. FEVI may reduce the level of storage and delivery provided to the Corporation for the last 15 years of the agreement to reflect capacity required to serve customers on FEVI's pipeline system. The Corporation expects to pay approximately $16 million in demand charges in 2014 to FEVI for storage capacity at the Mt. Hayes storage facility.

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 7.20 per cent and 9.19 per cent and are being repaid over a 35 year period. Each of the arrangements allow for the assets to be turned back over to the municipalities at the end of 17 years. If the assets are turned back to the municipalities, the expected payment would be equal to the carrying value of the obligation on the Corporation's financial statements at that point in time.

Capital Structure

The Corporation's principal business of regulated natural gas transmission and distribution requires ongoing access to capital in order to allow the Corporation to fund the maintenance, replacement and expansion of infrastructure. The Corporation maintains a capital structure in line with the deemed capital structure approved by the BCUC at 38.5 per cent equity and 61.5 per cent debt (2012 – 40 per cent equity and 60 per cent debt).

Credit Ratings

Securities issued by the Corporation are rated by DBRS Inc. ("DBRS") and Moody's Investors Service, Inc. ("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 credit ratings assigned to the Corporation's various securities as at December 31, 2013:

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

In June 2013, Moody's affirmed the long-term credit ratings of the Corporation of A1 and A3 but changed the rating outlook from stable to negative.

Projected Capital Expenditures

The Corporation has estimated 2014 capital expenditures before contributions in aid of construction and including cost of removal of approximately $296 million. Capital expenditures include forecasted 2014 costs associated with the Tilbury LNG Facility Expansion Project of approximately $100 million. The 2014 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 LNG Facility Expansion Project ("Expansion Project")

In November 2013, the Province signed a Special Direction directing the BCUC to allow the Corporation to expand its LNG facilities at Tilbury Island in Delta, BC. The Expansion Project will increase the LNG production and storage capabilities at the Tilbury LNG Facility. The Special Direction set out a number of requirements for the BCUC as follows:

- to exempt the Expansion Project from a CPCN process;
- to impose an upper limit of $400 million on costs related to the Expansion Project; and
- to allow for recovery of the costs of the Expansion Project from customers.

The Expansion Project is expected to be put in service in 2016.

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 issues.

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 issues to meet its principal debt obligations when due.

Credit Facilities

As at December 31, 2013, the Corporation has a $500 million syndicated credit facility available of which $363 million was unused. In July 2013, the Corporation extended the maturity of its credit facility to mature in August 2015. The new agreement has substantially similar terms to the facility it replaced.

As at December 31	**2013**	2012
($ millions)		
Total credit facility	**500**	500
Short-term notes	**(87)**	(33)
Letters of credit outstanding	**(50)**	(51)
Credit facility available	**363**	416

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 2013 and 2012, none of these restrictions constrained the distribution of subsidiary earnings not otherwise needed for reinvestment.

OFF-BALANCE SHEET ARRANGEMENTS

As at December 31, 2013, the Corporation had no material off-balance sheet arrangements, with the exception of letters of credit outstanding of $50 million (2012 - $51 million).

RELATED PARTY TRANSACTIONS

In the normal course of business, the Corporation transacts with its 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:

Years Ended December 31	**2013**	2012
($ millions)		
Natural gas transmission and distribution revenue recovered from FEVI [(a)]	**3**	4
Operation and maintenance expense charged to FBC [(b)]	**3**	2
Operation and maintenance expense charged to FEVI [(c)]	**10**	9
Operation and maintenance expense charged to FHI [(c)]	**1**	2
Other income recovered from FHI [(d)]	**47**	46
	64	63

(a) The Corporation charged FEVI, a subsidiary of FHI, for transporting natural gas through the Corporation's pipeline system.

(b) The Corporation charged FBC, an indirect subsidiary of Fortis, for office rent and management services.

(c) The Corporation charged FHI and FEVI for management services, labour and materials.

(d) As part of a tax loss utilization plan ("TLUP"), the Corporation received dividend income from FHI relating to a $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.

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:

Years Ended December 31	**2013**	2012
($ millions)		
Natural gas storage costs charged by FEVI [(a)]	**16**	16
Operation and maintenance expense charged by FBC [(b)]	**4**	2
Operation and maintenance expense charged by FHI [(c)]	**12**	11
Finance charges paid to FHI [(d)]	**47**	46
	79	75

(a) FEVI charged the Corporation for storing natural gas at the Mt. Hayes LNG storage facility. These charges were included in regulatory liabilities on the consolidated balance sheets.

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

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

(d) As part of the TLUP described in Related Party Recoveries (d) above, the Corporation paid FHI interest on $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 accrued liabilities on the consolidated balance sheets, are as follows:

As at December 31	**2013**		2012	
($ millions)	**Amount Due From**	**Amount Due To**	Amount Due From	Amount Due To
FEVI	**2**	**-**	2	**-**
FEW	**1**	**-**	-	**-**
FHI	**2**	**-**	-	**-**
FBC	**-**	**1**	-	**-**
	5	**1**	2	**-**

The amounts are unsecured and non-interest bearing.

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 may be subject to negotiated settlement procedures in BC. Failing a negotiated settlement, rate applications may be pursued through a public hearing process. The BCUC has approved rates for 2012 and 2013. A decision from the BCUC on the Corporation's delivery rates for 2014 and proposed rate setting methodology for the next five years is expected in the third quarter of 2014. 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 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 and the Corporation intends to apply to the BCUC during 2014 to maintain US GAAP for regulatory purposes until December 31, 2018 or the earlier of (iii) above.

If the OSC relief does not continue as detailed above, the Corporation would then be required to become a U.S. 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, the application of IFRS at that time, could result in volatility in the Corporation's earnings as compared to that which would otherwise be recognized under US GAAP.

Asset Breakdown, Operating & Maintenance and Expansion Risk

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. 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

Approximately 70 per cent of the employees of the Corporation are 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 Risk

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 Risk

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 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 created by differences in the short and long-term interest rates, and the timing of long-term regulated debt issuances 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.

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.

Going forward, a decrease in natural gas production growth due to low market prices and increased demand due to industrial growth, coal plant retirements and the potential for LNG exports are factors that may lead to materially higher market natural gas prices and increased volatility. This has the potential to impact natural gas competitiveness over the longer term.

The Corporation employs various price risk management strategies to reduce the exposure of customers' commodity rates to natural gas price volatility. In the past these strategies have included the use of hedging tools involving both physical and financial transactions. As ordered by the BCUC, the Corporation discontinued most hedging activities by mid-2011, with existing hedges being managed to expiry. The absence of such hedging tools results in the Corporation's customers being more exposed to market price volatility on a go forward basis.

Government policy has also impacted the competitiveness and perception of the benefits of natural gas in BC. In 2008 the Government of BC introduced changes to energy policy including greenhouse gas emission reduction targets and a consumption tax on carbon-based fuels. It did not, however, 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 cost, will continue to exist in the future. An inability of the Corporation 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 to derivative instruments, including natural gas commodity swaps and options. 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 addition of the Mt. Hayes LNG Storage facility, located on Vancouver Island in 2011, helps 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. As BC has significant natural gas resources, it is uncertain at this time what effect this increase in demand could have on regional market prices and infrastructure development.

There can be no assurance that the current regulatory-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.

CHANGES IN ACCOUNTING POLICIES

The following new US GAAP accounting pronouncement that is applicable to, and was adopted by, the Corporation effective January 1, 2013 is described as follows:

Disclosures About Offsetting Assets and Liabilities

The Corporation adopted the amendments to Accounting Standards Codification ("ASC") Topic 210, *Balance Sheet - Disclosures About Offsetting Assets and Liabilities* as outlined in Accounting Standards Update ("ASU") Nos. 2011-11 and 2013-01. The amendments improve the transparency of the effect or potential effect of netting arrangements on a company's financial position by expanding the level of disclosures required by entities for such arrangements. The amended disclosures are intended to assist financial statement users in understanding significant quantitative differences between balance sheets prepared under US GAAP and IFRS. ASU No. 2013-01 limits the scope of the new offsetting disclosure requirements previously issued in ASU No. 2011-11, to certain derivative instruments, repurchase and reverse repurchase agreements, and securities borrowing and lending arrangements that are either offset on the balance sheet or subject to an enforceable master netting or similar arrangement. The above-noted amendments were applied retrospectively and did not impact the Corporation's consolidated financial statements for the years ended December 31, 2013 and 2012.

FINANCIAL INSTRUMENTS

Fair Value Estimates

The following table summarizes the fair value measurements of the Corporation's long-term debt and natural gas commodity derivative contracts as of December 31, 2013 and 2012, all of which are Level 2 of the fair value hierarchy and recorded on the consolidated balance sheet at their carrying value:

As at December 31	**2013**		2012	
($ millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Long-term debt	**1,545**	**1,842**	1,545	2,039
Natural gas commodity swaps and options and gas purchase contract premium[1]	**3**	**3**	26	26

[1] Included in accounts payable as at December 31, 2013 and 2012.

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, 2013, the Corporation's outstanding derivative balances were as follows:

($ millions)	**Gross Derivatives Balance[1]**	**Netting[2]**	**Cash Collateral**	**Total Derivatives Balance**
Natural gas commodity derivatives:				
Accounts payable and accrued liabilities	**3**	**-**	**-**	**3**

[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.

At December 31, 2012, the Corporation's outstanding derivative balances were as follows:

($ millions)	Gross Derivatives Balance[1]	Netting[2]	Cash Collateral	Total Derivatives Balance
Natural gas commodity derivatives:				
Accounts payable and accrued liabilities	26	-	-	26

[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 unrealized losses at December 31, 2013 and 2012, with respect to the derivative instruments:

As at December 31	**2013**	2012
($ millions)		
Unrealized loss on natural gas commodity derivatives[1,2]	**3**	26

[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. 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, 2013, the Corporation recorded $578 million in current and long-term regulatory assets (December 31, 2012 - $589 million) and $94 million in current and long-term regulatory liabilities (December 31, 2012 - $90 million).

Depreciation and Amortization

Depreciation and amortization, 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, 2013, the Corporation's property, plant and equipment and intangible assets were $2,773 million, or approximately 62 per cent of total assets, compared to $2,725 million, or approximately 61 per cent of total assets, as at December 31, 2012. 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.

Capitalized Overhead

As required by the BCUC, the Corporation capitalizes overhead costs that may not be directly attributable to specific items of property, plant and equipment, but which relate to the overall capital expenditure program. These capitalized overheads are allocated over constructed property, plant and equipment and amortized over their estimated service lives. The methodology for calculating and allocating these general expenses to property, plant and equipment is established by the BCUC. In 2013, capitalized overhead totaled $33 million (2012 - $32 million). Any change in the methodology of calculating and allocating general overhead costs to property, plant and equipment could have a significant impact on the amounts recorded as operating expenses and property, plant and equipment.

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, 2013 goodwill totaled $769 million (2012 - $769 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) when 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 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 of the Corporation was below its carrying value.

As at October 1, 2013, 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 $45 million as at December 31, 2013 (2012 - $45 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 2013, was 6.38 per cent, which is a decrease from the assumed long-term rate of return of 6.62 per cent which was used for 2012.

The assumed discount rate, used to measure the Corporation's projected pension benefit obligations on the measurement date of December 31, 2013 was 4.75 per cent, up from 4.00 per cent used on December 31, 2012. The increase in discount rates reflects the increased 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 2014 related to its defined benefit pension plans, prior to regulatory adjustments, to be approximately $5 million lower than in 2013. The lower net benefit pension cost is primarily due to increased investment returns in 2013, the effect of the increase in the discount rates effective December 31, 2013 partially offset by changes in assumed rates of mortality.

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 2013 net benefit cost and the projected 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	5	48
1% decrease in the expected rate of return	(4)	(39)
1% increase in the discount rate	(11)	(75)
1% decrease in the discount rate	13	93

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 obligations.

As at December 31, 2013, the Corporation had a pension projected benefit liability of $63 million (2012 - $86 million) and an OPEB projected benefit liability of $100 million (2012 - $103 million). During 2013, the Corporation recorded pension and OPEB net benefit cost, inclusive of regulatory adjustments, of $18 million (2012 - $19 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, 2013 and 2012. 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 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, 2013, the amount of accrued unbilled revenue recorded in accounts receivable was approximately $94 million (2012 - $97 million) on annual natural gas transmission and distribution revenues of $1,162 million (2012 - $1,218 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, 2013, 2012 and 2011. 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	**2013**	2012	2011
($ millions)			
Revenues	**1,211**	1,266	1,392
Net earnings	**104**	112	110
Total assets	**4,464**	4,443	4,438
Long-term debt[1]	**1,545**	1,545	1,545
Common dividends paid	**131**	85	85

[1] Excluding current portion of long-term debt.

2013/2012 – Revenues decreased $55 million and net earnings decreased $8 million compared to 2012. For a discussion of the reasons for the decrease in revenues and net earnings, refer to the "Consolidated Results of Operations" section of this MD&A. The increase in assets was mainly due to capital expenditures partially offset by a decrease in cash and cash equivalents. Long-term debt is comparable to the prior year. The

increase in dividends was due to the GCOC Stage One Decision which reduced the equity component of FEI's capital structure from 40 per cent to 38.5 per cent.

2012/2011 – Revenues decreased $126 million over 2011. The decrease in revenue was primarily due to lower gas sales volumes due to warmer weather and lower natural gas costs in 2012 compared to 2011 partially offset by higher gas volumes for transportation customers, higher rate base and higher revenue from the TLUP. Net earnings increased $2 million over 2011. The increase was primarily due to increased rate base, higher margin from transportation customers, higher contribution from the current year TLUP and lower than forecast operation and maintenance expenditures partially offset by lower margin associated with lower than forecast customer additions in 2012 and lower capitalized allowance for funds used during construction compared to the same period in 2011. The increase in assets was mainly due to capital expenditures partially offset by a decrease in accounts receivable due to a lower price of natural gas and lower sales volumes as compared to the same period in 2011. Long-term debt and dividends are comparable to the prior year.

SUMMARY OF QUARTERLY RESULTS

The following table sets forth unaudited quarterly information for each of the eight quarters ended March 31, 2012 through December 31, 2013. 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)**
($ millions)		
December 31, 2013	409	47
September 30, 2013	173	(17)
June 30, 2013	200	(1)
March 31, 2013	429	75
December 31, 2012	388	46
September 30, 2012	170	(10)
June 30, 2012	223	4
March 31, 2012	485	72

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 2013/2012 - Earnings have increased quarter over quarter primarily due to higher rate base and higher margin from industrial customers partially offset by lower margin associated with lower than forecast customer additions and higher income taxes.

June 2013/2012 - Earnings were lower primarily due to the retroactive impact of a lower allowed ROE in 2013 compared to 2012, the retroactive impact of the decrease in the equity component of the capital structure, a decrease in margin from industrial customers and lower margin associated with lower than forecast customer additions partially offset by higher rate base and lower income taxes.

September 2013/2012 – The higher net loss was primarily due to higher operation and maintenance expense due to the timing of the expenditures, a lower allowed ROE in 2013 compared to 2012, a decrease in the equity component of the capital structure and lower margin associated with lower than forecast customer additions partially offset by higher rate base.

December 2013/2012 – Net earnings were higher primarily due to higher margin due to the timing of the recognition of customer demand, lower than forecasted finance charges, higher rate base and a higher allowance for funds used during construction partially offset by a lower allowed ROE in 2013 compared to 2012, a decrease in the equity component of the capital structure and higher income taxes.

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, 2015. 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 COPE collective agreement representing customer service employees expires on March 31, 2014.

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. The amount of damages which may be awarded to Surrey at a subsequent hearing cannot be reasonably determined or estimated at this time and, accordingly, no amount has been accrued in the financial statements.

OUTSTANDING SHARE DATA

As at the filing date of this MD&A the Corporation had issued and outstanding 64,910,782 common shares.

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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