FORTIS BC

FORTISBC ENERGY INC.

MANAGEMENT DISCUSSION & ANALYSIS

For the quarter and nine months ended September 30, 2024

November 4, 2024

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 2024 and comparative periods contained in the following MD&A has been prepared in accordance with accounting principles generally accepted in the United States of America ("US GAAP") and is presented in Canadian dollars. The MD&A should be read in conjunction with the Corporation's Unaudited Condensed Consolidated Interim Financial Statements and notes thereto for the quarter and nine months ended September 30, 2024, prepared in accordance with US GAAP and the Corporation's Annual Audited Consolidated Financial Statements and notes thereto together with the MD&A for the year ended December 31, 2023, with 2022 comparatives, prepared in accordance with US GAAP.

In this MD&A, FHI refers to the Corporation's parent, FortisBC Holdings Inc., FBC refers to FortisBC Inc., FAES refers to FortisBC Alternative Energy Services Inc., ACGS refers to Aitken Creek Gas Storage ULC, and Fortis refers to the Corporation's ultimate parent, Fortis Inc. On November 1, 2023, FHI sold its ownership of ACGS to an entity not related to Fortis, after which ACGS ceased to be a related party to the Corporation.

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. Any capitalized terms in this Forward-Looking Statement section that are not otherwise defined in this section are as defined in this MD&A.

The forward-looking information in this MD&A includes, but is not limited to, the expectation that the British Columbia Utilities Commission will issue its decision with respect to FEI and FBC's Rate Framework application in mid-2025; statements regarding the Corporation's expected level of capital expenditures, including forecasted project costs, and its expectations to finance those capital expenditures through credit facilities, equity injections from FHI and debenture issuances; the Corporation's estimated contractual obligations; expected expenditures as rate base additions resulting from the Corporation's DSM Expenditures Plan including the timing of such expenditures; the expectation that the British Columbia Utility Commission's decision with respect to FEI's proposed amendments to its RNG Program, in combination with the announced changes to provincial biomethane legislation, will minimize any potential future carbon tax liability on unsold biomethane inventory; the expectation that any applicable Accounting Standards Updates issued by the Financial Accounting Standards Board that are not mentioned in this MD&A will not have a material impact on the disclosure to the Corporation's consolidated financial statements; and the expectation that the EIFEL Proposals will not have a material impact on the Corporation's financial results.

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 (including absence of administrative monetary penalties); the competitiveness of natural gas pricing when compared with alternate sources of energy; continued demand for natural gas; absence of climate change impacts; absence of adverse weather conditions and natural disasters; absence of environmental, health and safety issues; the ability to maintain, replace or expand the Corporation's assets; the availability of natural gas supply; the ability to obtain and maintain applicable permits; that the Indigenous engagement process will not delay or otherwise impact the Corporation's ability to obtain government or regulatory approvals; the adequacy of the Corporation's existing insurance arrangements; the ability to arrange sufficient and cost effective financing (including absence of adverse rating actions by credit rating agencies); absence of interest costs risks; continued energy demand, population growth and new housing starts; the absence of counterparty credit risk; the ability of the Corporation to attract and retain a skilled workforce; the ability to maintain and renew collective bargaining agreements on acceptable terms; no material change in employee future benefit costs; absence of information technology infrastructure failure; absence of cybersecurity failure; absence of pandemic and public health crises impacts; the ability to continue to report under US GAAP beyond the Canadian securities regulators exemption to 2027 or earlier; and the absence of damages, fines, or penalties arising from legal, administrative and other proceedings.

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); natural gas competitiveness risk; commodity price risk; climate change risk; weather and natural disasters risk; environment, health and safety matters risk; asset breakdown, operation, maintenance and expansion risk; natural gas supply risk; permits risk; risks related to Indigenous rights and engagement; underinsured and uninsured losses; capital resources and liquidity risk; interest costs risk; impact of changes in economic conditions risk; counterparty credit risk; human resources risk; labour relations risk; employee future benefits risk; information technology infrastructure risk; cybersecurity risk; pandemic and public health crises risk; continued reporting in accordance with US GAAP risk; legal, administrative and other proceedings risk; and other risks described in the Corporation's most recent Annual Information Form ("AIF"). For additional information with respect to these risk factors, reference should be made to the "Business Risk Management" section of the Corporation's MD&A and AIF for the year ended December 31, 2023.

All forward-looking information in this MD&A is qualified in its entirety by this cautionary statement and, except as required by law, the Corporation undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise after the date hereof.

CORPORATE OVERVIEW

The Corporation is the largest distributor of natural gas in British Columbia ("BC"), serving approximately 1,093,200 residential, commercial, industrial, and transportation customers through approximately 51,600 kilometers of natural gas pipelines. The Corporation provides transmission and distribution services to its customers and obtains natural gas and renewable 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 rates, construction plans, and financing.

The Corporation is an indirect, wholly owned subsidiary of Fortis, a leader in the North American regulated electric and natural gas utility industry. Fortis shares are listed on both the Toronto Stock Exchange and the New York Stock Exchange.

REGULATION

Allowed Return on Equity and Capital Structure

In September 2023, the BCUC issued its decision on Stage 1 of the Generic Cost of Capital ("GCOC") Proceeding ("GCOC Stage 1 Decision") for FEI and FBC. In its decision, the BCUC determined that FEI's deemed equity component of capital structure and allowed ROE will change from 38.5 per cent and 8.75 per cent to 45 per cent and 9.65 per cent, respectively, effective January 1, 2023. The 2023 year-to-date net impact of the change in cost of capital was recognized in the third quarter of 2023. The BCUC also determined that neither a formulaic ROE automatic adjustment mechanism nor specific criteria or other triggers for future cost of capital proceedings are warranted, and instead will remain in effect until otherwise determined by the BCUC.

Multi-Year Rate Plan ("MRP") for 2020 to 2024

In June 2020, the BCUC issued its decision on FEI's MRP application for the years 2020 to 2024 ("MRP Decision"). The approved MRP includes, amongst other items, a level of operation and maintenance expense per customer indexed for inflation less a fixed productivity adjustment factor, a similar approach to growth capital, a forecast approach to sustainment capital, an innovation fund recognizing the need to accelerate investment in clean energy innovation, a number of service quality indicators designed to ensure the Corporation maintains service levels, and a 50/50 sharing between customers and the Corporation of variances from the allowed return on equity ("ROE").

Variances from the allowed ROE subject to sharing include certain components of other revenue and operating and maintenance costs, as well as variances in the utility's regulated rate base amounts, while variances associated with revenues and other expenses, including those that are not controllable or associated with clean growth expenditures, are subject to flow-through treatment and refunded to or recovered from customers.

In December 2023, the BCUC approved a 2024 delivery rate increase of 8.00 per cent over 2023 rates, on an interim and refundable basis pending the outcome of the 2024-2027 Demand Side Management ("DSM") Expenditures Plan Application, which was subsequently approved in February 2024. As part of this decision, a further increase to the revenue deficiency deferral established in 2023 resulting from the GCOC Stage 1 Decision was approved for 2024. The 8.00 per cent rate increase includes a 2024 forecast average rate base of approximately $5,817 million.

Rate Framework for 2025 to 2027 ("Rate Framework")

In April 2024, FEI and FBC filed an application with the BCUC requesting approval of a Rate Framework for the years 2025 to 2027. The Rate Framework builds upon the current MRP and for FEI includes, amongst other items, a revised level of operation and maintenance expense per customer indexed for inflation less a fixed productivity adjustment factor, a similar approach to growth capital, a forecast approach to sustainment and other capital, continued collection of an innovation fund recognizing the need to accelerate investment in clean energy innovation, an updated set of service quality indicators designed to ensure the Corporation maintains service levels, and a continued 50/50 sharing between customers and the Corporation of variances from the allowed ROE. The Rate Framework also proposes a continuation of the main deferral mechanisms currently in place under the MRP. The regulatory process will continue throughout 2024, with a decision expected in mid-2025.

Price Risk Mitigation Application

In June 2023, the BCUC approved FEI's Price Risk Mitigation Application to implement fixed price financial derivatives as a strategy to limit the exposure to fluctuations in natural gas prices for customers who receive commodity supply from FEI. This approval builds on FEI's existing pricing strategy and will allow the enhanced use of these financial derivative instruments for up to a certain amount of FEI's annual baseload commodity portfolio, for the term beginning in April 2024. The settlement of these transactions will be captured in the Commodity Cost Reconciliation Account ("CCRA").

Customer Rates and Deferral Mechanisms

Customer rates include both the delivery charge and the cost of natural gas, consisting of the commodity cost and the storage and transport cost. The Corporation's customer rates are based on estimates and forecasts. In order to manage volatility in rates arising from variances from forecast associated with these costs, a number of regulatory deferral accounts are in place.

Variances from regulated forecasts used to set rates for natural gas revenue and cost of natural gas are flowed back to customers in future rates through approved regulatory deferral mechanisms and therefore these variances do not have an impact on net earnings for the quarters ended September 30, 2024 and 2023.

FEI reviews the costs of natural gas with the BCUC either quarterly or annually to ensure the rates passed on to customers are fair and reflect actual costs. FEI received approval to decrease the cost of the commodity rate effective April 1, 2023, July 1, 2023, and October 1, 2023, and to maintain the commodity rate effective January 1, 2024, April 1, 2024, and July 1, 2024. FEI also received approval to decrease the storage and transport rate effective January 1, 2024.

As part of the MRP for the years 2020 to 2024, the BCUC has approved certain regulatory deferral mechanisms, including those that capture revenue shortfalls and incremental costs incurred beyond the control of the Corporation. These deferral mechanisms capture variances from regulated forecasts and flow them through customer rates in subsequent years. Variances from the allowed ROE, including most components of operating and maintenance costs, as well as variances in the utility's regulated rate base amounts, are shared. The Rate Framework for the years 2025 to 2027 also proposes a continuation of the main deferral mechanisms currently in place under the existing MRP.

CONSOLIDATED RESULTS OF OPERATIONS

	Quarter ended			Nine months ended		
Periods ended September 30	**2024**	2023	Variance	**2024**	2023	Variance
Gas sales *(petajoules)*	**32**	27	5	**153**	147	6
($ millions)						
Revenue	**241**	291	(50)	**1,129**	1,399	(270)
Cost of natural gas	**45**	65	(20)	**282**	581	(299)
Operation and maintenance	**76**	72	4	**226**	219	7
Property and other taxes	**24**	20	4	**66**	60	6
Depreciation and amortization	**84**	77	7	**252**	232	20
Total expenses	**229**	234	(5)	**826**	1,092	(266)
Operating income	**12**	57	(45)	**303**	307	(4)
Add: Other income	**12**	99	(87)	**30**	200	(170)
Less: Finance charges	**39**	128	(89)	**118**	297	(179)
(Loss) earnings before income taxes	**(15)**	28	(43)	**215**	210	5
Income tax (recovery) expense	**(9)**	(17)	8	**47**	(1)	48
Net (loss) earnings	**(6)**	45	(51)	**168**	211	(43)
Net earnings attributable to non-controlling interests	**-**	1	(1)	**1**	1	-
Net (loss) earnings attributable to controlling interests	**(6)**	44	(50)	**167**	210	(43)

The following table outlines net earnings and the significant variances in the Consolidated Results of Operations for the quarter ended September 30, 2024 as compared to September 30, 2023:

Quarter		
Item	**Increase (Decrease)** *($ millions)*	**Explanation**
Net loss attributable to controlling interest	**(50)**	Net loss attributable to controlling interest for the quarter ended September 30, 2024 was $6 million compared to $44 million in net earnings attributable to controlling interest for the same period in 2023. The decrease was partially due to the timing of recognizing the impacts of the GCOC Stage 1 Decision in the comparative period, which included an effective date of January 1, 2023 and resulted in recognizing the year-to-date net impact of the change in cost of capital during the third quarter. For FEI, this resulted in an additional $23 million of earnings, on a net basis, in the comparative quarter compared to the third quarter of 2024. In addition to the above, the decrease was due to: • a $24 million lower income tax benefit as a result of the Corporation implementing a tax loss utilization plan ("TLUP") in the second quarter of 2023, where no similar TLUP has been implemented in 2024, and • lower favourable variances, primarily attributable to timing of operation and maintenance expenses as compared to those allowed in rates, net of amounts shared with customers, as compared to the same period in 2023.
Revenue	**(50)**	The decrease in revenue was primarily due to: • a decrease in revenue associated with regulatory deferrals, • a lower cost of natural gas recovered from customers, as approved by the BCUC, and • an increase in the refund of the Midstream Cost Reconciliation Account ("MCRA") gas storage and transport cost regulatory liability, compared to the prior year, partially offset by • an increase in delivery revenue approved for rate-setting purposes, resulting primarily from collecting in rates part of the 2024 impact of the GCOC Stage 1 Decision. Gas sales volumes were higher than the same quarter in the previous year primarily due to higher consumption by industrial and transportation customers. Variances between revenue associated with actual consumption and revenue forecasted for rate-setting purposes are captured either in the Revenue Stabilization Adjustment Mechanism ("RSAM") deferral account or the flowthrough deferral account, for which the income statement offsets are recognized in alternative revenue and other revenue, resulting in no net impact on total revenue compared to what is approved in rates in the current year.

Quarter		
Item	**Increase (Decrease)** *($ millions)*	**Explanation**
Cost of natural gas	**(20)**	The decrease was primarily due to: • a lower commodity cost, approved by the BCUC, of $2.230 per gigajoule ("GJ") for the third quarter of 2024, as compared to $3.159 per GJ for the third quarter of 2023, • a lower storage and transport cost, approved by the BCUC, of $1.102 per GJ for the third quarter of 2024, as compared to $1.543 per GJ for the third quarter of 2023, and • an increase in the refund of the MCRA gas storage and transport cost regulatory liability compared to the prior year, partially offset by • an increase in total consumption by those customers receiving bundled natural gas services from FEI, which includes both delivery service and the supply of gas commodity. Customers that purchase bundled services from FEI require the Corporation to not only provide delivery service, but also provide the gas commodity, which entails managing the commodity portfolio including the costs to procure, store and transport the gas. During the third quarter of 2024, volumes provided to customers under bundled services and customers that received only delivery service were both higher compared to the same quarter in 2023. Although total sales volumes were higher, only the higher volumes provided to customers under bundled services drove a higher cost of natural gas in the third quarter of 2024.
Operation and maintenance	**4**	The increase was primarily due to inflationary increases and the timing of incurring operating costs that are shared with customers, as well as higher costs associated with FEI's integrity management program, the variances of which are flowed through to customers, and higher costs, the variances of which are retained by the utility, partially offset by a lower service cost component of pension and other post employment benefits expense ("OPEB").
Property and other taxes	**4**	The increase was primarily due to a higher assessed value of assets and an increase in rates charged by municipalities.
Depreciation and amortization	**7**	The increase was primarily due to lower amortization of regulatory liabilities and a higher depreciable asset base compared to 2023.
Other income	**(87)**	Other income primarily consists of dividend income from TLUP structures, the equity component of allowance for funds used during construction ("AFUDC"), interest income, and the non-service cost component of pension and other post-employment benefits, which is recognized as a credit to other income. As part of the TLUP implemented in 2023, the Corporation received dividend income from FHI relating to a $4,700 million investment in preferred shares. The decrease was primarily due to lower dividend income due to FEI having a TLUP in place during 2023, where no TLUP has been implemented in 2024, and a decrease in interest income due to holding higher cash balances on average during the comparative period, partially offset by a higher equity component of AFUDC.

Quarter		
Item	**Increase (Decrease)** *($ millions)*	**Explanation**
Finance charges	**(89)**	The decrease was primarily due to FEI having a TLUP in place during 2023, where no similar TLUP has been implemented in 2024, partially offset by an increase in total borrowings used to finance the debt component of FEI's capital expenditure program.
Income tax recovery	**(8)**	The decrease was primarily due to FEI having a TLUP in place during 2023, where no similar TLUP has been implemented in 2024, partially offset by lower earnings before income taxes, and lower taxable temporary differences associated with certain regulatory assets and liabilities.

The following table outlines net earnings and the significant variances in the Consolidated Results of Operations for the nine months ended September 30, 2024 as compared to September 30, 2023:

Nine Months		
Item	**Increase (Decrease)** *($ millions)*	**Explanation**
Net earnings attributable to controlling interest	**(43)**	Net earnings attributable to controlling interest for the nine months ended September 30, 2024 were $167 million compared to $210 million for the same period in 2023. The decrease was primarily due to: • a $47 million lower income tax benefit as a result of the Corporation implementing a TLUP in the second quarter of 2023, where no similar TLUP has been implemented in 2024, • lower favourable variances, primarily attributable to timing of operation and maintenance expenses as compared to those allowed in rates, net of amounts shared with customers, as compared to the same period in 2023, and • a decrease in gas mitigation incentive revenue, partially offset by • a higher net investment in regulated assets, and • lower operating costs, the variances of which are retained by the utility. Both 2024 and 2023 net earnings are based on an allowed ROE of 9.65 per cent and a deemed equity component of capital structure of 45 per cent.
Revenue	**(270)**	The decrease in revenue was primarily due to the same reasons as identified in the quarter. For the nine months ended September 30, 2024, gas sales volumes were higher compared to the same period in 2023 primarily due to higher consumption by industrial customers, as well as higher consumption by residential and commercial customers.

Nine Months		
Item	**Increase (Decrease)** *($ millions)*	**Explanation**
Cost of natural gas	**(299)**	The decrease was primarily due to: • a lower commodity cost, approved by the BCUC, of $2.230 per GJ for the first quarter of 2024, as compared to $5.159 per GJ for the first quarter of 2023, • a lower commodity cost, approved by the BCUC, of $2.230 per GJ for the second quarter of 2024, as compared to $4.159 per GJ for the second quarter of 2023, • a lower commodity cost, approved by the BCUC, of $2.230 per GJ for the third quarter of 2024, as compared to $3.159 per GJ for the third quarter of 2023, • a lower storage and transport cost, approved by the BCUC, of $1.102 per GJ for the first nine months of 2024, as compared to $1.543 per GJ for the first nine months of 2023, and • an increase in the refund of the MCRA gas storage and transport cost regulatory liability compared to the prior year, partially offset by • an increase in total consumption by those customers receiving bundled natural gas services from FEI, which includes both delivery service and the supply of gas commodity.
Operation and maintenance	**7**	The increase was primarily due to inflationary increases and the timing of incurring operating costs that are shared with customers, as well as higher costs associated with FEI's integrity management program, the variances of which are flowed through to customers, partially offset by lower costs, the variances of which are retained by the utility, and a lower service cost component of pension and OPEB.
Property and other taxes	**6**	The increase was primarily due to to the same reasons as identified in the quarter.
Depreciation and amortization	**20**	The increase was primarily due to the same reasons as identified in the quarter.
Other income	**(170)**	The decrease was primarily due to the same reasons as identified in the quarter.
Finance charges	**(179)**	The decrease was primarily due to the same reasons as identified in the quarter.
Income tax expense	**48**	The increase was primarily due to FEI having a TLUP in place in the second quarter of 2023, where no similar TLUP has been implemented in 2024, higher earnings before income taxes, and lower deductible temporary differences associated with property, plant and equipment, partially offset by lower taxable temporary differences associated with certain regulatory assets and liabilities.

SUMMARY OF QUARTERLY RESULTS

The following table sets forth quarterly information for each of the eight quarters ended December 31, 2022 through September 30, 2024. 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)[1]
($ millions)		
September 30, 2024	241	(6)
June 30, 2024	332	29
March 31, 2024	556	144
December 31, 2023	538	127
September 30, 2023	291	44
June 30, 2023	358	44
March 31, 2023	750	122
December 31, 2022	724	91

1 Net earnings (loss) attributable to controlling interest.

A summary of the past eight quarters reflects the seasonality associated with the Corporation's business. Due to the seasonal nature of natural gas consumption patterns based on weather and its impact on revenues, the natural gas transmission and distribution operations of FEI normally generate higher net earnings in the first and fourth quarters of the fiscal year and lower net earnings in the second quarter, which are partially offset by net losses in the third quarter. Certain expenses such as depreciation, interest and operating expenses remain more evenly distributed throughout the fiscal year. As a result of the seasonality, interim net earnings are not indicative of net earnings on an annual basis. From time to time the Corporation has implemented tax loss utilization plans, which would have an impact on earnings recognized during interim periods depending on the timing of implementing such structures.

September 2024/2023 – The Corporation incurred a net loss of $6 million, compared to net earnings of $44 million, partially due to the timing of recognizing the impacts of the GCOC Stage 1 Decision in the comparative period, which included an effective date of January 1, 2023 and resulted in recognizing the year-to-date net impact of the change in cost of capital during the third quarter. For FEI, this resulted in an additional $23 million of earnings, on a net basis, in the comparative quarter compared to the third quarter of 2024. In addition, the variance is a result of the Corporation implementing a TLUP during 2023, where no similar TLUP has been implemented in 2024, and lower favourable variances, primarily attributable to timing of operation and maintenance expenses as compared to those allowed in rates, net of amounts shared with customers, as compared to the same period in 2023.

June 2024/2023 – Net earnings were lower due to a $23 million lower income tax benefit as a result of the Corporation implementing a TLUP in the second quarter of 2023, where no similar TLUP has been implemented in 2024, and lower favourable variances, primarily attributable to timing of operation and maintenance expenses as compared to those allowed in rates, net of amounts shared with customers, as compared to the same period in 2023, partially offset by a change in cost of capital resulting from the GCOC Stage 1 Decision, the impact of which was $11 million in the quarter.

March 2024/2023 – Net earnings were higher due to a change in cost of capital resulting from the GCOC Stage 1 Decision, the impact of which was $20 million in the quarter. The increase was also due to lower operating costs, the variances of which are retained by the utility, partially offset by a decrease in gas mitigation incentive revenue, and lower favourable variances, primarily attributable to timing of operation and maintenance expenses as compared to those allowed in rates, net of amounts shared with customers, as compared to the same period in 2023.

December 2023/2022 – Net earnings were higher due to a change in cost of capital resulting from the GCOC Stage 1 Decision, the impact of which was $11 million in the quarter. The increase was also due to a $15 million higher income tax benefit as a result of the Corporation implementing a TLUP in 2023 for a larger investment amount than a TLUP implemented in 2022, and a higher investment in regulated assets, partially offset by lower favourable variances primarily attributable to timing of operation and maintenance expenses, as compared to those allowed in rates, net of amounts shared with customers, as compared to the same period in 2022.

CONSOLIDATED FINANCIAL POSITION

The following table outlines the significant changes in the Consolidated Balance Sheets between September 30, 2024 and December 31, 2023:

Balance Sheet Account	Increase (Decrease) *($ millions)*	Explanation
Cash	**45**	The increase was primarily due to proceeds received from a $275 million equity issuance during the third quarter of 2024, as well as the receipt of a cash deposit relating to construction costs to be incurred for the Eagle Mountain Gas Pipeline ("EGP") Project, partially offset by repayments on credit facilities. Cash on hand at September 30, 2024 has primarily been invested in short-term deposits.
Accounts receivable and other current assets	**(227)**	The decrease was primarily due to: • lower tariff-based trade receivables, as a result of seasonality of revenues and a lower cost of natural gas recovered from customer in rates, as approved by the BCUC, • a decrease in income tax receivable, primarily due to the receipt of a tax refund during the third quarter of 2024, • lower gas cost mitigation receivables, and • a decrease in cash collateral paid for natural gas contracts.
Inventories	**(26)**	The decrease was primarily due to a lower weighted average cost of gas in storage and lower volumes of natural gas in storage due to seasonal drawdowns.
Prepaid expenses	**33**	The increase was primarily due to the payment of annual property taxes during the second quarter of 2024.

Balance Sheet Account	Increase (Decrease) *($ millions)*	Explanation
Regulatory assets (current and long-term)	**233**	The increase was primarily due to: • recognizing a long-term MCRA regulatory asset due to midstream costs incurred exceeding the amounts recovered in customer rates and through mitigation activity, • an increase in regulated deferred income tax liabilities, the offset of which has been deferred as a regulatory asset, • a higher RSAM regulatory asset due to variances in gas use for residential and commercial customers, • an increase in the revenue deficiency deferral established in 2023 resulting from the GCOC Stage 1 Decision, • an increase in Greenhouse Gas Reductions (Clean Energy) Regulation (“GGRR”) incentives paid, and • an increase in DSM due to expenditures during the period, partially offset by • a decrease in the CCRA regulatory asset due to amounts recovered in customer rates exceeding commodity costs incurred.
Property, plant and equipment, net	**530**	The increase was primarily due to capital expenditures of $638 million incurred, changes in accrued capital expenditures of $46 million, $17 million in equity AFUDC capitalized, and $3 million in finance lease asset additions, less: • depreciation expense, excluding net salvage provision, of $155 million, • contributions in aid of construction (“CIAC”) of $5 million received, and • costs of removal of $14 million incurred, which are recognized against the net salvage provision in regulatory liabilities.
Credit facilities	**208**	The increase was primarily a result of using proceeds from credit facilities to fund the debt component of the Corporation’s capital expenditure program during the period, including those associated with the EGP Project, partially offset by repayments on credit facilities primarily through proceeds from a $275 million equity injection from the Corporation's parent company, FHI, as well as from proceeds from the receipt of a cash deposit relating to construction costs to be incurred for the EGP Project.
Deferred income tax	**77**	The increase was primarily due to lower taxable temporary differences associated with certain regulatory deferral asset and liability accounts, higher deductible temporary differences associated with property, plant and equipment, and the utilization of carried-forward losses, partially offset by taxable temporary differences related to the deposit received for the EGP Project.
Other liabilities	**22**	The increase was primarily due to a change in the long-term portion of the fair value of natural gas derivatives.
Common shares	**275**	The increase was due to a $275 million FEI equity issuance during the third quarter of 2024, the proceeds of which were used to repay credit facilities in support of the equity component of FEI's capital expenditure program.

LIQUIDITY AND CAPITAL RESOURCES

Cash Flow Requirements and Liquidity

In the normal course of operations, the Corporation's cash flow requirements fluctuate seasonally based primarily on natural gas consumption. The Corporation maintains a committed credit facility that adequately meets any working capital deficiencies not funded through cash flow from operations, and for financing the debt component of the Corporation's capital expenditure program.

It is expected that operating expenses, interest costs, and other working capital will generally be paid out of operating cash flows, with varying levels of residual cash available for capital expenditures and/or dividend payments. Cash flow is also required to fund capital expenditure programs; pre-development capital costs; regulated deferral accounts, and those regulatory mechanisms that capture revenue shortfalls and incremental costs incurred beyond the control of the Corporation; and investments in DSM and natural gas for transportation programs under the Greenhouse Gas Reductions (Clean Energy) Regulations. Funding requirements are expected to be financed from a combination of cash flow from operations, borrowings under the credit facility, equity injections from FHI, and long-term debenture issuances in accordance with the deemed regulatory capital structure approved by the BCUC of 45 per cent equity and 55 per cent debt.

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 working capital deficiencies and payment of dividends. The Corporation may have to rely upon the proceeds of new debenture issuances to meet its principal debt obligations when they become due.

Summary of Consolidated Cash Flows

Nine months ended September 30	2024	2023	Variance
($ millions)			
Cash flows from (used in)			
Operating activities	**453**	609	(156)
Investing activities	**(714)**	(426)	(288)
Financing activities	**306**	(191)	497
Net change in cash	**45**	(8)	53

Operating Activities

Cash from operating activities was $156 million lower compared to the same period in 2023, primarily due to lower net earnings after non-cash adjustments, as well as due to the following:

- changes in regulatory assets and liabilities, which were driven by changes in the MCRA deferral account due to lower mitigation activities during 2024 as compared to the same period in 2023, and due to changes in the CCRA deferral account due to the variances in commodity costs incurred compared to those collected in customer rates being lower in 2024 compared to the same period in 2023, partially offset by

- the receipt of a cash deposit relating to construction costs to be incurred for the EGP Project and the receipt of a tax refund during the third quarter of 2024.

Investing Activities

Cash used in investing activities was $288 million higher compared to the same period in 2023 primarily due to higher capital expenditures, in part due to expenditures on the EGP Project for which FEI's funding commencement date began January 1, 2024, as well as higher DSM expenditures.

Financing Activities

Cash provided by financing activities was $306 million compared to the same period in 2023 when cash used in financing activities was $191 million. During 2024, net proceeds from the credit facility and from a $275 million issuance of common shares were used to fund a higher level of capital expenditures and lower cash provided from operating activities as compared to the same period in 2023, where proceeds from a $100 million issuance of common shares and higher cash provided from operating activities were used to fund a lower level of capital expenditures and for net repayments on existing credit facilities.

During the nine months ended September 30, 2024, FEI paid common share dividends of $175 million (2023 - $160 million) to its parent company, FHI.

Contractual Obligations

The Corporation's contractual obligations have not materially changed from those disclosed in the MD&A for the year ended December 31, 2023.

Credit Ratings

There have been no changes to the Corporation's credit ratings from those disclosed in the MD&A for the year ended December 31, 2023, which are summarized in the table below:

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

Credit Facilities and Debentures

Credit Facilities

In April 2024, the Corporation increased the size of its syndicated operating credit facility from $700 million to $900 million at substantially the same terms as before, with a revised maturity date of July 2028. The facility continues to incorporate a Sustainability Linked Loan component, with performance targets considering avoided emissions from renewable and low carbon gas and capital project opportunities with Indigenous participation. As at September 30, 2024, the Corporation also had a $55 million uncommitted letter of credit facility in place, which matures in March 2025.

The following summary outlines the Corporation's credit facilities:

($ millions)	**September 30, 2024**	December 31, 2023
Operating credit facility	**900**	700
Letter of credit facility	**55**	55
Draws on operating credit facility	**(273)**	(65)
Letters of credit outstanding	**(38)**	(36)
Credit facilities available	**644**	654

Debentures
On November 16, 2022, the Corporation filed a short form base shelf prospectus to establish a MTN Debentures Program and entered into a Dealers Agreement with certain affiliates of a group of Canadian Chartered Banks. The Corporation may, from time to time during the 25-month life of the shelf prospectus, issue MTN Debentures in an aggregate principal amount of up to $800 million. The establishment of the MTN Debenture Program has been approved by the BCUC.

As at September 30, 2024, $650 million remains available under the MTN Debentures Program.

PROJECTED CAPITAL EXPENDITURES

The Corporation continually updates its capital expenditure programs and assesses current and future operating, maintenance, replacement, expansion and removal expenditures that will be incurred in the ongoing operation of its business.

The initial approval from the BCUC to proceed with capital projects can occur through a number of processes, including revenue requirement applications and Certificate of Public Convenience and Necessity ("CPCN") applications. Once the projects are approved, the regulatory process allows for capital project costs to be reviewed by the BCUC subsequent to the capital project being completed and in service to confirm that all costs are recoverable in customer rates.

The 2024 projected capital expenditures are approximately $990 million, inclusive of AFUDC and customer CIAC, and are necessary to provide service, public and employee safety, and reliability of supply of natural gas to the Corporation's customer base. In addition to the rate base amounts approved in annual regulatory decisions, multi-year projects under construction earn a regulated return. The 2024 projected capital expenditures are dependent on timing of spending on multi-year capital projects, based in part on the timing of any remaining regulatory and permitting approvals required for certain projects. The 2023 annual capital expenditures were $589 million, inclusive of AFUDC and excluding CIAC.

Included in the 2024 projected capital expenditures is approximately $379 million expected to be spent by FEI during 2024 on the EGP Project. FEI started initial construction activities on the EGP Project in September 2023, which were funded through contributions received from Woodfibre LNG as part of an agreement which stipulates that FEI's funding commencement date begins January 1, 2024, up to an amount of $400 million, before Woodfibre LNG begins funding capital construction costs again.

Also included in these 2024 projected capital expenditures are more significant projects, including the Inland Gas Upgrade ("IGU") Project, Advanced Metering Infrastructure ("AMI") Project, Transmission Integrity Management Capabilities ("TIMC") Project, Tilbury Phase 1B Expansion Project, EGP Project, and Other Capital Projects, which were described in the MD&A for the year ended December 31, 2023.

FEI's disclosure around its significant capital projects has not changed materially from those disclosed in the MD&A for the year ended December 31, 2023, with the exception of the following updates.

Okanagan Capacity Upgrade ("OCU") Project
In July 2024, FEI filed an update with the BCUC outlining mitigation solutions for capacity shortfalls in the Okanagan due to expected gas load growth. As part of the update, a change in scope of the project was proposed, with a revised capital expenditure request of approximately $40 million. The regulatory process with respect to the revised OCU Project will continue throughout 2024, and is not expected to have a material impact on FEI's total 2024 projected capital expenditures.

Other Capital Projects

During March 2024, an Environmental Assessment certificate was issued by the Province of BC and during June 2024 an Environmental Assessment certificate was issued by the federal government to a partnership that includes FEI's parent, FHI, who is working towards building a marine jetty at the Tilbury site. If constructed, the marine jetty would make use of FEI's assets at the Tilbury site, including the Tilbury Phase 1B Expansion Project that has yet to be constructed, to service marine bunkering purposes.

DSM Expenditures Plan

In addition to the projected capital expenditures, FEI has a DSM Expenditures Plan which delivers a portfolio of energy efficiency and conservation measures and activities which was accepted by the BCUC in February 2024. The DSM Expenditures Plan is expected to result in approximately $627 million of expenditures for the periods 2024 to 2027 as rate base additions.

RELATED PARTY TRANSACTIONS

In the normal course of business, the Corporation transacts with its parent, FHI, ultimate parent, Fortis, and other related companies under common control, including FBC, in financing transactions and to provide or receive services and materials. In May 2023, Fortis announced FHI had entered into an agreement to sell its ownership of ACGS to an entity not related to Fortis, subject to required approvals and closing conditions. The transaction closed on November 1, 2023, after which ACGS ceased to be a related party to the Corporation. The following transactions were measured at the exchange amounts unless otherwise indicated.

Related Party Recoveries

The amounts charged to related parties were as follows:

	Quarter ended September 30		**Nine months ended September 30**	
($ millions)	**2024**	2023	**2024**	2023
Operation and maintenance expense charged to FBC (a)	**3**	2	**9**	6
Operation and maintenance expense charged to FHI (b)	**-**	-	**1**	1
Other income received from FHI (c)	**-**	89	**-**	175
Total related party recoveries	**3**	91	**10**	182

(a) The Corporation charged FBC for natural gas sales, office rent, management services, and other labour.

(b) The Corporation charged FHI for office rent, management services, and other labour.

(c) In 2023, the Corporation received dividend income from FHI relating to a $4,700 million investment in preferred shares as part of a TLUP.

Related Party Costs

The amounts charged by related parties were as follows:

	Quarter ended September 30		Nine months ended September 30	
($ millions)	**2024**	2023	**2024**	2023
Operation and maintenance expense charged by FBC (a)	**2**	1	**6**	5
Operation and maintenance expense charged by FHI (b)	**4**	3	**11**	10
Finance charges paid to FHI (c)	**-**	89	**-**	175
Gas storage and purchases charged by ACGS (d)	**-**	7	**-**	22
Total related party costs	**6**	100	**17**	212

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

(b) FHI charged the Corporation for corporate management services and governance costs.

(c) In 2023, FHI charged the Corporation interest on $4,700 million of intercompany subordinated debt as part of a TLUP.

(d) ACGS charged the Corporation for the lease of natural gas storage capacity and natural gas purchases.

Balance Sheet Amounts

The amounts due from related parties, included in accounts receivable and other current assets, and the amounts due to related parties, included in accounts payable and other current liabilities, were as follows:

	September 30, 2024		December 31, 2023	
($ millions)	**Amount Due From**	**Amount Due To**	Amount Due From	Amount Due To
FHI	**-**	**(1)**	-	-
Fortis	**-**	**-**	1	-
FBC	**-**	**-**	1	-
Total due from (due to) related parties	**-**	**(1)**	2	-

FINANCIAL INSTRUMENTS

Derivative Instruments

There were no material changes with respect to the nature and purpose, methodologies for fair value determination, and carrying values of the Corporation's natural gas contract derivatives from that disclosed in the MD&A for the year ended December 31, 2023. Additional details are provided in the notes to the Condensed Consolidated Interim Financial Statements.

As at September 30, 2024, natural gas contract derivatives were not designated as hedges and any unrealized gains or losses associated with changes in the fair value of the derivatives were deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the BCUC, and as shown in the following table:

($ millions)	**September 30, 2024**	December 31, 2023
Unrealized net loss recorded to current regulatory assets	**96**	96

Cash inflows and outflows associated with the settlement of all derivative instruments are included in operating cash flows on the Corporation's Consolidated Statements of Cash Flows.

Financial Instruments Not Carried at Fair Value

The following table includes the carrying value, excluding unamortized debt issuance costs, and estimated fair value of the Corporation's long-term debt:

		As at			
		September 30, 2024		December 31, 2023	
($ millions)	Fair Value Hierarchy	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Long-term debt	Level 2	**3,295**	**3,267**	3,295	3,245

ACCOUNTING MATTERS

New Accounting Policies
FEI considers the applicability and impact of all Accounting Standards Updates ("ASUs") issued by the Financial Accounting Standards Board ("FASB"). During the nine months ended September 30, 2024, there were no ASUs issued by FASB that have a material impact on these Condensed Consolidated Interim Financial Statements.

Future Accounting Pronouncements
The following updates have been issued by FASB but have not yet been adopted by the Corporation. Any ASUs issued by FASB that are not included in this MD&A were assessed and determined to be either not applicable to the Corporation or not expected to have a material impact on these Condensed Consolidated Interim Financial Statements.

Improvements to Reportable Segment Disclosures
ASU No. 2023-07, *Improvements to Reportable Segment Disclosures*, issued in December 2023, is effective for the Corporation's December 31, 2024 annual financial statements, and for interim periods beginning in 2025, on a retrospective basis. The ASU requires disclosure of incremental segment information, including those for single reportable segments, incorporating significant segment expenses and other items that are included in segment profit or loss. The Corporation does not expect the adoption of this ASU to have a material impact on the disclosures to its consolidated financial statements.

Improvements to Income Tax Disclosures
ASU No. 2023-09, *Improvements to Income Tax Disclosures*, issued in December 2023, is effective for the Corporation January 1, 2025 on a prospective basis, with retrospective application and early adoption permitted. Principally, it requires additional disclosure of income tax information by jurisdiction to reflect an entity's exposure to potential changes in tax legislation, and associated risks and opportunities. The Corporation is assessing the impact of adoption of this ASU on the disclosures to its consolidated financial statements.

OTHER DEVELOPMENTS

Collective Agreements
There are two collective agreements between the Corporation and Local 378 of the Canadian Office and Professional Employees Union now referred to as MoveUP. The first collective agreement, representing employees in specified occupations in the areas of administration and operations support, was ratified in October 2024 and expires on June 30, 2028. The second collective agreement, representing customer service employees was ratified during 2023 and expires on March 31, 2027.

The collective agreement between the Corporation and Local 213 of the International Brotherhood of Electrical Workers ("IBEW") expired on March 31, 2024 and is currently under negotiation. The IBEW represents employees in specified occupations in the areas of transmission and distribution.

Tax Legislation
During 2023, the Province of BC confirmed that biomethane legislation does not allow for unsold biomethane inventory acquired in previous months to be eligible for a carbon tax refund, which could cause the Corporation to fund the granting of a carbon tax credit to customers for a portion of future RNG sales. During the third quarter of 2024, the Provincial Government finalized changes to biomethane legislation to recognize the concept of biomethane inventory with a 24-month lifespan, as initially announced in the 2024 Provincial Budget. FEI also proposed amendments to its application with the BCUC with respect to its RNG Program to seek to balance its RNG supply and demand monthly, which the BCUC approved in March 2024 to take effect July 1, 2024. FEI

expects this decision, in combination with the changes to the biomethane legislation, will mitigate any potential future carbon tax liability on unsold biomethane inventory.

In November 2023, the Department of Finance Canada tabled revised draft legislation to implement certain tax proposals that are intended to limit the deductibility of certain interest costs and financing expenses in computing income for tax purposes (the "EIFEL Proposals"). Legislation was enacted in June 2024 with an effective date of January 1, 2024. The new legislation is not expected to have a material impact on the Corporation's financial results.

BUSINESS RISK MANAGEMENT

The business risks of the Corporation remain substantially unchanged from those outlined in the Corporation's MD&A for the year ended December 31, 2023.

OUTSTANDING SHARE DATA

As at the filing date of this MD&A, the Corporation had issued and outstanding 405,871,546 common shares, all of which are owned by FHI, a directly wholly-owned subsidiary of Fortis.

ADDITIONAL INFORMATION

Additional information about FEI, including its AIF, can be accessed at www.fortisbc.com or www.sedarplus.ca. The information contained on, or accessible through, either of these websites is not incorporated by reference into this document.

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