FORTISBC ENERGY INC.

MANAGEMENT DISCUSSION & ANALYSIS

For the quarter and nine months ended September 30, 2025

November 3, 2025

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 2025 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, 2025, 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, 2024, with 2023 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, 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. 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, statements regarding the Corporation's expected level of capital expenditures, including forecasted project costs and the potential impact of new or revised tariffs on forecast and actual capital expenditures, and its expectations to finance those capital expenditures through credit facilities, equity injections from FHI and debenture issuances; the Corporation's estimated contractual obligations; a BCUC decision on the annual review filing for 2026, including the request to set the 2025 delivery rate increase as permanent, deferral of the 2025 revenue deficiency, and the proposed period of recovery of equity issuance costs; and the expectation that any applicable Accounting Standard Update issued by the Financial Accounting Standards Board that are not included in the Corporation's Condensed Consolidated Interim Financial Statements will not have a material impact on the Corporation's Condensed Consolidated Financial Statements.

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 significant 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 at a cost that is not impacted by the potential of new or revised tariffs; 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 significant interest costs; continued energy demand, population growth and new housing starts; the absence of significant counterparty credit issues resulting in non-performance by counterparties; 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 significant 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, 2024.

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 1,100,700 residential, commercial, industrial, and transportation customers through approximately 51,700 kilometers of natural gas pipelines. The Corporation provides transmission and distribution services to its customers and obtains natural gas and Renewable Natural Gas ("RNG") supplies on behalf of most residential, commercial, and industrial customers. Natural gas supplies are sourced primarily from northeastern BC and, through the Corporation's Southern Crossing Pipeline, from Alberta.

The Corporation is regulated by the BCUC. Pursuant to the Utilities Commission Act (British Columbia), the BCUC regulates such matters as 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

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

In March 2025, the BCUC issued its decision on FEI and FBC's application requesting approval of a Rate Framework for the years 2025 to 2027. The Rate Framework builds upon the 2020-2024 Multi-Year Rate Plan ("MRP") and for FEI includes, amongst other items, updates to depreciation and capitalized overhead rates, 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 return on equity ("ROE"). The Rate Framework also includes a continuation of the main deferral mechanisms that were in place under the MRP.

In November 2024, the BCUC approved a 2025 delivery rate increase of 7.75 percent over 2024 rates, on an interim and refundable basis, and a 2025 forecast average rate base of $6,470 million. In July 2025, FEI filed updated annual review materials for 2025, requesting to set the 2025 delivery rate increase of 7.75 percent as permanent, an updated 2025 forecast average rate base of $6,452 million, and deferral of the 2025 revenue deficiency. The filing also included a request for a 2026 delivery rate increase of 10.07 percent over 2025 rates, and a 2026 forecast average rate base of $6,835 million. A decision is expected in the fourth quarter of 2025.

Recovery of Equity Issuance Costs

As part of the Stage 1 Generic Cost of Capital ("GCOC") Decision made in September 2023, the BCUC accepted that any reasonable and prudently incurred costs of issuing equity can be considered for recovery, over and above the approved costs of capital. In December 2024, FBC and FEI submitted an application outlining a methodology to determine the actual incurred equity issuance costs, to recognize those costs in a deferral account, and to collect those costs from customers through a future rate-setting process. The application was approved by the BCUC in June 2025. The deferral account, and the proposed period of recovery, of costs attributable to equity injections going back to January 1, 2023 have been included in the annual review filing for 2026.

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 the variances from forecast associated with some of these estimates and to manage volatility in rates, a number of regulatory deferral accounts are in place.

Variances from regulated forecasts used to set rates for natural gas revenue 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 periods ended September 30, 2025 and 2024.

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 has received approval to maintain the same commodity rate each quarter since January 1, 2024. That commodity rate was also approved to be maintained effective October 1, 2025. FEI received approval to increase the storage and transport rate effective January 1, 2025.

Under the MRP for 2020-2024 and the Rate Framework for 2025-2027, 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.

CONSOLIDATED RESULTS OF OPERATIONS

	Quarter ended			Nine months ended		
Periods ended September 30	**2025**	2024	Variance	**2025**	2024	Variance
Gas sales *(petajoules)*	**29**	32	(3)	**152**	153	(1)
($ millions)						
Revenue	**276**	241	35	**1,283**	1,129	154
Cost of natural gas	**58**	45	13	**374**	282	92
Operation and maintenance	**79**	76	3	**243**	226	17
Property and other taxes	**21**	24	(3)	**65**	66	(1)
Depreciation and amortization	**96**	84	12	**274**	252	22
Total expenses	**254**	229	25	**956**	826	130
Operating income	**22**	12	10	**327**	303	24
Add: Other income	**13**	12	1	**36**	30	6
Less: Finance charges	**38**	39	(1)	**115**	118	(3)
(Loss) earnings before income taxes	**(3)**	(15)	12	**248**	215	33
Income tax (recovery) expense	**(2)**	(9)	7	**50**	47	3
Net (loss) earnings	**(1)**	(6)	5	**198**	168	30
Net earnings attributable to non-controlling interests	**-**	-	-	**1**	1	-
Net (loss) earnings attributable to controlling interest	**(1)**	(6)	5	**197**	167	30

The following table outlines the net loss and significant variances in the Consolidated Results of Operations for the quarter ended September 30, 2025 as compared to September 30, 2024:

Quarter		
Item	**Increase (Decrease)** *($ millions)*	**Explanation**
Net loss attributable to controlling interest	**(5)**	Net loss attributable to controlling interest for the quarter ended September 30, 2025 was $1 million compared to $6 million in net loss for the same period in 2024. The decrease in loss was primarily due to: • higher investment in regulated assets, inclusive of the equity component of allowance for funds used during construction ("AFUDC") on FEI's investment in the EGP Project, which didn't reach $400 million until the fourth quarter of 2024, • higher 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 2024, and • lower operating costs compared to the same period in 2024, the variances of which are retained by the utility. Both 2025 and 2024 net earnings are based on an allowed ROE of 9.65 percent and a deemed equity component of capital structure of 45 percent.
Revenue	**35**	The increase in revenue was primarily due to: • an increase in revenue associated with regulatory deferrals, • a decrease in the refund of the Midstream Cost Reconciliation Account (“MCRA”) gas storage and transport cost regulatory liability, as approved by the BCUC, compared to the prior year, • an increase in delivery revenue approved for rate-setting purposes, resulting primarily from a higher investment in regulated assets, and • a higher cost of natural gas recovered from customers, as approved by the BCUC. Gas sales volumes were lower than the same quarter in the previous year primarily due to lower consumption by transportation, residential, and commercial customers, partially offset by higher consumption by LNG and industrial 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 flow-through 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.

<table>
<tr><th colspan="3">Quarter</th></tr>
<tr><th>Item</th><th>Increase (Decrease) ($ millions)</th><th>Explanation</th></tr>
<tr><td>Cost of natural gas</td><td>13</td><td>The increase was primarily due to:
a decrease in the refund of the MCRA gas storage and transport cost regulatory liability, as approved by the BCUC, compared to the prior year,
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, and
a higher storage and transport cost, approved by the BCUC, of $1.260 per GJ for the third quarter of 2025, as compared to $1.102 per GJ for the third quarter of 2024.
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 2025, volumes provided to customers under bundled services were higher compared to the same quarter in 2024, while volumes provided to customers that received only delivery service were lower compared to the same quarter in 2024. Although total sales volumes were lower, the higher volumes provided to customers under bundled services drove a higher cost of natural gas in the third quarter of 2025.</td></tr>
<tr><td>Depreciation and amortization</td><td>12</td><td>The increase was primarily due to higher amortization of regulatory assets and a higher depreciable asset base compared to 2024, partially offset by a decrease in the average depreciation rate applicable to the asset base, as approved in the Rate Framework Decision.</td></tr>
<tr><td>Income tax recovery</td><td>(7)</td><td>The decrease was primarily due to higher earnings before income taxes, higher taxable temporary differences associated with regulatory assets and liabilities, higher taxable temporary differences associated with changes in restricted interest pursuant to the excess interest and financing expenses limitation ("EIFEL") rules which limit the deductibility of interest expense for tax purposes, partially offset by higher deductible temporary differences associated with property, plant and equipment.</td></tr>
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The following table outlines net earnings and the significant variances in the Consolidated Results of Operations for the nine months ended September 30, 2025 as compared to September 30, 2024:

Nine Months		
Net earnings attributable to controlling interest	**30**	Net earnings attributable to controlling interest for the nine months ended September 30, 2025 were $197 million compared to $167 million for the same period in 2024. The increase was primarily due to: • higher investment in regulated assets, due to the same reasons as identified in the quarter, and • higher 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 2024, partially offset by • higher operating costs compared to the same period in 2024, which are retained by the utility. Both 2025 and 2024 net earnings are based on an allowed ROE of 9.65 percent and a deemed equity component of capital structure of 45 percent.
Revenue	**154**	The increase in revenue was primarily due to the same reasons as identified in the quarter. For the nine months ended September 30, 2025, gas sales volumes were lower compared to the same period in 2024 primarily due to lower consumption by transportation and residential customers, partially offset by higher consumption by LNG, industrial, and commercial customers.
Cost of natural gas	**92**	The increase was primarily due to: • a decrease in the refund of the MCRA gas storage and transport cost regulatory liability, as approved by the BCUC, compared to the prior year, • 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, and • a higher storage and transport cost, approved by the BCUC, of $1.260 per GJ for the first nine months of 2025, as compared to $1.102 per GJ for the first nine months of 2024.
Operation and maintenance	**17**	The increase was primarily due to inflationary increases and the timing of incurring operating costs that are shared with or flowed through to customers, which includes a higher service cost component of pension and OPEB expense, and higher costs, the variances of which are retained by the utility.
Depreciation and amortization	**22**	The increase was primarily due to the same reasons as identified in the quarter.
Other income	**6**	Other income primarily consists of the equity component of 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. The increase was primarily due to a higher equity component of AFUDC, partially offset by a decrease in the non-service cost component of pension and other post-employment benefits.

SUMMARY OF QUARTERLY RESULTS

The following table sets forth quarterly information for each of the eight quarters ended December 31, 2023 through September 30, 2025. 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, 2025	276	(1)
June 30, 2025	367	44
March 31, 2025	640	154
December 31, 2024	517	118
September 30, 2024	241	(6)
June 30, 2024	332	29
March 31, 2024	556	144
December 31, 2023	538	127

[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 ("TLUP"), which would have an impact on earnings recognized during interim periods depending on the timing of implementing such structures.

September 2025/2024 – Net loss was lower due to a higher investment in regulated assets, higher favourable regulated 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 2024, and lower operating costs, the variances of which are retained by the utility.

June 2025/2024 – Net earnings were higher due to a higher investment in regulated assets, and lower operating costs compared to the same period in 2024, the variances of which are retained by the utility.

March 2025/2024 – Net earnings were higher due to a higher investment in regulated assets, and higher favourable regulated 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 2024, partially offset by higher operating costs, the variances of which are retained by the utility.

December 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, partially offset by a higher investment in regulated assets, and higher favourable regulated variances, as compared to those allowed in rates, net of amounts shared with customers, as compared to the same period in 2023.

CONSOLIDATED FINANCIAL POSITION

The following table outlines the significant changes in the Consolidated Balance Sheets between September 30, 2025 and December 31, 2024:

Balance Sheet Account	Increase (Decrease) *($ millions)*	Explanation
Accounts receivable and other current assets	**(172)**	The decrease was primarily due to lower trade receivables, as a result of seasonality of revenues, as well as lower gas cost mitigation receivables.
Prepaid expenses	**24**	The increase was primarily due to the payment of annual property taxes during the second quarter of 2025.
Regulatory assets (current and long-term)	**219**	The increase was primarily due to: • an increase in regulated deferred income tax liabilities, the offset of which has been deferred as a regulatory asset, • an increase in Demand Side Management ("DSM") due to expenditures during the period, • a higher MCRA regulatory asset due to midstream costs exceeding amounts collected in customer rates and lower mitigation activities, • an increase in the revenue deficiency deferral, partially offset by • a change in the fair value of natural gas derivatives, the offset of which has been deferred as a regulatory asset, and • a decrease in the RNG variance account due to the transfer of RNG mitigation revenue from regulatory liabilities, and by amounts recovered in customer rates exceeding costs incurred to acquire RNG.
Property, plant and equipment, net	**297**	The increase was primarily due to capital expenditures of $777 million incurred, $24 million in equity AFUDC capitalized, and changes in accrued capital expenditures of $48 million, less: • depreciation expense, excluding net salvage provision, of $153 million, • contributions in aid of construction (“CIAC”), including certain amounts provided by Woodfibre LNG, of $378 million received, • disposal of assets of $6 million, the offset of which has been partially recognized in regulatory assets, • $2 million of net adjustments in finance leases, and • costs of removal of $13 million incurred, which are recognized against the net salvage provision in regulatory liabilities.
Credit facilities	**(59)**	The decrease was primarily a result of repayments on credit facilities using proceeds from a $225 million equity injection from the Corporation's parent company, FHI, as well as from proceeds from the receipt of cash deposits relating to construction costs to be incurred for the EGP Project, partially offset by borrowings on credit facilities to fund the debt component of the Corporation's capital expenditure program.

Balance Sheet Account	Increase (Decrease) *($ millions)*	Explanation
Regulatory liabilities (current and long-term)	**59**	The increase was primarily due to: • an increase in the Commodity Cost Reconciliation Account ("CCRA") regulatory liability due to costs recovered in customer rates exceeding commodity costs incurred, • an increase in the net salvage provision, driven in part by a higher average net salvage rate applicable to the asset base, as approved in the Rate Framework Decision, partially offset by • a decrease in the RNG mitigation revenue regulatory liability due to the transfer of amounts to the RNG variance account regulatory asset during the year.
Deferred income tax	**105**	The increase was primarily due to higher deductible temporary differences associated with property, plant and equipment, lower taxable temporary differences associated with regulatory assets and liabilities, partially offset by taxable temporary differences related to deposits received for the EGP Project.
Other liabilities	**(27)**	The decrease was primarily due to a change in the long-term portion of the fair value of natural gas derivatives.
Common shares	**225**	The increase was due to a $225 million equity issuance during the first quarter of 2025, 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 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. 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 percent equity and 55 percent debt, and in certain circumstances, funding provided by CIAC for certain capital expenditures.

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	2025	2024	Variance
($ millions)			
Cash flows from (used in)			
Operating activities	**500**	453	47
Investing activities	**(538)**	(714)	176
Financing activities	**31**	306	(275)
Net change in cash	**(7)**	45	(52)

Operating Activities
Cash from operating activities was $47 million higher compared to the same period in 2024, primarily due to:

- higher net earnings after non-cash adjustments, and
- changes in working capital, driven primarily by the receipt of cash deposits during 2025 relating to construction costs to be incurred for the EGP Project, as well as cash provided by a higher reduction in trade accounts receivable during 2025 as compared to the same period in 2024, partially offset by
- changes in regulatory assets and liabilities, which were driven by changes in the RNG variance account, partially offset by changes in the CCRA deferral account due to variances in commodity costs incurred compared to those collected in customer rates being lower in 2025 compared to the same period in 2024.

Investing Activities
Cash used in investing activities was $176 million lower compared to the same period in 2024 primarily due to lower net capital expenditures after CIAC, which include certain amounts provided by Woodfibre LNG on the EGP Project during 2025 whereas FEI funded the capital expenditures on the EGP Project during 2024, and $5 million related to proceeds on disposal of assets, partially offset by higher DSM expenditures.

Financing Activities
Cash provided by financing activities was $31 million compared to the same period in 2024 when cash provided by financing activities was $306 million. During 2025, net repayments on the credit facility were funded, in part, by a $225 million issuance of common shares, whereas 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.

During the nine months ended September 30, 2025, FEI paid common share dividends of $133 million (2024 - $175 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, 2024.

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, 2024, 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 July 2025, the Corporation extended the maturity date of its $900 million syndicated operating credit facility to July 2030. The credit 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. The Corporation also had a $55 million uncommitted letter of credit facility in place, which matures in March 2026.

The following summary outlines the Corporation's credit facilities:

($ millions)	**September 30, 2025**	December 31, 2024
Operating credit facility	**900**	900
Letter of credit facility	**55**	55
Draws on operating credit facility	**(459)**	(518)
Letters of credit outstanding	**(39)**	(39)
Credit facilities available	**457**	398

Debentures

On October 14, 2025, the Corporation entered into an agreement to issue $200 million of unsecured Medium Term Note ("MTN") Debentures. The MTN Debentures bear interest at a rate of 3.38 percent to be paid semi-annually and mature on October 16, 2030. The closing of the issuance occurred on October 16, 2025, with net proceeds being used to repay draws on the operating credit facility.

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 2025 projected capital expenditures are approximately $1,194 million, inclusive of AFUDC and excluding customer CIAC that is inclusive of approximately $494 million in deposit funding to be applied from Woodfibre LNG related to the EGP Project, 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 2025 projected capital expenditures are dependent on several factors, including the potential impact of new or revised tariffs and the 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 2024 capital expenditures were $1,022 million, inclusive of AFUDC and excluding CIAC.

Also included in these 2025 projected capital expenditures are more significant projects, including the Advanced Metering Infrastructure ("AMI") Project, the Transmission Integrity Management Capabilities ("TIMC") Project, the Tilbury LNG Storage Expansion Project, the Tilbury Phase 1B Expansion Project, the EGP Project, and Other Capital Projects, which were described in the MD&A for the year ended December 31, 2024.

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, 2024, with the exception of the following update.

Tilbury LNG Storage Expansion ("TLSE") Project
In October 2025, FEI's CPCN application for the TLSE Project was approved by the BCUC. Consistent with expansion options outlined in the CPCN, the approval will allow FEI to replace the original Tilbury Base Plant with a new, expanded LNG storage tank, as well as increased regasification capacity, to ensure FEI can continue to provide reliable and resilient energy services, including in the event of a disruption in the supply of natural gas to FEI's system. The TLSE Project is still subject to an Environmental Assessment process requiring approval.

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. 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)	**2025**	2024	**2025**	2024
Operation and maintenance expense charged to FBC (a)	**3**	3	**9**	9
Operation and maintenance expense charged to FHI (b)	**-**	-	**1**	1
Operation and maintenance expense charged to FAES (c)	**1**	-	**1**	-
Total related party recoveries	**4**	3	**11**	10

(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) The Corporation charged FAES for management services and other labour.

Related Party Costs

The amounts charged by related parties were as follows:

	Quarter ended September 30		Nine months ended September 30	
($ millions)	**2025**	2024	**2025**	2024
Operation and maintenance expense charged by FHI (a)	**3**	4	**11**	11
Operation and maintenance expense charged by FBC (b)	**2**	2	**6**	6
Total related party costs	**5**	6	**17**	17

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

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

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, 2025		December 31, 2024	
($ millions)	**Amount Due From**	**Amount Due To**	Amount Due From	Amount Due To
FHI	**-**	**-**	-	(2)
FBC	**2**	**-**	1	-
Total due from (due to) related parties	**2**	**-**	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, 2024. Additional details are provided in the notes to the Condensed Consolidated Interim Financial Statements.

As at September 30, 2025, 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, 2025**	December 31, 2024
Unrealized net loss recorded to current regulatory assets	**59**	100

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 Measured at Fair Value

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

		As at			
		September 30, 2025		December 31, 2024	
($ millions)	Fair Value Hierarchy	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Long-term debt	Level 2	**3,295**	**3,226**	3,295	3,252

ACCOUNTING MATTERS

New Accounting Policies

Improvements to Income Tax Disclosures

Accounting Standards Update ("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 in annual financial statements 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 does not expect the ASU to materially impact its annual disclosures.

FEI considers the applicability and impact of all ASUs issued by the Financial Accounting Standards Board ("FASB"). During the nine months ended September 30, 2025, there were no other ASUs issued by FASB that have a material impact on the 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 the Condensed Consolidated Interim Financial Statements were assessed and determined to be either not applicable to the Corporation or not expected to have a material impact on the Condensed Consolidated Interim Financial Statements.

Disaggregation of Income Statement Expenses

ASU No. 2024-03, *Disaggregation of Income Statement Expenses*, issued in November 2024, is effective for the Corporation's December 31, 2027 annual financial statements, and for interim periods beginning in 2028 on a prospective basis, with retrospective application and early adoption permitted. The ASU requires entities to disclose disaggregated information about five expense categories underlying its income statement line items. The Corporation is assessing the impact of adoption of this ASU on the disclosures to its consolidated financial statements.

Measurement of Credit Losses for Accounts Receivable and Contract Assets

ASU No. 2025-05, *Measurement of Credit Losses for Accounts Receivable and Contract Assets*, issued in July 2025, is effective for the Corporation's December 31, 2026 annual financial statements on a prospective basis, with early adoption permitted. The ASU provides entities with an option to use a practical expedient to estimate credit losses which would use existing conditions as of the balance sheet date, rather than forecast conditions for the contractual term of the asset. The Corporation is assessing the impact of adoption of this ASU on its consolidated financial statements.

Targeted Improvements to the Accounting for Internal-Use Software

ASU No. 2025-06, *Targeted Improvements to the Accounting for Internal-Use Software*, issued in September 2025, is effective for the Corporation's December 31, 2028 annual financial statements, and may be adopted prospectively, retrospectively, or using a modified transition approach, with early adoption permitted. The ASU removes references to development stages and requires capitalization of software costs once funding is authorized and project completion is probable, including assessment of whether significant development uncertainty exists. The guidance also clarifies that all capitalized internal-use software costs must follow the disclosure requirements in ASC Topic 360, *Property, Plant and Equipment*. The Corporation is assessing the impact of adoption of this ASU on 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 June 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 March 31, 2024. During October, a new collective agreement was ratified, which now expires on March 31, 2029. The IBEW represents employees in specified occupations in the areas of transmission and distribution.

Carbon Tax Legislation

On April 1, 2025, the provincial government of BC effectively repealed the consumer carbon tax by reducing the rate to zero. As a result of these changes, FEI will no longer collect carbon tax from customers to be remitted to the provincial government. For FEI's customers, the change will result in a reduction to their total utility bill. As a result of this change to the carbon tax legislated rate, the carbon tax payable included in accounts payable and other current liabilities in FEI's condensed consolidated financial statements as at September 30, 2025 was $nil (December 31, 2024 - $68 million).

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, 2024.

OUTSTANDING SHARE DATA

As at the filing date of this MD&A, the Corporation had issued and outstanding 418,568,459 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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