FORTIS BC

FORTISBC ENERGY INC.

MANAGEMENT DISCUSSION & ANALYSIS

For the quarter and six months ended June 30, 2021

July 28, 2021

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 2021 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 six months ended June 30, 2021, 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, 2020, with 2019 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.

FORWARD-LOOKING STATEMENT

Certain statements in this MD&A contain forward-looking information within the meaning of applicable securities laws in Canada ("forward-looking information"). The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words.

The forward-looking information in this MD&A includes, but is not limited to, statements regarding the Corporation's 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 forecasts and projections that make up the forward-looking information are based on assumptions, which include but are not limited to: absence of COVID-19 pandemic impacts; receipt of applicable regulatory approvals and requested rate orders; absence of administrative monetary penalties; the ability to continue to report under US GAAP beyond the Canadian securities regulators exemption to the end of 2023 or earlier; absence of asset breakdown; absence of environmental damage and health and safety issues; absence of climate change impacts; absence of adverse weather conditions and natural disasters; ability to maintain and obtain applicable permits; the adequacy of the Corporation's existing insurance arrangements; no adverse effect of the Indigenous peoples' settlement process on the Corporation; the ability to maintain and renew collective bargaining agreements on acceptable terms; no material change in employee future benefit costs; the ability of the Corporation to attract and retain a skilled workforce; absence of information technology infrastructure failure; absence of cyber-security failure; continued energy demand; the ability to arrange sufficient and cost effective financing; no material adverse rating actions by credit rating agencies; the competitiveness of natural gas pricing when compared with alternate sources of energy; continued population growth and new housing starts; the availability of natural gas supply; and the ability to hedge certain risks including no counterparties to derivative instruments failing to meet obligations.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. The factors which could cause results or events to differ from current expectations include, but are not limited to: COVID-19 pandemic risk; regulatory approval and rate orders risk (including the risk of imposition of administrative monetary penalties); continued reporting in accordance with US GAAP risk; asset breakdown, operation, maintenance and expansion risk; environment, health and safety matters risk; climate change risk; weather and natural disasters risk; permits risk; underinsured and uninsured losses; risks related to Indigenous rights and engagement; labour relations risk; employee future benefits risk; human resources risk; information technology infrastructure risk; cyber-security risk; interest rates risk; impact of changes in economic conditions risk; capital resources and liquidity risk; competitiveness and commodity price risk; counterparty credit risk; natural gas supply and weather related risks; 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 this MD&A and the Corporation's MD&A and AIF for the year ended December 31, 2020.

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 1,058,600 residential, commercial, industrial, and transportation customers in more than 135 communities. 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

Decision on 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 capital expenditures, are subject to flow-through treatment and refunded to or recovered from customers.

The MRP Decision approved updated FEI depreciation rates for property, plant and equipment and intangible assets, as well as updates to the provisions for removal costs collected as a component of depreciation on an accrual basis. These updates are effective for 2020 and have resulted in a net depreciation rate effect that is comparable to net depreciation rates previously in effect.

As part of the MRP Decision, FEI received approval to increase the allocation of overhead costs to property, plant and equipment and intangible assets, which relate to the overall capital expenditure program.

In December 2020, the BCUC approved a January 1, 2020 delivery rate increase of 2.0 per cent over 2019 rates as well as a January 1, 2021 delivery rate increase of 6.62 per cent over 2020 rates. These delivery rate increases include a 2020 forecast average rate base of $5,047 million and a 2021 forecast average rate base of $5,212 million.

Allowed Return on Equity and Capital Structure

In January 2021, the BCUC announced that a Generic Cost of Capital ("GCOC") Proceeding was being initiated which will include a review of the deemed common equity component of total capital structure and the allowed ROE on common equity for regulated utilities in BC. The BCUC determined the GCOC Proceeding will move forward in two stages and will determine at a later date the effective date to implement a new cost of capital, whether interim rates will be necessary or not, or whether a transition period will be required. The BCUC has engaged an independent consultant for the GCOC Proceeding, who has filed an initial report on the use of a Benchmark Utility to determine the cost of capital, alternatives, and practices in other jurisdictions. Participants will be filing written submissions in response in July 2021. A regulatory timetable for Stage 1 is expected to be determined thereafter.

COVID-19 Customer Recovery Fund Deferral Account

In response to the impact of the global COVID-19 pandemic on British Columbians, FEI applied for and received a final decision in June 2020 from the BCUC for approval of the COVID-19 Customer Recovery Fund deferral account which provides relief offerings in the form of bill payment deferrals and bill credits to certain eligible customers, and to capture the otherwise uncollectible revenues from the Corporation's customers resulting from the COVID-19 pandemic which could otherwise have an impact on net earnings.

As at June 30, 2021, the balance of the COVID-19 Customer Recovery Fund deferral account was $5 million (December 31, 2020 - $5 million), which includes a $4 million estimate of the expected uncollectible revenues related to COVID-19, the offset of which has been recognized as a credit loss allowance. The method of recovery of the COVID-19 Customer Recovery Fund deferral account will be the subject of a future rate filing once the extent of the financial impact on customers due to the COVID-19 pandemic is known. For those customers provided relief in the form of three-month bill payment deferrals, repayment plans began in the third quarter of 2020.

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 risk of forecast error 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 quarters ended June 30, 2021 and 2020.

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. In July 2020, FEI received approval to increase the commodity rate effective August 1, 2020, and in September 2020, FEI received approval to further increase the commodity rate effective October 1, 2020. In December 2020, FEI received approval to increase the storage and transport rate effective January 1, 2021.

As part of the MRP for the years 2020 to 2024, the BCUC has approved the continuation of 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.

Directions to the BCUC

In July 2021, the Provincial government announced amendments to the Greenhouse Gas Reduction (Clean Energy) Regulation ("GGRR") to enable increased acquisition of renewable gases. The amendments include:

- Increasing the amount of renewable gas FEI can acquire from 5 per cent to 15 per cent of system load;
- Enabling FEI to acquire hydrogen, lignin and synthesis gas; and
- Increasing the price cap for the acquisition of renewable gas to $31 per gigajoule, indexed to inflation.

The amendments to the GGRR further expand FEI's ability to invest in renewable gas, supporting the transition to a lower carbon economy in support of policies established by various levels of government.

CONSOLIDATED RESULTS OF OPERATIONS

	Quarter Ended			Six Months Ended		
Periods Ended June 30	**2021**	2020	Variance	**2021**	2020	Variance
Gas sales *(petajoules)*	**42**	41	1	**122**	123	(1)
($ millions)						
Revenue	**316**	248	68	**902**	714	188
Cost of natural gas	**106**	66	40	**361**	226	135
Operation and maintenance	**70**	58	12	**136**	124	12
Property and other taxes	**18**	17	1	**36**	34	2
Depreciation and amortization	**71**	60	11	**143**	121	22
Total expenses	**265**	201	64	**676**	505	171
Operating income	**51**	47	4	**226**	209	17
Add: Other income	**3**	14	(11)	**5**	16	(11)
Less: Finance charges	**37**	48	(11)	**73**	84	(11)
Earnings before income taxes	**17**	13	4	**158**	141	17
Income tax expense (recovery)	**3**	(6)	9	**34**	17	17
Net earnings	**14**	19	(5)	**124**	124	-

The following table outlines net earnings and the significant variances in the Consolidated Results of Operations for the quarter ended June 30, 2021 as compared to June 30, 2020:

Quarter		
Item	**Increase (Decrease)** *($ millions)*	**Explanation**
Net earnings	**(5)**	Net earnings for the quarter ended June 30, 2021 were $14 million compared to $19 million for the same period in 2020. The decrease was primarily due to: • a $3 million lower income tax benefit as a result of the Corporation implementing a tax loss utilization plan ("TLUP") in the second quarter of 2020, where no similar TLUP was implemented in 2021, • lower favourable variances attributable to timing of operation and maintenance expenses for the quarter, as compared to those allowed in rates, net of amounts shared with customers, as compared to the same period in 2020, and • the recognition of a non-recurring income tax recovery not subject to rate-setting in 2020, partially offset by • a higher investment in regulated assets. Both 2021 and 2020 net earnings are based on an allowed ROE of 8.75 per cent and a deemed equity component of capital structure of 38.5 per cent.
Revenue	**68**	The increase in revenue as compared to the same period in 2020 was primarily due to: • a higher cost of natural gas recovered from customers, as approved by the BCUC, • an increase in revenue associated with regulatory deferrals, • an increase in revenue approved for rate-setting purposes, resulting from higher investment in regulated assets, and • an increase in the recovery of the Midstream Cost Reconciliation Account ("MCRA") gas storage and transport cost regulatory asset during the quarter, compared to the prior year refund of the MCRA gas storage and transport cost regulatory liability. Gas sales volumes were comparable to the same quarter in the previous year. The variance between revenue associated with actual consumption and revenue forecasted for rate-setting purposes is 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 impact on total revenue.

Quarter		
Item	**Increase (Decrease)** *($ millions)*	**Explanation**
Cost of natural gas	**40**	The increase was primarily due to: • a higher commodity cost, approved by the BCUC, of $2.844 per gigajoule for the second quarter of 2021, as compared to $1.549 per gigajoule for the second quarter of 2020, • a higher storage and transport cost, approved by the BCUC, of $1.350 per gigajoule for 2021, as compared to $1.087 per gigajoule for 2020, • an increase in the recovery of the MCRA gas storage and transport cost regulatory asset during the quarter, compared to the prior year refund of the MCRA gas storage and transport cost regulatory liability, and • an increase in total consumption of gas 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 second quarter of 2021, volumes provided to customers under bundled services and those that received delivery service only were both higher compared to the same quarter in 2020. The higher volumes provided to customers under bundled services drove a higher cost of natural gas in the second quarter of 2021.
Operation and maintenance	**12**	The increase was primarily due to the timing of incurring costs and inflationary increases, as well as higher costs associated with FEI's integrity management program, higher regulatory fees, and an increase in insurance premiums, the variances of which are flowed through to customers.
Depreciation and amortization	**11**	The increase was primarily due to lower amortization of regulatory liabilities, as well as a higher depreciable asset base compared to the same quarter in 2020.
Other income	**(11)**	Other income primarily consists of dividend income from TLUP structures, the equity component of allowance for funds used during construction ("AFUDC"), 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 2020, the Corporation received dividend income from FHI relating to a $2,500 million investment in preferred shares. The decrease was primarily due to lower dividend income due to FEI having a TLUP in place in the second quarter of 2020, where no similar TLUP was implemented in 2021, partially offset by a higher equity component of AFUDC in 2021.
Finance charges	**(11)**	The decrease was primarily due to FEI having a TLUP in place in the second quarter of 2020, where no similar TLUP was implemented in 2021, partially offset by the issuance of Medium Term Note Debentures ("MTN Debentures") in July 2020 and April 2021, which were used to repay credit facilities carrying lower interest rates.
Income tax expense	**9**	The increase was primarily due to lower deductible temporary differences associated with property, plant and equipment, lower TLUP tax recovery, higher earnings before tax, and the absence of a non-recurring income tax recovery realized in 2020.

The following table outlines net earnings and the significant variances in the Consolidated Results of Operations for the six months ended June 30, 2021 as compared to June 30, 2020:

Six Months		
Item	**Increase (Decrease)** *($ millions)*	**Explanation**
Net earnings	**-**	For the six months ended June 30, 2021, net earnings were $124 million, consistent with net earnings for the same period in 2020. Net earnings were comparable primarily due to: • a higher investment in regulated assets, offset by • a $3 million lower income tax benefit as a result of the Corporation implementing a TLUP in the second quarter of 2020, where no similar TLUP was implemented in 2021, • lower favourable variances attributable to timing of operation and maintenance expenses for the quarter, as compared to those allowed in rates, net of amounts shared with customers, as compared to the same period in 2020, and • the recognition of a non-recurring income tax recovery not subject to rate-setting in 2020.
Revenue	**188**	The increase was primarily due to the same reasons as identified in the quarter. Gas sales volumes were comparable for the six months ended June 30, 2021 as compared to the same period in 2020.
Cost of natural gas	**135**	The increase was primarily due to: • a higher commodity cost, approved by the BCUC, of $2.844 per gigajoule for the first half of 2021, as compared to $1.549 per gigajoule for the same period in 2020, • a higher storage and transport cost, approved by the BCUC, of $1.350 per gigajoule for 2021, as compared to $1.087 per gigajoule for 2020, and • an increase in the recovery of the MCRA gas storage and transport cost regulatory asset, compared to the prior year refund of the MCRA gas storage and transport cost regulatory liability.
Operation and maintenance	**12**	The increase was primarily due to the same reasons as identified in the quarter.
Depreciation and amortization	**22**	The increase was primarily due to the same reasons as identified in the quarter.
Other income	**(11)**	The decrease was primarily due to the same reasons as identified in the quarter.
Finance charges	**(11)**	The decrease was primarily due to the same reasons as identified in the quarter.
Income tax expense	**17**	The increase was primarily due to the same reasons as identified in the quarter and higher taxable temporary differences associated with certain regulatory deferrals.

SUMMARY OF QUARTERLY RESULTS

The following table sets forth unaudited quarterly information for each of the eight quarters ended September 30, 2019 through June 30, 2021. The information has been obtained from the Corporation's Unaudited Condensed Consolidated Interim Financial Statements. 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)		
June 30, 2021	316	14
March 31, 2021	586	110
December 31, 2020	476	78
September 30, 2020	195	(14)
June 30, 2020	248	19
March 31, 2020	466	105
December 31, 2019	427	82
September 30, 2019	183	(15)

[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, the natural gas transmission and distribution operations of FEI normally generate higher net earnings in the first and fourth quarters and lower net earnings in the second quarter, which are partially offset by net losses in the third quarter. As a result of the seasonality, interim net earnings are not indicative of net earnings on an annual basis.

June 2021/2020 – Net earnings were lower due to a $3 million lower income tax benefit as a result of the Corporation implementing a TLUP in the second quarter of 2020, where no similar TLUP was implemented in 2021; lower favourable variances attributable to timing of operation and maintenance expenses for the quarter as compared to those allowed in rates, net of amounts shared with customers; and the recognition of a non-recurring income tax recovery not subject to rate-setting in 2020; partially offset by a higher investment in regulated assets.

March 2021/2020 – Net earnings were higher primarily due to higher investment in regulated assets; and higher favorable variances attributable to timing of operation and maintenance expenses for the quarter, as compared to those allowed in rates, net of amounts shared with customers.

December 2020/2019 – Net earnings were lower due to higher operation and maintenance expenses incurred, as compared to those allowed in rates, net of amounts shared with customers; a $1 million lower income tax benefit from the TLUP; and a decrease in gas mitigation incentive revenues, which is retained by the utility; partially offset by higher investment in regulated assets.

September 2020/2019 – Net loss was lower primarily due to higher investment in regulated assets; and a higher favourable variance attributable to timing of operation and maintenance expenses incurred, as compared to those allowed in rates, net of amounts shared with customers; partially offset by a decrease in gas mitigation incentive revenue which is retained by the utility.

CONSOLIDATED FINANCIAL POSITION

The following table outlines the significant changes in the Consolidated Balance Sheets between June 30, 2021 and December 31, 2020:

Balance Sheet Account	Increase (Decrease) *($ millions)*	Explanation
Cash	**24**	The increase in cash was primarily due to the issuance of $150 million of unsecured MTN Debentures during the second quarter of 2021, partially offset by repayments on the credit facility.
Accounts receivable, net	**(112)**	The decrease was primarily due to: • lower tariff-based trade receivables, primarily as a result of seasonality of sales, • lower cash collateral paid for natural gas contracts, • a change in the fair value of natural gas derivatives, and • lower tax receivables, partially offset by • higher gas cost mitigation receivables.
Regulatory assets (current and long-term)	**50**	The increase was primarily due to: • an increase in Demand Side Management ("DSM") activities, • an increase in deferred income tax liabilities, the offset of which is deferred as a regulatory asset, • a higher flow-through deferral account related to variances from regulated forecast items, and • the change in fair market value of natural gas derivatives, partially offset by • a lower RSAM deferral balance, which captures variances in gas use for residential and commercial customers, and • a lower MCRA regulatory asset, which moved from a regulatory asset position at December 31, 2020 to a regulatory liability position at June 30, 2021 due to the variance between midstream costs incurred and collected in customer rates.
Property, plant and equipment, net	**74**	The increase was primarily due to capital expenditures of $185 million incurred during the quarter, and $2 million in equity AFUDC, less: • depreciation expense, excluding net salvage provision, of $91 million, • changes in accrued capital expenditures of $10 million, • costs of removal of $10 million incurred, which is included as part of the net salvage provision in regulatory liabilities, and • contributions in aid of construction of $2 million received.
Credit facilities	**(258)**	The decrease was primarily a result of net repayments with proceeds received from a $100 million equity injection from the Corporation's parent company, FHI, during the first quarter of 2021 and from the issuance of $150 million in unsecured MTN Debentures during the second quarter of 2021.
Accounts payable and other current liabilities	**(25)**	The decrease was primarily due to: • lower gas cost payables, as a result of lower volume, partially offset by a higher cost of gas purchased, • lower capital accruals, and • the seasonal decrease in credit balances related to customer payment plan arrangements, partially offset by • higher property tax payable.
Long-term debt	**150**	The increase was due to the issuance of $150 million of unsecured MTN Debentures during the second quarter of 2021, net of debt issuance costs and amortization of deferred debt issuance costs, the proceeds of which were used to repay existing credit facilities in support of the debt component of FEI's capital expenditure program.
Deferred income tax	**31**	The increase was primarily due to higher deductible temporary differences associated with property, plant and equipment, and utilization of loss carryforwards to reduce current year's taxes.

Balance Sheet Account	Increase (Decrease) *($ millions)*	Explanation
Common shares	**100**	The increase is due to a $100 million equity issuance during the first quarter of 2021. The proceeds 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 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 38.5 per cent equity and 61.5 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.

Due to the economic condition of certain of the Corporation's customers, the overall demand for natural gas and billings and recovery of revenues could be affected by the COVID-19 pandemic. As described under the "COVID-19-Pandemic" and "Capital Resources and Liquidity" risks in the Business Risk Management section of the Corporation's MD&A for the year ended December 31, 2020, there could be higher than normal working capital deficiencies in the short-term and, if required, the Corporation would seek additional liquidity from a number of sources including equity injections from FHI, accessing the debt capital markets, and increasing the size of the committed credit facilities.

Summary of Consolidated Cash Flows

Six Months Ended	2021	2020	Variance
($ millions)			
Cash flows provided by (used for)			
Operating activities	**381**	368	13
Investing activities	**(233)**	(240)	7
Financing activities	**(124)**	(123)	(1)
Net change in cash	**24**	5	19

Operating Activities

Cash provided by operating activities was $13 million higher in 2021 compared to the same period in 2020 primarily due to:

- higher net earnings, after non-cash adjustments, and
- changes in regulatory assets and liabilities, primarily a result of changes in the MCRA and RSAM deferral accounts compared to what has been recovered in customer rates, partially offset by
- lower cash provided by changes in working capital, primarily due to a decrease in accounts receivable.

Investing Activities

Cash used for investing activities was $7 million lower in 2021 compared to the same period in 2020 primarily due to lower capital expenditures compared to the same period in 2020, partially offset by higher investment in DSM activities.

Financing Activities

Cash used for financing activities was $1 million higher in 2021 compared to the same period in 2020, primarily driven by higher net repayments of credit facilities in the first quarter of 2021 as compared to the same period in 2020, which was financed primarily by the issuance of $150 million of unsecured MTN Debentures and a $100 million issuance of common shares (2020 - $40 million).

During the six months ended June 30, 2021, FEI paid common share dividends of $110 million (2020 - $107 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, 2020.

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, 2020, which are summarized in the table below:

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

Credit Facilities and Debentures

Credit Facilities

As at June 30, 2021, the Corporation had a $700 million syndicated credit facility available which, in July 2021, was extended to mature in July 2026, and a $55 million uncommitted letter of credit facility which matures in March 2023.

The following summary outlines the Corporation's credit facilities:

($ millions)	**June 30, 2021**	December 31, 2020
Credit facility	**700**	700
Letter of credit facility	**55**	55
Draws on credit facility	**-**	(258)
Letters of credit outstanding	**(41)**	(46)
Credit facilities available	**714**	451

Debentures

On April 9, 2020, 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.

On April 12, 2021, FEI entered into an agreement to sell $150 million of MTN Debentures Series 34. The MTN Debentures bear interest at a rate of 2.42 per cent to be paid semi-annually and mature on July 18, 2031. The closing of the issuance occurred on April 14, 2021, with net proceeds being used to repay existing credit facilities.

As at June 30, 2021, $450 million remains available under the MTN Debenture 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 2021 projected capital expenditures are approximately $476 million, inclusive of AFUDC and excluding customer contributions in aid of construction, 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.

Included in these 2021 projected capital expenditures are more significant projects, including the Inland Gas Upgrade, Pattullo Gas Line Replacement ("PGR"), Okanagan Capacity Upgrade, Tilbury LNG Storage Expansion, Transmission Integrity Management Capabilities ("TIMC"), and Tilbury Phase 1B Expansion projects, among others, which were described in the MD&A for the year ended December 31, 2020.

FEI's disclosure around its major capital projects has not changed significantly from those disclosed in the MD&A for the year ended December 31, 2020 with the exception of the following updates.

In February 2021, FEI filed a CPCN application for the coastal transmission system section of the TIMC Project ("CTS TIMC"), with a forecast cost of the capital project of approximately $100 million, exclusive of feasibility and development costs already incurred. In May 2021, FEI filed a CPCN application for an Advanced Metering Infrastructure project to automate the meter reading process for FEI customers, with a forecast cost of the capital project for the installation of advanced meters of approximately $400 million, excluding AFUDC and project management costs, to be incurred throughout the duration of the project. In June 2021, FEI received approval from the BCUC for the PGR project substantially as filed.

While the Corporation intends to execute on its capital expenditure program while considering current COVID-19 pandemic safety restrictions in place, any new or additional restrictions would increase the risk of not completing the 2021 capital work as forecast.

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 and ACGS, 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 the Corporation's parent and other related parties under common control were as follows:

	Quarter ended June 30		**Six months ended June 30**	
($ millions)	**2021**	2020	**2021**	2020
Operation and maintenance expense charged to FBC (a)	**1**	2	**3**	3
Operation and maintenance expense charged to FHI (b)	**1**	1	**1**	1
Other income received from FHI (c)	**-**	13	**-**	13
Total related party recoveries	**2**	16	**4**	17

(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 received dividend income from FHI relating to a $nil (2020 - $2,500 million) investment in preferred shares that existed in 2020. During the six months ended June 30, 2021, no TLUP has been implemented.

Related Party Costs

The amounts charged by the Corporation's parent and other related parties under common control were as follows:

	Quarter ended June 30		**Six months ended June 30**	
($ millions)	**2021**	2020	**2021**	2020
Operation and maintenance expense charged by FBC (a)	**2**	2	**3**	3
Operation and maintenance expense charged by FHI (b)	**3**	3	**6**	6
Finance charges paid to FHI (c)	**-**	13	**-**	13
Gas storage and purchases charged by ACGS (d)	**7**	5	**15**	12
Total related party costs	**12**	23	**24**	34

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

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

(c) The Corporation paid FHI interest on $nil (2020 - $2,500 million) on intercompany subordinated debt as part of a TLUP that existed in 2020. During the six months ended June 30, 2021, no TLUP has been implemented.

(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 on the Consolidated Balance Sheets, and the amounts due to related parties, included in accounts payable and other current liabilities on the Consolidated Balance Sheets, are as follows:

	June 30, 2021		December 31, 2020	
($ millions)	**Amount Due From**	**Amount Due To**	Amount Due From	Amount Due To
Fortis Inc.	**-**	**-**	1	-
FBC	**-**	**-**	2	-
FHI	**-**	**(1)**	1	-
ACGS	**-**	**(2)**	-	(1)
Total (due to) due from related parties	**-**	**(3)**	4	(1)

During 2020, $17 million was transferred from FEI's tax instalment account to ACGS' tax instalment account at the Canada Revenue Agency ("CRA"). The transfer resulted in a decrease to FEI's income tax receivable balance and a decrease to ACGS' income taxes payable balance as permitted by the CRA for associated entities.

During 2020, FEI paid $6 million to an affiliated entity related to the purchase of capital expenditures.

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, 2020. Additional details are provided in the notes to the Condensed Consolidated Interim Financial Statements.

As at June 30, 2021, 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)	**June 30, 2021**	December 31, 2020
Unrealized net (loss) gain recorded to current regulatory (assets) liabilities	**(5)**	2

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 long-term debt.

		As at			
		June 30, 2021		December 31, 2020	
($ millions)	Fair Value Hierarchy	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Long-term debt	Level 2	**3,145**	**3,764**	2,995	3,933

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 six months ended June 30, 2021, there were no ASUs issued by FASB that have a material impact on the Condensed Consolidated Interim Financial Statements.

Future Accounting Pronouncements

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 the Condensed Consolidated Interim 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, expires on June 30, 2023. The second collective agreement, representing customer service employees, expires on March 31, 2022.

The collective agreement between the Corporation and Local 213 of the International Brotherhood of Electrical Workers ("IBEW") was ratified in June 2021 and expires on March 31, 2024. The IBEW represents employees in specified occupations in the areas of transmission and distribution.

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, 2020.

OUTSTANDING SHARE DATA

As at the filing date of this MD&A, the Corporation had issued and outstanding 347,369,254 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.sedar.com. The information contained on, or accessible through, either of these websites is not incorporated by reference into this document.

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