FORTISALBERTA INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS

For the three and six months ended June 30, 2021

July 28, 2021

The following Management's Discussion and Analysis ("MD&A") of FortisAlberta Inc. (the "Corporation") should be read in conjunction with the following: (i) the unaudited condensed interim financial statements and notes thereto for the three and six months ended June 30, 2021, prepared in accordance with accounting principles generally accepted in the United States of America ("US GAAP"); (ii) the audited annual financial statements and notes thereto for the year ended December 31, 2020, prepared in accordance with US GAAP; and (iii) the MD&A for the year ended December 31, 2020.

In December 2017, the Ontario Securities Commission approved the extension of the Corporation's exemptive relief to continue reporting under US GAAP rather than International Financial Reporting Standards ("IFRS") until the earlier of January 1, 2024, and the effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within IFRS specific to entities with activities subject to rate regulation. All financial information presented in this MD&A has been derived from the unaudited condensed interim financial statements for the three and six months ended June 30, 2021, and the annual audited financial statements for the year ended December 31, 2020, prepared in accordance with US GAAP, and is expressed in Canadian dollars unless otherwise indicated.

In this MD&A, FAHI refers to the Corporation's parent, Fortis Alberta Holdings Inc. and Fortis refers to the Corporation's ultimate parent, Fortis Inc.

FORWARD-LOOKING STATEMENTS

The Corporation includes forward-looking information in the MD&A within the meaning of applicable securities laws in Canada ("forward-looking information"). The purpose of the forward-looking information is to provide management's expectations regarding the Corporation's future growth, results of operations, performance, business prospects and opportunities, and may not be appropriate for other purposes. All forward-looking information is given pursuant to the safe harbour provisions of applicable Canadian securities legislation. 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 reflects management's current beliefs and is based on information currently available to management.

The forward-looking information in the MD&A includes, but is not limited to, statements regarding: the expected timing of filing of regulatory applications and receipt of regulatory decisions; the expectation that sufficient cash will be generated to pay all operating costs and interest expense from internally generated funds; the expectation that sufficient cash to finance ongoing capital expenditures will be generated from a combination of long-term debt and short-term borrowings, internally generated funds and equity contributions; the expectation that the Corporation will continue to have access to the required capital on reasonable market terms; and the Corporation's forecast gross capital expenditures for 2021. The forecasts and projections that make up the forward-looking information are based on assumptions that include, but are not limited to: the receipt of applicable regulatory approvals and requested rate orders; no significant operational disruptions or environmental liability due to a catastrophic event or environmental upset caused by severe weather, other acts of nature or other major events; the continued ability to maintain the electricity system to ensure its continued performance; no severe and prolonged economic downturn; no significant variability in interest rates; sufficient liquidity and capital resources; maintenance of adequate insurance coverage; the ability to obtain licenses and permits; retention of existing service areas; continued maintenance of information and operations technology infrastructure; favourable labour relations; and sufficient human resources to deliver service and execute the capital program.

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. Risk factors that could cause results or events to differ from current expectations are detailed in the "Business Risk and Risk Management" section of the MD&A for the year ended December 31, 2020 and in continuous disclosure materials filed from time to time with Canadian securities regulatory authorities. Key risk factors include, but are not limited to: regulatory approval and rate orders; utility asset disposition risk; loss of service areas; change in government policies; capital resources and liquidity risks; a downturn in economic conditions including the strength and operations of the oil and natural gas production industry and related commodity prices; risks relating to widespread outbreak of an illness or communicable disease, any other public health crisis, or pandemic outbreaks, including the novel coronavirus ("COVID-19") pandemic; continued reporting in accordance with US GAAP risk; operating and maintenance risks; risk of loss of permits and rights-of-way; environmental and wildfire risks; weather conditions and climate-change; insurance coverage risk; risk of failure of information and operations technology infrastructure; cybersecurity risk; labour relations risk; and human resources risk.

All forward-looking information in the MD&A is qualified in its entirety by the above cautionary statements 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.

THE CORPORATION

The Corporation is a regulated electric distribution utility in the Province of Alberta. Its business is the ownership and operation of electric facilities that distribute electricity generated by other market participants from high-voltage transmission substations to end-use customers. The Corporation does not own or operate generation or transmission assets and is not involved in the direct sale of electricity. It is intended that the Corporation remain a regulated electric utility for the foreseeable future, focusing on the delivery of safe, reliable, and cost-effective electricity services to its customers in Alberta.

The Corporation operates a largely rural low-voltage distribution network of approximately 128,000 kilometres in central and southern Alberta, which serves approximately 574,200 electricity customers comprised of residential, commercial, farm, oil and gas, and industrial consumers.

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

The Corporation is regulated by the Alberta Utilities Commission (the "AUC") pursuant to the *Alberta Utilities Commission Act* (the "AUCA"). The AUC's jurisdiction, pursuant to the *Electric Utilities Act*, the *Public Utilities Act*, the *Hydro and Electric Energy Act* and the *AUCA*, includes the approval of distribution tariffs for regulated distribution utilities such as the Corporation, including the rates and terms and conditions on which service is to be provided by those utilities. The Corporation recognizes amounts to be recovered from, or refunded to, customers in those periods in which related applications are filed with, or decisions are received from, the AUC. The timing of recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that otherwise expected using US GAAP for entities not subject to rate regulation.

On March 11, 2020, the World Health Organization characterized the outbreak of COVID-19 as a pandemic, which resulted in a series of public health and emergency measures being put in place to combat the spread of the virus. In response to the COVID-19 pandemic, the Corporation has taken steps to protect the health and safety of employees and the public. As the rollout of vaccinations has progressed and stress on the health care system eased, the Province of Alberta has lifted restrictions. The Corporation continues to monitor the progress of COVID-19 variants and the potential impact on business operations. The extent of the COVID-19 pandemic continues to inform the Corporation's assessment of the financial impacts on its operations, financial condition, and liquidity. Potential economic impacts of the COVID-19 pandemic are discussed in the "Business Risk and Risk Management" section of the MD&A for the year ended December 31, 2020.

REGULATORY MATTERS

Performance-Based Regulation

Effective January 1, 2018, the AUC approved a second performance-based regulation ("PBR") term, from 2018 to 2022. Under PBR, a formula incorporating an inflation factor and a productivity factor (I-X) (the "formula"), that estimates inflation (I) annually and assumes a set level of productivity improvements (X), is used to determine distribution rates on an annual basis. Each year this formula is applied to the preceding year's distribution rates.

The base distribution rates, subject to escalation by the formula, for the second PBR term are based on a notional 2017 revenue requirement approved by the AUC. The impact of changes to return on equity ("ROE"), cost of debt and capital structure during the PBR term apply only to the portion of rate base that is funded by revenue provided by mechanisms separate from going-in rates escalated by the formula.

In the second PBR term, incremental capital funding to recover costs related to capital expenditures that are not recovered through going-in rates escalated by the formula will be available through two mechanisms. The capital tracker mechanism from the first PBR term, from 2013 to 2017, will continue for capital expenditures identified as Type 1. Type 1 capital must be extraordinary, not previously included in the utility's rate base, and required by a third party. Type 2 capital includes all capital in the notional going-in rate base with a provision for a prescribed level of annual capital additions funded through a K-Bar mechanism. The K-Bar amount is established for each year of the PBR term based on the revenue requirement associated with this projected notional rate base for Type 2 capital programs. The notional 2017 rate base and the level of annual capital additions were calculated using an AUC prescribed methodology, including both actual and historical averages.

The second PBR term also includes mechanisms for the recovery or settlement of items determined to flow through directly to customers ("Y factor"). The AUC also approved a Z factor, a PBR re-opener and an efficiency carry-over mechanism. The Z factor permits an application for recovery of costs related to significant unforeseen events. The PBR re-opener permits an application to re-open and review the PBR plan to address specific problems with the design or operation of the PBR plan. The use of the Z factor and PBR re-opener mechanisms is associated with certain thresholds. The efficiency carry-over mechanism provides an incentive by permitting a utility to continue to benefit from efficiency gains achieved during the PBR term. If a utility achieves a ROE over the PBR term greater than the approved ROE for ratemaking purposes, the utility is eligible to collect additional PBR revenue for the two years after the end of the PBR term.

2023 Cost-of-Service Application

In 2022, the Corporation will be entering into the final year of its second five-year term of PBR. In June 2021, the AUC issued Decision 26354-D01-2021 confirming that the Alberta distribution utilities will be rebased on a cost of service ("COS") methodology. The completion of rebasing at the transition point from one ratemaking term into another re-aligns a utility's reasonable costs to provide service with the revenues it is permitted to collect in customer rates over the subsequent forecast period. In addition, the decision outlined the manner in which 2023 distribution rates will be established. The AUC has prescribed a minimum level of detail each utility must include in its application to support the 2023 revenue requirement forecasts but has not prescribed a specific methodology for developing the forecasts. The AUC will assess the 2023 forecasts guided by the nature, size, or complexity of the associated cost in order to facilitate a streamlined review of the utilities' applications. The Corporation is required to file its 2023 COS application in the fourth quarter of 2021.

Third PBR Term

In July 2021, the AUC issued Decision 26356-D01-2021 confirming that the Alberta distribution utilities will return to a third PBR term commencing in 2024 upon completion of the 2023 COS year. The AUC has initiated a new proceeding to consider the design of the third PBR term. The AUC has identified three main issues: (i) a review of incremental capital funding provisions; (ii) a review of the (I) factor, and (iii) consideration of a mechanism to share earnings. The Corporation, along with the other Alberta distribution utilities, will submit evidence in the fourth quarter of 2022 that considers the design of a PBR plan for a third term, with a decision expected in the third quarter of 2023.

2021 Annual Rates Application
In December 2020, the AUC issued Decision 25843-D01-2020 approving the Corporation's 2021 rates and riders, effective on an interim basis for January 1, 2021, including an increase of approximately 0.9% to the distribution component of customer rates. The increase in the distribution component of customer rates reflects: (i) an I-X of 2.12%; (ii) a refund of $1.5 million for the true-up of going-in rates; (iii) a refund of $5.4 million for the true-up of the 2018, 2019 and 2020 K-Bar amounts; (iv) a 2021 K-Bar placeholder of $76.8 million; (v) a net refund of $14.6 million for the true-up of the 2018, 2019, and 2020 Alberta Electric System Operator ("AESO") contributions hybrid deferral; (vi) a placeholder refund of $11.6 million for the 2021 AESO contributions hybrid deferral; (vii) a refund of $1.2 million for the true-up of the Corporation's approved 2016 and 2017 K factor amounts; and (viii) a net refund of Y factor amounts of $1.5 million.

Phase II Distribution Tariff Application
A Phase II Distribution Tariff Application ("DTA") is undertaken periodically to propose revisions to rate design and rate class cost allocations that will determine how much of the Corporation's revenue requirement will be recovered from each customer rate class. The DTA also establishes the billing determinants that will apply to each rate class. The Corporation filed a Phase II DTA in October 2020, which proposed a revised rate design intended to achieve improved alignment between revenues collected from, and costs assigned to, specific rate classes. During this process, the AUC considered issues outside of traditional rate design, including the recovery methodology for certain distribution costs attributable to Rural Electrification Associations ("REAs"), which are currently collected from other load customers under the Corporation's regulated tariff. The record of the Corporation's Phase II DTA closed in April 2021.

In July 2021, the AUC issued Decision 25916-D01-2021 directing the Corporation to update certain aspects of its cost allocation study, rate calculations, customer and retailer terms and conditions, and billing determinant forecast methodology in a compliance filing due September 8, 2021. The AUC's approval of changes to the Corporation's applied-for rate design is subject to a requirement to manage 2022 inter-rate class impacts to "nil", to the extent possible, and incorporate the associated rate adjustments in the Corporation's forthcoming 2023 COS rebasing application.

In this decision, the AUC also directed the Corporation to cease applying Payment in Lieu of Notice ("PILON") system exit charges, effective January 1, 2022. These PILON exit charge provisions, which were originally intended to provide the Corporation with revenue support following downward adjustments to large customers' minimum demand requirements or, alternatively, the departure of large customers, were found by the AUC to be largely ineffective under, and incompatible with, the Corporation's price-cap PBR plan.

Finally, the AUC directed the Corporation to remove amounts attributable to system costs incurred by REAs from the Corporation's regulated revenue requirement in the forthcoming 2023 COS rebasing application. This determination follows an earlier AUC ruling in 2020 that held that REAs were not customers of the Corporation and, therefore, cannot be charged amounts under the Corporation's regulated tariff. The Corporation is permitted to recover the costs that would otherwise be attributable to REAs from its other load customers until the end of 2022. The Corporation is exploring its legal options in regards to this, and other aspects of Decision 25916-D01-2021. The Corporation is assessing the impact that this decision could have on its 2023 COS rebasing application and its future financial results and related disclosures.

2022 Generic Cost of Capital
In December 2020, the AUC initiated the 2022 Generic Cost of Capital ("GCOC") proceeding to assess the establishment of cost of capital parameters for 2022. During January 2021, the Corporation and other participants made submissions requesting that the 2022 cost of capital parameters remain unchanged from 2021.

In March 2021, the AUC issued its decision on the 2022 GCOC proceeding. In this decision, the AUC confirmed that its approval of an 8.50% ROE and 37% equity ratio for the Corporation for 2021 will be extended on a final basis through the end of 2022. In making this decision, the AUC cited current persistent market instability as making the completion of an efficient GCOC proceeding difficult. The AUC confirmed that it would initiate a future GCOC proceeding to determine the ROE and equity ratio for the post-2022 period.

In April 2021, the Office of the Utilities Consumer Advocate ("UCA") filed an application seeking permission to appeal the GCOC decision to the Alberta Court of Appeal. The UCA's application, which alleges that the AUC did not properly consider the fair return standard in arriving at its 2022 GCOC decision, is currently scheduled to be heard in September 2021. The UCA also filed a review and variance application on the same merits with the AUC in April 2021 and a decision as to whether the AUC will review, and potentially vary, its 2022 GCOC decision is expected in the third quarter of 2021.

Revised Tariff Recovery Mechanism for Future AESO Customer Contributions

In April 2021, the AUC issued Decision 26061-D01-2021, confirming that a change to the distribution facility owner ("DFO") tariff recovery mechanism applicable to future payments made under the AESO customer contribution policy will be applied on a prospective basis. The AUC has proposed recovery of such contributions as an operating expense or through the application of regulatory deferral accounts, rather than through inclusion in rate base. Under the revised tariff recovery mechanism, which is to be applied to all payments made after the date of the decision, the amounts paid, and associated debt financing costs will be recoverable from customers while the ROE will not. The AUC confirmed that any AESO customer contributions made prior to the release of the decision will continue to be treated as rate base additions in accordance with past practice. As such, the AUC confirmed that changes are not required to be made to the current PBR plans or to currently approved PBR rates, therefore, this decision is not expected to have a significant impact on the Corporation's financial results during 2021.

In May 2021, the Alberta DFOs filed proposals on the specific accounting mechanisms to recover future AESO customer contributions and associated debt financing costs. Final submissions are due in August 2021 and a decision is expected in the fourth quarter of 2021.

RESULTS OF OPERATIONS

	Three months ended June 30			Six months ended June 30		
($ thousands)	2021	2020	Variance	2021	2020	Variance
Total revenues	176,598	164,210	12,388	350,623	330,470	20,153
Cost of sales	54,198	47,359	6,839	108,892	99,436	9,456
Depreciation	53,586	52,111	1,475	106,625	103,990	2,635
Amortization	4,101	3,709	392	8,115	7,362	753
Other (expense) income	(132)	(177)	45	821	607	214
Income before interest expense and income tax	64,581	60,854	3,727	127,812	120,289	7,523
Interest expense	26,990	25,757	1,233	53,147	51,840	1,307
Income before income tax	37,591	35,097	2,494	74,665	68,449	6,216
Income tax expense	1,598	2,189	(591)	3,463	4,062	(599)
Net income	35,993	32,908	3,085	71,202	64,387	6,815

Net income for the three months ended June 30, 2021, increased $3.1 million compared to the same period in 2020. The increase was primarily due to: (i) electric rate revenue related to rate base growth; (ii) higher residential customers; and (iii) other revenue related to the Customer Rights Agreement with the Corporation's rate regulated option ("RRO") retailer, EPCOR Energy Alberta GP Inc ("EPCOR"), which became effective January 1, 2021. These increases were partially offset by an increase in cost of sales primarily due to an increase in the provision for inventory obsolescence, higher labour costs and an increase in fleet costs due to higher fuel costs and operating vehicle usage.

Net income for the first half of 2021 increased $6.8 million compared to the same period in 2020. The increase was primarily due to an increase in electric rate revenue associated with rate base growth and an increase in residential energy deliveries, due to favourable weather variances and higher residential customers; partially offset by lower demand revenue from oil and gas customers. In addition, other revenue increased due to the Customer Rights Agreement with the Corporation's RRO retailer, EPCOR, which became effective January 1, 2021. These increases were partially offset by higher cost of sales primarily due to an increase in contractor costs associated with vegetation management, an increase in the provision for inventory obsolescence, an increase in fleet costs due to higher fuel costs and operating vehicle usage, and higher labour costs.

The following table outlines the significant variances in the Results of Operations for the three months ended June 30, 2021 as compared to June 30, 2020:

Item	Variance ($ millions)	Explanation
Total revenues	12.4	The increase was primarily due to $9.2 million higher electric rate revenue associated with rate base growth and higher residential customers, while demand revenue from industrial, oil and gas customers remained consistent with the comparative period. Additionally, there was an increase in revenues for franchise fees and linear taxes, which are passed through to customers and therefore do not affect net income. As approximately 85% of the Corporation's distribution revenue was derived from fixed or largely fixed billing determinants, changes in quantities of energy delivered were not entirely correlated with changes in overall revenue. Revenue was a function of numerous variables, many of which were independent of actual energy deliveries. Other revenue increased by $3.4 million primarily due to the recognition of revenue associated with the Customer Rights Agreement with the Corporation's RRO retailer, EPCOR, which became effective January 1, 2021, and higher revenues associated with recoveries for distributed generation feasibility studies, high load move support, and transmission service requests. In addition, $0.7 million of revenue was recognized from the sale of emission offsets generated by the Corporation's Energy Efficiency Offset Project. The emission offsets, generated by the replacement of high-pressure sodium streetlights with light emitting diode streetlights, meet the requirements of the Government of Alberta's Technology Innovation and Emission Reduction ("TIER") Regulation and, annually, are verified, registered, and sold.
Cost of sales	6.8	The increase in cost of sales was primarily due to an increase in the provision for inventory obsolescence, higher labour costs, and an increase in fleet costs due to higher fuel costs and operating vehicle usage. Due to employees and contractors working remotely during the COVID-19 pandemic, operating expenses were lower for the three months ended June 30, 2021 and 2020. Additionally, there was an increase in operating expenses for franchise fees and linear tax which are passed through to customers and do not affect net income.
Depreciation	1.5	The increase was primarily due to a higher depreciable asset base compared to the prior period, partially offset by a change in estimate to depreciation for AESO contribution investments that was effective in the fourth quarter of 2020.
Interest Expense	1.2	The increase was primarily due to the issuance of debentures in December 2020, which was used to repay a short-term credit facility carrying a lower interest rate, and a higher level of debt used to finance the increased investment in rate base.

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

Item	Variance ($ millions)	Explanation
Total revenues	20.2	The increase was primarily due to $15.0 million higher electric rate revenue associated with rate base growth, an increase in residential energy deliveries, due to favourable weather variances, and higher residential customers; partially offset by lower demand revenue from oil and gas customers. Additionally, there was an increase in revenues for franchise fees and linear taxes, which are passed through to customers and therefore do not affect net income. Other revenue increased by $4.9 million primarily due to the recognition of revenue associated with the Customer Rights Agreement with the Corporation's RRO retailer, EPCOR, which became effective January 1, 2021, and higher revenues associated with recoveries for distributed generation feasibility studies, high load move support, and transmission service requests.
Cost of sales	9.5	The increase in cost of sales was primarily due to an increase in contractor costs associated with vegetation management, an increase in the provision for inventory obsolescence, an increase in fleet costs due to higher fuel costs and operating vehicle usage, and higher labour costs. Additionally, there was an increase in operating expenses for franchise fees and linear tax which are flowed through to customers and do not affect net income.
Depreciation	2.6	The increase was primarily due to a higher depreciable asset base compared to the prior period, partially offset by a change in estimate to depreciation for AESO contribution investments that was effective in the fourth quarter of 2020.
Interest Expense	1.3	The increase was primarily due to the issuance of debentures in December 2020, which was used to repay a short-term credit facility carrying a lower interest rate, and a higher level of debt used to finance the increased investment in rate base.

SUMMARY OF QUARTERLY RESULTS

The following table sets forth certain quarterly information of the Corporation:

($ thousands)	Total Revenues	Net Income
June 30, 2021	176,598	35,993
March 31, 2021	174,025	35,209
December 31, 2020	153,379	33,145
September 30, 2020	168,976	35,271
June 30, 2020	164,210	32,908
March 31, 2020	166,260	31,479
December 31, 2019	162,153	32,251
September 30, 2019	166,019	37,281

Changes in total revenues and net income quarter over quarter are a result of many factors, including energy deliveries, number of customer sites, regulatory decisions, ongoing investment in energy infrastructure, inflation and changes in income tax. While approximately 85% of the Corporation's distribution revenue is derived from fixed or largely fixed billing determinants, seasonality can affect the revenue recognized in the Corporation's quarterly operations. As approved by the AUC, the allowance for funds used during construction ("AFUDC") is recognized in the first and fourth quarters of the year.

June 30, 2021 / 2020

Net income for the three months ended June 30, 2021, increased $3.1 million compared to the same period in 2020. The increase was primarily due to: (i) electric rate revenue related to rate base growth; (ii) higher residential customers; and (iii) other revenue related to the Customer Rights Agreement with the Corporation's RRO retailer, EPCOR, which became effective January 1, 2021. These increases were partially offset by an increase in cost of sales primarily due to an increase in the provision for inventory obsolescence, higher labour costs and an increase in fleet costs due to higher fuel costs and operating vehicle usage.

March 31, 2021 / 2020

Net income for the three months ended March 31, 2021 increased $3.7 million compared to the same period in 2020. The increase was primarily due to an increase in electric rate revenue associated with rate base growth, residential customer additions and higher residential energy deliveries as a result of weather variances, partially offset by a reduction in demand for commercial and oil and gas customers. In addition, other revenue increased as a result of the recognition of revenue associated with the Customer Rights Agreement, which became effective January 1, 2021. These increases were partially offset by higher cost of sales primarily due to the timing of contractor costs associated with vegetation management and higher depreciation expense due to continued capital investment.

December 31, 2020 / 2019

Net income for the three months ended December 31, 2020 increased $0.9 million compared to the same period in 2019. The increase was primarily due to an increase in electric rate revenue associated with rate base growth and customer additions, as well as a decrease in income tax expense mainly due to an increase in the available 2020 AESO contributions period deductions and a decrease in deferred tax expense attributable to the utilization of tax loss carryforwards in 2019. These increases were partially offset by a decrease in alternative revenue in 2020, as the efficiency carry-over mechanism, an amount of additional PBR revenue awarded for performance in the first PBR term, only applied to the first two years of the second PBR term, being 2018 and 2019. The increase in net income was further offset by an increase in cost of sales due to the timing of contractor costs associated with vegetation management and higher labour costs.

September 30, 2020 / 2019

Net income for the three months ended September 30, 2020 decreased $2.0 million compared to the same period in 2019. The decrease was primarily associated with higher cost of sales due to an increase in labour costs and higher depreciation expense as a result of continued capital investment. Further contributing to the decrease in net income was a reduction in alternative revenue in 2020, primarily due to the efficiency carry-over mechanism. Partially offsetting these decreases was an increase in electric rate revenue associated with rate base growth and lower general operating expenses attributable to employees and contractors working remotely during the COVID-19 pandemic.

FINANCIAL POSITION

The following table outlines the significant changes in the Balance Sheet as at June 30, 2021 as compared to December 31, 2020:

Item	Increase (Decrease) ($ millions)	Explanation
Assets:		
Accounts receivable	(10.2)	The decrease was primarily due to lower receivables related to transmission rates and riders collectable from customers that the Corporation administers on behalf of the AESO and flows through to customers.
Regulatory assets (current and long-term)	37.6	The increase was primarily due to an increase in the AESO charges deferral of $17.8 million and an increase of $18.0 million in the regulated deferred income tax liability, the offset of which was deferred as a regulatory asset.
Property, plant and equipment, net	42.9	The increase was primarily due to continued investment in the Corporation's capital expenditure program, partially offset by depreciation and customer contributions.
Liabilities and Equity:		
Accounts payable and other current liabilities	(22.3)	The decrease was primarily driven by lower accruals for labour and capital expenditures, as well as lower amounts payable to the AESO for customer transmission charges.
Deferred income tax	18.1	The increase was primarily due to higher deductible temporary differences relating to capital asset expenditures and temporary differences associated with certain regulatory deferral accounts.
Debt (including short-term borrowings)	51.8	The change was primarily related to an increase in short-term borrowings under a demand note with Fortis of $80.0 million, partially offset by a net repayment of the committed credit facility of $26.0 million. The overall increase in debt was required to finance the debt component of the Corporation's capital expenditure program.
Total equity	28.9	The increase was primarily due to net income of $71.2 million, less dividends paid of $42.5 million.

SOURCES AND USES OF LIQUIDITY AND CAPITAL RESOURCES

The Corporation's primary sources of liquidity and capital resources are the following:

- funds generated from operations;
- the issuance and sale of debt instruments;
- bank financing and credit facility;
- occasional intercompany borrowings from Fortis; and
- equity contributions from the Corporation's parent company.

STATEMENTS OF CASH FLOWS

	Three months ended June 30			Six months ended June 30		
($ thousands)	2021	2020	Variance	2021	2020	Variance
Cash, beginning of period	—	610	(610)	611	607	4
Cash from (used in):						
Operating activities	85,008	92,743	(7,735)	160,274	113,837	46,437
Investing activities	(72,645)	(74,615)	1,970	(169,739)	(187,460)	17,721
Financing activities	(12,363)	(18,128)	5,765	8,854	73,626	(64,772)
Cash [(1)], end of period	—	610	(610)	—	610	(610)

(1) *Cash is comprised of restricted cash.*

Cash Flow Requirements

The Corporation expects that operating costs, interest expense, 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 and it is expected that these will be financed from a combination of cash flows from operations, borrowings under the committed credit facility, borrowing of demand notes from Fortis, equity injections from Fortis via FAHI, and long-term debenture issuances.

The Corporation's ability to service its debt obligations and pay dividends 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 need to rely upon the proceeds of new debenture issuances to meet its principal obligations when they become due.

Due to the economic condition of certain of the Corporation's customers, the overall demand for electricity could be affected by the COVID-19 pandemic as described in the "Business Risk and Risk Management" section of the MD&A for the year ended December 31, 2020. As a result, there is risk for higher than normal working capital deficiencies in the short-term. If required, the Corporation will seek additional liquidity from a number of sources, including equity injections from Fortis via FAHI, borrowing of demand notes from Fortis, accessing the debt capital markets, and increasing the size of the committed credit facility.

Operating Activities

For the three and six months ended June 30, 2021, net cash provided from operating activities was $7.7 million lower and $46.4 million higher, respectively, than for the same periods in 2020. The net changes for the three and six months were primarily due to in the timing and volume of collection from customers, and payments to the AESO, for transmission related amounts.

Investing Activities

For the three months ended June 30, 2021, net cash used in investing activities decreased $2.0 million as compared to the same period in 2020. Capital expenditures decreased $5.9 million with reductions in AESO contributions, externally driven, customer growth and sustainment capital projects in 2021. This decrease was partially offset by the change in accounts payable related to the capital expenditure programs.

For the six months ended June 30, 2021, net cash used in investing activities decreased $17.7 million as compared to the same period in 2020. Capital expenditures were lower by $38.3 million primarily due to lower AESO contributions, as a result of a reduction in the scope of transmission upgrade projects during 2021. This decrease was partially offset by the change in accounts payable related to the capital expenditure programs.

Capital Expenditures Forecast

The 2021 projected gross capital expenditures are approximately $398 million, inclusive of AFUDC and excluding customer contributions, and are necessary to provide service, public and employee safety, and reliability of distribution electricity to the Corporation's customer base. The 2021 projected capital expenditures are based on detailed forecasts, which include numerous assumptions such as projected growth in the number of customer sites, weather, cost of labour and materials, and other factors that could cause actual results to differ from forecast.

Sustainable investments

Included in the 2021 projected gross capital expenditures forecast are approximately (i) $13 million of expenditures to enable the integration and connection of renewable energy resources, including distributed energy resources and independent power producers, which enable the connection of wind and solar energy-producing facilities to the distribution system and support a reduction in carbon emissions; (ii) $6 million related to wildfire mitigation in the Corporation's service territory; and (iii) $4 million to support the Waterton Battery Energy Storage Project which utilizes a battery energy storage system and an advanced distribution controls system to facilitate reliable access to the grid and provide economic and social benefits to the community. Funding for the Waterton Project was provided by Alberta Innovates, Emissions Reduction Alberta, and the Department of Natural Resources Renewable Energy and Smart Grid Deployment Programs, all of which support utilities in reducing carbon emissions and optimizing electricity usage while encouraging innovation.

Financing Activities
For the three months ended June 30, 2021, cash used in financing activities decreased $5.8 million compared to the same period in 2020. The change in cash used resulted from an increase in short-term borrowings during the second quarter. During the second quarter ended June 30, 2021, the Corporation paid dividends of $21.2 million (2020 - $20.0 million) to its parent company FAHI.

For the six months ended June 30, 2021, cash from financing activities decreased $64.8 million compared to the same period in 2020 as there was a higher amount of cash provided from operating activities in 2021. During the six months ended June 30, 2021, the Corporation paid dividends of $42.5 million (2020 - $40.0 million) to its parent company FAHI.

CONTRACTUAL OBLIGATIONS

The Corporation's contractual obligations have not changed materially from those disclosed in the MD&A for the year ended December 31, 2020.

CAPITAL MANAGEMENT

The Corporation's objective when managing capital is to ensure ongoing access to capital to allow it to build and maintain the electric distribution facilities within the Corporation's service territory. The ratio of debt and equity financing of these investments is determined by their nature and is maintained by the Corporation through the issuance of debentures or other debt, dividends paid to, or equity contributions received from, Fortis via FAHI.

The AUC determines the capital structure for Alberta utilities to finance their regulated operations. The Corporation's capital structure approved by the AUC for ratemaking purposes is 37% equity and 63% debt. This capital structure excludes the financing of goodwill and other non-regulated items that do not impact the deemed regulatory capital structure. These items are deemed to be financed primarily through equity and result in an overall ratio that differs from the regulated capital structure.

Summary of Capital Structure

As at:	June 30, 2021		December 31, 2020	
	$ millions	%	$ millions	%
Total debt	2,440.6	60.4	2,388.8	60.3
Equity	1,601.7	39.6	1,572.8	39.7
	4,042.3	100.0	3,961.6	100.0

The Corporation has externally imposed capital requirements by virtue of its trust indenture and committed credit facility such that consolidated debt cannot exceed 75% of the Corporation's consolidated capitalization ratio, which is based on the Corporation's total capital structure. As at June 30, 2021, the Corporation was in compliance with these externally imposed capital requirements.

As at June 30, 2021, the Corporation had an unsecured $80.0 million (December 31, 2020 - $nil) demand note outstanding with Fortis. The demand note bears interest approximating the bankers' acceptance discount rate plus a stamping fee of 1.0%.

As at June 30, 2021, the Corporation had an unsecured committed credit facility with an available amount of $250.0 million maturing in August 2024. As at June 30, 2021, the Corporation had $11.0 million drawn on the credit facility (December 31, 2020 – $37.0 million). The weighted average effective interest rate for the first half of 2021 on the credit facility was 2.3% (2020 – 2.9%).

In July 2021, the Corporation renegotiated and amended its syndicated credit facility, extending the maturity date of the facility to August 2026 from August 2024. The amended agreement contains substantially similar terms and conditions as the previous agreement.

CREDIT RATINGS

Debentures issued by the Corporation are rated by DBRS Morningstar and Standard and Poor's ("S&P"). The ratings assigned to the debentures issued by the Corporation are reviewed by these agencies on an ongoing basis.

The table below summarizes the ratings assigned to the Corporation's debentures as at June 30, 2021:

Rating Agency	Credit Rating	Type of Rating	Outlook
DBRS Morningstar	A (low)	Senior Unsecured Debt	Stable
S&P	A-	Senior Unsecured Debt	Stable

During 2020, DBRS Morningstar issued an updated credit rating report confirming the Corporation's rating and outlook. In April 2021, S&P confirmed the Corporation's rating at A- and updated the outlook to stable from negative.

OUTSTANDING SHARES

Authorized – unlimited number of:

- Common shares;
- Class A common shares; and
- First preferred non-voting shares, redeemable, cumulative dividend at 10% of the redemption price.

Issued:

- 63 Class A common shares, with no par value.

OFF-BALANCE SHEET ARRANGEMENTS

With the exception of letters of credit outstanding of $0.3 million as at June 30, 2021 (December 31, 2020 - $0.4 million), the Corporation had no off-balance sheet arrangements.

RELATED PARTY TRANSACTIONS

In the normal course of business, the Corporation transacts with related parties, including Fortis and other subsidiaries of Fortis. Amounts due to related parties were measured at the exchange amount and were as follows:

As at: ($ thousands)	**June 30, 2021**	December 31, 2020
Total liabilities		
Related parties (1)	1,281	2,445
Short-term borrowings		
Related parties (2)	80,000	—

(1) *This reflects charges from related parties primarily associated with information technology services and is included in accounts payable and other current liabilities and long-term other liabilities.*

(2) *This amount is for a demand note from Fortis that is expected to be repaid within twelve months.*

The Corporation invoices related parties on terms and conditions consistent with invoices issued to third parties, which require amounts to be paid on a net 30-day basis with interest on overdue amounts. Terms and conditions on amounts invoiced to the Corporation by related parties are net 30 days with interest being charged on any overdue amounts.

Related party transactions included in total revenues, cost of sales, and interest expense were measured at the exchange amount and were as follows:

	Three months ended June 30		Six months ended June 30	
($ thousands)	2021	2020	2021	2020
Included in total revenues [(1)]	146	24	262	135
Included in cost of sales [(2)]	991	886	2,659	2,554
Included in interest expense [(3)]	62	94	62	483

(1) Includes services provided to related parties related to information technology, electric rate revenue, material sales, and intercompany employee services.

(2) Includes charges from related parties related to corporate governance expenses, information technology services, consulting services, travel and accommodation expenses, charitable donations, membership fees and professional development costs.

(3) Reflects interest expense paid on demand notes borrowed from Fortis in 2021 and 2020.

All services provided to or received from related parties were billed on a cost-recovery basis.

FINANCIAL INSTRUMENTS

The following table represents the fair value measurements of the Corporation's financial instruments:

Long-term debt as at: ($ thousands)	**June 30, 2021**	**December 31, 2020**
Fair value [(1)]	2,829,762	3,098,239
Carrying value [(2)]	2,358,739	2,358,721

(1) The fair value of the long-term debt was estimated using level 2 inputs. It was calculated using indicative prices provided by a third party for the same or similarly rated issues of debt with similar maturities. Since the Corporation does not intend to settle the long-term debt prior to maturity, the excess of the estimated fair value above the carrying value does not represent an actual liability.

(2) Carrying value is presented gross of debt issuance costs of $16,044 (December 31, 2020 – $16,386).

The fair value of the Corporation's financial instruments reflects a point-in-time estimate based on current and relevant market information about the instruments as at the balance sheet dates. The estimates cannot be determined with precision as they involve uncertainties and matters of judgment and, therefore, may not be relevant in predicting the Corporation's future earnings or cash flows.

The carrying value of financial instruments included in current assets, long-term other assets, current liabilities, and long-term other liabilities on the balance sheet approximate their fair value, which reflects the short-term maturity, normal trade credit terms and/or nature of these financial instruments.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Corporation's financial statements in accordance with US GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances.

Due to changes in facts and circumstances, and the inherent uncertainty in making estimates, actual results may differ materially from current estimates. Estimates and judgments are reviewed periodically and as adjustments become necessary, they are recognized in the period they become known.

There were no material changes to the Corporation's critical accounting estimates for the three and six months ended June 30, 2021, from those disclosed in the MD&A for the year ended December 31, 2020. The Corporation considered the impact of the COVID-19 pandemic on critical accounting estimates and there were no material impacts on the financial results for the three and six months ended June 30, 2021.

CHANGES IN ACCOUNTING POLICIES

The Corporation's 2021 unaudited condensed interim financial statements have been prepared following the same accounting policies as those used in preparing the Corporation's 2020 audited annual financial statements, except as follows.

Simplifying the Accounting for Income Taxes

Effective January 1, 2021, the Corporation adopted the applicable sections of Accounting Standards Update ("ASU") 2019-12, *Income Taxes (Topic 740), Simplifying the Accounting for Income Taxes,* which provided amendments to reduce complexity in the accounting standard. The ASU was adopted using a prospective approach and did not have a significant effect on the recognition and measurement of the Corporation's current and deferred income taxes in the current period.

FUTURE ACCOUNTING PRONOUNCEMENTS

The Corporation considers the applicability and impact of all ASUs issued by the FASB. The Corporation has assessed the ASUs issued and determined the ASUs to be either not applicable to the Corporation or not expected to have a material impact on the financial statements.

OTHER DEVELOPMENTS

Collective Agreement

The Corporation's three-year Collective Agreement with the United Utility Workers' Association ("UUWA"), which represent approximately 79% of the Corporation's employees, expired on December 31, 2020. In the fourth quarter of 2020, the Corporation and the UUWA entered into collective bargaining negotiations. In July 2021, a tentative agreement was reached for presentation to the UUWA membership with a ratification vote scheduled for the third quarter of 2021.

Corporate Income Tax Audit

The Corporation is currently undergoing a corporate income tax audit of its 2016 tax year by the Canada Revenue Agency ("CRA"). The Corporation continues to work through a number of complex tax matters with the CRA. As at June 30, 2021, there are no changes to existing tax positions.

BUSINESS RISK AND RISK MANAGEMENT

The Corporation's business risks have not changed materially from those disclosed in the "Business Risk and Risk Management" section of the MD&A for the year ended December 31, 2020.

Note: Additional information about the Corporation is available on SEDAR at www.sedar.com and on the Corporation's website at www.fortisalberta.com. The information contained on, or accessible through, any of these websites is not incorporated by reference into this document.