FORTISALBERTA INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the three and twelve months ended December 31, 2020

February 12, 2021

The following Management's Discussion and Analysis ("MD&A") of FortisAlberta Inc. (the "Corporation") should be read in conjunction with the Corporation's Audited Financial Statements and notes thereto for the year ended December 31, 2020, prepared in accordance with accounting principles generally accepted in the United States of America ("US GAAP"). In December 2017, the Ontario Securities Commission ("OSC") 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 ("IASB") 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 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.

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; economic conditions; 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 this MD&A 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; loss of service areas; 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; environmental and wildfire risks; capital resources and liquidity risks; continued reporting in accordance with US GAAP risk; operating and maintenance risks; weather conditions and climate-change; risk of failure of information and operations technology infrastructure; cybersecurity risk; insurance coverage risk; risk of loss of permits and rights-of-way; 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 127,000 kilometres in central and southern Alberta, which serves approximately 572,200 electricity customers comprised of residential, commercial, farm, oil and gas, and industrial consumers.

As a significant portion of the Corporation's distribution revenue is derived from fixed or largely fixed billing determinants, changes in quantities of energy delivered are not entirely correlated with changes in revenue. Revenue is a function of numerous variables, many of which are independent of actual energy deliveries.

The Corporation is an indirect, wholly-owned subsidiary of Fortis Inc. (''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 "*EUA*"), the *Public Utilities Act* (the *"PUA"*), the *Hydro and Electric Energy Act* (the "*HEEA*") 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. Safety is a priority at the Corporation. In response to the COVID-19 pandemic, the Corporation has taken steps to protect the health and safety of employees and the public including, but not limited to, determining those employees essential to ensuring uninterrupted service to customers and modifying workplace processes to ensure social distancing and enhanced hygiene practices. The impacts of the COVID-19 pandemic on the Corporation's financial condition and results of operations for the year ended December 31, 2020 have been described throughout this MD&A. The duration and 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 this MD&A.

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.

In December 2016, the AUC issued Decision 20414-D01-2016 (the "Second-Term PBR Decision") outlining the manner in which distribution rates will be determined by utilities regulated under PBR (the "PBR Utilities") during the second PBR term.

The second PBR term 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 return on equity ("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.

The going-in rates for the second PBR term were based on a notional 2017 revenue requirement. The components of the notional 2017 revenue requirement were determined using an AUC prescribed methodology primarily based on entity-specific historical experience, with an 8.50% ROE and a capital structure of 37% equity and 63% debt applied to the notional 2017 rate base, the calculation of which is described below. The cost of debt in the notional revenue requirement is a weighted average cost of historical debt. The impact of changes to 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. For 2020, the Corporation's ROE has been maintained at 8.50%, with a capital structure of 37% equity and 63% debt.

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 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 actuals and historical averages.

In February 2018, the AUC issued Decision 22394-D01-2018 (the "Second-Term Compliance Decision") confirming the manner in which distribution rates will be determined pursuant to the Second-Term PBR Decision and refusing all utility requests for certain anomalous cost adjustments to be applied in the determination of the notional 2017 going-in revenue requirement. The Corporation filed a Review and Variance Application and sought permission to appeal the Second-Term Compliance Decision to the Alberta Court of Appeal.

In October 2018, the AUC issued Decision 23479-D02-2018, which granted the applied-for review of the Second-Term Compliance Decision. The AUC subsequently initiated a standalone proceeding in February 2019 to clarify the definition of, and criteria for, anomaly adjustments for the purposes of establishing going-in rates for the second PBR term. Decision 24325-D01-2020 was issued in January 2020, which rescinded the previously approved anomaly criteria in favour of a principle-based approach, provided additional clarification regarding the concept of an anomaly adjustment for purposes of rebasing, and granted participants the opportunity to apply for one or more anomaly adjustments. In May 2020, the Corporation discontinued its appeal of the Second-Term Compliance Decision with the Alberta Court of Appeal and filed an application for certain anomaly cost adjustments to be applied in the determination of the notional 2017 going-in revenue requirement, based on the AUC's updated approach. In November 2020, the AUC issued Decision 25422-D01-2020, which denied the inclusion of all anomaly cost adjustments applied for by the Corporation.

In December 2020, as part of Decision 25843-D01-2020 approving the Corporation's 2021 rates and riders, the AUC approved the Corporation's notional 2017 going-in revenue requirement, associated going-in rates, and 2018 K-Bar amount as final.

2018 Independent System Operator Tariff Application

On September 22, 2019, the AUC issued Decision 22942-D02-2019, with respect to the 2018 Independent System Operator ("ISO") Tariff Application filed by the Alberta Electric System Operator ("AESO") (the "ISO Decision"). The ISO Decision included approval of a proposed change to the method in which the AESO's customer contribution policy ("ACCP") is accounted for between distribution facility owners ("DFO") and transmission facility owners ("TFO") that would prevent the Corporation's future investment under the ACCP. The ISO Decision also determined that the Corporation would transfer the unamortized AESO contributions balance as at December 31, 2017, $403.8 million, representing prior investments made by the Corporation under the ACCP, to the incumbent TFO in the Corporation's service area, AltaLink Management Ltd.

On September 25, 2019, the Corporation filed a request for immediate review and variance of the ISO Decision (the "Immediate Review and Variance Letter") with the AUC requesting that an expedited proceeding be undertaken to reevaluate the proposed changes to the ACCP. The Immediate Review and Variance Letter identified a number of significant matters to the Corporation that require reconsideration and clarification by the AUC, including the financial and ratemaking impacts of the transfer of unamortized historical AESO contributions as at December 31, 2017 and the treatment of amounts invested, or to be invested, post January 1, 2018.

On October 2, 2019, the AUC confirmed that it had commenced an expedited review of the ISO Decision on its own motion and requested that the Corporation provide information regarding the significant matters raised in the Immediate Review and Variance Letter. On October 8, 2019, the Corporation filed the additional information requested by the AUC, accompanied by a request for the AUC to suspend the implementation of the proposed changes to the ACCP, pending the AUC's review of the ISO Decision. On October 25, 2019, the AUC granted the suspension of the implementation of the proposed changes to the ACCP as requested by the Corporation. In December 2019, the AUC issued a letter confirming that it would not conclude its reconsideration prior to the end of 2019. In the same communication, the AUC confirmed its intention to issue supplementary information requests ("IRs") to the Corporation and AML in January 2020. In February 2020, following the provision of responses to these IRs, the Corporation filed a motion requesting an oral hearing to permit the AUC to address the complex issues that had arose during the proceeding. In May 2020, the AUC confirmed that the outstanding matters will be determined by a written process and requested the Corporation and AML provide expert tax evidence. In July 2020, the Corporation and AML filed the expert tax evidence requested by the AUC.

On November 4, 2020, the AUC issued Decision 24932-D01-2020 (the "ISO Review and Variance Decision") rescinding the proposed changes to the ACCP and granting the Corporation retention of its unamortized historical AESO contributions, denying the proposed retroactive changes for 2018 to 2020. The ISO Review and Variance Decision also directed the Corporation to change the depreciation rate for AESO contributions to reflect the parameters associated with the underlying transmission facilities. Accordingly, the Corporation has adjusted the estimated service life and the associated depreciation rate of the unamortized AESO contributions resulting in the recognition of a $14.0 million refund to customers as at December 31, 2020 for the related decrease in depreciation expense.

In November 2020, the AUC initiated a new proceeding to consider whether the ACCP should be modified on a prospective basis and, if approved, the date on which any new policy related to AESO contributions would commence. Virtual oral argument was held at the end of January 2021 and a decision is expected in the second quarter of 2021.

AESO Transmission Cost Allocation Practices for DCG Customers
The ISO Decision also included findings relating to the application of the AESO's transmission cost allocation practices at point of delivery substations that may impact ratemaking treatment of distribution connected generation ("DCG") costs. In November 2019, the Corporation filed an application for review and variance to address the AUC's determination that transmission costs resulting from the connection of distributed generation to the distribution grid should be allocated to DCG customers at the discretion of the DFO. In the second and third quarters of 2020, the Corporation participated in a series of stakeholder consultations held by the AESO intended to resolve this matter. In December 2020, the AUC issued Decision 25848-D01-2020 approving adjustments to the AESO's transmission cost allocation practices for DCG customers on a prospective basis. In 2021, as directed by the AUC, the Corporation will unwind its AESO supply transmission service deferral account for amounts paid to the AESO for supply transmission service costs that would have otherwise been allocated to DCG customers, with no resulting impact on net income.

Generic Cost of Capital
In December 2018, the AUC initiated a proceeding to consider establishing a formula-based approach to setting the approved ROE and to consider whether any process changes are necessary for determining capital structure in years in which the ROE formula is in place. In April 2019, the AUC confirmed that the proceeding will also include a traditional assessment of ROE and deemed capital structure for the 2021 to 2022 test period. The Corporation made submissions with respect to this proceeding in January 2020. In March 2020, the AUC suspended this proceeding in consideration of the ongoing effects of the COVID-19 pandemic and associated economic uncertainty in respect of the national and global financial markets. In October 2020, the AUC confirmed the currently approved ROE of 8.50% and deemed capital structure of 37% equity and 63% debt for 2021.

In December 2020, the AUC initiated the 2022 Generic Cost of Capital proceeding to assess the establishment of cost of capital parameters for 2022 and possibly one or more additional years. This proceeding is expected to be ongoing throughout 2021.

Electric Distribution System Purchases
When the Corporation and a municipality or Rural Electrification Associations ("REA") come to an agreement to transfer electric distribution system assets to the Corporation, the transfer and purchase price for ratemaking purposes are subject to regulatory oversight. The municipality or REA is required to apply to the AUC to cease and discontinue its operations. Concurrently, the Corporation is required to apply to the AUC to alter its electric service area to include the electric service area of the municipality or REA. Distribution assets transferred to the Corporation in connection with acquisitions have been valued using the Replacement Cost New minus Depreciation ("RCN-D") method. The Corporation completes RCN-D valuations by first estimating the costs it would incur to replace applicable assets at current standards. The RCN value is thereafter reduced by a depreciation amount to account for the estimated accumulated depreciation at the time that the assets are to be transferred to the Corporation.

In December 2018, the AUC issued a letter announcing the initiation of a generic proceeding to establish the rate treatment methodology in respect of distribution system purchases by distribution utilities under 2018 to 2022 PBR plans. This proceeding was concluded with the issuance of Decision 24405-D01-2019 in September 2019. In Decision 24405-D01-2019, the AUC determined that incremental capital requirements related to system acquisitions would be funded under K-Bar. However, the AUC approved continuing with Y factor rate treatment for the difference between the incremental distribution revenue arising from customer additions and the incremental revenue requirement associated with the electric distribution systems of the Municipality of Crowsnest Pass and the Town of Fort Macleod ("Fort Macleod") as these acquisitions were initiated prior to the generic proceeding.

In March 2018, Fort Macleod approved the sale and transfer of the Fort Macleod electric distribution system and related assets (the "system") to the Corporation for an RCN-D value of $4.8 million, plus goods and services tax ("GST"). In 2018, an application to transfer the Fort Macleod system to the Corporation and an associated application for approval of the purchase price for ratemaking purposes was filed with the AUC. These applications, however, were held in abeyance until completion of the generic proceeding to establish the rate treatment methodology for distribution system purchases and were resumed in 2019 following the issuance of Decision 24405-D01-2019. In October 2019, the AUC approved the discontinuation of operations and transfer of the Fort Macleod system to the Corporation. The sale closed on November 12, 2019 at the agreed purchase price of $4.8 million plus GST. In July 2020, the AUC approved a purchase price of the Fort Macleod system, adjusted for true-ups to the RCN-D value, for ratemaking purposes of $4.7 million, with recovery through a Y factor. The Corporation recognized a $0.1 million adjustment to property, plant and equipment that was recorded in goodwill to reflect the fair value of the Fort Macleod system.

2020 Annual Rates Application

In September 2019, the Corporation submitted its 2020 Annual Rates Application. The rates and riders, proposed to be effective on an interim basis for January 1, 2020, included an increase of approximately 4.9% to the distribution component of customer rates. The increase in the distribution component of customer rates reflected: (i) an I-X of 1.06%; (ii) a collection of $0.2 million for the true-up of going-in rates; (iii) a net collection of $1.5 million for the true-up of the 2018 and 2019 K-Bar amounts; (iv) a 2020 K-Bar placeholder of $58.4 million; (v) a refund of $11.5 million for the 2018, 2019 and 2020 AESO contributions hybrid deferral; and (vi) a net refund of Y factor amounts of $1.3 million.

In December 2019, the AUC issued Decision 24876-D01-2019 approving the Corporation's 2020 rates, as filed in the 2020 Annual Rates Application, on an interim basis.

2021 Annual Rates Application

In November 2020, the Corporation filed an updated 2021 Annual Rates Application incorporating the impacts of the ISO Review and Variance Decision. 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 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 January 2020, which proposed a revised rate design intended to achieve improved alignment between revenues collected from, and costs assigned to, specific rate classes.

Shortly after filing the DTA, certain REAs challenged the Corporation's proposal to allocate distribution costs to them on jurisdictional grounds. In April 2020, the AUC determined that it does not have the authority to allocate upstream distribution costs to REAs, as requested by the Corporation. The Corporation sought further direction from the Alberta Court of Appeal regarding the correctness of the AUC's decision and proposed that the AUC's consideration of the Phase II DTA be withdrawn, pending the determination of proceedings with the Alberta Court of Appeal. In May 2020, the AUC approved the Corporation's request to withdraw its Phase II DTA. In July 2020, the Alberta Court of Appeal dismissed the Corporation's application for permission to appeal the AUC's decision.

As directed by the AUC, the Corporation re-filed its Phase II DTA in October 2020 excluding its proposal to allocate upstream distribution charges to REAs. In December 2020, the Corporation held a virtual technical conference with the AUC and intervenors to the proceeding. Virtual oral argument is scheduled for April 2021 and a decision is expected in the third quarter of 2021.

Distribution System Inquiry
In December 2018, the AUC issued Bulletin 2018-17, which initiated an inquiry into various matters relating to the continuing evolution of the electric distribution grid in Alberta. The AUC stated that "[T]he purpose of the inquiry is to map out the key issues related to the future of the electric distribution grid, to aid in developing the necessary regulatory framework to accommodate the evolution of the electric system."

The AUC confirmed that this inquiry would be completed in three modules. Module One would consider the range of anticipated technological changes expected to occur over the next several years, as well as attempt to understand the drivers and timing of associated capital costs. Module Two would consider the kinds of legislative, policy and regulatory frameworks that would be required to support the ongoing evolution of Alberta's distribution grids and how they may interact with existing utility business models. Module Three would focus on understanding how rate designs can be used to send signals promoting efficient capital investment and prevent uneconomic bypass of existing utility infrastructure.

During 2019, inquiry participants, including the Corporation, took part in a written submission process and attended a technical conference hosted by the AUC in respect of Module One matters. During 2020, the Corporation filed written submissions and participated in a virtual technical conference in respect of Modules Two and Three. In July 2020, the Corporation and other participants submitted concluding remarks to the AUC and the record of the distribution system inquiry was closed. A report on the outcomes of the inquiry is anticipated in the first quarter of 2021.

Utility Payment Deferral Program
On March 18, 2020, the Alberta government announced a program to help residential, farm and small commercial customers avoid additional financial hardship during the COVID-19 pandemic (the "Utility Payment Deferral Program" or the "Program"). Under the Program, those customers who were unable to pay their utility bill could defer payment for up to 90 days, with payment due within one year thereafter.

The Alberta government and the AUC worked with industry stakeholders, including the Alberta electric and gas utilities and the AESO, to develop deferral mechanisms for electricity retailers and the AESO to manage the cash flow impacts that would otherwise result from customers' reliance on the Program.

Utility bills are comprised of charges related to the provision of energy, distribution service and transmission service. The electric retail utilities have accumulated the cash flow impacts and related carrying costs of the uncollected delivery and distribution charges of customer bills deferred under the Program for future recovery through regulatory mechanisms. The Corporation is a distribution utility that outsources all its retail functions under an AUC-approved arrangement. Consequently, the deferral of electricity and distribution delivery charges has no impact to the Corporation's cash flow or collectability of its accounts receivable.

In accordance with the *EUA,* the Corporation is required to arrange, and pay for, transmission service with the AESO and to collect revenue from customers to address these transmission costs. The Corporation collects this revenue by invoicing the customers' retailers through the transmission component of the Corporation's AUC-approved rates. Under the Utility Payment Deferral Program, electricity retailers deferred an amount equivalent to the transmission service component of deferred customer bills from their payments to the Corporation. The Corporation then deferred payment of corresponding amounts for what otherwise would be due to the AESO for future recovery via the deferral program administered by the AESO.

The 90-day term of the Utility Payment Deferral Program ended on June 18, 2020. Repayments of amounts deferred under the Program are in progress with $0.3 million outstanding, as at December 31, 2020. As electricity retailers remit the transmission service component of customer repayments to the Corporation, the Corporation remits payment of corresponding amounts to the AESO. Customers have until June 18, 2021 to repay their deferred utility bills.

SIGNIFICANT CONTRACTS

The EUA provides that an owner of an electric distribution system is required to act, or to authorize a substitute party to act, as a provider of electricity services, including the wholesale purchase and retail sale of electricity, to eligible customers under a regulated rate option and as a default supplier to customers otherwise unable to obtain electricity services. In May 2019, the Corporation entered into an arrangement whereby it continues to convey these obligations to EPCOR Energy Alberta GP Inc. ("EPCOR") under an eight-year Customer Rights Agreement (the "Agreement") beginning in 2021. The Agreement provides for successive options to renew every three-years. In December 2019, the AUC issued Decision 24839-D01-2019 approving those aspects of the Agreement that require regulatory approval, being the provision of regulated rate option electricity services. In December 2020, the Corporation received an upfront payment of $52.4 million from EPCOR pursuant to the terms of the Agreement.

RESULTS OF OPERATIONS

	Three months ended December 31			Twelve months ended December 31		
($ thousands)	2020	2019	Variance	2020	2019	Variance
Total revenues	153,379	162,153	(8,774)	652,825	649,668	3,157
Cost of sales	55,016	47,331	7,685	204,688	196,605	8,083
Depreciation	41,304	50,998	(9,694)	197,833	200,252	(2,419)
Amortization	3,676	3,364	312	14,475	14,078	397
Other income	934	918	16	1,392	1,298	94
Income before interest expense and income tax	54,317	61,378	(7,061)	237,221	240,031	(2,810)
Interest expense	25,713	25,733	(20)	103,644	103,826	(182)
Income before income tax	28,604	35,645	(7,041)	133,577	136,205	(2,628)
Income tax expense (recovery)	(4,541)	3,394	(7,935)	774	5,653	(4,879)
Net income	33,145	32,251	894	132,803	130,552	2,251

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.

Net income for the twelve months ended December 31, 2020 increased $2.3 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 and a decrease in deferred tax expense mainly due to the utilization of tax loss carryforwards in 2019. Further contributing to the increase in net income was lower general operating expenses attributable to employees and contractors working remotely during the COVID-19 pandemic. 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 higher labour costs and higher contractor costs associated with vegetation management.

The following table outlines the significant variances in the Result of Operations for the three months ended December 31, 2020 as compared to December 31, 2019:

Item	Variance ($ millions)	Explanation
Total revenues	(8.8)	The decrease to total revenues was primarily due to $6.6 million lower electric rate revenue as a result of the ISO Review and Variance Decision as described in the Regulatory Matters section of this MD&A, partially offset by rate base growth and customer additions. In addition, alternative revenue decreased by $1.5 million in 2020, primarily due to the efficiency carry-over mechanism that was recognized in the fourth quarter of 2019. The decrease to total revenues was partially offset by net increases in revenue related to flow-through items that were fully offset in cost of sales.
Cost of sales	7.7	The increase was primarily due to the timing of contractor costs associated with vegetation management, higher labour costs, and net increases in costs that qualify as flow-through items that were fully offset in electric rate revenue. Labour and benefits costs and contractor costs comprised approximately 55% of total costs of sales.
Depreciation	(9.7)	The decrease was primarily due to a change in estimate to the depreciation for the AESO contribution investments as described in the Regulatory Matters section of this MD&A. The decrease was partially offset by an increase to depreciation as a result of continued investment in capital assets.
Income tax expense (recovery)	(7.9)	The decrease was primarily due to an increase in the available 2020 AESO contribution period deduction and a decrease in deferred tax expense attributable to the utilization of tax loss carryforwards in 2019.

The following table outlines the significant variances in the Results of Operations for the twelve months ended December 31, 2020 as compared to December 31, 2019:

Item	Variance ($ millions)	Explanation
Total revenues	3.2	The increase to total revenues was primarily due to $9.8 million higher electric rate revenue associated with rate base growth and customer additions, and net increases in revenues related to flow-through items that were offset in cost of sales. The increase in electric rate revenue was partially offset by a reduction in K-Bar and AESO Hybrid revenues associated with the ISO Review and Variance Decision described in the Regulatory Matters section of this MD&A. In addition, alternative revenue decreased by $5.8 million in 2020, primarily due to the efficiency carry-over mechanism that was recognized in 2019.
Cost of sales	8.1	The increase was primarily due to higher labour costs, contractor costs associated with vegetation management, and net increases in costs that qualify as flow-through items that were fully offset in electric rate revenue. The increase was partially offset by lower general operating expenses, primarily associated with lower vehicle, staff and office costs attributable to employees and contractors working remotely during the COVID-19 pandemic. Labour and benefits costs and contractor costs comprised approximately 56% of total costs of sales.
Depreciation	(2.4)	The decrease was primarily due to a change in estimate to the depreciation for the AESO contribution investments as described in the Regulatory Matters section of this MD&A. The decrease was partially offset by an increase to depreciation as a result of continued investment in capital assets.
Income tax expense (recovery)	(4.9)	The decrease was primarily due to a decrease in deferred tax expense attributable to the utilization of tax loss carryforwards in 2019.

SUMMARY OF QUARTERLY RESULTS

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

($ thousands)	Total Revenues	Net Income
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
June 30, 2019	162,362	34,303
March 31, 2019	159,134	26,717

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. As approved by the AUC, the allowance for funds used during construction ("AFUDC") is recognized in the first and fourth quarters of the year. Seasonality does not significantly affect the Corporation's quarterly operations as approximately 85% of the Corporation's distribution revenue is derived from fixed or largely fixed billing determinants.

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.

June 30, 2020 / 2019

Net income for the three months ended June 30, 2020 decreased $1.4 million compared to the same period in 2019. The decrease was primarily associated with higher depreciation expense as a result of continued capital investment and an increase in income tax expense as a result of lower current period deductions related to AESO contributions. Further contributing to the decrease in net income was a reduction in alternative revenue in 2020, primarily due to the efficiency carry-over mechanism. Net income was further reduced by a decrease in electric rate revenue due to lower energy deliveries and demand resulting from the COVID-19 pandemic and the downturn in the oil and gas sector. Partially offsetting these decreases was an increase in electric rate revenue associated with rate base growth and customer additions and a decrease in cost of sales primarily related to lower general operating expenses attributable to employees and contractors working remotely during the COVID-19 pandemic.

March 31, 2020 / 2019

Net income for the three months ended March 31, 2020 increased $4.8 million compared to the same period in 2019. The increase was primarily due to revenue associated with rate base growth and customer additions, and lower cost of sales primarily due to the timing of contractor costs associated with vegetation management. These increases were partially offset by a decrease in alternative revenue in 2020, primarily due to the efficiency carry-over mechanism. Net income also decreased due to higher depreciation expense associated with continued capital investment and an increase in interest expense as a result of higher short-term borrowings.

SUMMARY OF SELECTED ANNUAL FINANCIAL INFORMATION

The following table sets forth selected annual financial information of the Corporation for the three years ended December 31, 2020, 2019 and 2018:

($ thousands)	2020	2019	2018
Total revenues *(1)*	652,825	649,668	622,529
Net income *(1)*	132,803	130,552	120,028
Assets *(2)*	5,083,881	4,831,498	4,685,287
Non-current liabilities (2)	3,208,528	2,924,414	2,928,313

(1) *See Results of Operations for commentary on total revenues and net income.*
(2) *See Financial Position for a discussion of significant changes in assets and non-current liabilities, including long-term debt.*

FINANCIAL POSITION

The following table outlines the significant changes in the Balance Sheet as at December 31, 2020 as compared to December 31, 2019:

Item	Variance ($ millions)	Explanation
Assets:		
Accounts receivable	(16.9)	The decrease was primarily driven by the timing of collections of transmission related amounts from customers.
Regulatory assets (current and long-term)	56.1	The increase was primarily due to an increase in the deferred income tax regulatory asset of $41.8 million, an increase in the AESO charges deferral of $14.0 million, and the addition of the AESO supply transmission service deferral of $2.1 million.
Property, plant and equipment, net	198.5	The increase was primarily due to continued investment associated with the Corporation's capital program, partially offset by depreciation and customer contributions.
Intangible assets, net	8.6	The increase was primarily due to continued investment in computer software, partially offset by amortization.
Liabilities and Shareholder's Equity:		
Accounts payable and other current liabilities	(34.4)	The decrease was primarily driven by lower amounts payable to the AESO for customer transmission charges, partially offset by higher labour accruals and higher payables associated with capital expenditures.
Regulatory liabilities (current and long-term)	7.6	The increase was primarily due to increases in the non-asset retirement obligation provision of $20.3 million and the incremental capital deferral of $17.4 million, partially offset by a decrease in the AESO charges deferral of $30.4 million.
Other liabilities	46.7	The increase is primarily related to payment received from EPCOR for the rights to provide the regulated retail option services to the Corporation's eligible customers under the Customer Rights Agreement.
Deferred income tax	41.7	The increase was primarily due to higher deductible temporary differences relating to capital asset expenditures.
Debt (including short-term borrowings)	128.6	The increase was primarily due to the issuance of $175.0 million senior unsecured debentures in December 2020 and an increase in short-term borrowings under the committed credit facility of $37.0 million, partially offset by a net repayment of $89.0 million in Fortis demand notes. The overall increase in debt was required to finance the debt component of the Corporation's capital program.
Total shareholder's equity	62.4	The increase was primarily due to net income of $132.8 million and an equity injection of $10.0 million, less dividends paid of $80.0 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; and
- equity contributions from the Corporation's parent company.

STATEMENTS OF CASH FLOWS

	Three months ended December 31			Twelve months ended December 31		
($ thousands)	2020	2019	Variance	2020	2019	Variance
Cash, beginning of period	610	604	6	607	—	607
Cash from (used in):						
Operating activities	151,342	100,867	50,475	325,357	392,592	(67,235)
Investing activities	(103,220)	(98,348)	(4,872)	(383,421)	(373,256)	(10,165)
Financing activities	(48,121)	(2,516)	(45,605)	58,068	(18,729)	76,797
Cash [1], end of period	611	607	4	611	607	4

[1] *Cash is comprised of restricted cash.*

Operating Activities

For the three months ended December 31, 2020, net cash provided from operating activities was $50.5 million higher compared to the same period in 2019. The increase was primarily due to the payment received for the Customer Rights Agreement in December 2020.

For the twelve months ended December 31, 2020, net cash provided from operating activities was $67.2 million lower compared to the same period in 2019. The decrease was primarily due to higher payments to the AESO for transmission related amounts, partially offset by the payment received for the Customer Rights Agreement in December 2020.

The Corporation expects to be able to pay all operating costs and interest expense out of operating cash flows, with some residual available for dividend payments and/or capital expenditures.

Investing Activities

	Three months ended December 31			Twelve months ended December 31		
($ thousands)	2020	2019	Variance	2020	2019	Variance
Capital expenditures:						
Sustainment (1)	62,642	33,013	29,629	188,803	150,851	37,952
Customer growth (2)	22,976	40,603	(17,627)	101,740	151,681	(49,941)
Externally driven and other (3)	11,494	10,934	560	42,198	50,288	(8,090)
Distribution system purchases (4)	—	4,770	(4,770)	—	4,770	(4,770)
AESO contributions (5)	3,132	(8,951)	12,083	39,359	(957)	40,316
Gross capital expenditures	100,244	80,369	19,875	372,100	356,633	15,467
Less: customer contributions	(7,942)	(11,057)	3,115	(34,140)	(43,754)	9,614
Net capital expenditures	92,302	69,312	22,990	337,960	312,879	25,081
Adjustment to net capital expenditures for:						
Indirect capitalized overhead	6,477	5,781	696	26,928	22,801	4,127
Non-cash working capital	(1,438)	11,063	(12,501)	(13,637)	17,109	(30,746)
Costs of removal, net of salvage proceeds	5,551	4,266	1,285	24,463	21,852	2,611
Capitalized depreciation, capital inventory, AFUDC and other	328	7,926	(7,598)	7,707	(1,385)	9,092
Cash used in investing activities	103,220	98,348	4,872	383,421	373,256	10,165

(1) *Includes planned maintenance, urgent replacements, capacity increases, facilities, vehicles and information technology.*

(2) *Includes new customer connections.*

(3) *Includes upgrades associated with substations, line moves, new connections for independent power producers, and SCADA (Supervisory Control and Data Acquisition).*

(4) *Reflects the purchase of the electric distribution system of the Town of Fort Macleod in 2019.*

(5) *Reflects the Corporation's required contributions towards transmission projects as determined by the AUC approved investment levels; paid when transmission projects are approved.*

For the three months ended December 31, 2020, net cash used in investing activities increased $4.9 million as compared to the same period in 2019, primarily due to an increase in sustainment expenditures of $29.6 million for projects associated with planned maintenance and distribution capacity increases. AESO contributions increased $12.1 million compared to 2019 primarily due to project refunds in 2019. Partially offsetting these increases were lower customer growth expenditures of $17.6 million due to a reduction in requests for new customer connections across most customer categories, lower non-cash working capital, and capital inventory.

For the twelve months ended December 31, 2020, net cash used in investing activities increased $10.2 million as compared to the same period in 2019. The increase is primarily attributable to higher AESO contributions of $40.3 million due to a large transmission upgrade project in 2020 and various project refunds in 2019. Sustainment expenditures increased $38.0 million as a result of additional projects associated with planned maintenance and distribution capacity increases. In addition, there were higher capital inventory expenditures during the year in order to secure access to materials during the COVID-19 pandemic. Partially offsetting these increases were the following: (i) lower customer growth expenditures of $49.9 million primarily due to a reduction in requests for new connections across most customer categories (with an offsetting reduction in customer contributions of $9.6 million); (ii) lower non-cash working capital of $30.7 million; and (iii) lower externally driven expenditures of $8.1 million resulting from a decrease in substation upgrade expenditures due to permit and license delays in 2020.

It is expected that ongoing capital expenditures will be financed from funds generated by operating activities, proceeds from the issuance of long-term debt, drawings on the long-term committed credit facility, and equity contributions from Fortis via Fortis Alberta Holdings Inc., the Corporation's parent and an indirectly wholly owned subsidiary of Fortis.

Capital Expenditures Forecast
The Corporation's 2021 forecast of gross capital expenditures is approximately $346.0 million. 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.

Financing Activities
For the three months ended December 31, 2020 cash from financing activities decreased $45.6 million compared to the same period in 2019. In the fourth quarter of 2020, the Corporation completed a $175.0 million long-term debt issuance, repaid a $150.0 million bilateral credit facility, made net repayments of $64.0 million under the committed credit facility, received a $10.0 million equity contribution, and paid dividends of $20.0 million. During the fourth quarter of 2019, the Corporation received an $89.0 million demand note from Fortis, made net repayments of $70.0 million under the committed credit facility, and paid dividends of $18.7 million.

For the twelve months ended December 31, 2020 cash from financing activities increased $76.8 million compared to the same period in 2019, primarily due to lower cash from operating activities available to finance investing activities. In the twelve months ended December 31, 2020, the Corporation completed a $175.0 million long-term debt issuance, made net borrowings of $37.0 million under the committed credit facility, increased bank indebtedness by $6.3 million, repaid the $89.0 million demand note from Fortis, paid dividends of $80.0 million, and received an equity contribution of $10.0 million. During the same period in 2019, the Corporation made net repayments of $45.0 million under the committed credit facility, reduced bank indebtedness by $7.5 million, received an $89.0 million demand note from Fortis, paid dividends of $75.0 million, and received an equity contribution of $20.0 million.

The Corporation anticipates it will be able to meet interest payments on outstanding indebtedness from operating cashflows but expects to rely upon the proceeds of new indebtedness to meet the principal obligations when due.

CONTRACTUAL OBLIGATIONS

The Corporation's contractual obligations as at December 31, 2020 were as follows:

($ thousands)	Total	2021	2022-2023	2024-2025	Thereafter
Principal payments on long-term debt *(1)*	2,360,000	—	—	150,000	2,210,000
Interest payments on long-term debt	2,318,625	105,930	211,860	206,910	1,793,925
Joint use agreement *(2)*	45,500	2,275	4,550	4,550	34,125
Other *(3)*	7,698	3,493	3,985	220	—
Total contractual obligations	4,731,823	111,698	220,395	361,680	4,038,050

(1) *Payments are shown exclusive of discounts.*
(2) *The Corporation and an Alberta transmission service provider have entered into an agreement to allow for joint attachments of distribution facilities to the transmission system. The agreement remains in effect, in perpetuity, until the Corporation no longer has attachments to the transmission system. Due to the unlimited duration of this contract, the calculation of future payments after year 2025 includes payments to the end of 20 years. However, the payments under this agreement may continue into the future for an indeterminable period of time.*
(3) *Other contractual obligations include performance and restricted share unit obligations, defined benefit pension contributions, and operating leases for facilities and office premises. During the third quarter of 2020, the Corporation filed an actuarial valuation of the defined benefit component of the pension plans for funding purposes as at December 31, 2019 with Alberta Finance. The actuarial valuation set the minimum funding contributions for 2020 through 2022 at approximately $0.6 million per year.*

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 Fortis Alberta Holdings Inc.

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.

The Corporation has items on its balance sheet outside of its regulated operations, such as goodwill, that are not contemplated in the regulated capital structure. These items are financed primarily through equity contributions and result in an overall ratio that differs from the regulated capital structure.

Summary of Capital Structure

As at December 31	2020		2019	
	$ millions	%	$ millions	%
Total debt	2,388.8	60.3	2,260.3	59.9
Shareholder's equity	1,572.8	39.7	1,510.4	40.1
	3,961.6	100.0	3,770.7	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 December 31, 2020, the Corporation was in compliance with these externally imposed capital requirements.

In December 2020, the Corporation entered into an agreement with a syndicate of agents, to sell $175.0 million of senior unsecured debentures at a rate of 2.63%, to be paid semi-annually, and mature in 2051. The net proceeds of the issuance were used to primarily repay existing indebtedness incurred under the bilateral and long-term credit facilities.

As at December 31, 2020, the Corporation had an unsecured committed credit facility with an available amount of $250.0 million maturing in August 2024. Drawings under the long-term credit facility are available by way of prime loans, bankers' acceptances and letters of credit. Prime loans bear an interest rate of prime and bankers' acceptances are issued at the applicable bankers' acceptance discount rate plus a stamping fee of 1.0%. The weighted average effective interest rate for the year ended December 31, 2020 on the long-term credit facility was 2.6% (2019 - 3.7%). As at December 31, 2020, the Corporation had $37.0 million drawn on the long-term credit facility (December 31, 2019 - $nil) and $0.4 million drawn in letters of credit (December 31, 2019 - $0.4 million).

In March 2020, the Corporation negotiated a $150.0 million non-revolving one-year bilateral credit facility. In December 2020, the Corporation repaid all borrowings, and the facility was terminated upon repayment. The weighted average effective interest rate for the year ended December 31, 2020 on the bilateral credit facility was 1.1%.

As at December 31, 2020, the Corporation had no demand notes outstanding with Fortis (December 31, 2019 - $89.0 million). Demand note bears interest approximating the bankers' acceptance discount rate plus a stamping fee of 1.0%.

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 December 31, 2020:

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

During 2020, DBRS Morningstar and S&P issued updated credit rating reports confirming the Corporation's rating and outlook.

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 $0.4 million as at December 31, 2020 (December 31, 2019 – $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 from or to related parties were measured at the exchange amount and were as follows at December 31:

($ thousands)	2020	2019
Accounts receivable		
Loans [(1)]	31	41
Related parties	4	239
	35	280
Accounts payable and other current liabilities		
Related parties [(2)]	2,445	—
Short-term borrowings		
Related party [(3)]	—	89,000

(1) *These loans are to officers of the Corporation for employee share purchase plan loans.*
(2) *This reflects charges from related parties associated with information technology services.*
(3) *This was for a demand note from Fortis that was repaid in the first quarter of 2020.*

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 of $3.2 million (December 31, 2019 – $nil) are included in intangible assets and measured at the exchange amount at the date of the transaction.

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

	Three months ended December 31		Twelve months ended December 31	
($ thousands)	2020	2019	2020	2019
Included in other revenue [(1)]	24	296	241	301
Included in cost of sales [(2)]	1,241	870	4,927	4,750
Included in interest expense [(3)]	—	192	512	268

(1) *Includes services provided to related parties, including Fortis and subsidiaries of Fortis, related to information technology, material sales and intercompany employee services.*
(2) *Includes charges from related parties, including Fortis and subsidiaries of Fortis, 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 from Fortis.*

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

FINANCIAL INSTRUMENTS

The following table represents the fair value measurements of the Corporation's financial instruments as at December 31:

Long-term debt ($ thousands)	2020	2019
Fair value [1]	3,098,239	2,722,054
Carrying value [2]	2,358,721	2,183,688

[1] *The fair value of the long-term debt was estimated using level 2 inputs. It is 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 $16,386 (December 31, 2019 – $15,633).*

The fair value of the Corporation's financial instruments reflect a point-in-time estimate based on current and relevant market information about the instruments as at the balance sheet dates. The estimates cannot be determined with precision as they involve uncertainties and matters of judgment 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. The Corporation's critical accounting estimates are discussed below.

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 twelve months ended December 31, 2020.

Regulation

Generally, the accounting policies of the Corporation are subject to examination and approval by the AUC. The timing of recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that otherwise expected for entities not subject to rate regulation. Certain estimates are necessary since the regulatory environment in which the Corporation operates often requires amounts to be recorded at estimated values until finalization and adjustment, if any, are determined pursuant to subsequent regulatory decisions or other regulatory proceedings. The final amounts approved by the AUC for deferral as regulatory assets and liabilities and the approved recovery or settlement periods may differ from those originally expected. Any resulting adjustments to original estimates are recognized in the period they become known.

Revenue Recognition

Revenues are recognized as earned, at AUC approved rates where applicable, including amounts recognized on an accrual basis for services rendered but not yet billed. The unbilled revenue accrual at the end of each period is based on the difference between the forecast revenue and the actual amounts billed. The development of the revenue forecast is based upon numerous assumptions such as energy deliveries, customer sites, economic activity and weather conditions.

Expense Accruals

Expenses and liabilities are recognized as incurred, including amounts recognized on an accrual basis for expenses or liabilities incurred but not yet invoiced. These accruals are made based upon estimates of the value of services rendered or goods received that are not yet invoiced, or for liabilities incurred.

Depreciation and Amortization

Depreciation and amortization estimates are based on depreciation and amortization rates derived from capital asset balances and depreciation parameters, including the service life of assets and expected net salvage percentages. Management annually assesses if updates are required to depreciation and amortization rates based on changes in capital asset balances and new information related to the service life of assets.

Income Tax

Income tax is determined based on estimates of the Corporation's current income tax and estimates of deferred income tax resulting from temporary differences between the carrying value of assets and liabilities in the financial statements and their income tax values. A deferred income tax asset or liability is determined for each temporary difference based on enacted income tax rates and laws in effect when the temporary differences are expected to be recovered or settled. Income tax benefits associated with income tax positions taken, or expected to be taken, on an income tax return are recognized only when the more likely than not threshold is met. The income tax benefits are measured at the largest amount of benefit that is greater than 50% likely of being realized upon settlement.

Pension and Other Post-Employment Benefits

The Corporation's defined benefit pension plans and the other post-employment benefit plan are subject to judgments utilized in the actuarial determination of the expense and the related obligation. The primary assumptions utilized by management in determining the expense and obligation are the discount rate and the expected long-term rate of return on plan assets. Other assumptions utilized are the average rate of compensation increase, average remaining service life of the active employee group, employee and retiree mortality rates, extended health care trend rate and dental care cost trend rate. All assumptions are assessed and concluded on, in consultation with the Corporation's external actuarial advisor.

Discount rates, which are used to determine the projected benefit obligation, reflect market interest rates on high quality bonds with cash flows that match the timing and amount of expected pension benefit payments. This methodology is consistent with that used to determine the discount rates in the previous year.

As in previous years, the Corporation's actuary provides a range of expected long-term pension asset returns based on the actuary's internal modeling. The expected long-term return on pension plan assets used falls within the conservative to normal range as indicated by the actuary.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of net identifiable assets on the acquisition of a business. The goodwill recognized in the financial statements primarily results from push-down accounting applied when the Corporation was acquired by Fortis in 2004. Goodwill, which is not amortized, is recorded at initial cost less any write-down for impairment.

The carrying value of goodwill is assessed for impairment annually, or more frequently if events or changes in circumstances arise that suggest the carrying value of goodwill may be impaired. If that is the case, goodwill is written down to estimated fair value and an impairment loss is recognized. No such event or change in circumstances occurred during the year ended December 31, 2020.

The Corporation's assessment of impairment of goodwill is performed annually in October and indicated that no impairment was required for the years ended December 31, 2020 and 2019.

Contingencies

The Corporation is subject to various legal proceedings and claims that arise in the ordinary course of business operations. It is management's judgment that the amount of liability, if any, from these actions would not have a material effect on the Corporation's financial statements.

CHANGES IN ACCOUNTING POLICIES

Accounting for Credit Losses

Effective January 1, 2020, the Corporation adopted Accounting Standards Codification ("ASC") 326, *Financial Instruments - Credit Losses*, which requires the use of reasonable and supportable forecasts in the estimate of credit losses and the recognition of expected losses upon initial recognition of a financial instrument, in addition to using past events and current conditions. The Corporation records an allowance for credit losses to reduce accounts receivable on the Balance Sheets for amounts estimated to be uncollectible. The allowance is estimated based on historical collection patterns, the current and forecasted economic environment, and other conditions. Accounts receivable are written off in the period in which they are deemed uncollectible. The ASC was adopted using a modified retrospective approach and did not have a material impact on the financial statements.

Cloud Computing Arrangements

Effective January 1, 2020, the Corporation adopted Accounting Standard Update ("ASU") 2018-15, *Customer's Accounting for Implementation Costs incurred in a Cloud Computing Arrangement that is a Service Contract.* Principally, the ASU aligns the requirements for capitalizing implementation costs incurred in a cloud computing arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software. Eligible implementation costs are recorded to other assets on the Balance Sheets and amortized to cost of sales on the Statements of Income and Comprehensive Income over the economic life of the cloud computing arrangement. The ASU was adopted using a prospective approach and did not have a material impact on the financial statements.

FUTURE ACCOUNTING PRONOUNCEMENTS

The Corporation considers the applicability and impact of all ASUs issued by the Financial Accounting Standards Board ("FASB"). The following updates have been issued by the FASB but have not yet been adopted by the Corporation. Any ASUs not included below were assessed and determined to be not applicable to the Corporation or are not expected to have a material impact on the financial statements.

Simplifying the Accounting for Income Taxes

ASU 2019-12, *Income Taxes (Topic 740), Simplifying the Accounting for Income Taxes* was issued in December 2019, providing amendments to reduce complexity in the accounting standard. The new guidance is effective January 1, 2021 and the sections applicable to the Corporation will be applied on a prospective basis. The Corporation has substantially completed its analysis and does not expect the adoption of the ASU to have a material impact on the financial statements.

BUSINESS RISK AND RISK MANAGEMENT

Regulatory

The regulated operations of the Corporation are subject to the uncertainties faced by regulated utility companies. Those uncertainties include whether customer rates approved by the AUC will provide a reasonable opportunity to the Corporation for recovery of the estimated costs of providing utility services, including a fair return on the portion of approved rate base funded by the equity component of the capital structure, on a timely basis. The ability of the Corporation to recover the actual costs of providing services and to earn the approved ROE depends on the Corporation's ability to operate using the revenues provided through regulatory mechanisms.

Through the regulatory process, the AUC approves the allowed ROE for rate-making purposes and capital structure. Regulatory treatment that allows the Corporation to earn a fair risk-adjusted rate of return, comparable to that available on alternative investments of similar risk, is essential for maintaining access to capital.

The fundamental risk faced by all regulated utilities is that the regulator-approved rates will not provide sufficient revenue to recover all of the costs associated with providing service. During the PBR term, the formula that determines annual customer rates exposes the Corporation to the following specific risks: (i) that the Corporation will experience inflationary increases in excess of the inflationary factor set by the AUC in the formula; (ii) that the Corporation will be unable to achieve the productivity improvements expected over the PBR term; (iii) that the costs related to the Corporation's capital expenditures will be in excess of that provided for in the base formula and the incremental capital funding mechanism; and (iv) that material unforeseen costs will be incurred and that they will not qualify, or be approved, as a Z factor.

The Corporation's rate base, including the cost of replacement or upgrades to existing facilities and the addition of new facilities, continue to require the approval of the AUC. There is no assurance that the Corporation will receive regulatory orders in a timely manner, and the Corporation may incur costs prior to having approved rates. A failure to obtain approval of capital expenditures may adversely affect the Corporation's results of operations or financial position.

In the interest of regulatory efficiency, the AUC can employ generic proceedings to address regulatory matters that impact multiple utilities. While generic proceedings allow for regulatory efficiencies, there is the risk that a collective result will not adequately address individual utility circumstances.

Utility Asset Disposition ("UAD")

The Corporation is exposed to the risk that the unrecovered costs associated with utility assets subsequently deemed by the AUC to have been subject to an extraordinary retirement, including removals from service resulting from sudden obsolescence, will not be recoverable from customers. This exposure persists in the wake of the AUC's Decision 2013-417 (the "UAD Decision") and the previous provincial government's decision to remove portions of Bill 13, *An Act to Secure Alberta's Energy Future*, which were intended to address utility asset disposition related risks by legislative means. Currently, the Corporation has no asset retirements considered to be extraordinary.

Regulated Rate Option

As an owner of an electricity distribution network under the *EUA*, the Corporation is required to act, or to authorize a substitute party to act, as a provider of electricity services, including the wholesale purchase and retail sale of electricity, to eligible customers under a regulated rate and to appoint a retailer as default supplier to provide electricity services to customers otherwise unable to obtain electricity services. In order to remain solely a distribution utility, the Corporation appointed EPCOR as its regulated rate and default provider. As a result of this appointment, EPCOR assumed all of the Corporation's contractual rights and obligations in respect of the provision of these services. In the unlikely event that EPCOR is unable or unwilling to act as regulated rate provider or as default supplier, and no other party is willing to act as regulated rate provider or as default supplier, the Corporation would be required under the *EUA* to act as a provider of electricity services to eligible customers under a regulated rate or to provide electricity services to customers otherwise unable to obtain electricity services. If the Corporation could not secure outsourcing for these functions, the Corporation would be required to administer these responsibilities by adding staff, facilities, and/or equipment, as necessary.

Loss of Service Areas

The Corporation serves customers residing within various municipalities throughout its service areas. Periodically, municipal governments in Alberta give consideration to creating their own electricity distribution utilities by purchasing the assets of the Corporation located within their municipal boundaries. Upon the termination of a franchise agreement, a municipality has the right, subject to AUC approval, to purchase the Corporation's assets within its municipal boundaries pursuant to the *Municipal Government Act,* with the price based upon replacement cost less depreciation and to be as agreed to by the Corporation and the municipality. Failing an agreement between the parties, the price is to be determined by the AUC.

Additionally, under the *HEEA*, if a municipality that owns an electricity distribution system expands its boundaries, the municipality can acquire the Corporation's assets in the annexed area. In such circumstances, the *HEEA* provides that the AUC may determine that the municipality should pay compensation to the Corporation for any facilities transferred on the basis of replacement cost less depreciation. Given the historical population and economic growth of Alberta and its municipalities, the Corporation is occasionally affected by transactions of this type.

Within certain portions of the Corporation's service area that overlaps with REAs, consumers who chose to voluntarily become members have the right to obtain electric distribution service from an REA as defined in the integrated operating agreements between the Corporation and those REAs.

In general, eligibility criteria originally limited the provision of service to REA members whose land is used for agricultural activity. However, as a result of the outcome of an arbitration completed in 2016 between the Corporation and EQUS REA, Ltd. ("EQUS"), an integrated operating agreement was established between the Corporation and EQUS that does not contain eligibility criteria. As currently framed, the integrated operating agreement with EQUS may result in consumers choosing to receive service from EQUS in overlapping areas, where they previously would have been obligated to take service, except agricultural/farm service, from the Corporation.

The consequence to the Corporation of a municipality purchasing its distribution assets or the loss of the opportunity to serve consumers receiving distribution services from a REA would be a reduction in revenue associated with the loss of these customers and the consequent transfer of assets.

Government Policies Impacting the Electricity Industry

The regulatory framework under which the Corporation operates is impacted by significant shifts in government policy and/or changes in government, which creates uncertainty about public policy priorities and directions, particularly around electricity and environmental issues. The regulations that govern the competitive wholesale and retail electricity markets in Alberta continue to evolve and the extent to which the Government of Alberta may participate in, and make adjustments to, the regulations cannot be foreseen. If significant changes were to occur in these regulations, it could adversely affect the ability of the Corporation to recover its costs or to earn a reasonable return on its capital.

Capital Resources and Liquidity

The Corporation's financial position could be adversely affected if it fails to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and the repayment of maturing debt. Funds generated from operations after payment of expected expenses, including interest payments on any outstanding debt, will not be sufficient to fund all anticipated capital expenditures and the repayment of all outstanding liabilities when due. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including regulatory approval or exemption, the regulatory environment in Alberta, the results of operations and financial position of the Corporation and Fortis, conditions in the capital and bank credit markets, the credit ratings assigned by rating agencies, and general economic conditions. There can be no assurance that sufficient capital will be available on acceptable terms to fund capital expenditures and repay existing debt.

Economic Conditions

Alberta's economy is impacted by a number of factors including the level of oil and gas exploration and production activity in the province, which is influenced by the market prices of oil and gas, government mandated oil production limits and access to market. A general and extended decline in Alberta's economy would be expected to have the effect of reducing requests for electricity service over time and may increase the number of salvaged sites. Significantly reduced requests for services in the Corporation's service areas and existing customers reduced demand and energy consumption could materially reduce the Corporation's revenues and its capital spending forecast, specifically related to customer growth, externally driven and AESO contribution expenditures. A reduction in capital spending would, in turn, affect the Corporation's rate base and earnings growth.

In 2020, Alberta experienced a notable economic downturn related to the combined impacts of the COVID-19 pandemic and a decline in world oil prices. There were no material impacts to the Corporation's revenues in 2020 as approximately 85% of the Corporation's distribution revenue is derived from fixed or largely fixed billing determinants. However, the Corporation's revenues and capital program in future years may be impacted by a reduction in requests for electricity service, an increased number of salvaged sites, and reduced demand and energy consumption.

Economic Impacts of the COVID-19 Pandemic

In March 2020, the World Health Organization declared COVID-19 a pandemic. The result was significant disruptions to businesses, including the closure of non-essential businesses and educational institutions, the imposition of travel restrictions, and a global economic slowdown. The COVID-19 pandemic is an evolving situation that has caused volatility in capital markets and adversely impacted economic activity and conditions around the world. The timing, availability and administration of vaccines are expected to affect the duration and extent of the pandemic. The impact of the COVID-19 pandemic on the Corporation's operational and financial performance is expected to evolve through the duration of the pandemic. While the following potential impacts to the Corporation may not materialize or significantly change, they are being considered and monitored. At the time of filing this MD&A, potential areas that could be impacted include, but are not limited to, availability of personnel, energy usage and revenues, customer retention, the timing of capital expenditures, supply chain, the amount and timing of operating and maintenance expenses, ability to access debt markets, timing of regulatory filings, valuation of goodwill, valuation of long-lived assets and accounts receivable valuation.

Counterparty risk with retailer billings arising from the pandemic is mitigated through the Corporation obtaining an acceptable form of prudential, which includes a cash deposit, a letter of credit, an investment grade credit rating from a major rating agency, or a financial guarantee from an entity with an investment grade credit rating. Currently, the Corporation does not expect a significant change in risk related to its retailer billings. The Corporation continues to provide safe and reliable electric service to customers, restrict business travel, and allow employees and contractors who can remain off-site to continue to do so by working remotely.

The duration and extent of the pandemic will continue to inform the Corporation's assessment of the financial impacts on its operations, financial condition and liquidity. At the time of filing this MD&A, there is uncertainty around both the duration and the extent of the virus' impact and therefore it is unclear as to whether the COVID-19 pandemic will have a material adverse effect on the Corporation.

Continued Reporting in Accordance with US GAAP
In December 2017, the OSC approved the extension of the Corporation's exemptive relief order which permits the Corporation to continue reporting in accordance with US GAAP, until the earliest of: (i) January 1, 2024; (ii) the first day of the financial year that commences after the Corporation ceases to have activities subject to rate regulation; or (iii) the effective date prescribed by the IASB for the mandatory application of a standard within IFRS specific to entities with activities subject to rate regulation.

In January 2021, the IASB issued an exposure draft, *Regulatory Assets and Regulatory Liabilities* (the "Exposure Draft"), that is expected to result in a permanent mandatory standard specific to companies subject to rate regulation. If the OSC relief does not continue as detailed above, the Corporation may then be required to become a United States Securities and Exchange Commission registrant in order to continue reporting under US GAAP, otherwise the Corporation would be required to adopt IFRS.

The impact of a standard based on the Exposure Draft cannot be fully assessed at this time.

Operating and Maintenance
The Corporation is required to operate and maintain its electric distribution system in a manner that enables the provision of safe and reliable utility service to customers and that will ensure the safety of employees, contractors and the general public. An inability to discharge these responsibilities may result in material adverse consequences for the Corporation.

The Corporation's distribution assets require normal course maintenance, improvement and replacement in accordance with applicable standards. The Corporation determines expenditures that must be made to maintain and replace equipment in order to ensure the continued safe and reliable operation of its distribution assets. An inability on the part of the Corporation to perform required work in a timely manner may result in increased costs and service disruptions for customers.

The Corporation continually develops expenditure programs and assesses current and future operating and maintenance expenses that will be incurred in the ongoing operation of its distribution assets. The Corporation's analysis is based on assumptions as to the costs of services and equipment, regulatory requirements, revenue requirement approvals, and other matters, all of which are uncertain. If the Corporation's actual costs to provide utility services exceed AUC approved customer rates these additional costs may not be recoverable through rates. An inability to recover these additional costs could have a material adverse effect on the financial condition and results of operations of the Corporation.

Permits and Rights-of-Way
The acquisition, ownership and operation of distribution assets requires numerous permits, approvals and certificates from federal, provincial and municipal government agencies and from First Nations. The Corporation may not be able to obtain or maintain all required approvals. If there is a delay in obtaining any required approval, or if the Corporation fails to maintain or obtain any required approval or fails to comply with any applicable law, regulation or condition of an approval, the operation of its assets and the distribution of electricity could be prevented or become subject to additional costs, any of which could have a material adverse effect on the Corporation.
It is frequently necessary for portions of the Corporation's power lines to cross certain private and public lands. In those cases, the Corporation must secure permission to cross such lands through easements or rights-of-way. The inability to secure such easements or rights-of-way could increase the costs to provide distribution service beyond amounts forecast in customer rates.

Certain of the Corporation's distribution assets may be located on land that is not known to be deeded and for which it has not acquired appropriate rights. In addition, the Corporation has distribution assets on First Nations' lands, for which access permits are held by TransAlta Utilities Corporation ("TransAlta"). In order for the Corporation to acquire these access permits, both the individual First Nations and Crown-Indigenous Relations and Northern Affairs Canada must grant approval. The Corporation may not be able to acquire the access permits from TransAlta and may be unable to negotiate land usage agreements with property owners or, if negotiated, such agreements may be on terms that are less than favourable to the Corporation and, therefore, may have a material adverse effect on the Corporation.

Environmental
The Corporation is subject to numerous laws, regulations and guidelines governing the generation, management, storage, transportation, recycling and disposal of hazardous substances and other waste materials, and otherwise relating to the protection of the environment. Environmental damages and associated costs could arise due to a variety of events, including the impact of severe weather on the Corporation's facilities, human error or misconduct, or equipment failure. Costs arising from compliance with such environmental laws, regulations and guidelines may become material to the Corporation. In addition, the process of obtaining environmental permits and approvals, including any necessary environmental assessments, can be lengthy, contentious and expensive. The Corporation would seek to recover the costs associated with environmental protection, compliance and damage in customer rates; however, there is no assurance that such costs will be recoverable through rates and, if substantial, unrecovered costs may have a material adverse effect on the Corporation's results of operations, cash flow and financial position.

The Corporation is also subject to the risk of contamination of air, soil and water primarily related to the use and/or disposal of petroleum-based products, mainly transformer, hydraulic and lubricating oil, in the Corporation's day-to-day operating and maintenance activities. Contamination typically occurs through the accidental release of transformer or lubricating oils either through equipment failure or human error. The Corporation could be found to be responsible for remediation of contaminated properties, whether or not such contamination was actually caused by the Corporation. Environmental laws make owners, operators and senior management subject to prosecution or administrative action for breaches of environmental laws, including the failure to obtain regulatory approvals. Changes in environmental laws governing contamination could lead to significant increases in costs to the Corporation.

To identify, mitigate and monitor environmental performance the Corporation has established an Environmental Management System ("EMS"). The Corporation's EMS is consistent with the principles of the International Organization for Standardization 14001. The Corporation has an independent external audit completed every three years on the entire EMS to ensure compliance with International Organization for Standardization 14001. The most recent external EMS audit was completed in the third quarter of 2018. As at December 31, 2020, there were no environmental liabilities recorded in the Corporation's financial statements and there were no unrecorded environmental liabilities known to management.

Wildfire
Electric distribution facilities have the potential to cause fires as a result of equipment failure, trees falling on and lightning strikes to distribution lines or equipment, and other causes. Risks associated with fire damage are related to weather, the extent of forestation and grassland cover, habitation and third-party facilities located on or near the land on which the facilities are situated. The Corporation may become liable for fire suppression costs, regeneration and timber value costs, and third-party claims in connection with fires on land where facilities are located if it is found that such facilities were the cause of a fire, and such claims, if successful, could be material.

The Corporation has a wildfire agreement with the Government of Alberta (the "Crown"), which limits the Corporation's liability for the Crown's forest fire suppression costs in the forest protection area. The agreement allows the Corporation to limit its liability to 25% of the fire suppression costs to a maximum of $100,000 per incident, following approval by the Crown of the Corporation's annual wildfire management plan for wildfire prevention. Absent this approval or work not completed as per the annual wildfire management plan, the Corporation's liability is limited to 50% of the fire suppression costs to a maximum of $200,000 per incident. The Corporation's wildfire management plan is presented for approval annually, prior to the wildfire season, with the most recent approval being received in February 2020 and effective March 1, 2020.

While the Corporation maintains insurance for costs associated with fires, including fire suppression costs and liability for third-party claims, the insurance is subject to coverage limits as well as time-sensitive claims discovery and reporting provisions, and there can be no assurance that the liabilities that may be incurred by the Corporation will be covered by its insurance.

Weather and Climate-Change
The Corporation's physical assets are exposed to the effects of severe weather conditions and other acts of nature, some of which could be caused by climate-change. Although the physical assets have been constructed and are operated and maintained to withstand severe weather and other acts of nature, there is no assurance that they will successfully do so in all circumstances. Many of the physical assets are located in remote areas that makes it more difficult to perform maintenance and repairs if such assets are damaged. Losses resulting from repair costs and lost revenues could substantially exceed insurance coverage. Furthermore, the Corporation could be subject to claims from its customers for damages caused by the failure to transmit or distribute electricity to them in accordance with the Corporation's contractual obligations.

In the event of a material uninsured loss or liability caused by severe weather conditions or other acts of nature, the Corporation may apply to the AUC to recover such losses through customer rates. However, in light of the AUC's UAD Decision there is a risk that such losses could be deemed an "extraordinary retirement" and that any unrecovered costs associated with the loss of utility assets due to severe weather conditions or other acts of nature would not be recovered from customers.

Insurance Coverage
The Corporation maintains insurance coverage at all times with respect to certain potential liabilities and the accidental loss of value of certain of its assets, in amounts and with such insurers, as it considers appropriate, taking into account relevant factors, including the practices of owners of similar assets and operations. However, the Corporation's distribution assets are not covered by insurance, as is customary in North America, as the coverage is not readily available nor is the cost of the coverage considered economically viable.

It is anticipated that existing insurance coverage will be maintained. However, there can be no assurance that the Corporation will be able to obtain or maintain adequate insurance in the future at rates it considers reasonable or that insurance will continue to be available on terms as favourable as the Corporation's existing arrangements, or that insurance companies will meet their obligation to pay claims. Further, there can be no assurance that available insurance will cover all losses or liabilities that may arise in the conduct of the Corporation's business. The occurrence of a significant uninsured claim, a claim in excess of the insurance coverage limits maintained by the Corporation, or a claim that falls within a significant self-insured retention could have a material adverse effect on the Corporation's results of operations, cash flow, and financial position.

In the event of a material uninsured loss or liability, the Corporation may apply to the AUC to recover such losses through customer rates. However, in light of the AUC's UAD Decision, there is a risk that such losses could be deemed an "extraordinary retirement" and that any unrecovered costs associated with the loss of utility assets would not be recoverable from customers.

Information and Operations Technology and Cybersecurity
The Corporation's ability to operate effectively is dependent upon developing and maintaining information systems and infrastructure that support the operation of its distribution facilities, provide the electricity market with billing and load settlement information and support the financial and general operating aspects of the business.

Exposure of the Corporation's information and operations technology systems to external threats poses a risk to the security of these systems and information. Such cybersecurity threats include unauthorized access to information and operations technology systems due to hacking, viruses and other causes that can result in service disruptions, acts of war or terrorism, system failures and the deliberate or inadvertent disclosure of confidential business, employee and customer information.

The Corporation is required to protect information and operations technology systems and to safeguard the confidentiality of business, employee and customer information in order to operate effectively and to comply with regulatory and legal requirements. The Corporation has security measures, systems, policies and controls designed to protect and secure the integrity of its information and operations technology systems; however, cybersecurity threats frequently change and require ongoing monitoring and detection capabilities. In the event the Corporation's information and operations technology security measures are breached, it could experience service disruptions, property damage, or corruption or unavailability of critical data or confidential business, employee and customer information. A material breach could adversely affect the financial performance of the Corporation, its reputation and standing with customers, regulators, or financial markets and expose it to claims for third-party damage. The financial impact of a material breach in cybersecurity, act of war or terrorism could be material and may not be covered by insurance policies or, in the case of utilities, through regulatory recovery.

Cybersecurity breaches, acts of war or terrorism, grid disturbances or security breaches involving the misappropriation of sensitive, confidential and proprietary customer, employee, financial or system operating information could significantly disrupt the Corporation's business operations and have an adverse effect on its reputation. The Corporation assessed its cybersecurity measures and continues to strengthen and protect the Corporation's technological infrastructure from potential malicious attacks as employees continue to work remotely during the COVID-19 pandemic.

Labour Relations

Approximately 79% of the employees of the Corporation are members of the United Utility Workers' Association ("UUWA"). The Corporation's three-year Collective Agreement with the UUWA expired on December 31, 2020. In the fourth quarter of 2020, the Corporation and the UUWA entered into collective bargaining negotiations, which are ongoing. The Corporation considers its relationship with the UUWA to be satisfactory; however, there can be no assurance that current relations will not be impacted through the collective bargaining process. The inability to maintain a collective bargaining agreement on acceptable terms could result in increased labour costs or costs associated with service interruptions arising from labour disputes not provided for in customer rates, which could have a material adverse effect on the Corporation's results of operations, cash flow, and financial position.

Human Resources

The Corporation's ability to deliver service in a cost-effective manner is dependent on the ability of the Corporation to attract, develop and retain a skilled workforce. Given the demographics of the Corporation's workforce, there will likely be an increase in retirement of critical workforce segments in future years. Meeting the capital program and customer expectations could be challenging if the Corporation does not continue to attract and retain qualified personnel.

Note: Additional information, including the Corporation's Annual Information Form and Audited Financial Statements, 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.