FORTISALBERTA INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the three and twelve months ended December 31, 2019

February 12, 2020

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, 2019, prepared in accordance with accounting principles generally accepted in the United States of America ("US GAAP"). In December 2017, the Ontario Securities Commission approved the extension of the Corporation's exemptive relief to continue reporting under US GAAP rather than International Financial Reporting Standards ("IFRS") until the earlier of January 1, 2024 and the effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within IFRS specific to entities with activities subject to rate regulation. All financial information presented in this MD&A has been derived from the Audited Financial Statements for the year ended December 31, 2019 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 2020. 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" 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; political risk; a severe and prolonged economic downturn; environmental risks; capital resources and liquidity risks; operating and maintenance risks; weather conditions in geographic areas where the Corporation operates; 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 126,000 kilometres in central and southern Alberta, which serves approximately 568,000 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''). Fortis is a leader in the North American regulated electric and gas utility business, with 2019 revenue of $8.8 billion and total assets of approximately $53 billion at December 31, 2019. Approximately 9,000 Fortis employees serve utility customers in five Canadian provinces, nine US states and three Caribbean countries.

The Corporation is regulated by the Alberta Utilities Commission (the "AUC") pursuant to the *Alberta Utilities Commission Act* (the "*AUC Act*"). 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 *AUC Act*, 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.

REGULATORY MATTERS

Performance-Based Regulation

Effective January 1, 2013, the AUC prescribed that distribution utilities in Alberta, including the Corporation, move to a form of rate regulation referred to as performance-based regulation ("PBR") for an initial five-year term, from 2013 to 2017. Effective January 1, 2018, the AUC approved a second PBR term, from 2018 to 2022.

Under PBR, a formula incorporating an inflation factor and a productivity factor (I-X) (the "formula"), that estimates inflation (I) annually and assumes a set level of productivity improvements (X), is used to determine distribution rates on an annual basis. Each year this formula is applied to the preceding year's distribution rates.

The first PBR term included mechanisms for the recovery or settlement of items determined to flow through directly to customers ("Y factor") and the recovery of costs related to capital expenditures that were not being recovered through the formula ("K factor" or "capital tracker"). The AUC also approved a Z factor, a PBR re-opener and an efficiency carry-over mechanism. The Z factor permitted an application for recovery of costs related to significant unforeseen events. The PBR re-opener permitted 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 was associated with certain thresholds. The efficiency carry-over mechanism provided an incentive by permitting a utility to continue to benefit from efficiency gains achieved during the PBR term for two years following the end of that term. If a utility achieves a return on equity over a PBR term greater than the approved return, the utility is eligible to collect additional PBR revenue, calculated to a maximum of 50 basis points on the equity portion of the notional rate base, for the first two years of the subsequent term.

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, from 2018 to 2022.

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% return on equity ("ROE") and a capital structure of 37% equity and 63% debt applied to notional 2017 rate base assets. 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 a 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 2019, the Corporation's ROE has been maintained at 8.50%, with a capital structure of 37% equity and 63% debt.

The second PBR term incorporates mechanisms consistent with those in the first PBR term, except that 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 term 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 going-in 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. In the Second-Term Compliance Decision, the AUC refused all utility requests for certain anomalous cost adjustments to be applied in the determination of the notional 2017 going-in revenue requirement and confirmed the K-Bar capital funding mechanism. The AUC also determined that depreciation matters would not be considered in rebasing. The Corporation filed a Review and Variance Application in respect of these matters and sought permission to appeal the Second-Term Compliance Decision to the Alberta Court of Appeal.

In March 2018, the Corporation submitted a Rebasing Compliance Filing (the "Rebasing Compliance Filing") in accordance with the Second-Term Compliance Decision. In October 2018, the AUC issued Decision 23355-D02-2018 (the "Rebasing Compliance Decision") confirming the Corporation's calculation of the notional 2017 revenue requirement and the 2018 K-Bar amount, as determined in the Second-Term Compliance Decision, and directed the Corporation to true-up its PBR rates for 2018 and 2019 accordingly in an update to its 2019 Annual Rates Application as discussed below.

In October 2018, the AUC issued Decision 23479-D02-2018 in respect of the Review and Variance Application for the Second-Term Compliance Decision that led to the AUC initiating a review 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. The Corporation filed its evidence for this review proceeding in March 2019. The AUC held a stakeholder consultation meeting in September 2019. In January 2020, the AUC issued a decision establishing new criteria for anomaly adjustments for the second PBR term and requested the PBR utilities submit their intent to file an application. The Corporation filed an intent to submit an application in February 2020.

In May 2019, the AUC initiated a review of the Second-Term PBR Decision and the Second-Term Compliance Decision to determine the method to incorporate approved changes to depreciation parameters into rates during the 2018 to 2022 PBR term. In January 2020, the AUC issued Decision 24609-D01-2020 confirming that changes to depreciation parameters are to be incorporated into incremental capital funding mechanisms. The AUC provided PBR utilities with an opportunity to file depreciation studies by July 2020. The Corporation does not anticipate filing a depreciation study in 2020.

Phase II applications propose revised rate design and rate class cost allocations that will determine how much of the revenue requirement should be recovered from each customer class and the billing determinants that will apply to each class. In the Second-Term PBR Decision, PBR Utilities were invited to submit a Phase II application subsequent to the approval of the Rebasing Compliance Filing. The Corporation filed a Phase II application in January 2020 with rates anticipated to be effective in 2021 or 2022.

Capital Tracker Applications
In June 2018, the Corporation filed a 2017 Capital Tracker True-Up Application to update 2017 K factor revenue for actual 2017 capital tracker expenditures. In January 2019, the AUC issued Decision 23649-D01-2019, which disallowed capital tracker treatment for costs associated with the battery operated tools portion of the Capital Tools program. The Corporation filed a compliance filing in February 2019.

In June 2019, the AUC issued Decision 24369-D01-2019 approving the 2017 K factor revenue true-up as filed in the Corporation's 2017 Capital Tracker Compliance Filing with the exception of revenue associated with the Corporation's Alberta Electric System Operator ("AESO") Contributions program that was subject to the AUC Review and Variance proceeding discussed below.

In April 2018, the AUC initiated a Review and Variance proceeding to address the ratemaking for AESO contributions in the second PBR term. In November 2018, the AUC issued Decision 23505-D01-2018, which approved the use of a hybrid deferral account approach to incremental capital funding for AESO contributions during the second PBR term. This approach provides for the true-up of capital costs associated with AESO contribution projects that received permit and license prior to January 1, 2018 through deferral account treatment (the "AESO Hybrid Deferral"). For contribution projects that receive permit and license during the 2018 to 2022 PBR term, capital cost recovery is provided through the K-Bar mechanism.

In January 2019, the Corporation submitted a compliance filing pursuant to Decision 23505-D01-2018 for its final 2016 and 2017 AESO contribution capital tracker amounts. In October 2019, the AUC issued Decision 24281-D01-2019, which finalized the Corporation's 2016 and 2017 AESO Contributions Program capital tracker amounts, and, in turn, updated going-in rates for the second PBR term, the AESO Hybrid Deferral account, and K-Bar. In December 2019, the Corporation submitted a compliance filing pursuant to Decision 24281-D01-2019 that resulted in a decrease to capital tracker revenue for 2016 and 2017, included in alternative revenue, of $0.7 million. The consequential earnings impact of the resulting changes to going-in rates for the second PBR term, the AESO Hybrid Deferral account and K-Bar was $0.5 million. In January 2020, the AUC issued Decision 25143-D01-2020 approving the Corporation's compliance filing as filed.

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 and an oral hearing is scheduled for April 2020. This proceeding is expected to be concluded before the end of 2020.

Electric Distribution System Purchases
When the Corporation and a municipality or a Rural Electrification Association ("REA") come to an agreement to transfer electric distribution system assets to the Corporation, the transfer and purchase 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 are 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 factor to account for the estimated accumulated depreciation at the time that the assets are to be transferred to the utility. The Corporation applies to the AUC for recovery of the RCN-D value in rates.

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 addressed under K-Bar on a go forward basis. However, the AUC approved Y factor rate treatment for the difference between the incremental distribution revenue arising from customer additions and the revenue requirement associated with the electric distribution systems of the Municipality of Crowsnest Pass ("CNP") and the Town of Fort Macleod ("Fort Macleod").

In July 2016, CNP decided to cease the operation of, and to transfer, the CNP electric distribution system and related assets (the "system") to the Corporation for a purchase price of $3.7 million, plus GST, and the related applications were filed with the AUC. In June 2018, the AUC issued Decision 21785-D01-2018 in respect of the transfer of the CNP system to the Corporation. The AUC provided conditional approval of the transfer of the CNP system but did not approve a final purchase price for ratemaking purposes. In July 2018, the AUC provided approval of the transfer of the CNP system to the Corporation and the Corporation completed the purchase of the CNP system. In October 2018, the Corporation filed a request for approval of an adjusted purchase price for ratemaking purposes of $2.4 million in accordance with AUC directions. In the first quarter of 2019, the Corporation recognized a $1.3 million adjustment to property, plant and equipment that was recorded in goodwill to reflect the fair value of the CNP system. In October 2019, the AUC approved the purchase price of the CNP system for ratemaking purposes of $2.4 million, with recovery through a Y factor.

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 GST. In June 2018, an application to transfer the Fort Macleod system to the Corporation was filed with the AUC by Fort Macleod. In October 2018, an application for approval of the purchase price for ratemaking purposes was filed with the AUC by the Corporation. These applications, however, were held in abeyance until completion of the generic proceeding to establish the rate treatment methodology for distribution system purchases. The process to consider applications concerning the sale and transfer of the Fort Macleod system resumed 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. The AUC's consideration of the final purchase price for ratemaking purposes is ongoing.

2019 Annual Rates Application

In October 2018, the Corporation filed an updated 2019 Annual Rates Application in accordance with the Rebasing Compliance Decision. The rates and riders, proposed to be effective on an interim basis for January 1, 2019, include a decrease of approximately 0.5% to the distribution component of customer rates. The decrease in the distribution component of customer rates, incorporating the determinations of the Rebasing Compliance Decision, reflected: (i) an I-X of 1.83%; (ii) a refund of $0.2 million for the true-up of going-in rates; (iii) a refund of $1.9 million for the true-up of the 2018 K-Bar; (iv) a 2019 K-Bar placeholder of $35.9 million; (v) a refund of $11.7 million for the difference between the 2016 and 2017 K factor amounts approved or applied for and the amounts collected; (vi) a refund of $1.1 million of K factor carrying costs; and (vii) a net collection of Y factor amounts of $4.6 million, including $5.9 million for the efficiency carry-over mechanism associated with results achieved in the first PBR term.

In December 2018, the AUC issued Decision 23893-D01-2018 approving the Corporation's 2019 rates, as filed in the 2019 Annual Rates Application, on an interim basis.

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, include 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, including a refund of $0.8 million for the 2018, 2019 and 2020 incremental capital requirements for the system purchases of CNP and Fort Macleod.

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.

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." In March 2019, the AUC expanded the scope of this proceeding to include matters relating to natural gas distribution utilities and provided further direction regarding the process that will be followed as the inquiry unfolds.

The AUC confirmed that this inquiry will be completed in three modules. Module One will 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 will consider the kinds of legislative, policy and regulatory frameworks that will be required to support the ongoing evolution of Alberta's distribution grids and how they may interact with existing utility business models. Module Three will 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. In November 2019, the AUC advised that Modules Two and Three will be addressed as a combined module and, in December 2019, issued an extended process schedule for the combined module along with additional guidance on the format and content of written submissions. Written submissions are to be filed in March 2020 and will be followed by a technical meeting and an oral hearing scheduled for April and May 2020, respectively. The Distribution System Inquiry is expected to extend into 2021.

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 filed by the AESO (the "Decision"). The Decision included findings relating to the application of the AESO's transmission cost allocation practices at point of delivery ("POD") substations that may impact ratemaking treatment of distribution connected generation ("DCG") costs. In November 2019, the Corporation filed an application for review and variance of this aspect the Decision and in December 2019, the AUC determined that it would consider the review and variance applications of the Corporation and a separate consumer group concurrently.

The Decision also approved a proposed change to the method in which the AESO's customer contribution policy is accounted for between distribution facility owners ("DFO") and transmission facility owners ("TFO") that would prevent the Corporation's future investment under the AESO's customer contribution policy ("ACCP"). The previous ACCP permitted DFOs, including the Corporation, to invest in transmission assets (AESO contributions) under certain circumstances.

As part of approving the proposed changes, the AUC also determined that the Corporation would transfer the unamortized AESO contributions 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 ("AML"). The Decision directed the AESO and AML to develop a joint proposal for the implementation of the revised ACCP.

On September 25, 2019, the Corporation filed a request for immediate review and variance of the 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 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 consideration of the review and variance. 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 indicating that prior to making a final decision it requires additional information from the Corporation and AML with respect to the evidence submitted. The Corporation expects that the AUC's consideration of these matters will extend through the first quarter of 2020.

The Corporation has determined that the occurrence of a loss contingency in respect of the revised ACCP is not determinable due to the ongoing AUC review of the Decision. Based on the number of significant matters identified, an estimate of loss cannot be reasonably determined as at December 31, 2019 and no estimate has been included in the financial statements.

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 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.

RESULTS OF OPERATIONS

	Three months ended December 31			Twelve months ended December 31		
($ thousands)	2019	2018	Variance	2019	2018	Variance
Total revenues	162,153	150,880	11,273	649,668	622,529	27,139
Cost of sales	47,331	54,667	(7,336)	196,605	206,560	(9,955)
Depreciation	50,998	47,697	3,301	200,252	185,954	14,298
Amortization	3,364	2,444	920	14,078	9,698	4,380
Other income	918	986	(68)	1,298	962	336
Income before interest expense and income tax	61,378	47,058	14,320	240,031	221,279	18,752
Interest expense	25,733	25,661	72	103,826	100,213	3,613
Income before income tax	35,645	21,397	14,248	136,205	121,066	15,139
Income tax expense (recovery)	3,394	(762)	4,156	5,653	1,038	4,615
Net income	32,251	22,159	10,092	130,552	120,028	10,524

Net income for the three months ended December 31, 2019 increased $10.1 million compared to the same period in 2018. The increase was primarily due to higher revenue associated with rate base growth and customer additions, net of a negative adjustment related to 2016 and 2017 capital tracker revenue associated with AESO contributions. In addition, contributing to the increase were lower labour costs related to incentive compensation and lower contract manpower costs associated with vegetation management in 2019, and a voluntary retirement program was completed in 2018. These increases were partially offset by higher income tax, depreciation and amortization expenses. Income tax expense increased as a result of lower current period deductions related to AESO contributions and higher pre-tax net income. Depreciation and amortization expense increased due to continued capital investment and an overall increase in depreciation and amortization rates.

Net income for the twelve months ended December 31, 2019 increased $10.5 million compared to the same period in 2018. The increase was primarily due to higher revenue associated with rate base growth and customer additions, partially offset by a negative adjustment related to the incremental capital deferral and a prior year true-up of 2016 and 2017 capital tracker revenue. In addition, contributing to the increase were lower labour costs related to incentive compensation and lower contract manpower costs associated with vegetation management in 2019, and a voluntary retirement program was completed in 2018. These increases were partially offset by higher depreciation, amortization, income tax and interest expenses. Depreciation and amortization expense increased due to continued capital investment and an overall increase in depreciation and amortization rates. Income tax expense increased as a result of lower current period deductions related to AESO contributions and higher pre-tax net income. Interest expense increased as a result of the long-term debt issuance in September 2018.

The following table outlines the significant variances in the Results of Operations for the three months ended December 31, 2019 as compared to December 31, 2018:

Item	Variance ($ millions)	Explanation
Total revenues	11.3	The increase in total revenues was primarily due to an increase of $11.4 million in electric rate revenue associated with rate base growth and customer additions, and net increases in revenue related to flow-through items that were fully offset in cost of sales.
Cost of sales	(7.3)	The decrease was primarily due to lower labour costs related to incentive compensation and lower contract manpower costs associated with vegetation management in 2019, and a voluntary retirement program was completed in 2018. The decreases were partially offset by net increases in costs that qualify as flow-through items that were fully offset in electric rate revenue. Labour and benefits and contract manpower costs comprised approximately 52% of total cost of sales.
Depreciation	3.3	The increase was due to continued investment in capital assets and an overall increase in depreciation rates. Refer to the Critical Accounting Estimates section of this MD&A for further information.
Income tax expense	4.2	The increase was primarily due to lower current period deductions related to AESO contributions and higher pre-tax net income.

The following table outlines the significant variances in the Results of Operations for the twelve months ended December 31, 2019 as compared to December 31, 2018:

Item	Variance ($ millions)	Explanation
Total revenues	27.1	The increase in total revenues was primarily due to an increase of $29.9 million in electric rate revenue associated with rate base growth and customer additions, and net increases in revenues related to flow-through items that were fully offset in cost of sales, partially offset by a negative adjustment related to the incremental capital deferral. In addition, alternative revenue was $3.5 million lower due to the true-up of 2016 and 2017 capital tracker revenue in 2018.
Cost of sales	(10.0)	The decrease was primarily due to lower labour costs related to incentive compensation and lower contract manpower costs associated with vegetation management in 2019, and a voluntary retirement program was completed in 2018. The decreases were partially offset by net increases in costs that qualify as flow-through items that were fully offset in electric rate revenue. Labour and benefits and contract manpower costs comprised approximately 54% of total cost of sales.
Depreciation	14.3	The increase was due to continued investment in capital assets and an overall increase in depreciation rates. Refer to the Critical Accounting Estimates section of this MD&A for further information.
Amortization	4.4	The increase was due to continued investment in intangible assets and an overall increase in amortization rates. Refer to the Critical Accounting Estimates section of this MD&A for further information.
Interest expense	3.6	The increase was primarily attributable to the issuance of long-term debt in September 2018.
Income tax expense	4.6	The increase was primarily due to lower current period deductions related to AESO contributions and higher pre-tax net income.

SUMMARY OF QUARTERLY RESULTS

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

($ thousands)	Total Revenues	Net Income
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
December 31, 2018	150,880	22,159
September 30, 2018	165,343	38,577
June 30, 2018	154,216	32,244
March 31, 2018	152,090	27,048

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. There is no significant seasonality in the Corporation's operations.

December 31, 2019 / 2018

Net income for the three months ended December 31, 2019 increased $10.1 million compared to the same period in 2018. The increase was primarily due to higher revenue associated with rate base growth and customer additions, net of a negative adjustment related to 2016 and 2017 capital tracker revenue associated with AESO contributions. In addition, contributing to the increase were lower labour costs related to incentive compensation and lower contract manpower costs associated with vegetation management in 2019, and a voluntary retirement program was completed in 2018. These increases were partially offset by higher income tax, depreciation and amortization expenses. Income tax expense increased as a result of lower current period deductions related to AESO contributions and higher pre-tax net income. Depreciation and amortization expense increased due to continued capital investment and an overall increase in depreciation and amortization rates.

September 30, 2019 / 2018

Net income for the three months ended September 30, 2019 decreased $1.3 million compared to the same period in 2018. The decrease was primarily due to a true-up of 2016 and 2017 capital tracker revenue in 2018, higher depreciation and amortization from continued capital investment and an overall increase in depreciation and amortization rates, and higher interest expense related to the long-term debt issuance in September 2018. These decreases were partially offset by higher revenue associated with rate base growth and customer additions, lower labour costs related to incentive compensation, lower contract manpower costs associated with vegetation management, and decreases in income tax expense due to temporary differences relating to capital assets and deferrals.

June 30, 2019 / 2018

Net income for the three months ended June 30, 2019 increased $2.1 million compared to the same period in 2018. The increase was primarily due to higher revenue associated with rate base growth, customer additions, and customer usage and demand. In addition, in 2018 there was a negative adjustment related to prior year capital tracker revenue. These increases were partially offset by higher depreciation and amortization due to continued capital investment and an overall increase in depreciation and amortization rates, and higher interest expense related to the long-term debt issuance in September 2018.

March 31, 2019 / 2018

Net income for the three months ended March 31, 2019 decreased $0.3 million compared to the same period in 2018. The decrease in net income was mainly due to an increase in depreciation and amortization expense resulting from continued investment in capital assets and an overall increase in depreciation and amortization rates. There was also an increase in income tax expense due to lower current period deductions for AESO contributions. These decreases in net income were partially offset by an increase in revenue associated with rate base growth, customer additions, and customer usage and demand, net of a negative adjustment related to the true-up of the incremental capital deferral.

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, 2019, 2018 and 2017:

($ thousands)	2019	2018	2017
Total revenues [(1)]	649,668	622,529	599,950
Net income [(1)]	130,552	120,028	119,812
Assets [(2)]	4,831,498	4,685,287	4,449,231
Non-current liabilities [(2)]	2,924,414	2,928,313	2,718,204

(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 balances.*

FINANCIAL POSITION

The following table outlines the significant changes in the Balance Sheet as at December 31, 2019 as compared to December 31, 2018:

Item	Variance ($ millions)	Explanation
Assets:		
Regulatory assets (current and long-term)	(12.6)	The decrease was primarily due to a reduction in the deferred income tax regulatory deferral of $32.8 million, primarily related to a decrease in future provincial tax rates, partially offset by an increase in the AESO charges deferral of $19.9 million.
Property, plant and equipment, net	153.9	The increase was due to continued investment in system infrastructure, partially offset by depreciation and customer contributions.
Intangible assets, net	5.1	The increase was due to continued investment in computer software, partially offset by amortization.
Liabilities and Shareholder's Equity:		
Accounts payable and other current liabilities	36.6	The increase was primarily due to higher amounts payable to the AESO for transmission cost accruals, partially offset by lower payables for capital expenditures and lower incentive compensation and labour accruals.
Regulatory liabilities (current and long-term)	21.0	The increase was primarily due to increases in the non-asset retirement obligation provision of $16.6 million and the AESO charges deferral of $13.5 million, partially offset by a decrease in the K Factor deferral of $11.9 million.
Other liabilities	5.2	The increase was primarily due to an increase in the other post-employment benefit liability, primarily due to a plan amendment completed in 2019, and deferred revenue for operating and maintenance charges.
Deferred income tax	(27.4)	The decrease was primarily due to the reduction in future provincial tax rates, partially offset by temporary differences relating to capital assets and deferrals.
Debt (including short-term borrowings)	36.9	The increase was primarily related to the outstanding Fortis demand note.
Total shareholder's equity	73.7	The increase was primarily due to net income of $130.6 million and equity injections of $20.0 million, less dividends paid of $75.0 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)	2019	2018	Variance	2019	2018	Variance
Cash, beginning of period	604	28,171	(27,567)	—	82,735	(82,735)
Cash from (used in):						
Operating activities	100,867	30,375	70,492	392,592	215,377	177,215
Investing activities	(98,348)	(96,673)	(1,675)	(373,256)	(407,521)	34,265
Financing activities	(2,516)	38,127	(40,643)	(18,729)	109,409	(128,138)
Cash, end of period	607	—	607	607	—	607

Operating Activities

For the three and twelve months ended December 31, 2019, net cash provided from operating activities was $70.5 million and $177.2 million higher, respectively, compared to the same periods in 2018. These increases were primarily due to differences in the timing of collection from customers and payment to the AESO for transmission related amounts, and the timing of collection of accounts receivable balances for distribution revenue.

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 to the parent company and/or capital expenditures.

Investing Activities

	Three months ended December 31			Twelve months ended December 31		
($ thousands)	2019	2018	Variance	2019	2018	Variance
Capital expenditures:						
Customer growth *(1)*	40,603	47,702	(7,099)	151,681	160,343	(8,662)
Sustainment *(2)*	33,013	48,821	(15,808)	150,851	167,883	(17,032)
Externally driven and other *(3)*	10,934	17,831	(6,897)	50,288	61,044	(10,756)
Distribution System Purchases *(4)*	4,770	—	4,770	4,770	3,746	1,024
AESO contributions *(5)*	(8,951)	(9,752)	801	(957)	8,979	(9,936)
Gross capital expenditures	80,369	104,602	(24,233)	356,633	401,995	(45,362)
Less: customer contributions	(11,057)	(9,635)	(1,422)	(43,754)	(36,555)	(7,199)
Net capital expenditures	69,312	94,967	(25,655)	312,879	365,440	(52,561)
Adjustment to net capital expenditures for:						
Indirect capitalized overhead *(6)*	5,781	4,322	1,459	22,801	16,170	6,631
Non-cash working capital	11,063	(10,631)	21,694	17,109	6,841	10,268
Costs of removal, net of salvage proceeds	4,266	6,377	(2,111)	21,852	23,942	(2,090)
Capitalized depreciation, capital inventory, AFUDC and other	7,926	1,638	6,288	(1,385)	(4,872)	3,487
Cash used in investing activities	98,348	96,673	1,675	373,256	407,521	(34,265)

(1) *Includes new customer connections.*

(2) *Includes planned maintenance, urgent replacements, capacity increases, facilities, vehicles, LED streetlight conversions and information technology.*

(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 systems of the Town of Fort Macleod in 2019 and the Municipality of Crowsnest Pass in 2018.*

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

(6) *Relates to the change in classification of indirect capitalized overhead as discussed in the Critical Accounting Estimates section of this MD&A.*

For the three months ended December 31, 2019, the Corporation's gross capital expenditures were $80.4 million compared to $104.6 million for the same period in 2018. Sustainment expenditures decreased $15.8 million primarily due to lower planned maintenance, information technology and distribution capacity expenditures, and a reduction in vehicle purchases. Customer growth expenditures decreased $7.1 million primarily due to a reduction in residential customer projects. Externally driven expenditures decreased $6.9 million primarily due to reduced spending on substation upgrades. Partially offsetting these decreases was an increase in distribution system purchases as a result of the purchase of the Fort MacLeod system.

For the twelve months ended December 31, 2019, the Corporation's gross capital expenditures were $356.6 million compared to $402.0 million for the same period in 2018. Sustainment expenditures decreased $17.0 million, primarily due to a reduction in vehicle purchases and lower expenditures for distribution capacity, information technology and planned maintenance. Externally driven expenditures decreased $10.8 million primarily due to reduced spending for substation upgrades. AESO contributions decreased $9.9 million due to a reduction in the number of transmission upgrade projects and the refund of contributions compared to 2018. Customer growth expenditures decreased $8.7 million primarily due to a reduction in residential customer projects.

It is expected that ongoing capital expenditures will be financed from funds generated by operating activities, drawings on the committed credit facility, short-term borrowing from Fortis, proceeds from the issuance of long-term debt, 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 2020 forecast of gross capital expenditures is approximately $411.0 million. The 2020 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, 2019 cash from financing activities decreased $40.6 million compared to the same period in 2018. In the fourth quarter of 2019, the Corporation made net repayments of $70.0 million under the committed credit facility, reduced bank indebtedness by $2.7 million, increased short-term borrowings by $89.0 million with a demand note from Fortis, and paid dividends of $18.7 million. During the fourth quarter of 2018, the Corporation increased short-term borrowings by $45.0 million under the committed credit facility, increased bank indebtedness by $10.7 million and paid dividends of $17.5 million.

For the twelve months ended December 31, 2019 cash from financing activities decreased $128.1 million compared to the same period in 2018. In the twelve months ended December 31, 2019, the Corporation made net repayments of $45.0 million under the committed credit facility, reduced bank indebtedness by $7.5 million, increased short-term borrowings by $89.0 million with a demand note from Fortis, paid dividends of $75.0 million and received equity contributions of $20.0 million. During the same period in 2018, the Corporation completed a $150.0 million long-term debt issuance, increased bank indebtedness by $10.7 million, made net repayments of $5.0 million under the committed credit facility, paid dividends of $70.0 million and received $25.0 million in equity contributions. In 2019, the Corporation did not complete a long-term debt issuance and funded ongoing operating requirements and capital expenditures with a demand note from Fortis.

The Corporation anticipates it will be able to meet interest payments on outstanding indebtedness from internally generated funds 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, 2019 were as follows:

($ thousands)	Total	2020	2021-2022	2023-2024	Thereafter
Principal payments on long-term debt (1)	2,185,000	—	—	150,000	2,035,000
Interest payments on long-term debt	2,279,466	101,324	202,648	202,648	1,772,846
Joint use agreement (2)	45,740	2,287	4,574	4,574	34,305
Other (3)	12,264	5,981	6,220	58	5
Total contractual obligations	4,522,470	109,592	213,442	357,280	3,842,156

(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 expiry terms of this agreement state that the agreement remains in effect until the Corporation no longer has attachments to the transmission system. Due to the unlimited term of this contract, the calculation of future payments after year 2024 includes payments to the end of 20 years. However, the payments under this agreement may continue for an indefinite 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.*

CAPITAL MANAGEMENT

The Corporation's objective when managing capital is to ensure ongoing access to capital to allow it to build and maintain the electricity 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	2019		2018	
	$ millions	%	$ millions	%
Total debt	2,260.3	59.9	2,223.4	60.7
Shareholder's equity	1,510.4	40.1	1,436.7	39.3
	3,770.7	100.0	3,660.1	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, 2019, the Corporation was in compliance with these externally imposed capital requirements.

In June 2019, the Corporation renegotiated and amended its unsecured committed credit facility, extending the maturity date of the facility to August 2024 from August 2023. The amended agreement contains substantially similar terms and conditions as the previous agreement.

In December 2019, the Corporation filed a short-form base shelf prospectus with the securities regulatory authority in each of the provinces of Canada. During the 25-month life of the base shelf prospectus, the Corporation may issue medium-term note debentures in an aggregate principal amount of up to $500.0 million.

As at December 31, 2019, the Corporation had an unsecured committed credit facility with an available amount of $250.0 million, maturing in August 2024. Drawings under the committed 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, 2019 on the committed credit facility was 3.7% (2018 – 3.1%). As at December 31, 2019, the Corporation had no drawings on this facility (December 31, 2018 – $45.0 million).

As at December 31, 2019, the Corporation had an unsecured $89.0 million (December 31, 2018 - $nil) demand note outstanding with Fortis. The demand note bears interest approximating the bankers' acceptance discount rate plus a stamping fee of 1.0%.

CREDIT RATINGS

As at December 31, 2019, the Corporation's debentures were rated by DBRS Limited at A (low) and by Standard and Poor's ("S&P") at A-.

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, 2019 (December 31, 2018 – $0.3 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)	2019	2018
Accounts receivable		
Loans (1)	41	24
Related parties	239	206
	280	230
Short-term borrowings		
Related party (2)	89,000	—

(1) *These loans are to officers of the Corporation for employee share purchase plan loans.*
(2) *Demand note from Fortis that was borrowed in December 2019 and is expected to be repaid within twelve months.*

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

Related party transactions included in 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)	2019	2018	2019	2018
Included in other revenue (1)	296	30	301	149
Included in cost of sales (2)	870	1,364	4,750	4,690
Included in interest expense (3)	192	—	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, consulting services, travel and accommodation expenses, charitable donations, membership fees and professional development costs.*
(3) *Reflects interest expense on demand notes from Fortis borrowed throughout 2019.*

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

FINANCIAL INSTRUMENTS

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

Long-term debt ($ thousands)	2019	2018
Fair value (1)	2,722,054	2,465,514
Carrying value (2)	2,183,688	2,183,655

(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 $15,633 (December 31, 2018 – $15,997).*

The fair values 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.

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, which are periodically established in depreciation reviews prepared by an independent expert. Outside of these periodic reviews, management annually assesses if updates are required to depreciation and amortization rates based on changes in capital asset balances, while maintaining the previously determined depreciation parameters.

Depreciation and amortization in 2018 was based on depreciation and amortization rates derived from capital asset balances as at December 2014 and depreciation parameters established in a 2012 depreciation review. Effective January 1, 2019, depreciation and amortization rates were changed based on the results of a depreciation review, which updated rates for changes in capital asset balances and depreciation parameters. The impact to the financial results for the three months ended December 31, 2019 was an increase to depreciation of approximately $1.3 million and an increase to amortization of approximately $1.1 million as compared to 2018. The impact to the financial results for the twelve months ended December 31, 2019 was an increase to depreciation of approximately $4.5 million and an increase to amortization of approximately $4.3 million as compared to 2018.

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, and employee and retiree mortality rates. All assumptions are assessed and concluded 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.

The Corporation performs an annual quantitative assessment and the estimated fair value of the Corporation is compared to its carrying value. If the fair value of the Corporation is less than the carrying value, the excess is recognized as a goodwill impairment.

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

Indirect Capitalized Overhead
The Corporation has elected to change its accounting policy regarding the presentation of capitalized indirect overhead from within long-term regulatory assets to property, plant and equipment and intangible assets. Given the AUC's approach to rebasing for the second PBR term, the Corporation believes this presentation is preferable and better reflects the nature of the capitalized indirect overhead as an item of property, plant and equipment and intangible assets. This presentation is also consistent with the Corporation's regulatory reporting. The Corporation's original presentation was based on the AUC's approval of the capitalized indirect overhead deferral in 2010. Refer to Note 3 of the Audited Financial Statements for further Information.

Leases
Effective January 1, 2019, the Corporation adopted Accounting Standards Codification ("ASC") 842, *Leases*, which requires lessees to recognize a lease liability, initially measured at the present value of future lease payments, and a right-of-use ("ROU") asset for all leases with a lease term greater than 12 months.

The new lease standard also requires additional quantitative and qualitative disclosures for both lessees and lessors. The Corporation applied the transition provisions of the new lease standard as of the adoption date and did not retrospectively adjust prior periods. The Corporation elected a package of practical expedients that allowed it to not reassess: (i) whether existing contracts are or contain a lease; (ii) the lease classification of existing leases; or (iii) the initial direct costs for existing leases. Furthermore, the Corporation elected a practical expedient that permitted it to not evaluate existing land easements that were not previously accounted for as leases. The new lease standard will be applied on a prospective basis to all new or modified land easements after January 1, 2019. Finally, the Corporation utilized the hindsight practical expedient to determine the lease term. Upon adoption, the Corporation did not identify or record an adjustment to the opening balance of retained earnings, and there was no impact on net income or cash flows.

When a contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration, a ROU asset and liability are recognized. At inception, the ROU asset and liability are both measured at the present value of future lease payments, excluding variable payments that are based on usage or performance. Future lease payments include both lease components (e.g., rent, property taxes and insurance costs) and nonlease components (e.g., common area maintenance costs), which the Corporation accounts for as a single lease component. The present value is calculated using a secured interest rate based on the remaining lease term. Renewal and termination options are included in the lease term when it is reasonably certain that the option will be exercised.

Leases with a term of twelve months or less are not recorded on the balance sheet but are recognized as lease expense on a straight-line basis over the lease term. As at December 31, 2019, the Corporation's land easements have not resulted in the recognition of a ROU asset as the current easement contracts do not convey a right to control the land.

The Corporation as a lessor accounts for the lease arrangement as an operating lease. See Note 10 of the Audited Financial Statements for additional information related to the Corporation's leasing arrangements.

Pensions and Other Postretirement Plan Disclosures
The Corporation early adopted Accounting Standard Update ("ASU") 2018-14, *Changes to the Disclosure Requirements for Defined Benefit Plans* on a retrospective basis for all periods presented, as required by the ASU. The ASU amends and clarifies disclosure requirements related to defined benefit pension and other postretirement benefit plans. The adoption of this ASU 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.

Accounting for Credit Losses
ASU 2016-13, *Measurement of Credit Losses on Financial Instruments* was issued in June 2016, providing guidance that requires entities to record credit losses based on an expected credit loss methodology, rather than an incurred loss model, resulting in more timely recognition of credit losses. The expected credit losses will be recognized net to accounts receivable on the Balance Sheets. The new guidance is effective January 1, 2020 and will be applied using a modified retrospective approach. The Corporation has substantially completed its analysis and does not expect the adoption of this ASU to have a material impact on the financial statements.

Cloud Computing Arrangements
ASU 2018-15, *Customer's Accounting for Implementation Costs incurred in a Cloud Computing Arrangement that is a Service Contract*, was issued in August 2018, providing guidance on the 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. The new guidance is effective January 1, 2020 and will be applied on a prospective basis. The Corporation has substantially completed its analysis and does not expect the adoption of this ASU 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 is currently evaluating the impact of these amendments on accounting for current and deferred income taxes.

BUSINESS RISK

Regulatory Approval and Rate Orders

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.

Effective January 1, 2013, distribution utilities in Alberta, including the Corporation, are regulated under PBR. Following the first five-year PBR term ending in 2017, a second five-year term commenced in 2018. Refer to the Regulatory Matters section of this MD&A for further information on the PBR plan.

The fundamental risk faced by all regulated utilities, that regulator-approved rates will not provide sufficient revenue to recover all of the costs associated with providing service, still exists under PBR. 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.

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.

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 necessary staff, facilities, equipment or all three.

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, or in the absence 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 areas that overlap with REAs, eligible members have the right to obtain electric distribution service from their REA as defined in the integrated operating agreements between the Corporation and the REA. In general, eligibility criteria limited the provision of service to REA members whose land is used for agricultural activity. 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. The integrated operating agreement does not contain eligibility criteria. As currently framed, the new integrated operating agreement with EQUS may result in persons choosing to receive service from EQUS in overlapping areas, where they preciously would have been obligated to take any 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 customers 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.

Political Risk
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.

Economic Conditions
Alberta's economy is impacted by a number of factors including the level of oil and gas 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, or in the Corporation's service areas in particular, 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 capital spending forecast, specifically related to customer growth, externally driven and AESO contributions. A reduction in capital spending would, in turn, affect the Corporation's rate base and earnings growth.

Environmental Risks
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 in customer rates the costs associated with environmental protection, compliance and damage; 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. Between external audits, additional internal audits are completed on an annual basis. The 2019 internal audit did not identify any major non-compliance issues. As at December 31, 2019, there were no environmental liabilities recorded in the Corporation's financial statements and there were no unrecorded environmental liabilities known to management.

Electricity 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, 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 March 2019 and effective April 1, 2019.

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. For further information, refer to the "Business Risk - Insurance Coverage Risk" section of this MD&A.

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.

Operating and Maintenance Risk

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.

Weather

The Corporation's physical assets are exposed to the effects of severe weather conditions and other acts of nature. Although the physical assets have been constructed and are operated and maintained to withstand severe weather, there is no assurance that they will successfully do so in all circumstances. In addition, 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.

Information and Operations Technology and Cybersecurity Risk

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.

Insurance Coverage Risk

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.

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.

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 expires on December 31, 2020. The Corporation considers its relationships with the UUWA to be satisfactory; however, there can be no assurance that current relations will continue in future negotiations or that the terms under the current agreement will, upon its expiry, be renewed at all or on terms favourable to the Corporation. 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.