FORTISALBERTA INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the three and twelve months ended December 31, 2018

February 14, 2019

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, 2018, 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, 2018 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 2019. 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; favourable 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 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 electricity distribution utility in the Province of Alberta. Its business is the ownership and operation of electricity 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 electricity 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 125,000 kilometres in central and southern Alberta, which serves approximately 564,000 electricity customers comprised of residential, commercial, farm, oil and gas, and industrial consumers.

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 *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.

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 has approved a second PBR term, from 2018 to 2022.

Under PBR, a formula (I-X) that estimates inflation (I) annually and assumes 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. For the first PBR term, the 2012 distribution rates were the base rates upon which the formula was applied. The 2012 distribution rates were set using a traditional cost-of-service model whereby the AUC established the Corporation's revenue requirement, being those revenues corresponding to the costs associated with the distribution business, and provided a rate of return on a deemed equity component of capital structure ("ROE") applied to rate base assets. The Corporation's ROE for ratemaking purposes was 8.75% for 2012 with a capital structure of 41% equity and 59% debt. For the second PBR term, the going-in rates, upon which the 2018 formula is applied, are based on a notional 2017 revenue requirement corresponding to the costs experienced in providing distribution service in the first PBR term, with an 8.50% ROE and a capital structure of 37% equity and 63% debt applied to notional 2017 rate base assets. The components of the notional 2017 revenue requirement are determined using an AUC prescribed forecast methodology that is primarily based on entity-specific historical experience. The impact of changes to ROE 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 the formula.

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 efficiency incentive by permitting a utility to continue to benefit from any efficiency gains achieved during the PBR term for two years following the end of that term.

The second PBR term incorporates mechanisms consistent with the first PBR term, except that incremental capital funding to recover costs related to capital expenditures that are not recovered through 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 will include 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. A K-Bar amount will be established for each year of the term based on the resulting projected rate base for Type 2 capital programs.

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 industry with 2018 revenue of $8.4 billion and total assets of $53.0 billion. Fortis' 8,800 employees serve utility customers in five Canadian provinces, nine US states and three Caribbean countries.

REGULATORY MATTERS

Next Generation PBR

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 Corporation filed a rebasing application (the "Next Generation Compliance Filing") in April 2017 to establish a going-in revenue requirement and an incremental capital funding mechanism for the second PBR term. The going-in revenue requirement determined the going-in rates to which the PBR formula will be applied to establish base distribution rates for 2018. The Next Generation Compliance Filing achieved the rebasing necessary between PBR terms to re-establish the linkage between, and realign, the utility's revenues and costs.

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 going-in revenue requirement and confirmed significant changes to the K-Bar capital funding mechanism previously approved in the Second-Term PBR Decision. 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 Second Rebasing Compliance Filing (the "Second Rebasing Compliance Filing") in accordance with the Second-Term Compliance Decision. In October 2018, the AUC issued Decision 23355-D02-2018 (the "Second Rebasing Compliance Decision") confirming the Corporation's calculation of the notional 2017 revenue requirement and the 2018 K-Bar amount. The AUC directed the Corporation to true-up its PBR rates for 2018 and 2019 accordingly in an update to its 2019 Annual Rates Application from that filed in September 2018.

In October 2018, the AUC issued Decision 23479-D02-2018 in respect of the Review and Variance Application for the Second-Term Compliance Decision. This decision confirmed the AUC would initiate a review proceeding to clarify the definition of and criteria for anomaly adjustments for the purposes of establishing going-in rates for the second PBR term. Alberta PBR Utilities will have the opportunity to apply for anomaly adjustments in accordance with the clarification determined in this proceeding. All other matters put forth for review were denied.

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 Second Rebasing Compliance Filing. The outcome of the Phase II application will apply for the entirety of the second PBR term. The Corporation anticipates filing a Phase II application in 2019. However, the timeline for this regulatory application is subject to scheduling as determined by the AUC.

Capital Tracker Applications

In June 2017, the Corporation filed a 2016 Capital Tracker True-Up Application to update 2016 K factor revenue for actual 2016 capital tracker expenditures. In January 2018, the AUC issued Decision 22741-D01-2018 directing the Corporation to provide clarifying information and additional calculations for certain of its 2016 capital tracker programs in a compliance filing in February 2018. Pursuant to this compliance filing, K factor revenue related to 2016 was reduced by $0.5 million in the first quarter of 2018.

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, including a new Load Settlement Replacement capital tracker program for 2016 and 2017. Pursuant to this application, K factor revenue related to 2017 was reduced by $1.3 million in the second quarter of 2018. In

January 2019, the AUC issued Decision 23649-D01-2019, which disallowed the costs associated with battery operated tools portion of the Capital Tools capital tracker program and directed the Corporation to provide additional information regarding historical force-of-nature events incorporated in the Corporation's previously approved depreciation study. The Corporation will file a compliance filing in February 2019.

In July 2018, the AUC issued Decision 23372-D01-2018 approving the 2016 K factor revenue true-up amount as filed in the Corporation's 2016 capital tracker compliance filing, including the new Load Settlement Replacement capital tracker program for 2016 and 2017. In the third quarter of 2018, the Corporation recognized an increase of $4.7 million in alternative revenue for the true-up of 2016 and 2017 K factor revenue for the Load Settlement Replacement program.

Decision 22741-D01-2018 also contained findings regarding prior years' approvals made in respect of the Corporation's Alberta Electric System Operator ("AESO") contributions and their treatment in rebasing for the second PBR term. The Corporation filed a Review and Variance Application in respect of this aspect of the decision and also brought an application for permission to appeal its findings to the Alberta Court of Appeal. The AUC subsequently suspended the Corporation's Review and Variance Application, initiating its own Review and Variance proceeding to determine how AESO contributions would be treated in rebasing for the second PBR term.

In November 2018, the AUC issued Decision 23505-D01-2018 in respect of the AUC initiated Review and Variance proceeding for the treatment of AESO contributions in rebasing. In this decision, the AUC approved the use of a hybrid deferral account approach to incremental capital funding for AESO contributions during the second PBR term. This approach provides recovery of capital costs associated with AESO contribution projects that received permit and license prior to January 1, 2018 through deferral account treatment. For contribution projects that receive permit and license during the 2018 to 2022 PBR term, capital cost recovery will be provided through the K-Bar mechanism.

In January 2019, the Corporation filed a compliance filing for its final 2016 and 2017 AESO contribution capital tracker amounts.

2018 Annual Rates Application

In October 2017, the AUC directed the Corporation to use the approved 2017 PBR rates on an interim basis for 2018. In March 2018, the Corporation filed for 2018 PBR rates to be effective April 1, 2018. While the PBR rates were applied prospectively, they included the retrospective approval for the January 1, 2018 to March 31, 2018 period.

The rates and riders, proposed to be effective on an interim basis for April 1, 2018, included an increase of approximately 5.5% to the distribution component of customer rates. However, the overall distribution tariff impact, which included the impact of transmission and generation, was an increase of 1.8%. The increase in the distribution component of rates reflected: (i) a combined inflation and productivity factor (I-X) of negative 0.2%; (ii) a K-Bar placeholder of $24.0 million; (iii) a net collection of Y factor amounts of $6.2 million, including $5.8 million for the efficiency carry-over mechanism associated with the first PBR term; and (iv) a net collection of $5.7 million for the difference between the amounts collected from January to March 2018 under interim rates and the amounts that would have been collected through approved annual 2018 PBR rates.

In March 2018, the AUC issued Decision 23355-D01-2018 approving the Corporation's 2018 PBR rates as filed on an interim basis.

2019 Annual Rates Application

In October 2018, the AUC issued the Second Rebasing Compliance Decision and directed the Corporation to true-up its PBR rates for 2018 and 2019 accordingly in the 2019 Annual Rates Application filed on October 24, 2018. 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 Second Rebasing Compliance Decision, reflected: (i) a combined inflation and productivity factor (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.

Generic Cost of Capital

In July 2017, the AUC established a proceeding to determine the ROE and capital structure for 2018, 2019 and 2020. The proceeding commenced in October 2017 and an oral hearing was held in March 2018. In August 2018, AUC Decision 22570-D01-2018 approved a ROE of 8.50% and a capital structure of 37% equity and 63% debt on a final basis for 2018, 2019 and 2020.

In December 2018, the AUC initiated a proceeding to consider establishing a formula-based approach to setting the approved ROE, beginning for the year 2021, and to consider whether any process changes are necessary for determining capital structure in years in which the ROE formula is in place. Further proceeding details are expected to be available in the first quarter of 2019.

Electric Distribution System Purchases

If 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 and obtain approval of the purchase price for the distribution system assets and the related rate treatment.

In July 2016, the Municipality of Crowsnest Pass ("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 proposed 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 final approval of the transfer of the CNP system to the Corporation and, in October 2018, the Corporation filed a request for approval of an adjusted purchase price for ratemaking purposes of $2.4 million.

In March 2018, the Town of Fort Macleod ("Fort Macleod") approved the sale and transfer of the Fort Macleod electric distribution system and related assets (the "system") to the Corporation for $4.8 million, plus GST. In June 2018, an application to transfer the Fort Macleod system to the Corporation was filed with the AUC. In October 2018, an application for approval of the purchase price for ratemaking purposes was filed with the AUC by the Corporation.

In December 2018, the AUC issued a letter announcing the initiation of a generic proceeding to establish the rate treatment methodology in respect of distribution system purchases by distribution utilities under 2018 to 2022 PBR plans. Pending the outcome of the generic proceeding, the AUC suspended the proceedings for both the CNP system and the Fort Macleod system.

Electric 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 has requested comments from stakeholders, including the Corporation, regarding the specific scope of the inquiry and the processes that will be followed.

In Bulletin 2018-17, 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." Information provided by the AUC indicates that the topics to be covered in the inquiry will include, but not necessarily be limited to: technological requirements and impacts on system planning, the role of regulated electric distribution service providers in grid modernization, and the means by which the distribution system can evolve to provide appropriate price signals to participating stakeholders. The Electric Distribution System Inquiry is expected to be ongoing throughout 2019.

2018 Independent System Operator Tariff Application

In 2018, the Corporation participated in an application brought before the AESO for approval of the AESO's 2018 Independent System Operator tariff. The Corporation's participation in this proceeding, which is expected to extend throughout the first half of 2019, is directed towards addressing matters relating to the future application of the AESO's Customer Contribution Policy to the Corporation and the AESO's current transmission cost allocation practices.

RESULTS OF OPERATIONS

	Three Months Ended December 31			Twelve Months Ended December 31		
($ thousands)	2018	2017	Variance	2018	2017	Variance
Total revenues	150,880	151,887	(1,007)	622,529	599,950	22,579
Cost of sales	55,657	51,662	3,995	210,320	198,621	11,699
Depreciation	46,722	45,333	1,389	182,250	180,065	2,185
Amortization	2,429	2,297	132	9,642	9,507	135
Other income	986	1,082	(96)	962	1,970	(1,008)
Income before interest expense and income tax	47,058	53,677	(6,619)	221,279	213,727	7,552
Interest expense	25,661	24,158	1,503	100,213	93,310	6,903
Income before income tax	21,397	29,519	(8,122)	121,066	120,417	649
Income tax expense (recovery)	(762)	127	(889)	1,038	605	433
Net income	22,159	29,392	(7,233)	120,028	119,812	216

Net income for the three months ended December 31, 2018 decreased $7.2 million compared to the same period in 2017. The decrease was primarily due to costs associated with a voluntary retirement program completed in the fourth quarter of 2018, an increase in interest expense related to the long-term debt issuance in September 2018 and an increase in depreciation due to continued investment in capital assets.

Net income for the twelve months ended December 31, 2018 increased $0.2 million compared to the same period in 2017. The increase was primarily due to revenue associated with rate base growth and customer additions, the efficiency carry-over mechanism associated with performance in the first PBR term and the true-up of 2016 and 2017 capital tracker revenues. These increases were partially offset by higher operating costs driven by costs associated with a voluntary retirement program completed in 2018 and higher contract manpower costs, primarily those associated with vegetation management, an increase in interest expense related to the long-term debt issuances in September 2017 and September 2018, and an increase in depreciation due to continued investment in capital assets.

The following table outlines the significant variances in the Results of Operations for the three months ended December 31, 2018 as compared to December 31, 2017:

Item	Variance ($ millions)	Explanation
Total revenues	(1.0)	Electric rate revenue and alternative revenue increased by $0.4 million primarily due to the efficiency carry-over mechanism associated with performance in the first PBR term. Other revenue decreased by $1.4 million primarily due to a decrease in related party revenue.
Cost of sales	4.0	The increase was mainly driven by costs associated with a voluntary retirement program completed in the fourth quarter of 2018 and net increases in costs that qualify as flow-through items that were fully offset in electric rate revenue. Labour and benefit costs and contract manpower costs comprised approximately 61% of total cost of sales.
Depreciation	1.4	The increase was due to continued investment in capital assets.
Interest expense	1.5	The increase was primarily attributable to the issuance of long-term debt in September 2018.

The following table outlines the significant variances in the Results of Operations for the twelve months ended December 31, 2018 as compared to December 31, 2017:

Item	Variance ($ millions)	Explanation
Total revenues	22.6	Electric rate revenue and alternative revenue increased by $22.6 million primarily due to revenue associated with rate base growth and customer additions, the efficiency carry-over mechanism associated with performance in the first PBR term, net increases in revenues related to flow-through items that were offset in cost of sales, and the true-up of 2016 and 2017 capital tracker revenues.
Cost of sales	11.7	The increase was mainly driven by costs associated with a voluntary retirement program completed in 2018, higher contract manpower costs, primarily those associated with vegetation management, and net increases in costs that qualify as flow-through items that were fully offset in electric rate revenue. Labour and benefit costs and contract manpower costs comprised approximately 60% of total cost of sales.
Depreciation	2.2	The increase was due to continued investment in capital assets.
Interest expense	6.9	The increase was primarily attributable to the issuances of long-term debt in September 2017 and September 2018.

SUMMARY OF QUARTERLY RESULTS

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

($ thousands)	Total Revenues	Net Income
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
December 31, 2017	151,887	29,392
September 30, 2017	152,499	35,011
June 30, 2017	148,661	31,164
March 31, 2017	146,903	24,245

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, 2018/2017
Net income for the three months ended December 31, 2018 decreased $7.2 million compared to the same period in 2017. The decrease was primarily due to costs associated with a voluntary retirement program completed in the fourth quarter of 2018, an increase in interest expense related to the long-term debt issuance in September 2018 and an increase in depreciation due to continued investment in capital assets.

September 30, 2018/2017
Net income for the three months ended September 30, 2018 increased $3.6 million compared to the same period in 2017. The increase was primarily due to the true-up of 2016 and 2017 capital tracker revenues, revenue associated with rate base growth and customer additions, and the efficiency carry-over mechanism associated with performance in the first PBR term. These increases were partially offset by higher operating costs driven by higher contract manpower costs, primarily those associated with vegetation management, and higher labour costs, an increase in income tax expense due to temporary differences relating to capital assets and deferrals, and an increase in interest expense related to the long-term debt issuance in September 2017.

June 30, 2018/2017
Net income for the three months ended June 30, 2018 increased $1.1 million compared to the same period in 2017. The increase was primarily due to revenue associated with rate base growth and customer additions, and the efficiency carry-over mechanism associated with performance in the first PBR term. These increases were partially offset by higher operating costs driven by higher contract manpower costs, primarily those associated with vegetation management, an increase in depreciation due to continued investment in capital assets, an increase in interest expense related to the long-term debt issuance in September 2017, and a negative adjustment related to the true-up of 2017 capital tracker revenue.

March 31, 2018/2017
Net income for the three months ended March 31, 2018 increased $2.8 million compared to the same period in 2017. The increase was mainly due to revenue associated with rate base growth and customer additions, and the efficiency carry-over mechanism associated with performance in the first PBR term. In addition, depreciation decreased given that analog meters were fully depreciated in 2017. These increases were partially offset by higher operating costs driven by higher contract manpower costs, an increase in interest expense related to the long-term debt issuance in September 2017, and a negative adjustment related to the true-up of 2016 capital tracker revenue.

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, 2018, 2017 and 2016:

($ thousands)	2018	2017	2016
Total revenues [(1)]	622,529	599,950	572,239
Net income [(1)]	120,028	119,812	120,694
Assets [(2)]	4,685,287	4,449,231	4,058,911
Non-current liabilities [(2)]	2,928,313	2,718,204	2,492,828

[(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, 2018 as compared to December 31, 2017:

Item	Variance ($ millions)	Explanation
Assets:		
Cash and cash equivalents	(78.8)	The decrease was primarily driven by a $50.0 million borrowing under the committed credit facility at the end of December 2017 for an AESO payment of $65.9 million in the first quarter of 2018, and the timing of the collection of cash payments from customers.
Accounts receivable	46.2	The higher balance was primarily driven by an increase in amounts collectible from customers on behalf of the AESO related to higher transmission rates and riders, and the timing of collections of distribution revenue from customers.
Regulatory assets (current and long-term)	57.0	The increase was primarily due to increases in deferred income tax regulatory deferral of $46.7 million and deferred overhead costs of $12.4 million, partially offset by a decrease in regulatory defined benefit pension deferrals of $2.1 million.
Property, plant and equipment, net	203.6	The increase was due to continued investment in system infrastructure, partially offset by depreciation and customer contributions.
Intangible assets, net	9.3	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	(51.4)	The decrease was primarily driven by the timing of an AESO payment of $65.9 million in the first quarter of 2018, partially offset by higher amounts payable to the AESO for transmission cost accruals, and an increase in interest payable related to the long-term debt issuance in September 2018.
Regulatory liabilities (current and long-term)	7.4	The increase was primarily due to increases in the provision for non-asset retirement obligation removal costs of $18.4 million and K-Bar deferral of $2.2 million, partially offset by a decrease in the AESO charges deferral of $13.1 million.
Deferred income tax	51.4	The increase was primarily due to temporary differences relating to capital assets and deferrals.
Debt (including short-term borrowings)	155.0	The increase was primarily related to the issuance of $150.0 million senior unsecured debentures in September 2018.
Total shareholder's equity	76.8	The increase was primarily due to net income of $120.0 million and equity injections of $25.0 million received from Fortis in 2018, less dividends paid of $70.0 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)	2018	2017	Variance	2018	2017	Variance
Cash, beginning of period	28,171	3,933	24,238	82,735	3,933	78,802
Cash from (used in)						
Operating activities	26,053	147,985	(121,932)	199,207	348,619	(149,412)
Investing activities	(92,351)	(97,746)	5,395	(391,351)	(380,509)	(10,842)
Financing activities	38,127	28,563	9,564	109,409	110,692	(1,283)
Cash, end of period	-	82,735	(82,735)	-	82,735	(82,735)

Operating Activities

For the three months ended December 31, 2018, net cash provided from operating activities was $121.9 million lower than for the same period in 2017. The decrease was primarily due to the timing of transmission costs paid to the AESO and the timing of collection of accounts receivable balances for distribution revenue.

For the twelve months ended December 31, 2018, net cash provided from operating activities was $149.4 million lower than for the same period in 2017. The decrease was primarily due to the timing of transmission costs paid to the AESO and the timing of flow through of transmission costs as revenue was collected from customers on a different timeline than costs were paid to the AESO.

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)	2018	2017	Variance	2018	2017	Variance
Capital expenditures						
Customer growth [(1)]	47,702	39,218	8,484	160,343	123,130	37,213
Externally driven and other [(2)]	17,831	20,724	(2,893)	61,044	76,917	(15,873)
Sustainment [(3)]	48,821	60,926	(12,105)	167,883	198,039	(30,156)
Distribution system purchases [(4)]	-	-	-	3,746	-	3,746
AESO contributions [(5)]	(9,752)	(4,167)	(5,585)	8,979	15,002	(6,023)
Gross capital expenditures	104,602	116,701	(12,099)	401,995	413,088	(11,093)
Less: customer contributions	(9,635)	(9,755)	120	(36,555)	(29,946)	(6,609)
Net capital expenditures	94,967	106,946	(11,979)	365,440	383,142	(17,702)
Adjustment to net capital expenditures for:						
Non-cash working capital	(10,631)	(13,506)	2,875	6,841	(18,639)	25,480
Costs of removal, net of salvage proceeds	6,377	299	6,078	23,942	19,766	4,176
Capitalized depreciation, capital inventory, AFUDC and other	1,638	4,007	(2,369)	(4,872)	(3,760)	(1,112)
Cash used in investing activities	92,351	97,746	(5,395)	391,351	380,509	10,842

(1) *Includes new customer connections.*
(2) *Includes upgrades associated with substations, line moves, new connections for independent power producers, and SCADA (Supervisory Control and Data Acquisition).*
(3) *Includes planned maintenance, urgent replacements, capacity increases, facilities, vehicles, LED streetlight conversions and information technology.*
(4) *Reflects the purchase of electric distribution systems.*
(5) *Reflects the Corporation's required contributions towards transmission projects as determined by the AUC approved investment levels; paid when transmission projects are approved.*

For the three months ended December 31, 2018, the Corporation's gross capital expenditures were $104.6 million compared to $116.7 million for the same period in 2017. Sustainment expenditures decreased $12.1 million primarily due to decreases in facility-related expenditures, LED streetlight conversions and urgent replacements. Partially offsetting these decreases was an increase in customer growth expenditures of $8.5 million across most customer categories.

For the twelve months ended December 31, 2018, the Corporation's gross capital expenditures were $402.0 million compared to $413.1 million for the same period in 2017. Sustainment expenditures decreased $30.2 million primarily due to lower planned maintenance expenditures related to the pole management program and a decrease in facility-related expenditures. Externally driven expenditures decreased $15.9 million primarily due to a reduction in line move expenditures and reduced spending on three substation upgrade projects in 2018. Partially offsetting these decreases was an increase in customer growth expenditures of $37.2 million across most customer categories and an increase in system purchases of $3.7 million as a result of the purchase of the CNP system.

It is expected that ongoing capital expenditures will be financed from funds generated by operating activities, drawings on the committed credit facility, proceeds from the issuance of 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 2019 forecast of gross capital expenditures is approximately $405.0 million. The 2019 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, 2018, cash from financing activities increased $9.6 million compared to the same period in 2017. This increase was primarily due to an increase in short-term borrowings in 2018 of $15.5 million, partially offset by a $5.0 million increase in net repayments under the committed credit facility in 2018.

For the twelve months ended December 31, 2018, cash from financing activities decreased $1.3 million compared to the same period in 2017. This decrease was primarily due to a $50.0 million decrease in the amount of the long-term debt issuance in 2018 compared to 2017. This decrease was partially offset by a $35.0 million increase in net borrowings under the committed credit facility in 2018 and an increase in short-term borrowings in 2018 of $13.3 million.

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, 2018 were as follows:

($ thousands)	Total	2019	2020-2021	2022-2023	Thereafter
Long-term debt (1)	2,185,000	-	-	-	2,185,000
Interest payments on long-term debt	2,380,790	101,324	202,648	202,648	1,874,170
Joint use agreement (2)	49,800	2,490	4,980	4,980	37,350
Other (3)	15,038	5,414	9,136	488	-
Total contractual obligations	4,630,628	109,228	216,764	208,116	4,096,520

(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 2023 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, operating leases for facilities and office premises, and shared service agreements.*

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	2018		2017	
	$ millions	%	$ millions	%
Total debt	2,223.4	60.7	2,068.4	60.3
Shareholder's equity	1,436.7	39.3	1,360.0	39.7
	3,660.1	100.0	3,428.4	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, 2018, the Corporation was in compliance with these externally imposed capital requirements.

In June 2018, the Corporation renegotiated and amended its unsecured committed credit facility, extending the maturity date of the facility to August 2023 from August 2022. The amended agreement contains substantially similar terms and conditions as the previous agreement.

In September 2018, the Corporation entered into an agreement with a syndicate of agents, pursuant to which the Corporation sold $150.0 million of senior unsecured debentures. The debentures bear interest at a rate of 3.73%, to be paid semi-annually, and mature in 2048. The net proceeds of the issue were used to repay existing indebtedness incurred under the committed credit facility to finance capital expenditures and for general corporate purposes.

As at December 31, 2018, the Corporation had an unsecured committed credit facility with an available amount of $250.0 million, maturing in August 2023. 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, 2018 on the committed credit facility was 3.1% (2017 – 2.2%). As at December 31, 2018, the Corporation had $45.0 million drawings on this facility (December 31, 2017 – $50.0 million).

CREDIT RATINGS

As at December 31, 2018, the Corporation's debentures were rated by DBRS at A (low) and by Standard and Poor's ("S&P") at A-. In December 2018, S&P confirmed the Corporation's credit rating of A- and maintained its outlook for the Corporation as Negative, reflecting S&P's view of a modest change to Fortis' financial measures following US corporate tax reform.

OUTSTANDING SHARES

Authorized – unlimited number of:

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

Issued:

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

OFF-BALANCE SHEET ARRANGEMENTS

With the exception of letters of credit outstanding of $0.3 million as at December 31, 2018 (December 31, 2017 – $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 as at December 31:

($ thousands)	2018	2017
Accounts receivable		
Loans [(1)]	24	47
Related parties	206	233
	230	280

[(1)] *These loans are to officers of the Corporation and include items such as stock option loans and employee share purchase plan loans.*

The Corporation bills related parties on terms and conditions consistent with billings 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 billed 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 and cost of sales were measured at the exchange amount and were as follows:

	Three Months Ended December 31		Twelve Months Ended December 31	
($ thousands)	2018	2017	2018	2017
Included in other revenue (1)	30	1,568	149	2,495
Included in cost of sales (2)	1,364	1,149	4,690	4,407

(1) *Includes services provided to related parties, including Fortis and subsidiaries of Fortis, related to metering, 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 and professional development costs.*

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)	2018	2017
Fair value (1)	2,465,514	2,428,501
Carrying value (2)	2,183,655	2,033,624

(1) *The fair value of the long-term debt was estimated using level 2 inputs based on the indicative prices for the same or similarly rated issues for debt of the same remaining maturities.*

(2) *Carrying value is presented gross of debt issuance costs of $15,997 (December 31, 2017 – $15,261).*

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 and current 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 parameters, including the service life of assets and expected net salvage percentages, which are periodically determined based on depreciation studies prepared by an independent expert.

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.

Employee Future 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 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

The accounting policies that were adopted by the Corporation in 2018 are described below.

Revenue from Contracts with Customers
Effective January 1, 2018, the Corporation adopted Accounting Standards Codification ("ASC") 606, *Revenue from Contracts with Customers*, which clarifies the principles for recognizing revenue and requires additional disclosures. The Corporation adopted the new standard using the modified retrospective approach, under which comparative periods are not restated and the cumulative impact is recognized at the date of adoption and supplemented by additional disclosures. Upon adoption, there were no adjustments to the opening balance of retained earnings.

The majority of the Corporation's revenue is generated from the distribution of electricity to end-use customers based on published tariff rates, as approved by the AUC. Revenues are recognized in the period services are provided, at AUC approved rates where applicable, and when collectability is reasonably assured.

The majority of the Corporation's contracts have a single performance obligation as the promise to transfer individual goods or services is not separately identifiable from other obligations in the contracts and therefore not distinct. Substantially all of the Corporation's performance obligations are satisfied over time as energy is delivered because of the continuous transfer of control to the customer, generally using an output measure of progress being kilowatt hours delivered. The billing of energy sales is based on customer meter readings, which occur systematically throughout each month.

In accordance with the *EUA*, the Corporation is required to arrange and pay for transmission service with the AESO and collect transmission revenue from its customers, which is done by invoicing the customers' retailers through the Corporation's transmission component of its AUC approved rates. As the Corporation is solely a distribution utility and, as such, does not own or operate any transmission facilities, it is largely a conduit for the flow through of transmission costs to end-use customers as the transmission facility owner does not have a direct relationship with the customers. Therefore, the Corporation reports revenues and expenses related to transmission services on a net basis in other revenue in the Statements of Income and Comprehensive Income.

Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost
Effective January 1, 2018, the Corporation adopted Accounting Standards Update ("ASU") 2017-07, *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*, which requires current service costs to be disaggregated and grouped in the statement of earnings with other employee compensation costs arising from services rendered. The other components of net periodic benefit costs must be presented separately and outside of operating income. The components of net periodic benefit cost other than the current service cost component are included in other income in the Statements of Income and Comprehensive Income. There was no impact to net income.

Restricted Cash
Effective January 1, 2018, the Corporation adopted ASU 2016-18, *Restricted Cash*, which requires that a statement of cash flows explain the change during the period in the total of cash, cash equivalents and amounts generally described as restricted cash or restricted cash equivalents. The Corporation adopted the new guidance retrospectively and the Statements of Cash Flows for the year ended December 31, 2017 was adjusted to reclassify $3.9 million of restricted cash. There was no impact to net income.

FUTURE ACCOUNTING PRONOUNCEMENTS

The Corporation considers the applicability and impact of all ASU's issued by the Financial Accounting Standards Board ("FASB"). The following ASU's 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 either not applicable to the Corporation or are not expected to have a material impact on the financial statements.

Leases
ASU 2016-02, *Leases* ("ASC 842") was issued in February 2016 and is effective for annual and interim periods beginning after December 15, 2018. Principally, it requires balance sheet recognition of a right-of-use asset and a lease liability by lessees for those leases that are classified as operating leases with a lease term greater than 12 months, as well as additional disclosures. The Corporation adopted ASC 842 on January 1, 2019 using the modified retrospective approach and there have been no material adjustments identified to opening retained earnings.

The Corporation has selected the optional transition method, which allows entities to continue to apply the current lease guidance in the comparative periods presented in the year of adoption and apply the transition provisions of the new guidance on the effective date of the new guidance. The Corporation elected a package of practical expedients that allows it to not reassess the lease classification of existing leases, whether any existing contracts are a lease or contain a lease, and the initial direct costs for any existing leases. The Corporation also elected the practical expedient that permits entities to not evaluate existing land easements that were not previously accounted for as leases. Additionally, the Corporation elected an accounting policy that permits it to not separate non-lease components from lease components by class of underlying assets. Finally, the Corporation utilized the hindsight practical expedient to determine the lease term.

Upon adoption on January 1, 2019, the Corporation will recognize right-of-use assets and corresponding lease liabilities of approximately $3.0 million for operating leases primarily related to office facilities.

Financial Instruments
ASU 2016-13, *Measurement of Credit Losses on Financial Instruments*, was issued in June 2016, is effective January 1, 2020, and is to be applied on a modified retrospective basis. Principally, it requires entities to use an expected credit loss methodology and to consider a broader range of reasonable and supportable information to estimate credit losses. The Corporation is assessing the impact of adoption.

Pensions and Other Postretirement Plan Disclosures
ASU 2018-14, *Changes to the Disclosure Requirements for Defined Benefit Plans,* was issued in August 2018, is effective January 1, 2021 with earlier adoption permitted, and is to be applied on a retrospective basis for all periods presented. Principally, it modifies the disclosure requirements for employers with defined benefit pension or other postretirement plans. The Corporation is assessing the impact of adoption.

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, is effective January 1, 2020 with earlier adoption permitted, and is to be applied either on a retrospective basis or on a prospective basis to all implementation costs incurred after the effective date of the new guidance. Principally, it 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 Corporation is assessing the impact of adoption.

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 approval by the AUC of customer rates that provide a reasonable opportunity to recover on a timely basis the estimated costs of providing services, including a fair return on the portion of approved rate base funded by the equity component of the capital structure. 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 a form of rate regulation referred to as PBR. Following the first five-year PBR term which ended in 2017, a second five-year term commenced in 2018. Refer to "The Corporation" and "Regulatory Matters" sections 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.

Capital expenditures, including the cost of upgrades to existing facilities and the addition of new facilities, continue to require the approval of the AUC for inclusion in rate base. 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 Government of Alberta's decision to remove portions of Bill 13, *An Act to Secure Alberta's Energy Future*, which 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 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 Energy Alberta GP Inc. ("EPCOR") as its regulated rate provider. As a result of this appointment, EPCOR assumed all of the Corporation's rights and obligations in respect 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 need to administer these retail responsibilities by adding necessary staff, facilities and/or equipment.

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, the eligibility criteria has 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, an integrated operating agreement was established between the Corporation and this REA. The integrated operating agreement permits EQUS REA to serve any person within the overlapping service area that wishes to become a member of EQUS REA and receive distribution service from it, irrespective of any eligibility criteria. As a consequence, the integrated operating agreement with EQUS REA may result in persons choosing to receive service from EQUS REA that prior to the agreement would otherwise be entitled only to receive 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. 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. A decline in Alberta's economy and increased electricity costs due to the renewable energy increases, the phasing out of coal fueled generation and the upcoming capacity market also may result in existing customers reviewing and reducing their demand and energy consumption. 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, and related revenues from customers.

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 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 ("ISO") 14001. The Corporation has an independent external audit completed every three years on the entire EMS to ensure compliance with ISO 14001. The most recent external EMS audit was completed in the third quarter of 2018. As at December 31, 2018, 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 2018 and effective April 1, 2018.

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.

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 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 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 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 the Department of Aboriginal Affairs and Northern Development 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 80% 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.