FORTISALBERTA INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the three and twelve months ended December 31, 2016

February 8, 2017

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, 2016, prepared in accordance with accounting principles generally accepted in the United States ("US GAAP"). All financial information presented in this MD&A has been 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 2017. 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 licences 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 which 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 risk; 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 technology infrastructure; cyber-security risk; insurance coverage risk; risk of loss of permits and rights-of-way; labour relations risk; human resources risk; and the ability to report under US GAAP beyond 2018.

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 122,000 kilometres in central and southern Alberta, which serves approximately 549,000 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 ("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 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 a five-year term. Under PBR, a formula that estimates inflation annually and assumes productivity improvements ("I-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 2012 distribution rates are the base rates upon which the formula was first applied and they were set using a traditional cost-of-service model whereby the AUC established the Corporation's revenue requirements, 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 deemed equity ratio of 41%. For 2013, 2014 and 2015, the Corporation's ROE was set at 8.30% with a deemed equity ratio of 40%. For 2016 and 2017, the Corporation's ROE has been set at 8.30% and 8.50%, respectively, with a deemed equity ratio of 37%. The impact of changes to ROE and capital structure during the PBR term apply only to the portion of rate base that is funded by revenue provided by mechanisms separate from the formula.

The PBR plan includes 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 are not being recovered through the formula ("K factor" or "capital tracker"). The AUC also approved a Z factor, a PBR re-opener and an ROE efficiency carry-over mechanism. The Z factor permits an application for recovery of costs related to significant unforeseen events. The PBR re-opener permits an application to re-open and review the PBR plan to address specific problems with the design or operation of the PBR plan. The use of the Z factor and PBR re-opener mechanisms is associated with certain thresholds. The ROE efficiency carry-over mechanism provides 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.

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 electric and gas utility business, serving customers across Canada and in the United States and the Caribbean.

REGULATORY MATTERS

Capital Tracker Applications

In February 2016, the AUC issued Decision 20497-D01-2016 (the "2016 Capital Tracker Decision") related to the Corporation's 2014 True-Up and 2016-2017 Capital Tracker Application. In that Application, the Corporation had sought: (i) capital tracker revenue for 2016 and 2017 of $71.5 million and $89.9 million, respectively; (ii) an update to the 2014 capital tracker revenue to reflect actual capital tracker expenditures; and (iii) approval of additional revenue related to capital tracker amounts for 2013, 2014 and 2015 that had not been fully approved in the 2015 Capital Tracker Decision received in March 2015. The 2016 Capital Tracker Decision also addressed depreciation-related matters.

With respect to the depreciation-related matters, the AUC directed that the impact of a 2015 depreciation technical update not be included in the determination of the K factor amounts for 2015, 2016 and 2017. Actual depreciation expense, as reflected in the financial results of the Corporation, continues to be determined in accordance with the depreciation rates established by the 2015 depreciation technical update.

The effects of the 2016 Capital Tracker Decision reduced the applied for capital tracker revenue for 2016 and 2017 by $0.6 million and $0.4 million, respectively, and these reductions were reflected in the Corporation's required Compliance Filing. In September 2016, the AUC approved the Corporation's Compliance Filing in Decision 21520-D01-2016, including capital tracker revenue for 2016 and 2017 of $70.9 million and $89.5 million, respectively.

In June 2016, the Corporation filed a 2015 True-Up Application to update 2015 capital tracker revenue for actual capital tracker expenditures and the effects of the 2016 Capital Tracker Decision. The AUC issued its decision on the 2015 True-Up Application in January 2017, approving the 2015 capital tracker amount as filed, pending the Corporation submitting a Compliance Filing in February 2017.

For the year ended December 31, 2016, capital tracker revenue related to prior years was reduced by $0.7 million to update the 2014 and 2015 capital tracker revenues for actual capital tracker expenditures for those years and reflect additional capital tracker amounts for 2013, 2014, and 2015 not previously approved. Capital tracker revenue related to 2016 has been updated to $58.8 million, $12.1 million lower than the $70.9 million per the Compliance Filing, to reflect actual capital expenditures, associated carrying costs, and the impact of the 2016 Generic Cost of Capital Decision, discussed below.

The Corporation included the adjustments related to the 2016 Capital Tracker Decision and the 2015 Capital Tracker True-Up Application in its 2017 Annual Rates Application, discussed below. Any further differences between the 2015 and 2016 capital tracker revenues collected from customers and that reflecting actual capital expenditures will be included in a rates filing in 2017, for refund to, or collection from, customers in 2018.

Generic Cost of Capital

In October 2016, the AUC issued Decision 20622-D01-2016 (the "2016 GCOC Decision") related to the 2016 and 2017 Generic Cost of Capital proceeding. In this decision, the AUC maintained an 8.30% allowed ROE for 2016 and increased the allowed ROE to 8.50% for 2017. The decision also set the equity portion of capital structure at 37% for most utilities, which is a decrease from 40% for the Corporation.

For Alberta utilities under PBR, including the Corporation, the impact of the changes to the allowed ROE and capital structure resulting from the 2016 GCOC Decision applies to the portion of rate base that is funded by capital tracker revenue only.

2017 Annual Rates Application

In September 2016, the Corporation filed its 2017 Annual Rates Application. The rates and riders, proposed to be effective on an interim basis for January 1, 2017, included a decrease of approximately 2.4% to the distribution component of customer rates. However, the overall distribution tariff impact, which included the impact of transmission and generation, is an increase of 4.6%.

The decrease in the distribution component of rates reflects: (i) a combined inflation and productivity factor (I-X) of negative 1.9%; (ii) a K factor placeholder of $89.5 million, which is 100% of the depreciation and return associated with the 2017 forecast capital tracker expenditures; (iii) a refund of $13.1 million, which is the difference between the 2013-2016 K factor amounts applied for or approved and the amounts collected; (iv) a refund of $0.5 million of K factor carrying costs; and (v) a net collection of Y factor amounts of $0.5 million. The refund of $13.1 million was primarily due to the over collection of 2015 capital tracker revenue, as accounted for in the K factor deferrals on the balance sheets as at December 31, 2016 and 2015.

In December 2016, the Commission issued a decision approving the 2017 rates, options, and riders schedules, on an interim basis, effective January 1, 2017 with rate mitigation measures for residential customers only. The Commission imposed this rate mitigation strategy until April 1, 2017 in order to partially offset the impact of the transmission and generation-related increase discussed above. The Corporation has been directed to file an application in February 2017 for revised residential distribution rates to be effective April 1, 2017. These revised rates will reflect the collection of residential distribution revenue as though the proposed increase of 4.6% had been implemented on January 1, 2017.

Utility Asset Disposition Matters

In Decision 2011-474 (the "2011 GCOC Decision"), the AUC made statements regarding cost responsibility for stranded assets, which the Corporation, along with the other Alberta Utilities (the "Utilities") challenged as being incorrectly made. Stranded assets are generally understood to be utility assets no longer used to provide utility services as a result of extraordinary circumstances. The AUC's statements implied that the shareholder is responsible for the cost of stranded assets in a broader sense than that generally understood by regulated utilities and also conflicted with the provisions of the *EUA*. As a result, the Utilities filed a leave to appeal motion with the Alberta Court of Appeal (the "Court of Appeal"). In addition, the Utilities filed a Review and Variance Application with the AUC, which prompted the AUC to initiate a Utility Asset Disposition proceeding to further examine the issues raised by the Utilities.

In November 2013, the AUC issued Decision 2013-417 (the "UAD Decision") regarding the Utility Asset Disposition proceeding. The decision confirmed that no changes to existing regulations, rules and practices relative to the recovery of utility asset costs in the ordinary course of business are required. The decision indicated, however, that utilities will be responsible for the gains or losses related to the extraordinary retirement of utility assets. The Utilities also filed a leave to appeal motion with the Court of Appeal concerning the UAD Decision.

The appeal of the 2011 GCOC Decision and the UAD Decision was heard in June 2015. In September 2015, the Court of Appeal issued a decision that dismissed that appeal (the "2015 UAD Appeal"). The basis for the Court of Appeal's decision was that the AUC should be accorded deference for its conclusions with respect to utility asset disposition matters.

In November 2015, the Utilities filed an Application with the Supreme Court of Canada (the "Supreme Court") seeking leave to appeal the 2015 UAD Appeal. In April 2016, the Supreme Court dismissed the leave to appeal application.

The Court of Appeal and Supreme Court decisions have no immediate impact on the Corporation's financial position. However, the Corporation is exposed to the risk that unrecovered costs associated with utility assets subsequently deemed by the AUC to have been subject to an "extraordinary" retirement will not be recoverable from customers.

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 ("PBR Utilities") during the second PBR term, which will be 2018 to 2022.

As directed, the PBR Utilities will file a rebasing application ("Next Generation Compliance Filing") in March 2017 that will establish a going-in revenue requirement for the second PBR term. The going-in revenue requirement will be used to determine the going-in rates upon which the PBR formula will be applied to establish distribution rates for 2018. The Next Generation Compliance Filing will achieve the rebasing necessary between PBR terms to re-establish the linkage between and realign a utility's revenues and costs. A decision on the Next Generation Compliance Filing is expected in the second half of 2017.

Consistent with the first PBR term, annual distribution rates will be determined using a formula that estimates inflation and assumes productivity improvements (I-X) applied to the preceding year's distribution rates. The inflation factor (I) will be determined annually in the same manner as during the first PBR term. The productivity factor (X) is set at 0.30% for the second PBR term, compared to 1.16% for the first PBR term.

Also consistent with the first PBR term, the second PBR term will include: a Y factor, for the recovery or settlement of items determined to flow through directly to customers; a Z factor, which permits an application for recovery of costs related to significant unforeseen events; a PBR re-opener, which permits an application to re-open and review the PBR plan to address specific problems with the design or operation of the PBR plan; and an ROE efficiency carry-over mechanism, which provides 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. Incremental capital funding to recover costs related to capital expenditures that are not recovered through the formula will continue in the second PBR term, but will be available through two mechanisms, as discussed below.

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. PBR Utilities will be required to submit, as part of their Annual Rates Application, a forecast K Factor amount, of which 90% will be reflected in distribution rates as a placeholder. Annually, a Type 1 True-Up application will be required to test the prudency of the capital expenditures and to true-up to the actual K Factor amount.

Type 2 capital will be all capital included in the going-in rate base and will be incrementally funded through a K-bar mechanism. PBR Utilities will be required to submit a K-bar amount as part of their Annual Rates Application. The 2018 K-bar amount will form the basis upon which future annual K-bar amounts will be determined using a formulaic approach and K-bar amounts will not be subject to true-up for actual capital expenditures.

Other matters covered by the Second-Term PBR Decision include Phase II applications and depreciation studies. 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. PBR Utilities are invited to submit a Phase II application subsequent to the approval of the Next Generation 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 2018.

With respect to depreciation studies, PBR Utilities were directed to use the last approved depreciation study in their Next Generation Compliance Filing. PBR Utilities are permitted to file separate applications in 2018 to seek approval of an updated depreciation study and depreciation changes will be reflected in distribution rates effective January 1, 2018, on a prospective basis. The Corporation anticipates filing an application for approval of an updated depreciation study in 2018.

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 is 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 2015, the Corporation was granted AUC approval to, and did acquire, the electric distribution systems of the Kingman REA Ltd. and the VNM REA Ltd. for $5.1 million and $16.0 million, respectively. Subsequently, in 2016, upon request by the Office of the Utilities Consumer Advocate, the AUC initiated a review of its decisions regarding these acquisitions to confirm that the purchase prices paid by the Corporation were properly determined. While the scope of the proceeding, as established by the AUC, will not permit the withdrawal of the approval for the transfer of assets involved in the acquisitions, this proceeding may result in amounts other than the purchase prices paid being approved for recovery in the Corporation's rates. A decision on this matter is expected in the second quarter of 2017.

In July 2016, the Corporation and the Municipality of Crowsnest Pass ("CNP") agreed to the acquisition by the Corporation of CNP's electric distribution system for a proposed purchase price of $3.7 million, and filed the related Applications with the AUC. In December 2016, as a result of the AUC decision to review the purchase prices of the Kingman and VNM REA acquisitions, the AUC suspended its consideration of the acquisition of CNP until it issues a decision on the purchase prices of the Kingman and VNM REAs. In the interim, the Corporation has an operating agreement with CNP to oversee and maintain its electric distribution system and has placed the proposed purchase price of $3.7 million, plus GST, in trust, as disclosed in Note 2(d) to the 2016 annual financial statements. A decision on this matter is expected in the second half of 2017.

RESULTS OF OPERATIONS

Highlights

	Three Months Ended December 31			Twelve Months Ended December 31		
($ thousands)	2016	2015	Variance	2016	2015	Variance
Revenues	142,613	139,186	3,427	572,239	563,071	9,168
Cost of sales	47,215	50,236	(3,021)	189,351	182,875	6,476
Depreciation	42,742	40,026	2,716	169,693	158,051	11,642
Amortization	2,344	2,464	(120)	9,867	9,755	112
Other income	802	1,675	(873)	2,459	2,982	(523)
Income before interest expense and income tax	51,114	48,135	2,979	205,787	215,372	(9,585)
Interest expense	21,730	19,497	2,233	84,956	78,705	6,251
Income before income tax	29,384	28,638	746	120,831	136,667	(15,836)
Income tax (recovery) expense	(378)	(307)	(71)	137	(849)	986
Net income	29,762	28,945	817	120,694	137,516	(16,822)

Net income for the three months ended December 31, 2016 increased $0.8 million compared to the same period in 2015. The increase was mainly due to rate base growth associated with capital expenditures funded by capital tracker revenue, revenue from new customers, and the timing of operating costs. The increase was partially offset by lower average energy consumption driven by a decline in oil and gas energy usage related to the slowdown in Alberta's economy.

Net income for the twelve months ended December 31, 2016 decreased $16.8 million compared to the same period in 2015. The decrease was primarily due to the recognition in the first half of 2015 of a positive $8.7 million capital tracker adjustment related to 2013 and 2014, and the recognition in the first half of 2016 of a negative $0.7 million capital tracker adjustment related to 2013, 2014 and 2015. Excluding these capital tracker adjustments, net income decreased $7.4 million mainly due to lower average energy consumption driven by the mild weather experienced in 2016, a decline in oil and gas energy usage related to the slowdown in Alberta's economy, higher operating costs, and higher income tax expense. These decreases were partially offset by rate base growth associated with capital expenditures funded by capital tracker revenue, although tempered by the impact of the GCOC Decision, and revenue from new customers.

The following table outlines the significant variances in the Results of Operations for the three months ended December 31, 2016 as compared to December 31, 2015:

Item	Variance ($ millions)	Explanation
Revenues	3.4	Electric rate revenue increased $3.3 million due to the approved I-X increase of 0.9%, revenue from new customers and an increase in flow-through items that were fully offset in cost of sales. Other revenue increased $0.1 million primarily due to the timing of the provision of third party services.
Cost of sales	(3.0)	The decrease was primarily driven by the timing of vegetation management costs and benefit costs, partially offset by net increases in costs that qualify as flow-through items that were fully offset in electric rate revenue. Labour and benefit costs and contracted manpower costs comprised approximately 58% of total cost of sales.
Depreciation	2.7	The increase was due to continued investment in capital assets.
Interest expense	2.2	The increase was primarily attributable to the issuance of long-term debt in September 2016 and a decrease in allowance for funds used during construction ("AFUDC").

The following table outlines the significant variances in the Results of Operations for the twelve months ended December 31, 2016 as compared to December 31, 2015:

Item	Variance ($ millions)	Explanation
Revenues	9.2	Electric rate revenue increased $9.4 million year over year. In 2015, a positive capital tracker revenue adjustment of $8.7 million was recognized, whereas, comparatively, in 2016, a negative capital tracker adjustment of $0.7 million was recognized. Excluding these capital tracker adjustments, electric rate revenue increased $18.8 million due to the approved I-X increase of 0.9%, revenue from new customers, and flow-through items that were fully offset in cost of sales. These increases were partially offset by lower average energy consumption and the impact of the 2016 GCOC Decision on capital tracker revenue. Other revenue decreased $0.2 million primarily due to a reduction in the provision of third party services.
Cost of sales	6.5	The increase was primarily driven by net increases in costs that qualify as flow-through items that were fully offset in electric rate revenue, higher labour and benefit costs driven by inflation and wage increases, higher costs related to regulatory proceedings, and an increase in vegetation management costs. Labour and benefit costs and contracted manpower costs comprised approximately 60% of total cost of sales.
Depreciation	11.6	The increase was due to continued investment in capital assets.
Interest expense	6.3	The increase was primarily attributable to the issuances of long-term debt in September 2015 and September 2016.
Income tax expense	1.0	The increase was primarily attributable to a change in deferrals subject to future income tax without an offsetting regulatory asset.

SUMMARY OF QUARTERLY RESULTS

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

($ thousands)	Revenues	Net Income
December 31, 2016	142,613	29,762
September 30, 2016	143,829	30,387
June 30, 2016	143,806	29,613
March 31, 2016	141,991	30,932
December 31, 2015	139,186	28,945
September 30, 2015	141,751	36,771
June 30, 2015	135,484	30,417
March 31, 2015	146,650	41,383

Changes in 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. The quarterly information presented above has been impacted by specific regulatory decisions. As approved by the AUC, AFUDC is recognized in the first and fourth quarters of the year. There is no significant seasonality in the Corporation's operations.

December 31, 2016/September 30, 2016

Net income for the quarter ended December 31, 2016 decreased $0.6 million compared to the quarter ended September 30, 2016. Electric rate revenue decreased $0.8 million mainly due to a negative capital tracker adjustment in the fourth quarter of 2016, offset by revenue from new customers and higher average energy consumption due to colder temperatures. Other revenue decreased by $0.4 million as a result of a reduction in the provision for third party services. Cost of sales decreased $0.4 million mainly as a result of the timing of vegetation management costs, partially offset by an increase in labour and benefit costs. Due to the timing of the recognition of AFUDC, other income was higher by $0.8 million and interest expense was lower by $0.9 million.

September 30, 2016/June 30, 2016
Net income for the quarter ended September 30, 2016 increased $0.8 million compared to the quarter ended June 30, 2016. Revenue was comparable quarter over quarter as higher energy deliveries related to irrigation were offset by the negative capital tracker adjustment of $2.0 million associated with the 2016 GCOC Decision. Cost of sales increased $0.8 million mainly due to the timing of general operating costs, contracted manpower, and labour costs. Depreciation decreased $0.8 million as a result of the timing of capital additions.

June 30, 2016/March 31, 2016
Net income for the quarter ended June 30, 2016 decreased $1.3 million compared to the quarter ended March 31, 2016. Revenue increased $1.8 million mainly due to higher energy deliveries related to the start of irrigation season, offset by net decreases in revenue related to flow-through items that were fully offset in cost of sales. Cost of sales decreased $0.9 million mainly due to the timing of benefit costs and a reduction in costs that qualify as flow-through items, partially offset by an increase in the use of contracted manpower due to the timing of contracted activities. Other income decreased $1.7 million and interest expense decreased $1.5 million related to the equity and debt portions of the AFUDC, respectively. Depreciation increased $0.5 million as a result of the continued investment in capital assets.

March 31, 2016/December 31, 2015
Net income for the quarter ended March 31, 2016 increased $2.0 million compared to the quarter ended December 31, 2015. Revenue increased $2.8 million due to the approved I-X increase of 0.9% and net increases in revenue related to flow-through items that were fully offset in cost of sales. Cost of sales decreased $2.5 million primarily due to the timing of the use of contracted manpower and general operating costs, partially offset by net increases in costs that qualify as flow-through items. Depreciation expense increased $2.2 million as a result of continued investment in capital assets. Interest expense increased $0.6 million as a result of an increase in credit facility borrowings.

December 31, 2015/September 30, 2015
Net income for the quarter ended December 31, 2015 decreased $7.8 million compared to the quarter ended September 30, 2015. Revenue decreased $2.6 million, primarily as a result of weather conditions reducing energy deliveries. Cost of sales increased $7.0 million mainly due to higher labour and benefit costs and the timing of general operating costs. The decreases in net income were partially offset by an increase in other income of $1.7 million and a decrease in interest expense of $1.5 million related to the equity and debt portions of AFUDC, respectively.

September 30, 2015/June 30, 2015
Net income for the quarter ended September 30, 2015 increased $6.4 million compared to the quarter ended June 30, 2015. Revenue increased $6.3 million mainly due to higher electric rate revenue as a result of customer growth and weather conditions increasing energy deliveries. Also contributing to the increase in net income were adjustments made in the second quarter of 2015 to reduce capital tracker revenue related to 2013 and 2014 upon further application of the 2015 Capital Tracker and 2015 GCOC decisions, and to true-up depreciation for net increases in depreciation rates effective January 1, 2015 based on the results of a technical update to the depreciation study.

June 30, 2015/March 31, 2015
Net income for the quarter ended June 30, 2015 decreased $11.0 million compared to the quarter ended March 31, 2015. Revenue decreased $11.2 million mainly due to the recognition of the capital tracker revenue adjustment related to 2013 and 2014 in the first quarter of 2015, partially offset by an increase in the number of customers and higher energy usage related to the start of irrigation season. Cost of sales decreased $3.1 million mainly due to the timing of benefit costs and a reduction in costs that qualify as flow-through items that were fully offset in electric rate revenue, partially offset by an increase in the use of contracted manpower due to the timing of contracted activities. Other income decreased $0.4 million and interest expense increased $1.3 million related to the equity and debt portions of the AFUDC, respectively. Depreciation increased $1.3 million due to net increases in depreciation rates based on the results of a technical update to the depreciation study.

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, 2016, 2015 and 2014:

($ thousands)	2016	2015	2014
Revenues (1)	572,239	563,071	518,035
Net income (1)	120,694	137,516	102,397
Assets (2)	4,058,911	3,822,606	3,460,624
Long-term debt (2)	1,819,478	1,670,545	1,521,542

(1) *See Results of Operations for commentary on revenue and net income.*
(2) *See Financial Position for a discussion of significant changes in asset and long-term debt balances.*

FINANCIAL POSITION

The following table outlines the significant changes in the Balance Sheet as at December 31, 2016 as compared to December 31, 2015:

Item	Variance ($ millions)	Explanation
Assets:		
Accounts receivable	(12.4)	The decrease was primarily driven by a decrease in transmission riders and the timing of collections from customers, partially offset by increased base rates for distribution and transmission services and growth in the number of customers.
Regulatory assets (current and long-term)	50.5	The increase was primarily due to increases in the deferred income tax regulatory deferral and deferred overhead costs, partially offset by the collection of K factor deferral capital tracker revenue in 2016.
Property, plant and equipment	195.2	The increase was due to continued investment in energy infrastructure, partially offset by depreciation and customer contributions.
Intangible assets	7.4	The increase was due to investment in computer software.
Liabilities and Shareholder's equity:		
Regulatory liabilities (current and long-term)	42.2	The increase was primarily due to an increase in the provision for future site restoration costs, an increase in the K factor deferral representing a reduction in capital tracker revenue to be refunded in future rates, and an increase in the Alberta Electric System Operator ("AESO") charges deferral.
Deferred income tax	43.6	The increase was primarily due to higher temporary differences related to capital assets.
Debt (including short-term borrowings)	153.5	The increase was mainly related to the issuance of $150.0 million senior unsecured debentures in September 2016.

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 operating lines of credit; and
- equity contributions from the Corporation's parent.

STATEMENTS OF CASH FLOWS

	Three Months Ended December 31			Twelve Months Ended December 31		
($ thousands)	2016	2015	Variance	2016	2015	Variance
Cash, beginning of period	14,426	-	14,426	4,742	-	4,742
Cash from (used in):						
Operating activities	96,020	70,945	25,075	327,645	256,991	70,654
Investing activities	(112,756)	(134,523)	21,767	(356,679)	(415,414)	58,735
Financing activities	2,310	68,320	(66,010)	24,292	163,165	(138,873)
Cash, end of period	-	4,742	(4,742)	-	4,742	(4,742)

Operating Activities

For the three months ended December 31, 2016, net cash provided from operating activities was $25.1 million higher than the same period in 2015. The increase was primarily due to the timing of the collection of accounts receivable balances and a decrease in cash expenses related to cost of sales. These increases were partially offset by the timing of the flow through of transmission costs as revenue was collected from customers on a different timeline than costs were paid to the AESO.

For the twelve months ended December 31, 2016, net cash provided from operating activities was $70.7 million higher than the same period in 2015. The increase was primarily due to the timing of the collection of accounts receivable balances, the timing of the flow through of transmission costs as revenue was collected from customers on a different timeline than costs were paid to the AESO, and the timing of the refund of customer deposits related to transmission-connected projects. These increases were partially offset by higher cash expenses related to cost of sales, the timing of payment of accounts payable balances, and higher cash interest paid.

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)	2016	2015	Variance	2016	2015	Variance
Capital expenditures:						
Customer growth [(1)]	34,899	36,202	(1,303)	121,465	158,612	(37,147)
Externally driven and other [(2)]	13,842	11,500	2,342	47,817	47,400	417
Sustainment [(3)]	46,974	42,097	4,877	167,752	151,883	15,869
Distribution system purchases [(4)]	-	21,131	(21,131)	-	21,131	(21,131)
AESO contributions [(5)]	11,091	6,117	4,974	37,982	54,844	(16,862)
Gross capital expenditures	106,806	117,047	(10,241)	375,016	433,870	(58,854)
Less: customer contributions	(4,896)	(6,545)	1,649	(19,978)	(30,447)	10,469
Net capital expenditures	101,910	110,502	(8,592)	355,038	403,423	(48,385)
Adjustment to net capital expenditures for:						
Non-cash working capital	1,075	19,305	(18,230)	(8,720)	889	(9,609)
Costs of removal, net of salvage proceeds	5,468	3,127	2,341	15,982	17,767	(1,785)
Capitalized depreciation, capital inventory, AFUDC, and other	4,303	1,589	2,714	(5,621)	(6,665)	1,044
Cash used in investing activities	112,756	134,523	(21,767)	356,679	415,414	(58,735)

(1) *Includes new customer connections*
(2) *Includes upgrades associated with substations, line moves, new connections for independent power producers and the distribution control centre*
(3) *Includes planned maintenance, capacity increases, facilities, vehicles and information technology*
(4) *The purchase of the electric distribution systems of the Kingman and VNM Rural Electrification Associations ("REAs")*
(5) *Reflects the Corporation's required contributions towards transmission projects as determined by the AUC approved investment levels and paid when transmission projects are approved*

For the three months ended December 31, 2016, the Corporation's gross capital expenditures were $106.8 million compared to $117.0 million for the same period in 2015. While gross capital expenditures were higher in 2015 mainly due to the purchase of the Kingman and VNM REA electric distribution systems for $21.1 million, AESO contributions and sustainment expenditures were higher in 2016 compared to 2015. AESO contributions increased $5.0 million due to the timing of AUC approvals for transmission upgrade projects. Sustainment expenditures increased $4.9 million primarily due to facility-related expenditures to meet operational requirements.

For the twelve months ended December 31, 2016, the Corporation's gross capital expenditures were $375.0 million, compared to $433.9 million for the same period in 2015. Capital expenditures related to customer growth decreased $37.1 million due to lower expenditures for all customer categories other than residential customers. Capital expenditures in 2015 included the purchase of the Kingman and VNM REA electric distribution systems for $21.1 million. AESO contributions decreased by $16.9 million in 2016 due to the volume and timing of AUC approvals for transmission upgrade projects compared to 2015. Partially offsetting the above decreases were sustainment expenditures that increased $15.9 million due to facility-related expenditures to meet operational requirements, higher spending for vehicles due to end-of-life replacements, and higher expenditures for capacity increases and planned maintenance.

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 has forecast gross capital expenditures for 2017 of approximately $408.9 million. The 2017 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 material, and other factors that could cause actual results to differ from forecast. A further decline in Alberta's economy, or in the Corporation's service areas in particular, could have the effect of reducing requests for electricity services from forecast. Significantly reduced requests for services in the Corporation's service areas could materially reduce capital spending, specifically capital spending related to customer growth, externally driven and AESO contributions, which in turn would decrease the related revenues from customers.

Financing Activities

For the three and twelve months ended December 31, 2016, cash from financing activities decreased $66.0 million and $138.9 million, respectively, compared to the same periods in 2015. These decreases were primarily due to an increase in dividends paid and a net decrease in short-term and credit facility borrowings.

Dividends paid increased as a result of the 2016 GCOC Decision, whereby the AUC adjusted the Corporation's capital structure for ratemaking purposes from 60% debt and 40% equity to 63% debt and 37% equity. To achieve the reduction in equity financing of the Corporation's regulated operations a $90.0 million dividend was paid to Fortis in the fourth quarter of 2016.

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, 2016 were as follows:

($ thousands)	Total	2017	2018-2019	2020-2021	Thereafter
Long-term debt [(1)]	1,835,000	-	-	-	1,835,000
Interest obligations on long-term debt	2,176,542	88,379	176,758	176,758	1,734,647
Joint use agreement [(2)]	50,920	2,546	5,092	5,092	38,190
Shared services agreements [(3)]	2,703	737	1,474	492	-
Office leases	3,154	757	1,386	884	127
Defined benefit pension contributions [(4)]	3,569	1,792	1,777	-	-
Performance and restricted share unit obligations [(5)(6)]	1,692	302	1,390	-	-
Total contractual obligations	4,073,580	94,513	187,877	183,226	3,607,964

(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 2021 includes payments to the end of 20 years. However, the payments under this agreement may continue for an indefinite period of time.*

(3) *The Corporation and an Alberta transmission service provider have entered into a number of service agreements to ensure operational efficiencies are maintained through coordinated operations. These service agreements have minimum expiry terms of five years from September 1, 2015, and are subject to extension based on mutually agreeable terms.*

(4) *The Corporation makes minimum defined pension contributions according to the actuarial valuation for funding purposes. The contributions are based on estimates provided under the latest completed actuarial valuation as at December 31, 2015, which provided funding for estimates for a three year period from the date of the valuation. Future actuarial valuations will establish the funding obligations for subsequent years, which could be materially different from prior years depending upon market conditions.*

(5) *The Corporation awarded performance share units ("PSUs") to its executive in 2016, 2015 and 2014. Each PSU represents a unit with an underlying value equivalent to the value of one common share of Fortis and is subject to a three-year vesting period and the achievement of performance measures, at which time a cash payment may be made as determined by the Governance and Human Resources Committee of the Board of Directors.*

(6) *The Corporation awarded restricted share units ("RSUs") to its executive in 2016 and 2015. Each RSU represents a unit with an underlying value equivalent to the value of one common share of Fortis and is subject to a three-year vesting period, at which time a cash payment may be made as determined by the Governance and Human Resources Committee of the Board of Directors.*

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 and/or equity contributions by Fortis via Fortis Alberta Holdings Inc.

The AUC determines the capital structure for Alberta utilities for financing their regulated operations. In the 2016 GCOC Decision, the AUC adjusted the Corporation's capital structure for ratemaking purposes to 63% debt and 37% equity. The approved capital structure for 2015 was 60% debt and 40% equity.

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:	2016		2015	
	$ millions	%	$ millions	%
Total debt	1,912.1	59.8	1,758.5	57.7
Shareholder's equity	1,286.7	40.2	1,291.0	42.3
	3,198.8	100.0	3,049.5	100.0

The Corporation has externally imposed capital requirements by virtue of its Trust Indenture and committed credit facility that limit the amount of debt that can be incurred relative to equity. As at December 31, 2016, the Corporation was in compliance with these externally imposed capital requirements.

In June 2016, the Corporation repaid the demand note outstanding with Fortis (December 31, 2015 - $35.0 million). The demand note was unsecured, due on demand and the Corporation incurred interest that approximated the Corporation's cost of short-term borrowing.

In July 2016, the Corporation renegotiated and amended its syndicated credit facility, extending the maturity date of the facility to August 2021 from August 2020. The amended agreement contains substantially similar terms and conditions as the previous agreement.

In September 2016, 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 3.34%, to be paid semi-annually, and mature in 2046. 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.

In November 2016, the Corporation negotiated a one-year bilateral credit facility to finance the $90.0 million dividend paid to Fortis as a result of the 2016 GCOC Decision.

As at December 31, 2016, the Corporation had unsecured committed credit facilities with an available amount of $340.0 million, consisting of a long-term credit facility of $250.0 million maturing in August 2021 and a bilateral credit facility of $90.0 million maturing in November 2017. Drawings under the credit facilities 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, 2016 on the credit facilities was 2.1% (2015 - 2.4%). As at December 31, 2016, there were no drawings under the long-term credit facility (December 31, 2015 - $53.0 million) and $90.0 million in drawings under the bilateral credit facility (December 31, 2015 - $nil).

CREDIT RATINGS

As at December 31, 2016, the Corporation's debentures were rated by DBRS at A (low) and by Standard and Poor's ("S&P") at A-. In December 2016, DBRS confirmed the Corporation's credit rating of A (low) with an outlook of Stable. In October 2016, S&P returned the Corporation's outlook to Stable from Negative as a result of the closing of Fortis' acquisition of ITC Holdings Corp.

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. Subject to applicable law, the Corporation shall have the right to redeem, at any time, all or any part of the then outstanding first preferred shares for $348.9 million together with any accrued and unpaid dividends up to the redemption date.

Issued:

- 63 Class A common shares, with no par value

OFF-BALANCE SHEET ARRANGEMENTS

With the exception of letters of credit outstanding of $0.1 million as at December 31, 2016 (December 31, 2015 - $0.4 million), the Corporation had no off-balance sheet arrangements.

RELATED PARTY TRANSACTIONS

In the normal course of business, the Corporation transacts with 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)	2016	2015
Accounts receivable		
Loans [(1)]	17	16
Related parties	10	117
	27	133
Short-term borrowings		
Related party [(2)]	-	35,000

(1) *These loans are to officers of the Corporation and may include stock option loans, employee share purchase plan loans and employee personal computer purchase program loans.*
(2) *Demand note from Fortis that was borrowed in October 2015 and repaid in the second quarter of 2016*

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, 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)	2016	2015	2016	2015
Included in other revenue [(1)]	26	28	125	477
Included in cost of sales [(2)]	1,270	768	4,790	3,549
Included in interest expense [(3)]	-	42	138	42

(1) *Includes services provided to Fortis and subsidiaries of Fortis related to metering, information technology, material sales and intercompany employee services*
(2) *Includes charges from Fortis and subsidiaries of Fortis related to corporate governance expenses, stock-based compensation costs, consulting services, travel and accommodation expenses, and pension costs*
(3) *Reflects interest expense paid on demand note from Fortis that was borrowed in October 2015 and repaid in the second quarter of 2016.*

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)	2016	2015
Fair value [(1)]	2,117,122	1,938,533
Carrying value [(2)]	1,833,594	1,683,825

(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 $14,116 (December 31, 2015 - $13,280).*

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, short-term borrowings and current liabilities on the balance sheets approximate their fair value, which reflects the short-term maturity, normal trade credit terms and/or nature of these financial instruments.

SIGNIFICANT 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 significant 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 primarily on depreciation parameters, including the service life of assets and expected net salvage percentages, which are periodically calculated in a depreciation study and approved by the AUC. The depreciation and amortization rates are subject to change when a new depreciation study is completed by the Corporation and approved by the AUC or when a technical update to the depreciation study is completed. A technical update adjusts depreciation and amortization rates based on current capital asset balances while retaining the depreciation parameters established in the last approved depreciation study.

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 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. Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recognized only when the more likely than not threshold is met. The 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 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 the net identifiable assets of operations acquired. Goodwill is carried at initial cost less any previous amortization and write-down for impairment. If the carrying value of the reporting unit exceeds its fair value, an impairment loss is recognized to the extent that the carrying amount of the goodwill exceeds its fair market value. During each fiscal year and as economic events dictate, management reviews the valuation of the goodwill, taking into consideration any events or circumstances that might have impaired the fair value.

The primary method for estimating fair value of the Corporation is the income approach, whereby net cash flow projections are discounted using an enterprise value method. The income approach uses several underlying estimates and assumptions with varying degrees of uncertainty, including the amount and timing of expected future cash flows, growth rates, and the determination of appropriate discount rates. A secondary valuation method, the market approach, as well as a reconciliation of the total estimated fair value of all reporting units to the Corporation's market capitalization, is also performed as an assessment of the conclusions reached under the income approach.

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 adverse effect on the Corporation's results of operations or financial position.

CHANGES IN ACCOUNTING POLICIES

The Corporation considers the applicability and impact of all Accounting Standards Updates ("ASU") issued by the Financial Accounting Standards Board ("FASB"). The following updates have been issued by 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.

Future Accounting Pronouncements

Revenue from Contracts with Customers

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers*. The amendments in this update create Accounting Standards Codification ("ASC") Topic 606, *Revenue from Contracts with Customers*, and supersede the revenue recognition requirements in ASC Topic 605, *Revenue Recognition*, including most industry-specific revenue recognition guidance throughout the codification. This standard clarifies the principles for recognizing revenue and can be applied consistently across various transactions, industries and capital markets. In 2016, a number of additional ASUs were issued that clarify implementation guidance in ASC Topic 606. This standard, and all related ASUs, is effective for annual and interim periods beginning after December 15, 2017. Early adoption is permitted for annual and interim periods beginning after December 15, 2016. The Corporation does not expect to early adopt.

The new guidance permits two methods of adoption: (i) the full retrospective method, under which comparative periods would be restated and the cumulative impact of applying the standard would be recognized as at January 1, 2017, the earliest period presented; and (ii) the modified retrospective method, under which comparative periods would not be restated and the cumulative impact of applying the standard would be recognized at the date of initial adoption, January 1, 2018. The Corporation expects to use the modified retrospective approach, however, it continues to monitor industry developments. Any significant industry developments could change the Corporation's expected method of adoption.

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 regulator, and is considered to be in the scope of ASU 2014-09. The Corporation does not expect that the adoption of this standard, and all related ASUs, will have a material impact on the recognition of revenue generated from the distribution of electricity to end-use customers; however, the Corporation does expect it will impact its required disclosures. Certain industry specific interpretive issues, including contributions in aid of construction, remain outstanding and the conclusions reached, if different than currently anticipated, could have a material impact on the Corporation's financial statements and related disclosures. The Corporation continues to closely monitor industry developments related to the new standard.

Leases

In February 2016, FASB issued ASU 2016-02, *Leases.* The amendments to this update create ASC Topic 842, *Leases,* and supersedes lease requirements in ASC Topic 840, *Leases.* The main provision of Topic 842 is the recognition of lease assets and lease liabilities on the balance sheet by lessees for those leases that were previously classified as operating leases. For operating leases, a lessee is required to do the following: (i) recognize a right-of-use asset and a lease liability, initially measured at the present value of the lease payments, on the balance sheet; (ii) recognize a single lease cost, calculated so that the cost of the lease is allocated over the lease term on a generally straight-line basis; and (iii) classify all cash payments within operating activities in the statement of cash flows. These amendments also require qualitative disclosures along with specific quantitative disclosures. This update is effective for annual and interim periods beginning after December 15, 2018 and is to be applied using a modified retrospective approach with practical expedient options. Early adoption is permitted. The Corporation is assessing the impact that the adoption of this update will have on its financial statements and related disclosures.

Measurement of Credit Losses on Financial Instruments

In June 2016, FASB issued ASU 2016-09, *Measurement of Credit Losses on Financial Instruments.* The amendments in this update require entities to use an expected credit loss methodology and to consider a broad range of reasonable and supportable information to inform credit loss estimates. This update is effective for annual and interim periods beginning after December 15, 2019 and is to be applied on a modified retroactive basis. Early adoption is permitted for annual and interim periods beginning after December 15, 2018. The Corporation is assessing the impact that the adoption of this update will have on its financial statements and related disclosures.

Simplifying the Test for Goodwill Impairment

In January 2017, FASB issued ASU 2017-04, *Simplifying the Test for Goodwill Impairment.* The amendments in this update simplify the subsequent measurement of goodwill by eliminating step two in the current two-step goodwill impairment test. An entity will apply a one-step quantitative test and record the amount of goodwill impairment as the excess of a reporting unit's carrying amount over its fair value, not to exceed the total amount of goodwill allocated to the reporting unit. The new guidance does not amend the optional qualitative assessment of goodwill impairment. This update is effective for annual and interim periods beginning after December 15, 2019 and is to be applied on a prospective basis. Early adoption is permitted for interim and annual goodwill impairment tests performed on testing dates after January 1, 2017. The Corporation expects to early adopt this standard in 2017; however, does not expect that early adoption will have a material impact on its financial statements and related disclosures.

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 ending in 2017, a second five-year term will commence 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 that those excess capital expenditures will not qualify, or be approved, for incremental capital funding where necessary; 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.

As discussed in the "Regulatory Matters" section of this MD&A, the Court of Appeal and the Supreme Court dismissed the appeals of the Utilities with respect to utility asset dispositions. The Corporation is now exposed to the risk that the unrecovered cost of assets subsequently deemed by the AUC to have been subject to an "extraordinary retirement" will not be recoverable from customers. 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. From time to time, 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 to be as agreed to by the Corporation and the municipality, failing which such 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 affected by transactions of this type from time to time.

Within certain portions of the Corporation's service areas, REAs have the right to provide electric distribution service to their eligible members 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, a new integrated operating agreement was established between the Corporation and this REA. The new integrated operating agreement permits EQUS REA to serve any person wishing to become a member of EQUS REA and receive distribution service from it, irrespective of any eligibility criteria. As a consequence, the new integrated operating agreement with EQUS REA may result in persons choosing to receive service from EQUS REA that prior to the new 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 an 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. Significantly reduced requests for services in the Corporation's service areas 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 14001 standard. As at December 31, 2016, 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 lands on which its 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 2016 and effective April 1, 2016.

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's distribution assets require maintenance, improvement and replacement. Accordingly, to ensure the continued performance of the physical assets, the Corporation determines expenditures that must be made to maintain and replace the assets. The Corporation could experience service disruptions and increased costs if it is unable to maintain its asset base. The inability to obtain AUC approval to include in customer rates the capital expenditures that the Corporation believes are necessary to maintain, improve and replace its distribution assets, the failure by the Corporation to properly implement or complete approved expenditure programs, or the occurrence of significant unforeseen equipment failures despite the maintenance program could have a material adverse effect on the Corporation.

The Corporation is responsible for operating and maintaining its assets in a safe manner, including the development and/or application of appropriate standards, processes and procedures to ensure the safety of the Corporation's employees, contractors, and the general public. The failure to do so may disrupt the Corporation's ability to safely distribute electricity, which could have a material adverse effect on the Corporation.

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. Such analysis is based on assumptions as to the costs of services and equipment, regulatory requirements, revenue requirement approvals, and other matters which are uncertain. If actual costs exceed AUC approved expenditures, it is uncertain as to whether any additional costs will be approved by the AUC and recovered through customer rates. The 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 recoverable from customers.

Information Technology and Cyber-Security 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 technology systems to external threats poses a risk to the security of these systems and information. Such cyber-security threats include unauthorized access to information technology systems due to hacking, viruses and other causes that can result in service disruptions, system failures and the deliberate or inadvertent disclosure of confidential business and customer information.

The Corporation is required to protect information 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 technology systems; however, cyber-security threats frequently change and require ongoing monitoring and detection capabilities. In the event the Corporation's information technology security measures are breached, it could experience service disruptions, property damage, corruption or unavailability of critical data or confidential employee and customer information. If the breach is material in nature it could adversely affect the financial performance of the Corporation and its reputation and standing with customers and the regulator, and expose it to claims of third-party damage, all of which could adversely affect the Corporation if the situation is not resolved in a timely manner, or if the financial impact of such adverse effects is not alleviated through insurance policies or through recovery from customers in future rates.

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 81% of the employees of the Corporation are members of the United Utility Workers' Association ("UUWA"). The Corporation's four-year Collective Agreement with the UUWA expires on December 31, 2017. 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 new 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 from the 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.

Reporting in Accordance with US GAAP

In January 2014, the Ontario Securities Commission (the "OSC") issued a relief order which permits the Corporation to continue to prepare its financial statements in accordance with US GAAP until the earliest of: (i) January 1, 2019; (ii) the first day of the financial year that commences after the Corporation ceases to have activities subject to rate regulation; or (iii) the effective date prescribed by the International Accounting Standards Board ("IASB") for the mandatory application of a standard within International Financial Reporting Standards ("IFRS") specific to entities with activities subject to rate regulation.

If the OSC relief does not continue as detailed above, the Corporation would then be required to become a U.S. Securities and Exchange Commission registrant in order to continue reporting under US GAAP, or adopt IFRS. The IASB has released an interim, optional standard on Regulatory Deferral Accounts and continues to work on a project focusing on accounting specific to rate-regulated activities. It is not yet known when this project will be completed or whether IFRS will, as a result, include a permanent, mandatory standard to be applied by entities with activities subject to rate regulation. In the absence of a permanent standard for rate regulated activities, the application of IFRS could result in volatility in earnings as compared to that which would be recognized under US GAAP.

The Corporation continues to closely monitor the efforts of the IASB to issue a permanent standard specific to entities with activities subject to rate regulation. In the event that such a standard will not be issued before, or issued with an effective date after, the expiry of the OSC relief order, the Corporation will consider seeking an extension to the OSC relief order.

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.