FORTISALBERTA INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the three and twelve months ended December 31, 2015

February 10, 2016

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, 2015, 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 2016. 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 121,000 kilometres in central and southern Alberta, which serves approximately 539,000 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* 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 has been set at 8.30% with a deemed equity ratio of 40%. 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

Generic Cost of Capital

In March 2015, the AUC issued Decision 2191-D01-2015 (the "2015 GCOC Decision") related to the 2013-2015 Generic Cost of Capital ("GCOC") proceeding. In this decision, the AUC set the Corporation's allowed ROE for ratemaking purposes for 2013-2015 at 8.30%, down from the interim ROE of 8.75%, and set the deemed equity ratio at 40%, down from 41%.

The AUC also determined that it would not re-establish a formula-based approach to setting annual ROE at this time. Instead, the allowed ROE of 8.30% and deemed equity ratio of 40% would remain in effect on an interim basis for 2016 and beyond.

For Alberta utilities under PBR, including FortisAlberta, the impact of the changes to the allowed ROE and capital structure resulting from the 2015 GCOC Decision applies to the portion of rate base that is funded by capital tracker revenue only. For assets not being funded by capital tracker revenue, no revenue adjustment is required for the change in allowed ROE and deemed equity ratio from that set in an earlier GCOC decision.

The Corporation, along with other Alberta Utilities (the "Utilities"), filed a Review and Variance application related to the 2015 GCOC Decision on grounds including the position that the AUC erred by using hindsight to arrive at the ROE. In January 2016, the AUC dismissed the Review and Variance application. The Corporation also filed an application with the Court of Appeal of Alberta (the "Court") for leave to appeal aspects of the 2015 GCOC Decision related to retrospective ratemaking and the risk associated with utility asset disposition matters, as discussed below. An appeal hearing is scheduled to be heard in May 2016.

In April 2015, the AUC initiated a GCOC proceeding to set the allowed ROE and capital structure for ratemaking purposes for 2016 and 2017. While the AUC approved a request by the Utilities to negotiate the matters at issue in the GCOC proceeding for 2016, a negotiated settlement was not reached and a 2016 and 2017 GCOC proceeding commenced. A hearing is scheduled for June 2016 and a decision is expected from the AUC before the end of 2016.

Capital Tracker Applications

The funding of capital expenditures during the PBR term is a material aspect of the PBR plan for the Corporation. The PBR plan provides a capital tracker mechanism to fund the recovery of costs associated with certain qualifying capital tracker expenditures.

In March 2015, the AUC issued Decision 3220-D01-2015 (the "2015 Capital Tracker Decision") related to the Corporation's 2013, 2014 and 2015 capital tracker application. The 2015 Capital Tracker Decision: (i) indicated that the majority of the Corporation's applied for capital trackers met the established criteria and were, therefore, approved for collection from customers as a K factor; (ii) approved the Corporation's accounting test to determine qualifying K factor amounts; and (iii) confirmed certain inputs to be used in the accounting test, including the conclusion that the weighted average cost of capital be based on actual debt rates and the allowed ROE and capital structure approved in the 2015 GCOC Decision.

In April 2015, the Corporation filed the required Compliance Filing related to the 2015 Capital Tracker Decision, which was approved in September 2015 substantially as filed. Capital tracker revenue of $17.4 million was approved for 2013 on an actual basis, and capital tracker revenue of $42.2 million and $62.2 million was approved on a forecast basis for 2014 and 2015, respectively. The Corporation collected $14.6 million and $29.2 million in 2013 and 2014, respectively, and collected $62.0 million in 2015, related to capital tracker expenditures.

In May 2015, the Corporation filed a 2014 True-Up and 2016-2017 Capital Tracker Application with the AUC. The Corporation sought: (i) capital tracker revenue for 2016 and 2017 of $71.5 million and $89.9 million, respectively; (ii) a reduction to the 2014 capital tracker revenue of $5.4 million to reflect actual capital tracker expenditures; and (iii) approval of additional revenue related to capital tracker amounts that had not been fully approved in the 2015 Capital Tracker Decision. A hearing related to this proceeding concluded in October 2015 and a decision from the AUC is expected in the first quarter of 2016.

The Corporation recognized capital tracker revenue of approximately $59.2 million in 2015, of which $8.7 million was related to updates to the 2013 and 2014 approved capital tracker amounts. The capital tracker revenue for 2015 of approximately $50.5 million incorporates an update for related 2015 capital tracker expenditures as compared to the approved forecast reflected in current rates. This resulted in a deferral of $11.5 million of 2015 capital tracker revenue as a regulatory liability.

Further adjustment to the capital tracker amounts for 2013, 2014 and 2015, for amounts re-applied for or presented for true-up, will result in an adjustment to revenue. Such an adjustment will be recognized when an AUC decision is received or when sufficient information is available to allow management to estimate the required adjustment in accordance with US GAAP.

Utility Asset Disposition Matters

In Decision 2011-474 (the "2011 GCOC Decision"), the AUC made statements regarding cost responsibility for stranded assets, which 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 Court. 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 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 issued a decision that dismissed that appeal (the "2015 UAD Appeal"). The basis for the Court's decision was that the AUC should be accorded deference for its conclusions with respect to utility asset disposition matters.

The Court's decision has 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.

In November 2015, the Utilities filed an application with the Supreme Court of Canada seeking leave to appeal the 2015 UAD Appeal. The outcome and timing of the leave application is unknown.

Rural Electrification Association Purchases

In September 2015, the AUC approved the discontinuation of the operations of Kingman Rural Electrification Association ("REA") Ltd., and the sale and transfer of Kingman REA's electricity distribution system to the Corporation for a purchase price of $5.1 million. The sale closed on October 1, 2015.

In October 2015, the AUC approved the discontinuation of the operations of VNM Rural Electrification Association Ltd., and the sale and transfer of VNM REA's electricity distribution system to the Corporation for a purchase price of $16.0 million. The sale closed on November 1, 2015.

2016 Annual Rates Application

In December 2015, the AUC approved the Corporation's 2016 Annual Rates Application substantially as filed on an interim basis. The rates and riders, effective January 1, 2016, include an increase of approximately 4.6% to the distribution component of customer rates. This increase reflects: (i) a combined inflation and productivity factor of 0.9%; (ii) a K factor placeholder of $64.4 million, which is 90% of the depreciation and return associated with the 2016 forecast capital tracker expenditures as filed for in the 2014 True-Up and 2016-2017 Capital Tracker Application; (iii) $16.8 million for adjustments to 2013, 2014 and 2015 capital tracker revenue as filed for in the Corporation's Compliance Filing related to the 2015 Capital Tracker Decision; and (iv) a net collection of Y factor amounts of $0.3 million.

Beyond the 2013-2017 PBR Term

With the current PBR term expiring in 2017, the AUC has initiated a generic proceeding to establish parameters for the next generation of PBR plans. The Utilities will be making submissions regarding matters for the next PBR term in the first quarter of 2016, and a hearing is scheduled for July 2016.

RESULTS OF OPERATIONS

Highlights

	Three Months Ended December 31			Twelve Months Ended December 31		
($ thousands)	2015	2014	Variance	2015	2014	Variance
Revenues	139,186	132,135	7,051	563,071	518,035	45,036
Cost of sales	50,236	47,848	2,388	182,875	176,076	6,799
Depreciation	40,026	36,422	3,604	158,051	144,119	13,932
Amortization	2,464	5,105	(2,641)	9,755	20,027	(10,272)
Other income	1,675	1,475	200	2,982	2,885	97
Income before interest expense and income tax	48,135	44,235	3,900	215,372	180,698	34,674
Interest expense	19,497	20,099	(602)	78,705	79,344	(639)
Income before income tax	28,638	24,136	4,502	136,667	101,354	35,313
Income tax (recovery) expense	(307)	(275)	(32)	(849)	(1,043)	194
Net income	28,945	24,411	4,534	137,516	102,397	35,119

Net income for the three months ended December 31, 2015 increased $4.5 million compared to the same period in 2014. The increase was mainly due to rate-base growth associated with capital expenditures and growth in the number of customers, and the net impact of a technical update on depreciation and amortization. These increases were partially offset by higher operating costs and a decrease in the provision of third-party services.

Net income for the twelve months ended December 31, 2015 increased $35.1 million compared to the same period in 2014. The increase was due to the impact of rate base growth associated with capital expenditures and growth in the number of customers, the recognition in 2015 of a capital tracker revenue adjustment of $8.7 million related to 2013 and 2014 as a result of the 2015 Capital Tracker and 2015 GCOC Decisions, and the net impact of a technical update on depreciation and amortization. These increases were partially offset by higher operating costs and a decrease in the provision of third-party services.

The following table outlines the significant variances in the Results of Operations for the three months ended December 31, 2015 as compared to December 31, 2014:

Item	Variance ($ millions)	Explanation
Revenues	7.1	Electric rate revenue increased by $9.5 million primarily due to the approved I-X increase of approximately 1.49% and estimated capital tracker revenue based on the 2015 Capital Tracker and the 2015 GCOC decisions. Also contributing to the increase in revenue was the growth in the number of customers and net increases in revenues related to flow-through items that were fully offset in the cost of sales. Other revenue decreased by $2.4 million primarily due to a decrease in the provision of third-party services.
Cost of sales	2.4	The increase was primarily driven by higher labour and benefit costs and net increases in costs that qualify as flow-through items, which were fully offset in electric rate revenue. Labour and benefit costs and contracted manpower costs comprised approximately 61% of total cost of sales.
Depreciation	3.6	The increase was due to continued investment in capital assets and net increases in depreciation rates based on the results of a technical update to the depreciation study. Refer to the "Significant Accounting Estimates" section of this MD&A for further information.
Amortization	(2.6)	The decrease is primarily due to decreases in amortization rates based on the results of a technical update to the depreciation study. Refer to the "Significant Accounting Estimates" section of this MD&A for further information.

The following table outlines the significant variances in the Results of Operations for the twelve months ended December 31, 2015 as compared to December 31, 2014:

Item	Variance ($ millions)	Explanation
Revenues	45.0	Electric rate revenue increased by $47.2 million primarily due to the approved I-X increase of 1.49% and estimated capital tracker revenue based on the 2015 Capital Tracker and the 2015 GCOC Decisions. Also contributing to the increase was: (i) the recognition of the capital tracker revenue adjustment related to 2013 and 2014 of $8.7 million in the first half of 2015; (ii) growth in the number of customers; and (iii) net increases in revenues related to flow-through items that were fully offset in the cost of sales. Other revenue decreased by $2.2 million primarily due to a decrease in the provision of third-party services.
Cost of sales	6.8	The increase was primarily due to net increases in costs that qualify as flow-through items, which were fully offset in electric rate revenue, and higher labour and benefit costs driven by wage increases. Labour and benefit costs and contracted manpower costs comprised approximately 60% of total cost of sales.
Depreciation	13.9	The increase was due to continued investment in capital assets and net increases in depreciation rates based on the results of a technical update to the depreciation study. Refer to the "Significant Accounting Estimates" section of this MD&A for further information.
Amortization	(10.3)	The decrease was primarily due to decreases in amortization rates based on the results of a technical update to the depreciation study. Refer to the "Significant Accounting Estimates" section of this MD&A for further information.

SUMMARY OF QUARTERLY RESULTS

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

($ thousands)	Revenues	Net Income
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
December 31, 2014	132,135	24,411
September 30, 2014	130,942	27,213
June 30, 2014	128,113	25,352
March 31, 2014	126,845	25,421

Changes in revenues and net income from quarter to quarter are a result of many factors including energy deliveries, number of customer sites, regulatory decisions, ongoing investment in energy infrastructure, and changes in income tax expense. The quarterly information presented above has been impacted by specific regulatory decisions. As approved by the AUC, the allowance for funds used during construction ("AFUDC") is recognized in the first and fourth quarters of the year. There is no significant seasonality in the Corporation's operations.

December 31, 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. Electric rate revenue has decreased by $2.7 million, primarily as a result of weather conditions reducing the demand for energy. Cost of sales increased by $7.0 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 by $6.3 million mainly due to higher electric rate revenue as a result of customer growth and weather conditions increasing the demand for energy. 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 by $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 demand relating 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.

March 31, 2015/December 31, 2014
Net income for the quarter ended March 31, 2015 increased $17.0 million compared to the quarter ended December 31, 2014. Revenue increased by $14.5 million primarily due to the recognition of the capital tracker revenue adjustment related to 2013 and 2014 of $10.3 million in the first quarter of 2015. The increase was also due to higher 2015 revenue resulting from the approved I-X increase of 1.49% and estimated capital tracker revenue based on the 2015 Capital Tracker and the 2015 GCOC Decisions, and net increases in revenues related to flow-through items that were fully offset in cost of sales. These increases were partially offset by $2.3 million in lower revenue related to the timing of the provision of third-party services. Cost of sales decreased $1.6 million primarily due to the timing of general operating costs and use of contracted manpower, partially offset by net increases in costs that qualify as flow-through items that were fully offset in electric rate revenue, and increases in labour and benefit costs. Interest expense decreased $1.4 million due to the repayment of $200.0 million senior unsecured debentures in October 2014 and lower carrying costs associated with lower Alberta Electric System Operator ("AESO") charges deferral account balances.

December 31, 2014/September 30, 2014
Net income for the quarter ended December 31, 2014 decreased $2.8 million compared to the quarter ended September 30, 2014. Revenue increased by $1.2 million mainly due to higher revenue related to the provision of third-party services, while cost of sales increased $4.8 million primarily due to higher labour and benefit costs and the timing of general operating costs. Interest expense increased $0.7 million due to the issuance of $275.0 million senior unsecured debentures in September 2014 and the repayment of $200.0 million senior unsecured debentures in October 2014. The decreases in net income were partially offset by an increase in other income of $1.5 million and a decrease in interest expense of $1.2 million related to the equity and debt portions of AFUDC, respectively.

September 30, 2014/June 30, 2014
Net income for the quarter ended September 30, 2014 increased $1.9 million compared to the quarter ended June 30, 2014. Revenue increased by $2.8 million mainly due to higher electric rate revenue as a result of customer growth, partially offset by net decreases in revenues related to flow-through items that were fully offset in cost of sales. Cost of sales increased $1.2 million primarily due to the timing of expenses, partially offset by net decreases in costs that qualify as flow-through items that were fully offset in electric rate revenue.

June 30, 2014/March 31, 2014
Net income for the quarter ended June 30, 2014 was comparable to the quarter ended March 31, 2014. Revenue increased by $1.3 million mainly due to an increase in the number of customers and higher demand related to the start of the irrigation season, partially offset by net decreases in revenues related to flow-through items that were fully offset in cost of sales. Cost of sales decreased $1.3 million primarily due to the timing of expenses and net decreases in costs that qualify as flow-through items that were fully offset in electric rate revenue. Other income decreased $1.3 million and interest expense increased $1.2 million related to the equity and debt portions of the AFUDC, respectively.

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, 2015, 2014 and 2013:

($ thousands)	2015	2014	2013
Revenues [(1)]	563,071	518,035	475,678
Net income [(1)]	137,516	102,397	93,732
Assets [(2)]	3,822,606	3,460,624	3,265,931
Long-term debt (excluding current portion) [(2)]	1,670,545	1,521,542	1,247,826

(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, 2015 as compared to December 31, 2014:

Item	Variance ($ millions)	Explanation
Assets:		
Accounts receivable	14.1	The increase was primarily driven by the timing of collections from customers, higher transmission riders, increased base rates for distribution and transmission services, and growth in the number of customers.
Income tax receivable	(7.3)	The decrease was mainly due to the refund of installments paid in 2014, which had been based on the preceding year's tax expense.
Regulatory assets (current and long-term)	85.3	The increase was primarily due to increases in the deferred income tax regulatory deferral, deferred overhead costs and the K factor deferral representing 2013 and 2014 capital tracker revenue to be collected from customers in 2016.
Property, plant and equipment	248.8	The increase was due to continued investment in energy infrastructure, partially offset by depreciation and customer contributions.
Intangible assets	15.8	The increase was mainly due to the purchase of land rights related to REA system acquisitions and the completion of information technology projects during the fourth quarter of 2015.
Liabilities and Shareholder's equity:		
Accounts payable and other current liabilities	(9.2)	The decrease was primarily due to a net refund of customer contributions, as the associated transmission-connected projects were completed.
Deferred income tax	69.2	The increase was primarily due to higher temporary differences relating to capital assets and an increase in the Alberta provincial statutory income tax rate to 12% from 10% effective July 1, 2015.
Debt (including short-term borrowings)	213.6	The increase was mainly related to the issuance of $150.0 million senior unsecured debentures in September 2015 and an increase in short-term borrowings.
Shareholder's equity	88.2	The increase was due to net income and equity injections received from Fortis in 2015, net of dividends paid.

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)	2015	2014	Variance	2015	2014	Variance
Cash, beginning of period	-	231,156	(231,156)	-	-	-
Cash from (used in):						
Operating activities	70,945	43,995	26,950	256,991	248,130	8,861
Investing activities	(134,523)	(89,413)	(45,110)	(415,414)	(304,816)	(110,598)
Financing activities	68,320	(185,738)	254,058	163,165	56,686	106,479
Cash, end of period	4,742	-	4,742	4,742	-	4,742

Operating Activities

For the three months ended December 31, 2015, net cash provided from operating activities was $27.0 million higher than the same period in 2014. The increase was primarily due to the timing of the cash flow-through of transmission costs as revenue was collected from customers on a different timeline than costs were paid to the AESO, higher cash earnings, and the timing of cash interest paid. These increases were partially offset by the timing of the refund of customer deposits related to transmission-connected projects, and unfavourable changes in working capital and regulatory deferrals.

For the twelve months ended December 31, 2015, net cash provided from operating activities was $8.9 million higher than the same period in 2014. The increase was due to higher cash earnings, the refund of $11.0 million cash taxes in 2015 as compared to $5.0 million in 2014, and the timing of the cash flow-through of transmission costs, as discussed above. The increases were partially offset by unfavourable changes in working capital and regulatory deferrals, 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)	2015	2014	Variance	2015	2014	Variance
Capital expenditures:						
Customer growth (1)	36,202	45,620	(9,418)	158,612	165,053	(6,441)
Externally driven and other (2)	11,500	11,538	(38)	47,400	45,019	2,381
Sustainment (3)	42,097	34,889	7,208	151,883	112,752	39,131
Distribution system purchases (4)	21,131	-	21,131	21,131	-	21,131
AESO contributions (5)	6,117	7,797	(1,680)	54,844	22,125	32,719
Gross capital expenditures	117,047	99,844	17,203	433,870	344,949	88,921
Less: customer contributions	(6,545)	(13,231)	6,686	(30,447)	(40,368)	9,921
Net capital expenditures	110,502	86,613	23,889	403,423	304,581	98,842
Adjustment to net capital expenditures for:						
Non-cash working capital	19,305	(4,599)	23,904	889	(3,769)	4,658
Costs of removal, net of salvage proceeds	3,127	4,906	(1,779)	17,767	15,391	2,376
Capitalized depreciation, capital inventory, AFUDC, and other	1,589	2,493	(904)	(6,665)	(11,387)	4,722
Cash used in investing activities	134,523	89,413	45,110	415,414	304,816	110,598

(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 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, 2015, the Corporation's gross capital expenditures were $117.0 million, compared to $99.8 million for the same period in 2014. Capital expenditures related to customer growth decreased $9.4 million due to lower expenditures for oil and gas customers, partially offset by higher expenditures for residential customers. Sustainment capital expenditures increased $7.2 million, primarily due to planned maintenance activities for the pole management program and expenditures for information technology life cycle projects, partially offset by lower expenditures for capacity increases. In addition, capital expenditures increased by $21.1 million as a result of the purchase of the Kingman and VNM REA electricity distribution systems. AESO contributions decreased $1.7 million due to the volume and timing of AUC approvals for transmission upgrade projects in 2015 compared to 2014.

For the twelve months ended December 31, 2015, the Corporation's gross capital expenditures were $433.9 million, compared to $344.9 million for the same period in 2014. Expenditures for customer growth decreased $6.4 million due to lower expenditures for oil and gas customers, partially offset by higher expenditures for residential and commercial customers. Externally driven capital expenditures increased $2.4 million due to increased expenditures for line moves. Sustainment capital expenditures increased $39.1 million due to planned maintenance activities for the pole management and cable injection programs, oilfield metering project and information technology life cycle projects. These increases were partially offset by lower expenditures for capacity increases. In addition, capital expenditures increased by $21.1 million as a result of the purchase of the Kingman and VNM REA electricity distribution systems. AESO contributions increased $32.7 million due to the volume and timing of AUC approvals for transmission upgrade projects in 2015 compared to 2014.

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 2016 of approximately $433.9 million. The 2016 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 general or 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 services over time. 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 months ended December 31, 2015, cash from financing activities increased $254.1 million compared to the same period in 2014. This increase was primarily due to the repayment of $200.0 million senior unsecured debentures in the fourth quarter of 2014 and an increase in short-term borrowings of $60.2 million quarter over quarter, partially offset by a $5.0 million decrease in equity contributions from Fortis.

For the twelve months ended December 31, 2015, cash from financing activities increased $106.5 million compared to the same period in 2014. This increase was primarily due to the repayment of $200.0 million senior unsecured debentures in 2014 and an increase in short-term borrowings of $66.0 million year over year. Partially offsetting these increases were lower proceeds received on the issuance of debt. In September 2015, senior unsecured debentures of $150.0 million were issued as compared to $275.0 million in September 2014. In addition, there was a $30.0 million decrease in equity contributions from Fortis.

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

CONTRACTUAL OBLIGATIONS

The Corporation's contractual obligations as at December 31, 2015 were as follows:

($ thousands)	Total	2016	2017-2018	2019-2020	Thereafter
Long-term debt [(1)]	1,685,000	-	-	-	1,685,000
Interest obligations on long-term debt	2,109,611	83,369	166,738	166,738	1,692,766
Joint use agreement [(2)]	50,920	2,546	5,092	5,092	38,190
Shared services agreements [(3)]	3,440	737	1,474	1,229	-
Office leases	2,816	756	1,171	624	265
Performance and restricted share unit obligations [(4)(5)]	1,175	316	859	-	-
Total contractual obligations	3,852,962	87,724	175,334	173,683	3,416,221

[(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 2020 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 awarded performance share units ("PSUs") to its executive in 2015, 2014 and 2013. 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.*

[(5)] *The Corporation awarded restricted share units ("RSUs") to its executive in 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 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. To ensure this access to capital, the Corporation targets a capital structure that includes approximately 60% debt and 40% equity. This targeted capital structure excludes the effects of goodwill and other items that do not impact the deemed regulatory capital structure. This ratio is maintained by the Corporation through the issuance of debentures or other debt and/or equity contributions by Fortis via Fortis Alberta Holdings Inc.

Summary of Capital Structure

As at December 31:	2015		2014	
	$ millions	%	$ millions	%
Total debt	1,758.5	57.7	1,544.9	56.2
Shareholder's equity	1,291.0	42.3	1,202.8	43.8
	3,049.5	100.0	2,747.7	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, 2015, the Corporation was in compliance with these externally imposed capital requirements.

In September 2015, the Corporation entered into an agreement with a syndicate of agents, pursuant to which the Corporation sold $150.0 million senior unsecured debentures. The debentures bear interest at a rate of 4.27%, to be paid semi-annually, and mature in 2045. 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 October 2015, the Corporation filed a short-form base shelf prospectus with the securities regulatory authority in each of the provinces of Canada. During the 25-month life of the base shelf prospectus, the Corporation may issue medium-term note debentures in an aggregate principal amount of up to $500.0 million.

As at December 31, 2015, the Corporation had an unsecured committed credit facility with an available amount of $250.0 million maturing in August 2020. Drawings under the committed credit facility are available by way of prime loans, bankers' acceptances and letters of credit. Prime loans bear an interest rate of prime and bankers' acceptances are issued at the applicable bankers' acceptance discount rate plus a stamping fee of 1.0%. The weighted average effective interest rate for the year ended December 31, 2015 on the committed credit facility was 2.4% (2014 - 3.0%). As at December 31, 2015, there were $53.0 million in drawings under the committed credit facility (December 31, 2014 - $23.0 million).

As at December 31, 2015, the Corporation had a $35.0 million (December 31, 2014 - $nil) demand note outstanding with Fortis. The demand note was unsecured, due on demand and the Corporation incurred interest that approximated the Corporation's cost of short-term borrowing.

CREDIT RATINGS

As at December 31, 2015, the Corporation's debentures were rated by DBRS at A (low) and by Standard and Poor's ("S&P") at A-. In December 2015, DBRS confirmed the Corporation's credit rating of A (low) but revised its outlook on the Corporation from Positive to Stable, reflecting DBRS's view of the current regulatory framework in Alberta. In February 2016, S&P revised the Corporation's outlook from Stable to Negative as a result of the announcement by Fortis that it had entered into an agreement to acquire ITC Holdings Corporation.

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 $0.4 million as at December 31, 2015 (December 31, 2014 - $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)	2015	2014
Accounts receivable		
Loans [(1)]	16	20
Related parties	117	58
	133	78
Accounts payable and other current liabilities		
Related parties	-	1,451

(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.*

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)	2015	2014	2015	2014
Included in other revenue [(1)]	28	212	477	469
Included in cost of sales [(2)]	768	1,574	3,549	4,270
Included in interest expense [(3)]	42	-	42	32

(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 notes from Fortis. The 2015 demand note was borrowed in October 2015 and is expected to be repaid in the first quarter of 2016. The 2014 demand note was borrowed and repaid during the first quarter of 2014.*

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)	2015	2014
Fair value [(1)]	1,938,533	1,856,403
Carrying value [(2)]	1,683,825	1,533,982

(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.*

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.

The depreciation and amortization rates used in 2014 were established by an AUC-approved depreciation study that was based on capital asset balances as at December 2010.

Effective January 1, 2015, depreciation and amortization rates were updated based on the results of a technical update to the last approved depreciation study, which incorporated the effect of capital asset balances as at December 2014. The impact to 2015 financial results was an increase to depreciation of approximately $3.9 million and a decrease to amortization of approximately $11.2 million.

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 they are more likely than not and they are measured at the largest amount of benefit that is greater than 50% likely of being realized upon settlement.

In the second quarter of 2015, the Corporation revised its estimated annual effective tax rate to reflect a change in the Alberta provincial statutory income tax rate from 10% to 12%, effective July 1, 2015, resulting from legislation that was enacted on June 29, 2015. As a result, deferred income tax expense reported for the first six months of 2015 was adjusted to reflect the effects of the change in the tax law and decreased by $0.2 million, and the total deferred income tax liability and corresponding deferred income tax regulatory asset increased by $11.7 million and $11.9 million, respectively. The current income tax recovery was not impacted by the change in rate.

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.

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, 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 update completes a joint effort by FASB and the International Accounting Standards Board ("IASB") to improve financial reporting by creating common revenue recognition guidance for US GAAP and International Financial Reporting Standards ("IFRS") that clarifies the principles for recognizing revenue and that can be applied consistently across various transactions, industries and capital markets. This standard is to be applied on a full retrospective or modified retrospective basis and was originally effective for annual and interim periods ending after December 15, 2016. In August 2015, FASB issued ASU 2015-14, *Deferral of the Effective Date.* The amendments in the update defer the effective date of ASU 2014-09 by one year to annual and interim periods beginning on or after December 15, 2017. Early adoption is permitted as of the original effective date. 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 is assessing the impact that the adoption of this standard will have on its financial statements and plans to have this assessment completed in 2016.

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 in the PBR 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 for a five-year term. 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 companies, 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, as a capital tracker where necessary; and (iv) that material unforeseen costs will be incurred and that they will not qualify, or be approved, as a Z factor. As discussed in the "Regulatory Matters" section of this MD&A, the AUC has initiated a generic proceeding to establish parameters for the next generation of PBR plans. There is no certainty that the next generation PBR plan will be similar to the current plan or that its design will be favourable for the Corporation.

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 dismissed the appeals of the Utilities with respect to utility asset dispositions. The Corporation is now exposed to the risk that 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 electric 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 *Hydro and Electric Energy Act*, if a municipality that owns an electric distribution system expands its boundaries, the municipality can acquire the Corporation's assets in the annexed area. In such circumstances, the *Hydro and Electric Energy Act* 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 territory, REAs have been granted by the AUC the right to provide electric distribution service to their eligible members. Members eligible to receive electric distribution service from an REA are those who meet the specific eligibility criteria defined in the integrated operating agreements between the Corporation and the REA. In general, this eligibility criteria has limited the provision of service to customers whose land is used for agricultural activity or as a rural estate property. This historical arrangement has been challenged by some self-operating REAs that are seeking to expand their services to a broader range of customers within the service area that overlaps that of the Corporation. The Corporation is actively resisting these efforts of these self-operated REAs, as it believes the legislative scheme in Alberta does not support this type of competition between the regulated utility and these small rural electricity cooperatives. There is a risk that the efforts of these self-operated REAs to expand their services to a broader range of customers could increase their ability to serve customers in competition with the Corporation.

The consequence to the Corporation of a municipality purchasing its distribution assets or an REA serving more customers in its service territory would be an erosion of its rate base, which would reduce the capital upon which the Corporation could earn a regulated return. A significant reduction of rate base could have a material adverse effect on the Corporation's financial position.

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, 2015, 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 2015 and effective April 1, 2015.

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 the repayment of all outstanding liabilities when due and all anticipated capital expenditures. 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 would likely apply to the AUC to recover such losses through customer rates. However, there can be no assurance that the AUC would approve any such application, in whole or in part. Any major damage to the Corporation's physical assets could result in lost revenues, repair costs and customer claims that are substantial in amount, which could have a material adverse effect on the Corporation.

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, 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 would likely apply to the AUC to recover the loss or liability through increased customer rates. However, there can be no assurance that the AUC would approve any such application, in whole or in part. The inability to recover these additional costs could have a material adverse effect on the Corporation's results of operations, cash flow, and financial position.

Permits and Rights-of-Way

The acquisition, ownership and operation of distribution assets requires numerous permits, approvals and certificates from federal, provincial and municipal government agencies and from First Nations. The Corporation may not be able to obtain or maintain all required approvals. If there is a delay in obtaining any required approval, or if the Corporation fails to maintain or obtain any required approval or fails to comply with any applicable law, regulation or condition of an approval, the operation of its assets and the distribution of electricity could be prevented or become subject to additional costs, any of which could have a material adverse effect on the Corporation.

It is frequently necessary for portions of the Corporation's power lines to cross certain private and public lands. In those cases, the Corporation must secure permission to cross such lands through easements or rights-of-way. The inability to secure such easements or rights-of-way could increase the costs to provide distribution service beyond amounts forecast in customer rates.

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

Labour Relations

Approximately 80% of the employees of the Corporation are members of the United Utility Workers' Association ("UUWA"). The Corporation's 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 Fortis and its reporting issuer subsidiaries, including the Corporation, to continue to prepare their 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 Fortis or its reporting issuer subsidiaries ceases to have activities subject to rate regulation; or (iii) the effective date prescribed by the IASB for the mandatory application of a standard within IFRS specific to entities with activities subject to rate regulation.

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 the Corporation's earnings as compared to that which would be recognized under US GAAP.

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.