FORTISALBERTA INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the three and nine months ended September 30, 2016

October 31, 2016

The following Management's Discussion and Analysis ("MD&A") of FortisAlberta Inc. (the "Corporation") should be read in conjunction with the following: (i) the unaudited interim financial statements and notes thereto for the three and nine months ended September 30, 2016, prepared in accordance with accounting principles generally accepted in the United States ("US GAAP"); (ii) the audited financial statements and notes thereto for the year ended December 31, 2015, prepared in accordance with US GAAP; and (iii) the MD&A for the year ended December 31, 2015. 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 the MD&A for the year ended December 31, 2015 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 544,000 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 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 ROE of 8.50% with a deemed equity ratio of 37% will remain in place for 2018 on an interim basis. 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. The Corporation 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. 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 was reflected in the Corporation's required Compliance Filing. In September 2016, the AUC approved the Corporation's Compliance Filing in Decision 21520-D01-2016, which approved 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. A decision from the AUC on the 2015 True-Up Application is expected in the first quarter of 2017.

For the nine months ended September 31, 2016, capital tracker revenue related to 2013, 2014 and 2015 was reduced by $0.7 million to reflect the impact of the 2016 Capital Tracker Decision and the true-up for 2015 actuals.

The Corporation expects to recognize capital tracker revenue of $60.3 million for 2016, down $10.6 million from 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 2016 capital tracker revenue 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.

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, include a decrease of approximately 2.4% to the distribution component of customer rates. This decrease 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 deferral account on the balance sheets as at September 30, 2016 and December 31, 2015. A decision on the 2017 Annual Rates Application is expected in the fourth quarter of 2016.

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 FortisAlberta.

For Alberta utilities under PBR, including FortisAlberta, 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. For the nine months ended September 30, 2016, capital tracker revenue was reduced by $2.0 million to reflect the impact of the 2016 GCOC Decision.

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 Court of Appeal of Alberta (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 May 2015, the AUC initiated a generic proceeding to establish parameters for the next generation of PBR. With the current five-year PBR term ending in 2017, the AUC is assessing whether the current PBR plan should be changed for the next term of 2018 to 2022. The AUC has identified three main issues: (i) rebasing and the establishment of going-in rates for the next PBR term; (ii) the productivity (X) factor, and (iii) the ongoing treatment of capital. In March 2016, the Corporation, along with the other Alberta distribution utilities, submitted common expert evidence to the AUC that considered the design of the PBR plan for the next term. The Corporation also presented its own evidence on matters to be considered in the implementation of the next generation of PBR. A hearing was held in July 2016 and a decision from the AUC is expected by the end of 2016.

RESULTS OF OPERATIONS

Highlights

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands)	2016	2015	Variance	2016	2015	Variance
Revenues	143,829	141,751	2,078	429,626	423,885	5,741
Cost of sales	47,631	43,191	4,440	142,136	132,639	9,497
Depreciation	41,964	39,331	2,633	126,951	118,025	8,926
Amortization	2,197	2,405	(208)	7,523	7,291	232
Other income	-	-	-	1,657	1,307	350
Income before interest expense and income tax	52,037	56,824	(4,787)	154,673	167,237	(12,564)
Interest expense	21,474	20,205	1,269	63,226	59,208	4,018
Income before income tax	30,563	36,619	(6,056)	91,447	108,029	(16,582)
Income tax expense (recovery)	176	(152)	328	515	(542)	1,057
Net income	30,387	36,771	(6,384)	90,932	108,571	(17,639)

Net income for the three months ended September 30, 2016 decreased $6.4 million compared to the same period last year. The decrease was mainly due to higher operating costs, a negative $2.0 million capital tracker adjustment as a result of the 2016 GCOC decision as described in the Regulatory Matters section above, and lower average energy consumption driven by the mild weather experienced in 2016 and a decline in oil and gas energy usage related to the slowdown in Alberta's economy. The decrease was partially offset by rate base growth associated with capital expenditures funded by capital tracker revenue and revenue from new customers.

Net income for the first nine months of 2016 decreased $17.6 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 $8.2 million mainly due to higher operating costs, a negative $2.0 million capital tracker adjustment as a result of the 2016 GCOC decision as described in the Regulatory Matters section above, and lower average energy consumption driven by the mild weather experienced in 2016 and a decline in oil and gas energy usage related to the slowdown in Alberta's economy. The decrease was partially offset by rate base growth associated with capital expenditures funded by capital tracker revenue and revenue from new customers.

The following table outlines the significant variances in the Results of Operations for the three months ended September 30, 2016 as compared to September 30, 2015:

Item	Variance ($ millions)	Explanation
Revenues	2.1	Electric rate revenue increased $1.4 million quarter over quarter 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. These increases were partially offset by lower average energy consumption and a negative $2.0 million capital tracker adjustment as a result of the 2016 GCOC Decision. Other revenue increased $0.7 million primarily due to an increase in the provision of third party services.
Cost of sales	4.4	The increase was primarily driven by higher labour and benefit costs driven by inflation and wage increases, higher costs related to regulatory proceedings, and 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 60% of total cost of sales.
Depreciation	2.6	The increase was due to continued investment in capital assets.
Interest expense	1.3	The increase was primarily attributable to the issuance of long-term debt in September 2015.

The following table outlines the significant variances in the Results of Operations for the nine months ended September 30, 2016 as compared to September 30, 2015:

Item	Variance ($ millions)	Explanation
Revenues	5.7	Electric rate revenue increased $6.1 million period over period. In 2015, a positive capital tracker revenue adjustment of $8.7 million was recognized, comparatively, in 2016, a negative capital tracker adjustment of $0.7 million was recognized. Excluding these capital tracker adjustments electric rate revenue increased $15.5 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 a negative $2.0 million capital tracker adjustment as a result of the 2016 GCOC Decision. Other revenue decreased $0.4 million primarily due to a decrease in the provision of third party services.

Item	Variance ($ millions)	Explanation
Cost of sales	9.5	The increase was primarily driven by higher labour and benefit costs driven by inflation and wage increases, higher contracted manpower mainly due to the timing of vegetation management, net increases in costs that qualify as flow-through items that were fully offset in electric rate revenue, and higher costs related to regulatory proceedings. Labour and benefit costs and contracted manpower costs comprised approximately 60% of total cost of sales.
Depreciation	8.9	The increase was due to continued investment in capital assets.
Interest expense	4.0	The increase was primarily attributable to the issuance of long-term debt in September 2015.
Income tax	1.1	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
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
December 31, 2014	132,135	24,411

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, 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.

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.

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 $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, 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.

FINANCIAL POSITION

The following table outlines the significant changes in the Balance Sheet as at September 30, 2016 as compared to December 31, 2015:

Item	Variance ($ millions)	Explanation
Assets:		
Accounts receivable	6.1	The increase was primarily driven by the timing of collections from customers and higher transmission riders, partially offset by lower energy consumption related to distribution services.
Regulatory assets (current and long-term)	38.2	The increase was primarily due to an increase in the deferred income tax regulatory deferral.
Property, plant and equipment	130.6	The increase was due to continued investment in energy infrastructure, partially offset by depreciation and customer contributions.
Intangible assets	5.9	The increase was due to the investment in computer software.
Liabilities and Shareholder's equity:		
Accounts payable and other current liabilities	20.4	The increase was primarily due to higher transmission costs payable, increases related to transmission connected projects that will be refunded as the projects are completed, and timing of interest payments on long-term debt.
Regulatory liabilities (current and long-term)	18.5	The increase was primarily due to an increase in the provision for future site restoration costs and an increase in the K factor deferral representing a reduction in 2015 and 2016 capital tracker revenue to be refunded in future rates, partially offset by decreases in the AESO deferral charges and the A1 rider deferral.
Deferred income tax	40.5	The increase was primarily due to higher temporary difference related to capital assets.
Debt (including short-term borrowings)	61.0	The increase was related to the issuance of $150.0 million senior secured debentures, offset by lower drawings on the Corporation's committed credit facility and a decrease in short-term debt.
Shareholder's equity	52.4	The increase was due to net income and equity injections received from Fortis in 2016, less 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 September 30			Nine Months Ended September 30		
($ thousands)	2016	2015	Variance	2016	2015	Variance
Cash, beginning of period	-	-	-	4,742	-	4,742
Cash from (used in):						
Operating activities	93,487	72,895	20,592	231,625	186,046	45,579
Investing activities	(85,803)	(90,305)	4,502	(243,923)	(280,891)	36,968
Financing activities	6,742	17,410	(10,668)	21,982	94,845	(72,863)
Cash, end of period	14,426	-	14,426	14,426	-	14,426

Operating Activities

For the three months ended September 30, 2016, net cash provided from operating activities was $20.6 million higher than for the same period in 2015. The increase was primarily due to 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 collection of accounts receivable balances. The increases were partially offset by the timing of payment of accounts payable balances and higher cash expenses related to cost of sales.

For the nine months ended September 30, 2016, net cash provided from operating activities was $45.6 million higher than for the same period in 2015. The increase was primarily due to 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, the timing of collection of accounts receivable balances, 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 September 30			Nine Months Ended September 30		
($ thousands)	2016	2015	Variance	2016	2015	Variance
Capital expenditures:						
Customer growth [(1)]	24,690	34,847	(10,157)	86,566	122,410	(35,844)
Externally driven and other [(2)]	12,984	14,243	(1,259)	33,975	35,900	(1,925)
Sustainment [(3)]	48,084	42,806	5,278	120,778	109,786	10,992
AESO contributions [(4)]	12,593	19,927	(7,334)	26,891	48,727	(21,836)
Gross capital expenditures	98,351	111,823	(13,472)	268,210	316,823	(48,613)
Less: customer contributions	(6,618)	(9,985)	3,367	(15,082)	(23,902)	8,820
Net capital expenditures	91,733	101,838	(10,105)	253,128	292,921	(39,793)
Adjustment to net capital expenditures for:						
Non-cash working capital	(5,578)	(14,827)	9,249	(9,795)	(18,416)	8,621
Costs of removal, net of salvage proceeds	4,918	6,194	(1,276)	10,514	14,640	(4,126)
Capitalized depreciation, capital inventory, AFUDC, and other	(5,270)	(2,900)	(2,370)	(9,924)	(8,254)	(1,670)
Cash used in investing activities	85,803	90,305	(4,502)	243,923	280,891	(36,968)

(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) *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 September 30, 2016, the Corporation's gross capital expenditures were $98.4 million compared to $111.8 million for the same period in 2015. Capital expenditures related to customer growth decreased $10.2 million due to lower expenditures for all customer categories, other than large general service customers, due to the timing of expenditures. Sustainment expenditures increased $5.3 million due to higher expenditures for urgent repairs as a result of unfavourable weather, vehicles due to end-of-life replacements, and system improvements. AESO contributions decreased $7.3 million due to a reduction in the volume of AUC approvals for transmission upgrade projects.

For the nine months ended September 30, 2016, the Corporation's gross capital expenditures were $268.2 million compared to $316.8 million for the same period in 2015. Capital expenditures related to customer growth decreased $35.8 million due to lower expenditures for all customer categories, other than residential customers, which had slightly higher expenditures due to higher demand in the first quarter. Sustainment expenditures increased $11.0 million due to increased spending for vehicles due to end-of-life replacements, planned maintenance activities for the pole management program, and the timing of software upgrades, partially offset by the timing of facility-related expenditures. AESO contributions decreased $21.8 million due to the volume and timing of AUC approvals for transmission upgrade projects in 2016 compared to 2015.

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 $382.1 million, down $51.8 million from the $433.9 million disclosed in the MD&A for the year ended December 31, 2015. The decrease is a result of lower AESO contributions due to a delay in construction projects and a reduction in customer requests for electricity services attributable to the current economic downturn in Alberta. 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.

Financing Activities

For the three months ended September 30, 2016, cash from financing activities decreased $10.7 million compared to the same period in 2015. This decrease was primarily due to higher repayments under the committed credit facility.

For the nine months ended September 30, 2016, cash from financing activities decreased $72.9 million compared to the same period in 2015. This decrease was primarily due to lower short-term borrowings, higher repayments under the committed credit facility, and an increase in dividends paid.

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 have not changed materially from those disclosed in the MD&A for the year ended December 31, 2015, except as discussed below.

During the second quarter of 2016, the Corporation filed an actuarial valuation of the defined benefit component of the pension plan for funding purposes as at December 31, 2015. The actuarial valuation set the minimum pension contributions for 2016 through 2018 at approximately $1.8 million per year.

The Corporation's obligation for future principal and interest payments have increased as a result of the September 2016 issuance of $150.0 million senior unsecured debentures as described below in the Capital Management section.

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 targeted a capital structure based on prior regulatory approvals that included approximately 60% debt and 40% equity. However, as a result of the 2016 GCOC Decision discussed in the Regulatory Matters section, the Corporation will now be targeting a capital structure that includes approximately 63% debt and 37% equity. To achieve this new capital structure, the Corporation anticipates a one-time dividend to be declared and paid in the fourth quarter of 2016.

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

Summary of Capital Structure

As at:	September 30, 2016		December 31, 2015	
	$ millions	%	$ millions	%
Total debt	1,819.5	57.5	1,758.5	57.7
Shareholder's equity	1,343.4	42.5	1,291.0	42.3
	3,162.9	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 September 30, 2016, the Corporation was in compliance with these externally imposed capital requirements.

As at September 30, 2016, the Corporation had an unsecured committed credit facility with an available amount of $250.0 million maturing in August 2021. 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 nine months ended September 30, 2016 on the committed credit facility was 2.1% (2015 - 2.4%). As at September 30, 2016, the Corporation had no drawings under the committed credit facility (December 31, 2015 - $53.0 million).

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.

CREDIT RATINGS

As at September 30, 2016, 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' view of the current regulatory framework in Alberta. 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 September 30, 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: ($ thousands)	September 30, 2016	December 31, 2015
Accounts receivable		
Loans [(1)]	19	16
Related parties	9	117
	28	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 September 30		Nine Months Ended September 30	
($ thousands)	2016	2015	2016	2015
Included in other revenue [(1)]	35	96	99	449
Included in cost of sales [(2)]	995	888	3,520	2,781
Included in interest expense [(3)]	-	-	138	-

[(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 a demand note from Fortis that was borrowed in October 2015 and repaid during 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:

Long-term debt as at: ($ thousands)	September 30, 2016	December 31, 2015
Fair value [(1)]	2,279,063	1,938,533
Carrying value[(2)]	1,833,588	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 $14,053 (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.

There were no material changes to the Corporation's significant accounting estimates during the three and nine months ended September 30, 2016 from those disclosed in the MD&A for the year ended December 31, 2015.

CHANGES IN ACCOUNTING POLICIES

The Corporation's 2016 unaudited interim financial statements have been prepared following the same accounting policies as those used in preparing the Corporation's 2015 audited annual financial statements.

Future Accounting Pronouncements

Revenue from Contracts with Customers

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standard Update ("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. This standard is to be applied on a full retrospective or modified retrospective basis and was originally effective for annual and interim periods beginning 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 after December 15, 2017. Early adoption is permitted as of the original effective date.

In March 2016, FASB issued ASU 2016-08, *Principal vs Agent Considerations*, in April 2016, FASB issued ASU 2016-10, *Identifying Performance Obligations and Licensing,* and in May 2016, FASB issued *Narrow-Scope Improvements and Practical Expedients* to clarify implementation guidance in ASC Topic 606. The effective date of these updates is the same as the effective date and transition requirements of ASU 2014-09.

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 measurement of revenue generated from the distribution of electricity to end-use customers. The Corporation has not yet selected a transition method and is assessing the impact that the adoption of this standard, and all related ASUs, will have on its other revenue streams, and all related disclosures. The Corporation plans to have this assessment substantially complete by the end of 2016.

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.

Classification of Certain Cash Receipts and Cash Payments
In August 2016, FASB issued ASU 2016-15, *Classification of Certain Cash Receipts and Cash Payments.* The amendments in this update address diversity in practice of how eight specific cash receipts and cash payments are presented in the statement of cash flows. This update is effective for annual and interim periods beginning after December 15, 2017 and is to be applied on a retroactive basis for each period presented. Early adoption is permitted. The Corporation does not expect the adoption of this update will have a material impact on its financial statements or related disclosures.

BUSINESS RISK

The Corporation's business risks have not changed materially from those disclosed in the Business Risk section of the MD&A for the year ended December 31, 2015.

Note: Additional information, including the Corporation's 2015 Annual Information Form and Audited Annual Financial Statements, is available on SEDAR at www.sedar.com and on the Corporation's website at www.fortisalberta.com.