FORTISALBERTA INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the three and nine months ended September 30, 2019

October 31, 2019

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 condensed interim financial statements and notes thereto for the three and nine months ended September 30, 2019, prepared in accordance with accounting principles generally accepted in the United States of America ("US GAAP"); (ii) the audited financial statements and notes thereto for the year ended December 31, 2018, prepared in accordance with US GAAP; and (iii) the MD&A for the year ended December 31, 2018. In December 2017, the Ontario Securities Commission approved the extension of the Corporation's exemptive relief to continue reporting under US GAAP rather than International Financial Reporting Standards ("IFRS") until the earlier of January 1, 2024 and the effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within IFRS specific to entities with activities subject to rate regulation. All financial information presented in this MD&A has been derived from the unaudited condensed interim financial statements for the three and nine months ended September 30, 2019 and the audited financial statements for the year ended December 31, 2018 prepared in accordance with US GAAP, and is expressed in Canadian dollars unless otherwise indicated.

FORWARD-LOOKING STATEMENTS

The Corporation includes forward-looking information in the MD&A within the meaning of applicable securities laws in Canada ("forward-looking information"). The purpose of the forward-looking information is to provide management's expectations regarding the Corporation's future growth, results of operations, performance, business prospects and opportunities, and may not be appropriate for other purposes. All forward-looking information is given pursuant to the safe harbour provisions of applicable Canadian securities legislation. The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects management's current beliefs and is based on information currently available to management.

The forward-looking information in the MD&A includes, but is not limited to, statements regarding: the expected timing of filing of regulatory applications and receipt of regulatory decisions; the expectation that sufficient cash will be generated to pay all operating costs and interest expense from internally generated funds; the expectation that sufficient cash to finance ongoing capital expenditures will be generated from a combination of long-term debt and short-term borrowings, internally generated funds and equity contributions; the expectation that the Corporation will continue to have access to the required capital on reasonable market terms; and the Corporation's forecast gross capital expenditures for 2019. The forecasts and projections that make up the forward-looking information are based on assumptions that include, but are not limited to: the receipt of applicable regulatory approvals and requested rate orders; no significant operational disruptions or environmental liability due to a catastrophic event or environmental upset caused by severe weather, other acts of nature or other major events; the continued ability to maintain the electricity system to ensure its continued performance; economic conditions; no significant variability in interest rates; sufficient liquidity and capital resources; maintenance of adequate insurance coverage; the ability to obtain licenses and permits; retention of existing service areas; continued maintenance of information technology infrastructure; favourable labour relations; and sufficient human resources to deliver service and execute the capital program.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Risk factors that could cause results or events to differ from current expectations are detailed in the "Business Risk" section of the MD&A for the year ended December 31, 2018 and in continuous disclosure materials filed from time to time with Canadian securities regulatory authorities. Key risk factors include, but are not limited to: regulatory approval and rate orders; loss of service areas; political risk; a severe and prolonged economic downturn; environmental risks; capital resources and liquidity risks; operating and maintenance risks; weather conditions in geographic areas where the Corporation operates; risk of failure of information and operations technology infrastructure; cybersecurity risk; insurance coverage risk; risk of loss of permits and rights-of-way; labour relations risk; and human resources risk.

All forward-looking information in the MD&A is qualified in its entirety by the above cautionary statements and, except as required by law, the Corporation undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise after the date hereof.

THE CORPORATION

The Corporation is a regulated electricity distribution utility in the Province of Alberta. Its business is the ownership and operation of electricity facilities that distribute electricity generated by other market participants from high-voltage transmission substations to end-use customers. The Corporation does not own or operate generation or transmission assets and is not involved in the direct sale of electricity. It is intended that the Corporation remain a regulated electricity utility for the foreseeable future, focusing on the delivery of safe, reliable and cost-effective electricity services to its customers in Alberta.

The Corporation operates a largely rural low-voltage distribution network of approximately 125,000 kilometres in central and southern Alberta, which serves approximately 566,000 electricity customers comprised of residential, commercial, farm, oil and gas, and industrial consumers.

As a significant portion of the Corporation's distribution revenue is derived from fixed or largely fixed billing determinants, changes in quantities of energy delivered are not entirely correlated with changes in revenue. Revenue is a function of numerous variables, many of which are independent of actual energy deliveries.

The Corporation is an indirect, wholly-owned subsidiary of Fortis Inc. (''Fortis''). Fortis is a leader in the North American regulated electric and gas utility business, with 2018 revenue of $8.4 billion and total assets of approximately $53.0 billion as at September 30, 2019. Approximately 8,800 Fortis employees serve utility customers in five Canadian provinces, nine US states and three Caribbean countries.

The Corporation is regulated by the Alberta Utilities Commission (the "AUC") pursuant to the *Alberta Utilities Commission Act* (the "*AUC Act*"). The AUC's jurisdiction, pursuant to the *Electric Utilities Act* (the "*EUA*"), the *Public Utilities Act* (the *"PUA"*), the *Hydro and Electric Energy Act* (the "*HEEA*") and the *AUC Act*, includes the approval of distribution tariffs for regulated distribution utilities such as the Corporation, including the rates and terms and conditions on which service is to be provided by those utilities. The Corporation recognizes amounts to be recovered from, or refunded to, customers in those periods in which related applications are filed with, or decisions are received from, the AUC. The timing of recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that otherwise expected using US GAAP for entities not subject to rate regulation.

REGULATORY MATTERS

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

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

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

In December 2016, the AUC issued Decision 20414-D01-2016 (the "Second-Term PBR Decision") outlining the manner in which distribution rates will be determined by utilities regulated under PBR (the "PBR Utilities") during the second PBR term, from 2018 to 2022.

The going-in rates for the second PBR term were based on a notional 2017 revenue requirement. The components of the notional 2017 revenue requirement were determined using an AUC prescribed methodology primarily based on entity-specific historical experience, with an 8.50% return on equity ("ROE") and a capital structure of 37% equity and 63% debt applied to notional 2017 rate base assets. The cost of debt in the notional revenue requirement is a weighted average cost of historical debt. The impact of changes to ROE, cost of debt and capital structure during a PBR term apply only to the portion of rate base that is funded by revenue provided by mechanisms separate from going-in rates escalated by the formula. For 2019, the Corporation's ROE has been maintained at 8.50%, with a capital structure of 37% equity and 63% debt.

The second PBR term incorporates mechanisms consistent with those in the first PBR term, except that incremental capital funding to recover costs related to capital expenditures that are not recovered through going-in rates escalated by the formula will be available through two mechanisms. The capital tracker mechanism from the first term will continue for capital expenditures identified as Type 1. Type 1 capital must be extraordinary, not previously included in the utility's rate base, and required by a third party. Type 2 capital includes all capital in the notional going-in rate base with a provision for a prescribed level of annual capital additions funded through a K-Bar mechanism. The notional going-in rate base was also calculated using an AUC prescribed methodology, including both actuals and historical averages. A K-Bar amount is established for each year of the term based on the revenue requirement associated with the resulting projected notional rate base for Type 2 capital programs.

In February 2018, the AUC issued Decision 22394-D01-2018 (the "Second-Term Compliance Decision") confirming the manner in which distribution rates will be determined pursuant to the Second-Term PBR Decision. In the Second-Term Compliance Decision, the AUC refused all utility requests for certain anomalous cost adjustments to be applied in the determination of the notional 2017 going-in revenue requirement and confirmed the K-Bar capital funding mechanism. The AUC also determined that depreciation matters would not be considered in rebasing. The Corporation filed a Review and Variance Application in respect of these matters and sought permission to appeal the Second-Term Compliance Decision to the Alberta Court of Appeal.

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

In October 2018, the AUC issued Decision 23479-D02-2018 in respect of the Review and Variance Application for the Second-Term Compliance Decision that led to the AUC initiating a review proceeding in February 2019 to clarify the definition of, and criteria for, anomaly adjustments for the purposes of establishing going-in rates for the second PBR term. PBR Utilities will have the opportunity to apply for anomaly adjustments in accordance with the clarification determined in this proceeding. The Corporation filed its evidence for this review proceeding in March 2019. The AUC held a stakeholder consultation meeting in September 2019. This proceeding is scheduled to conclude in November 2019, with a decision expected in early 2020.

In May 2019, the AUC initiated a review of the Second-Term PBR Decision and the Second-Term Compliance Decision to determine the method to incorporate approved changes to depreciation parameters into rates during the 2018 to 2022 PBR term. The review is considering whether changes to depreciation parameters impact both going-in rates and incremental capital funding mechanisms. The Corporation filed its evidence for this review proceeding in June 2019. This proceeding is scheduled to conclude in the fourth quarter of 2019, with a decision expected in early 2020.

Phase II applications propose revised rate design and rate class cost allocations that will determine how much of the revenue requirement should be recovered from each customer class and the billing determinants that will apply to each class. In the Second-Term PBR Decision, PBR Utilities were invited to submit a Phase II application subsequent to the approval of the Rebasing Compliance Filing. The outcome of the Phase II application will apply for the entirety of the second PBR term. The Corporation anticipates filing a Phase II application in the fourth quarter of 2019.

Capital Tracker Applications

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

In June 2019, the AUC issued Decision 24369-D01-2019 approving the 2017 K factor revenue true-up as filed in the Corporation's 2017 capital tracker compliance filing with the exception of revenue associated with the Corporation's Alberta Electric System Operator ("AESO") Contributions program, pending further regulatory process.

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

In January 2019, the Corporation submitted a compliance filing pursuant to Decision 23505-D01-2018 for its final 2016 and 2017 AESO contribution capital tracker amounts. In October 2019, the AUC issued Decision 24281-D01-2019, which finalized the Corporation's 2016 and 2017 AESO Contributions Program capital tracker amounts. Decision 24281-D01-2019 will result in a decrease to capital tracker revenue for 2016 and 2017, to be included in alternative revenue, of $0.7 million. The consequential impact of these adjustments on going-in rates for the second PBR term, the AESO Hybrid Deferral account and K-Bar will be $0.5 million.

Generic Cost of Capital
In December 2018, the AUC initiated a proceeding to consider establishing a formula-based approach to setting the approved ROE, beginning for the year 2022, and to consider whether any process changes are necessary for determining capital structure in years in which the ROE formula is in place. In April 2019, the AUC issued a process schedule indicating that evidence will be filed in this proceeding in January 2020 for the 2021 to 2022 test period. The AUC also confirmed that the proceeding will include a traditional assessment of ROE and deemed capital structure for the 2021 test period.

Electric Distribution System Purchases
If the Corporation and a municipality or a Rural Electrification Association ("REA") come to an agreement to transfer electric distribution system assets to the Corporation, the transfer and purchase are subject to regulatory oversight. The municipality or REA is required to apply to the AUC to cease and discontinue its operations. Concurrently, the Corporation is required to apply to the AUC to alter its electric service area to include the electric service area of the municipality or REA.

In December 2018, the AUC issued a letter announcing the initiation of a generic proceeding to establish the rate treatment methodology in respect of distribution system purchases by distribution utilities under 2018 to 2022 PBR plans. This proceeding was concluded with the issuance of Decision 24405-D01-2019 in September 2019. In Decision 24405-D01-2019, the AUC determined that incremental capital requirements related to system acquisitions would be addressed under K-Bar on a go forward basis. However, the AUC approved Y factor rate treatment for the Corporation's acquisitions of the Municipality of Crowsnest Pass ("CNP") and the Town of Fort Macleod ("Fort Macleod") electric distribution systems.

In July 2016, CNP decided to cease the operation of, and to transfer, the CNP electric distribution system and related assets (the "system") to the Corporation for a proposed purchase price of $3.7 million, plus GST, and the related applications were filed with the AUC. In June 2018, the AUC issued Decision 21785-D01-2018 in respect of the transfer of the CNP system to the Corporation. The AUC provided conditional approval of the transfer of the CNP system but did not approve a final purchase price for ratemaking purposes. In July 2018, the AUC provided final approval of the transfer of the CNP system to the Corporation and the Corporation completed the purchase of the CNP system. In October 2018, the Corporation filed a request for approval of an adjusted purchase price for ratemaking purposes of $2.4 million in accordance with AUC directions. In the first quarter of 2019, the Corporation recognized a $1.3 million adjustment to property, plant and equipment that was recorded in goodwill to reflect the fair value of the CNP system. In October 2019, the AUC approved the purchase price of the CNP System for ratemaking purposes of $2.4 million. The Corporation has applied for the recovery of the purchase price through a Y factor in its 2020 Annual Rates Application.

In March 2018, the Town of Fort Macleod ("Fort Macleod") approved the sale and transfer of the Fort Macleod electric distribution system and related assets (the "system") to the Corporation for $4.8 million, plus GST. In June 2018, an application to transfer the Fort Macleod system to the Corporation was filed with the AUC. In October 2018, an application for approval of the purchase price for ratemaking purposes was filed with the AUC by the Corporation. In October 2019, the AUC approved the discontinuation of operations and transfer of the Fort Macleod system to the Corporation. The AUC's consideration of the final purchase price for ratemaking purposes is ongoing.

2019 Annual Rates Application

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

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

2020 Annual Rates Application

In September 2019, the Corporation submitted its 2020 Annual Rates Application. The rates and riders, proposed to be effective on an interim basis for January 1, 2020, include an increase of approximately 4.9% to the distribution component of customer rates. The increase in the distribution component of customer rates reflected: (i) an I-X of 1.06%; (ii) a collection of $0.2 million for the true-up of going-in rates; (iii) a net collection of $1.5 million for the true-up of the 2018 and 2019 K-Bar amounts; (iv) a 2020 K-Bar placeholder of $58.4 million; (v) a refund of $11.5 million for the 2018, 2019 and 2020 AESO contributions hybrid deferral amounts pursuant to Decision 23505-D01-2018; and (vi) a net refund of Y factor amounts of $1.3 million, including a refund of $0.8 million as a placeholder for the 2018, 2019 and 2020 incremental capital requirements on the CNP and Fort Macleod system purchases. A decision on the 2020 Annual Rates Application is expected in the fourth quarter of 2019.

Distribution System Inquiry

In December 2018, the AUC issued Bulletin 2018-17, which initiated an inquiry into various matters relating to the continuing evolution of the electric distribution grid in Alberta. The AUC stated that "[T]he purpose of the inquiry is to map out the key issues related to the future of the electric distribution grid, to aid in developing the necessary regulatory framework to accommodate the evolution of the electric system." In March 2019, the AUC expanded the scope of this proceeding to include matters relating to natural gas distribution utilities and provided further direction regarding the process that will be followed as the inquiry unfolds.

The AUC confirmed that this inquiry will be completed in three modules. Module One will consider the range of anticipated technological changes expected to occur over the next several years, as well as attempt to understand the drivers and timing of associated capital costs. Module Two will consider the kinds of legislative, policy and regulatory frameworks that will be required to support the ongoing evolution of Alberta's distribution grids and how they may interact with existing utility business models. Module Three will focus on understanding how rate designs can be used to send signals promoting efficient capital investment and prevent uneconomic bypass of existing utility infrastructure. The Corporation filed a submission relating to Module One matters in July 2019 and, in September 2019, the AUC hosted a technical conference to discuss Module One topics with participants. The AUC's notes from the conference and next steps, including an opportunity to provide supplemental information, are expected to be issued in the fourth quarter of 2019. The Corporation expects that the AUC's consideration of the matters engaged in the Distribution System Inquiry will extend into 2021.

2018 Independent System Operator Tariff Application

On September 22, 2019, the AUC issued Decision 22942-D02-2019, with respect to the 2018 Independent System Operator Tariff filed by the AESO (the "Decision"). The Decision approved a proposed change to the method in which the AESO's customer contribution policy is accounted for between distribution facility owners ("DFO") and transmission facility owners ("TFO") that would prevent the Corporation's future investment under the AESO's customer contribution policy ("ACCP"). The previous ACCP permitted the DFOs, including the Corporation, to invest in transmission assets (AESO contributions) under certain circumstances.

As part of approving the proposed changes, the AUC determined that the Corporation would transfer the unamortized AESO contributions as at December 31, 2017, $403.8 million, relating to investments made by the Corporation under the ACCP, to the incumbent TFO in FortisAlberta's service area, AltaLink Management Ltd ("AML"). The Decision directed AESO and AML to develop a joint proposal for the implementation of the revised ACCP.

On September 25, 2019, the Corporation filed a request for immediate review and variance of Decision 22942-D02-2019 (the "Immediate Review and Variance Letter") with the AUC requesting that an expedited proceeding be undertaken to reevaluate the proposed changes to the ACCP. The Immediate Review and Variance Letter identified a number of significant matters to the Corporation that require reconsideration and clarification by the AUC, including the transfer of unamortized historical AESO contributions and the opportunity for future investments.

On October 2, 2019, the AUC confirmed that it had commenced an expedited review of the Decision on its own motion and requested that the Corporation provide information regarding the significant matters raised in the Immediate Review and Variance Letter. On October 8, 2019, the Corporation filed the additional information requested by the AUC, accompanied by a request for the AUC to suspend the implementation of the proposed changes to the ACCP, pending the AUC's consideration of the review and variance. On October 25, 2019, the AUC granted the suspension of the implementation of the proposed changes to the ACCP as requested by the Corporation. This suspension will remain in effect until the AUC expedited review of the Decision is completed which is expected in the fourth quarter of 2019.

The Corporation has determined that the occurrence of a loss contingency is not determinable due to the AUC's expedited review of the Decision. Based on the number of significant matters identified in the Immediate Review and Variance Letter, an estimate of loss cannot be reasonably determined as at September 30, 2019 and no estimate has been included in the unaudited condensed interim financial statements.

SIGNIFICANT CONTRACTS

The EUA provides that an owner of an electric distribution system is required to act, or to authorize a substitute party to act, as a provider of electricity services, including the sale of electricity, to eligible customers and to appoint a retailer as default supplier to customers otherwise unable to obtain electricity services. In May 2019, the Corporation entered into an arrangement whereby it continues to convey this obligation to EPCOR Energy Alberta GP Inc. under an eight-year Customer Rights Agreement beginning in 2021. The Agreement provides for successive options to renew every three-years and is subject to AUC approval.

RESULTS OF OPERATIONS

	Three months ended September 30			Nine months ended September 30		
($ thousands)	2019	2018	Variance	2019	2018	Variance
Total revenues	166,019	165,343	676	487,515	471,649	15,866
Cost of sales	48,911	51,833	(2,922)	152,607	154,663	(2,056)
Depreciation	49,018	45,579	3,439	146,002	135,528	10,474
Amortization	3,196	2,347	849	10,633	7,213	3,420
Other income (expense)	(84)	(183)	99	380	(24)	404
Income before interest expense and income tax	64,810	65,401	(591)	178,653	174,221	4,432
Interest expense	26,393	24,904	1,489	78,093	74,552	3,541
Income before income tax	38,417	40,497	(2,080)	100,560	99,669	891
Income tax expense	1,136	1,920	(784)	2,259	1,800	459
Net income	37,281	38,577	(1,296)	98,301	97,869	432

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

Net income for the nine months ended September 30, 2019 increased $0.4 million compared to the same period in 2018. The increase was primarily due to higher revenue associated with rate base growth and customer additions, net of a negative adjustment related to the incremental capital deferral. In addition, lower labour costs related to incentive compensation and lower contracted manpower costs associated with vegetation management, contributed to the increase. These increases were partially offset by higher depreciation and amortization expense due to continued investment in capital assets and an overall increase in depreciation and amortization rates, and higher interest expense related to the long-term debt issuance in September 2018.

The following table outlines the significant variances in the Results of Operations for the three months ended September 30, 2019 as compared to September 30, 2018:

Item	Variance ($ millions)	Explanation
Total revenues	0.7	The increase to total revenue was primarily due to $4.9 million higher electric rate revenue associated with rate base growth and customer additions, and net increases in revenues related to flow-through items that were offset in cost of sales. These increases to total revenue were partially offset by a reduction of $4.5 million in alternative revenue, due to the true-up of 2016 and 2017 capital tracker revenue in 2018.
Cost of sales	(2.9)	The decrease was primarily due to decreases in labour costs related to incentive compensation and lower contracted manpower costs primarily those associated with vegetation management. The decreases were partially offset by net increases in costs that qualify as flow-through items and were fully offset in electric rate revenue. Labour and benefits costs and contract manpower costs comprised approximately 56% of total cost of sales.
Depreciation	3.4	The increase was due to continued investment in capital assets and an overall increase in depreciation rates. Refer to the Critical Accounting Estimates section of this MD&A for further information.
Interest expense	1.5	The increase was primarily attributable to the issuance of long-term debt in September 2018.

The following table outlines the significant variances in the Results of Operations for the nine months ended September 30, 2019 as compared to September 30, 2018:

Item	Variance ($ millions)	Explanation
Total revenues	15.9	The increase to total revenue was primarily due to $18.6 million higher electric rate revenue associated with rate base growth and customer additions, and net increases in revenues related to flow-through items that were offset in cost of sales. These increases to total revenue were partially offset by a negative adjustment related to the incremental capital deferral and a reduction in alternative revenue of $2.9 million, due to the true-up of 2016 and 2017 capital tracker revenue in 2018.
Cost of sales	(2.1)	The decrease was primarily due to decreases in labour costs related to incentive compensation and lower contracted manpower costs primarily those associated with vegetation management. The decreases were partially offset by net increases in costs that qualify as flow-through items and were fully offset in electric rate revenue. Labour and benefits costs and contract manpower costs comprised approximately 56% of total cost of sales.
Depreciation	10.5	The increase was due to continued investment in capital assets and an overall increase in depreciation rates. Refer to the Critical Accounting Estimates section of this MD&A for further information.
Amortization	3.4	The increase was due to continued investment in intangible assets and an overall increase in amortization rates. Refer to the Critical Accounting Estimates section of this MD&A for further information.
Interest expense	3.5	The increase was primarily attributable to the issuance of long-term debt in September 2018.

SUMMARY OF QUARTERLY RESULTS

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

($ thousands)	Total Revenues	Net Income
September 30, 2019	166,019	37,281
June 30, 2019	162,362	34,303
March 31, 2019	159,134	26,717
December 31, 2018	150,880	22,159
September 30, 2018	165,343	38,577
June 30, 2018	154,216	32,244
March 31, 2018	152,090	27,048
December 31, 2017	151,887	29,392

Changes in total revenues and net income quarter over quarter are a result of many factors, including energy deliveries, number of customer sites, regulatory decisions, ongoing investment in energy infrastructure, inflation and changes in income tax. As approved by the AUC, the allowance for funds used during construction ("AFUDC") is recognized in the first and fourth quarters of the year. There is no significant seasonality in the Corporation's operations.

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

June 30, 2019 / 2018
Net income for the three months ended June 30, 3019 increased $2.1 million compared to the same period in 2018. The increase was primarily due to higher revenue associated with rate base growth, customer additions, and customer usage and demand. In addition, in 2018 there was a negative adjustment related to prior year capital tracker revenue. These increases were partially offset by higher depreciation and amortization due to continued capital investment and an overall increase in depreciation and amortization rates, and higher interest expense related to the long-term debt issuance in September 2018.

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

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

FINANCIAL POSITION

The following table outlines the significant changes in the Balance Sheet as at September 30, 2019 as compared to December 31, 2018:

Item	Variance ($ millions)	Explanation
Assets:		
Accounts receivable	(18.3)	The decrease was primarily driven by timing of collections from customers.
Regulatory assets (current and long-term)	(7.3)	The decrease was primarily due to a reduction in the deferred income tax regulatory deferral of $21.5 million related to a decrease in future provincial tax rates, partially offset by an increase in deferred overhead costs of $13.7 million.
Property, plant and equipment, net	103.3	The increase was due to continued investment in system infrastructure, partially offset by depreciation and customer contributions.
Liabilities and Shareholder's Equity:		
Accounts payable and other current liabilities	(16.4)	The decrease was primarily driven by lower labour accruals for incentive compensation and payables for capital expenditures, partially offset by higher amounts payable to the AESO for transmission costs.
Regulatory liabilities (current and long-term)	33.9	The increase was primarily due to increases in the AESO charges deferral of $30.8 million and the non-asset retirement obligation provision of $10.4 million, partially offset by a decrease in the K Factor deferral of $9.4 million.
Other Liabilities	5.4	The increase was primarily due an increase in the OPEB liability, arising from plan amendments.
Deferred income tax	(19.2)	The decrease was primarily due to the reduction of future provincial tax rates, partially offset by temporary differences relating to capital assets and deferrals.
Debt (including short-term borrowings)	20.5	The increase was primarily related to higher drawings on the Corporation's committed credit facility.
Total shareholder's equity	59.3	The increase was primarily due to net income of $98.3 million and equity injections of $20.0 million, less dividends paid of $56.3 million.

SOURCES AND USES OF LIQUIDITY AND CAPITAL RESOURCES

The Corporation's primary sources of liquidity and capital resources are the following:

- funds generated from operations;
- the issuance and sale of debt instruments;
- bank financing and credit facility; and
- equity contributions from the Corporation's parent company.

STATEMENTS OF CASH FLOWS

	Three months ended September 30			Nine months ended September 30		
($ thousands)	2019	2018	Variance	2019	2018	Variance
Cash, beginning of period	—	3,933	(3,933)	—	82,735	(82,735)
Cash from (used in):						
Operating activities	94,030	136,324	(42,294)	274,705	173,154	101,551
Investing activities	(84,348)	(91,178)	6,830	(257,888)	(299,000)	41,112
Financing activities	(9,078)	(20,908)	11,830	(16,213)	71,282	(87,495)
Cash, end of period	604	28,171	(27,567)	604	28,171	(27,567)

Operating Activities

For the three months ended September 30, 2019, net cash provided from operating activities was $42.3 million lower than for the same period in 2018. The decrease was primarily due to differences in the timing of collection from customers and payment to the AESO for transmission related amounts partially offset by the timing of collection of accounts receivable balances for distribution revenue.

For the nine months ended September 30, 2019, net cash provided from operating activities was $101.6 million higher than for the same period in 2018. The increase was primarily due to differences in the timing of collection from customers and payment to the AESO for transmission related amounts and the timing of collection of accounts receivable balances for distribution revenue.

The Corporation expects to be able to pay all operating costs and interest expense out of operating cash flows, with some residual available for dividend payments to the parent company and/or capital expenditures.

Investing Activities

	Three months ended September 30			Nine months ended September 30		
($ thousands)	2019	2018	Variance	2019	2018	Variance
Capital expenditures:						
Sustainment [(1)]	46,428	50,881	(4,453)	117,838	119,062	(1,224)
Customer growth [(2)]	37,045	34,108	2,937	111,078	112,641	(1,563)
Externally driven and other [(3)]	15,740	20,045	(4,305)	39,354	43,213	(3,859)
AESO contributions [(4)]	(2,839)	930	(3,769)	7,994	18,731	(10,737)
Distribution System Purchases [(5)]	—	3,746	(3,746)	—	3,746	(3,746)
Gross capital expenditures	96,374	109,710	(13,336)	276,264	297,393	(21,129)
Less: customer contributions	(9,354)	(10,362)	1,008	(32,697)	(26,920)	(5,777)
Net capital expenditures	87,020	99,348	(12,328)	243,567	270,473	(26,906)
Adjustment to net capital expenditures for:						
Non-cash working capital	(5,289)	(6,964)	1,675	6,046	17,471	(11,425)
Costs of removal, net of salvage proceeds	5,273	5,149	124	17,586	17,566	20
Capitalized depreciation, capital inventory, AFUDC and other	(2,656)	(6,355)	3,699	(9,311)	(6,510)	(2,801)
Cash used in investing activities	84,348	91,178	(6,830)	257,888	299,000	(41,112)

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

(2) *Includes new customer connections.*

(3) *Includes upgrades associated with substations, line moves, new connections for independent power producers, and SCADA (Supervisory Control and Data Acquisition).*

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

(5) *Reflects the purchase of the electric distribution system of the Municipality of Crowsnest Pass in 2018.*

For the three months ended September 30, 2019, the Corporation's gross capital expenditures were $96.4 million compared to $109.7 million for the same period in 2018. Sustainment expenditures decreased $4.5 million primarily due to a reduction in vehicle purchases. Externally driven expenditures decreased $4.3 million primarily due to reduced spending on substation upgrades, partially offset by an increase in line move expenditures. AESO contributions decreased $3.8 million due to the refund of contributions associated with transmission upgrade projects. Partially offsetting these decreases was an increase in customer growth expenditures of $2.9 million, primarily due to an increase in general service customer projects.

For the nine months ended September 30, 2019, the Corporation's gross capital expenditures were $276.3 million compared to $297.4 million for the same period in 2018. AESO contributions decreased $10.7 million due to a reduction in the number of transmission upgrade projects and the refund of contributions as compared to 2018. Externally driven expenditures decreased $3.9 million primarily due to reduced spending in substation upgrades, partially offset by an increase in line move expenditures. Customer growth expenditures decreased $1.6 million primarily due to a reduction in residential customer projects. Sustainment expenditures decreased $1.2 million primarily due to lower expenditures associated with urgent replacements, distribution capacity increases and vehicle purchases, partially offset by higher planned maintenance and metering expenditures.

It is expected that ongoing capital expenditures will be financed from funds generated by operating activities, drawings on the committed credit facility, proceeds from the issuance of debt, and equity contributions from Fortis via Fortis Alberta Holdings Inc., the Corporation's parent and an indirectly wholly owned subsidiary of Fortis.

Capital Expenditures Forecast

The Corporation's 2019 forecast of gross capital expenditures is approximately $353.0 million. The 2019 projected capital expenditures are based on detailed forecasts, which include numerous assumptions such as projected growth in the number of customer sites, weather, cost of labour and materials, and other factors that could cause actual results to differ from forecast.

Financing Activities

For the three months ended September 30, 2019 cash from financing activities increased $11.8 million compared to the same period in 2018. In the third quarter of 2019, the Corporation increased net short-term borrowings by $30.0 million under the committed credit facility and reduced bank indebtedness by $20.3 million. Compared to the third quarter of 2018, during which the Corporation completed a $150.0 million long-term debt issuance, made net repayments of $142.0 million under the committed credit facility and reduced bank indebtedness by $10.5 million.

For the nine months ended September 30, 2019 cash from financing activities decreased $87.5 million compared to the same period in 2018. In the nine months ended September 30, 2019, the Corporation increased net short-term borrowings by $25.0 million under the committed credit facility, reduced bank indebtedness by $4.8 million, paid dividends of $56.3 million and received equity contributions of $20.0 million. Compared to the same period in 2018, during which the Corporation completed a $150.0 million long-term debt issuance, made net repayments of $50.0 million under the committed credit facility, paid dividends of $52.5 and received $25.0 million in equity contributions.

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, 2018.

CAPITAL MANAGEMENT

The Corporation's objective when managing capital is to ensure ongoing access to capital to allow it to build and maintain the electricity distribution facilities within the Corporation's service territory. The ratio of debt and equity financing of these investments is determined by their nature and is maintained by the Corporation through the issuance of debentures or other debt, dividends paid to, or equity contributions received from, Fortis via Fortis Alberta Holdings Inc.

The AUC determines the capital structure for Alberta utilities to finance their regulated operations. The Corporation's capital structure approved by the AUC for ratemaking purposes is 37% equity and 63% debt.

The Corporation has items on its balance sheet outside of its regulated operations, such as goodwill, that are not contemplated in the regulated capital structure. These items are financed primarily through equity contributions and result in an overall ratio that differs from the regulated capital structure.

Summary of Capital Structure

As at:	September 30, 2019		December 31, 2018	
	$ millions	%	$ millions	%
Total debt	2,243.9	60.0	2,223.4	60.7
Shareholder's equity	1,496.0	40.0	1,436.7	39.3
	3,739.9	100.0	3,660.1	100.0

The Corporation has externally imposed capital requirements by virtue of its Trust Indenture and committed credit facility such that consolidated debt cannot exceed 75% of the Corporation's consolidated capitalization ratio, which is based on the Corporation's total capital structure. As at September 30, 2019, the Corporation was in compliance with these externally imposed capital requirements.

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

As at September 30, 2019, the Corporation had an unsecured committed credit facility with an available amount of $250.0 million, maturing in August 2024. Drawings under the committed credit facility are available by way of prime loans, bankers' acceptances and letters of credit. Prime loans bear an interest rate of prime and bankers' acceptances are issued at the applicable bankers' acceptance discount rate plus a stamping fee of 1.0%.

The weighted average effective interest rate for the nine months ended September 30, 2019 on the committed credit facility was 3.6% (2018 – 2.8%). As at September 30, 2019, the Corporation had $70.0 million drawings on this facility (December 31, 2018 – $45.0 million).

CREDIT RATINGS

As at September 30, 2019, the Corporation's debentures were rated by DBRS at A (low) and by Standard and Poor's ("S&P") at A-.

OUTSTANDING SHARES

Authorized – unlimited number of:

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

Issued:

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

OFF-BALANCE SHEET ARRANGEMENTS

With the exception of letters of credit outstanding of $0.4 million as at September 30, 2019 (December 31, 2018 – $0.3 million), the Corporation had no off-balance sheet arrangements.

RELATED PARTY TRANSACTIONS

In the normal course of business, the Corporation transacts with related parties, including Fortis and other subsidiaries of Fortis. Amounts due from or to related parties were measured at the exchange amount and were as follows:

As at: ($ thousands)	September 30, 2019	December 31, 2018
Accounts receivable		
Loans [(1)]	22	24
Related parties	—	206
	22	230

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

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

Related party transactions included in other revenue and cost of sales were measured at the exchange amount and were as follows:

	Three months ended September 30		Nine months ended September 30	
($ thousands)	2019	2018	2019	2018
Included in other revenue [(1)]	1	35	5	152
Included in cost of sales [(2)]	1,097	904	3,880	3,341
Included in interest expense [(3)]	76	—	76	—

(1) *Includes services provided to related parties, including Fortis and subsidiaries of Fortis, related to information technology, material sales and intercompany employee services.*
(2) *Includes charges from related parties, including Fortis and subsidiaries of Fortis, related to corporate governance expenses, consulting services, travel and accommodation expenses, charitable donations, membership fees and professional development costs.*
(3) *Reflects interest expense paid on demand notes from Fortis that were borrowed in the second and third quarter; and repaid in the third quarter.*

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, 2019	December 31, 2018
Fair value [(1)]	2,792,944	2,465,514
Carrying value [(2)]	2,183,679	2,183,655

(1) *The fair value of the long-term debt was estimated using level 2 inputs based on the indicative prices for the same or similarly rated issues for debt of the same remaining maturities.*
(2) *Carrying value is presented gross of debt issuance costs of $15,715 (December 31, 2018 – $15,997).*

The fair values of the Corporation's financial instruments reflect a point-in-time estimate based on current and relevant market information about the instruments as at the balance sheet dates. The estimates cannot be determined with precision as they involve uncertainties and matters of judgment and, therefore, may not be relevant in predicting the Corporation's future earnings or cash flows.

The carrying value of financial instruments included in current assets, long-term other assets, current liabilities and long-term other liabilities on the balance sheet approximate their fair value, which reflects the short-term maturity, normal trade credit terms and/or nature of these financial instruments.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Corporation's financial statements in accordance with US GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances.

Due to changes in facts and circumstances, and the inherent uncertainty in making estimates, actual results may differ materially from current estimates. Estimates and judgments are reviewed periodically and as adjustments become necessary they are recognized in the period they become known.

There were no material changes to the Corporation's critical accounting estimates for the three and nine months ended September 30, 2019 from those disclosed in the MD&A for the year ended December 31, 2018, except as follows.

Depreciation and Amortization
Depreciation and amortization estimates are based on depreciation and amortization rates derived from capital asset balances and depreciation parameters, including the service life of assets and expected net salvage percentages, which are periodically established in depreciation reviews prepared by an independent expert. Outside of these periodic reviews, management annually assesses if updates are required to depreciation and amortization rates based on changes in capital asset balances, while maintaining the previously determined depreciation parameters.

Depreciation and amortization in 2018 was based on depreciation and amortization rates derived from capital asset balances as at December 2014 and depreciation parameters established in a 2012 depreciation review. Effective January 1, 2019, depreciation and amortization rates were changed based on the results of a depreciation review, which updated rates for changes in capital asset balances and depreciation parameters. The impact to the three months ended September 30, 2019 financial results was an increase to depreciation of approximately $1.1 million and an increase to amortization of approximately $1.0 million as compared to 2018. The impact to the nine months ended September 30, 2019 financial results was an increase to depreciation of approximately $3.2 million and an increase to amortization of approximately $3.2 million as compare to 2018.

CHANGES IN ACCOUNTING POLICIES

The Corporation's 2019 unaudited condensed interim financial statements have been prepared following the same accounting policies as those used in preparing the Corporation's 2018 audited annual financial statements, except as follows.

Leases
Effective January 1, 2019, the Corporation adopted Accounting Standards Codification ("ASC") 842, *Leases*, which requires lessees to recognize a lease liability, initially measured at the present value of future lease payments, and a right-of-use ("ROU") asset for all leases with a lease term greater than 12 months. The new lease standard also requires additional quantitative and qualitative disclosures for both lessees and lessors. The Corporation applied the transition provisions of the new lease standard as of the adoption date and did not retrospectively adjust prior periods. The Corporation elected a package of practical expedients that allowed it to not reassess: (i) whether existing contracts are or contain a lease; (ii) the lease classification of existing leases; or (iii) the initial direct costs for existing leases. Furthermore, the Corporation elected a practical expedient that permitted it to not evaluate existing land easements that were not previously accounted for as leases. The new lease standard will be applied on a prospective basis to all new or modified land easements after January 1, 2019. Finally, the Corporation utilized the hindsight practical expedient to determine the lease term. Upon adoption, the Corporation did not identify or record an adjustment to the opening balance of retained earnings, and there was no impact on net income or cash flows.

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

Leases with a term of twelve months or less are not recorded on the balance sheet but are recognized as lease expense on a straight-line basis over the lease term. As at September 30, 2019, the Corporation's easements have not resulted in the recognition of a ROU asset as the current easement contracts do not convey a right to control.

FUTURE ACCOUNTING PRONOUNCEMENTS

The Corporation considers the applicability and impact of all Accounting Standard Updates ("ASUs") issued by the Financial Accounting Standards Board ("FASB"). The following updates have been issued by the FASB but have not yet been adopted by the Corporation. Any ASUs not included below were assessed and determined to be either not applicable to the Corporation or are not expected to have a material impact on the financial statements.

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

Pensions and Other Postretirement Plan Disclosures
ASU 2018-14, *Changes to the Disclosure Requirements for Defined Benefit Plans,* was issued in August 2018, is effective January 1, 2021 with earlier adoption permitted, and is to be applied on a retrospective basis for all periods presented. Principally, it modifies the disclosure requirements for employers with defined benefit pension or other postretirement plans and clarifies disclosure requirements. In addition, the amendments remove (a) the amounts in accumulated other comprehensive income expected to be recognized as components of net periodic benefit costs over the next fiscal period, (b) the amount and timing of plan assets expected to be returned to the employer, and (c) the effects of a one-percentage-point change on the assumed health care costs and the change in rates on service cost, interest cost and the benefit obligation for post-retirement health care benefits. The Corporation is early adopting ASU 2018-14 in 2019 and further assessing disclosure requirements.

Cloud Computing Arrangements
ASU 2018-15, *Customer's Accounting for Implementation Costs incurred in a Cloud Computing Arrangement that is a Service Contract,* was issued in August 2018, is effective January 1, 2020 with earlier adoption permitted, and is to be applied either on a retrospective basis or on a prospective basis to all implementation costs incurred after the effective date of the new guidance. Principally, it aligns the requirements for capitalizing implementation costs incurred in a cloud computing arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software. The Corporation is assessing the impact of adoption.

Note: Additional information, including the Corporation's Annual Information Form and Audited Financial Statements, is available on SEDAR at www.sedar.com and on the Corporation's website at www.fortisalberta.com. The information contained on, or accessible through, any of these websites is not incorporated by reference into this document.