FORTISALBERTA INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS

For the three and twelve months ended December 31, 2024

February 13, 2025

The following Management's Discussion and Analysis ("MD&A") of FortisAlberta Inc. (the "Corporation" or "FortisAlberta") has been prepared in accordance with National Instrument 51-102 – Continuous Disclosure Obligations and should be read in conjunction with the Audited Financial Statements and notes thereto for the years ended December 31, 2024 and 2023. Financial information for 2024 and comparative periods contained in this MD&A have been prepared in accordance with accounting principles generally accepted in the United States of America ("US GAAP"). In May 2022, the Alberta Securities Commission approved the extension of the Corporation's exemptive relief order which permits the Corporation to continue reporting in accordance with US GAAP rather than the IFRS Accounting Standards, until the earlier of January 1, 2027; and the later of (i) the effective date prescribed by the International Accounting Standards Board ("IASB") for the mandatory application of a standard within IFRS Accounting Standards specific to entities with activities subject to rate regulation or (ii) two years after the IASB publishes the final version of a mandatory rate-regulated standard. All financial information presented in this MD&A has been derived from the Audited Financial Statements for the year ended December 31, 2024 and 2023, and is expressed in Canadian dollars unless otherwise indicated.

In this MD&A, FAHI refers to the Corporation's direct parent entity, Fortis Alberta Holdings Inc. and Fortis refers to the Corporation's ultimate parent, Fortis Inc.

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", "assumes", "continues", "could", "depends", "expects", "forecasts", "intends", "may", "projects", "will", "would", "should", "if", 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 this MD&A includes, but is not limited to, statements regarding: the expected timing of filing of regulatory applications, regulatory hearings and appeals, and receipt of regulatory decisions; the expectations regarding the Corporation's revenue requirement and corresponding rates for 2023 to 2025; the Corporation's operation under the Third Generation Performance-Based Regulation ("PBR") Plan; potential impact of government announcements regarding approvals of renewable electricity rates and emission standards; the completion of the Alberta Utilities Commission's ("AUC" or the "Commission") reconsideration of matters related to the Alberta Electric System Operator ("AESO") Customer Contribution Policy; the expectation that sufficient cash will be generated to pay all operating costs, interest expenses and other working capital from internally-generated funds; the Corporation's ability to service debt obligations and pay dividends, including the borrowings under the Corporation's credit facility, borrowing under demand notes and new debenture issuances by the Corporation may be required; 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, including equity contributions from Fortis via FAHI; the expectation that the Corporation will continue to have access to the required capital on reasonable market terms, including with Related Parties; expectations related to the Corporation's purchase of the Tomahawk Rural Electrification Association Ltd. distribution system transaction; the Corporation's ability to resolve ongoing income tax audits; expectations regarding updated accounting standards; and the Corporation's forecast of gross capital expenditures for 2025.

Certain forward-looking information in this MD&A relating to the Corporation's expected capital expenditures may be considered "financial outlook" or "future-oriented financial information" within the meaning of applicable securities laws in Canada. Such future-oriented financial information has been approved by management of the Corporation as of the date of this MD&A, and has been included for the purposes of providing readers with information about the Corporation's current plans and expectations regarding capital expenditures and related aspects of the Corporation's business and operations.

However, readers are cautioned that reliance on such future-oriented financial information for other purposes may not be appropriate.

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, financial impact of regulatory decisions for future periods not currently in effect and requested rate orders; the ability to continue to report under US GAAP beyond the Canadian securities regulators exemption to the end of 2027 or earlier; absence of 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; absence of severe and prolonged economic downturn; absence of significant variability in interest expense; 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 and operations technology infrastructure; absence of cybersecurity events; successful mitigation of global supply chain shortages and rising inflation; absence of material impacts related to future processes unfolding with the tax authorities; favourable labour relations; and sufficient human resources to deliver, service and execute the capital expenditure 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 Management" section of this MD&A and in continuous disclosure materials filed from time to time with Canadian securities regulatory authorities. Key risk factors include, but are not limited to: regulatory approval and rate orders; government policy developments; utility asset disposition risk; risk that the Corporation could be impacted by future regulated rate options; a downturn in economic conditions including the strength and operations of the oil and natural gas production industry and related commodity prices; risks relating to a public health crisis; supply chain risk; reduction in customer base; municipal annexation risks; the AUC's reconsideration of matters related to the AESO Customer Contribution Policy; competition with Rural Electrification Association ("REA"); change in government policies; capital resources and liquidity risks; interest and inflation risk; insurance coverage risk; continued reporting in accordance with US GAAP risk; operating and maintenance risks; risk of loss of permits and rights-of-way; environmental risk; regulatory risk; weather conditions and climate-change risk; wildfire risk; risk of failure of information and operations technology infrastructure; cybersecurity risk; labour relations risk; human resources risk; and other risks described in the Corporation's most recent Annual Information Form.

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 because of new information, future events or otherwise after the date hereof. All subsequent forward-looking statements, whether written or oral, attributable to the Corporation or persons acting on the Corporation's behalf, are expressly qualified in their entirety by these cautionary statements.

CORPORATE OVERVIEW

The Corporation is a regulated electric distribution utility that operates solely in the Province of Alberta. Its business is the ownership and operation of electric facilities that distribute electricity generated by other market participants from high-voltage transmission substations to end-use customers. The Corporation is not involved in the generation of electricity. The Corporation does not own or operate generation or transmission assets and is not involved in the direct sale of electricity. Notwithstanding the foregoing, the Corporation is statutorily required to facilitate the interconnection of distributed generation (*"*DG*"*) facilities and micro-generation (*"*MG*"*) facilities to its distribution system.

The Corporation operates a largely rural and suburban low-voltage distribution network of approximately 133,000 kilometres that is primarily located in central and southern Alberta, which serves approximately 603,400 residential, commercial, farm, oil and gas, and industrial sites. The Corporation has facilitated the interconnection of approximately 9,000 customer generation sites to its distribution system, representing a combination of DG and MG facilities. Electricity from these facilities is generated from a variety of renewable sources, including solar photovoltaic, wind, and hydroelectric.

The Corporation is a wholly-owned subsidiary of FAHI, which is an indirect wholly-owned subsidiary of Fortis, a leader in the North American electric and natural gas utility business. Fortis shares are listed on both the Toronto Stock Exchange and the New York Stock Exchange.

The Corporation is regulated by the AUC pursuant to the *Alberta Utilities Commission Act* (*"AUCA"*). The AUC's jurisdiction, pursuant to the *Electric Utilities Act ("EUA")*, the *Public Utilities Act*, the *Hydro and Electric Energy Act ("HEEA"),* and the *AUCA*, 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

2023 Cost-of-Service ("COS") and Annual Rates Application

For 2023, the Corporation transitioned into a one year COS rebasing year, creating a COS interval between the second and third PBR terms. The completion of a COS rebasing between one PBR rate making term into another re-aligns a utility's reasonable costs to provide service with the revenues it is permitted to collect in customer rates. This re-aligned revenue requirement forms a starting point for setting PBR rates in future periods.

The AUC approved an overall distribution revenue requirement of approximately $660 million in support of FortisAlberta's 2023 capital expenditure program, as well as the Corporation's operating and income tax costs. This revenue requirement reflected a reduction of approximately $10 million for the effects of a prior AUC decision in the Corporation's most recent Phase II application, as described below, that prevented the recovery of costs from REAs under the Corporation's regulated tariff.

Amounts approved in the Corporation's 2023 rates and riders included: (i) a 5% increase in base distribution rates incorporating the collection of the Corporation's 2023 base distribution revenue requirement of approximately $660 million; and (ii) a net collection of $3.5 million associated with the true-up of Y factors for the Second PBR Term K-bar and AESO contributions hybrid deferral amounts, as well as the collection of $9.7 million, inclusive of tax gross-up, associated with the operation of the efficiency carry-over mechanism ("ECM"). The Corporation's 2023 rates will continue to be interim pending the initiation and completion of an AUC proceeding in which FortisAlberta will seek approval of an updated depreciation study. A decision on the depreciation study, and the associated changes to going-in rates, are expected to be received in 2025.

Third Generation Performance-Based Regulation ("PBR") Plan

From January 1, 2024, through December 31, 2028, the Corporation will operate under a third generation PBR plan. In October 2023, the AUC issued Decision 27388-D01-2023 for the 2024-2028 Performance-Based Regulation Plan for Alberta Electric and Gas Distribution Utilities, outlining the features of the third generation PBR plan. The third generation PBR plan will continue to be a price cap plan that will adjust FortisAlberta's distribution rates annually using an "I-X" escalation formula (the "formula") that incorporates an inflation factor ("I") and a productivity factor ("X") of 0.1%, as well as the inclusion of an X factor premium of 0.3%. The X factor premium is applied to base PBR rates and is intended to share efficiency benefits with customers on an annual basis. This formula will be applied to the preceding year's distribution rates at the end of each year of the PBR term to determine the subsequent year's PBR revenues.

The Corporation's base distribution rates for the third PBR term were determined using the 2023 COS revenue requirement. In 2024, the Corporation updated its base distribution rates in accordance with directions provided in the Third Generation PBR Compliance Filing decision. The impacts of any changes to return on equity ("ROE"), cost of debt and capital structure during the PBR term applies only to the portion of rate base that is funded by revenue provided by mechanisms separate from going-in rates escalated by the formula. Any changes in these items are recoverable through annual true-ups associated with these mechanisms.

During the third PBR term, incremental capital funding to recover costs related to capital expenditures that are not recovered through going-in rates escalated by the formula is available through a K-bar mechanism, with limited opportunity for additional capital funding being made available through a capital tracker mechanism or "Type 1" capital. A K-bar amount is established for each year of the third PBR term based on the revenue requirement associated with the Corporation's approved 2023 COS rate base of approximately $4,100 million, and a level of annual capital additions premised on 2018 - 2022 historical averages that are escalated as prescribed by the AUC. Ongoing escalation of K-bar amounts will incorporate I-X, exclusive of the X factor premium, and a customer growth escalator. The decision assumes that adequate future funding for certain capital expenditure programs approved on a forecast basis as part of the 2023 COS rebasing will be obtained from K-bar based on the escalated historical capital additions. Type 1 capital funding may be provided for capital expenditures that are material, not previously included in the utility's rate base, and are required by a third party. Eligible capital expenditures may include those related to net-zero objectives.

The third PBR term includes mechanisms for the recovery or settlement of items determined to flow through directly to customers ("Y factor") as well as a Z factor which permits an application for recovery of costs related to significant unforeseen events in excess of an established threshold. An asymmetrical earnings sharing mechanism ("ESM") is also included in the third generation PBR plan. The asymmetrical ESM incorporates a 200 basis point deadband above the approved ROE and two marginal sharing ranges. In the range of 200 bps to 400 bps, 60% of earnings will be retained by the utility. In the range of 400 bps to 500 bps, 20% of earnings are retained by the utility. Earnings in excess of 500 bps above the approved ROE may trigger a plan re-opener that would address specific problems with the design or operation of the PBR plan.

The AUC also imposed metrics to demonstrate a correlation between financial outcomes and measurable efficiency gains. These metrics will be reported as part of the Corporation's annual rates adjustment filing.

Appeal of Third Generation PBR Decision
In November 2023, the Corporation sought permission to appeal Decision 27388-D01-2023 to the Court of Appeal of Alberta ("the Court"). FortisAlberta's application for permission to appeal is based on the grounds that the AUC erred in law by: (i) failing to properly address the Corporation's unique circumstances in establishing the amount of the X factor premium; and (ii) basing the calculation of K-bar for the third PBR term on a five-year average of actual capital additions made between 2018 to 2022. The Corporation's application for permission to appeal this decision was heard by the Court on December 4, 2024 and a decision is expected in the first quarter of 2025.

Compliance Filing and 2024 Annual Rates Application
In March 2024, the AUC issued Decision 28576-D02-2024 approving the Corporation's PBR3 Compliance Filing and 2024 rates and riders, on an interim basis, effective January 1, 2024. The Corporation's 2023 going-in revenue requirement, currently approved on an interim basis, increased from $660 to $665 million to reflect true-ups for 2022 actuals, including higher recoverable income tax expense. FortisAlberta's approved distribution rates for 2024 include an increase of approximately 9% for: (i) an I-X escalation of 3.62%, inclusive of the X factor premium of 0.03%; (ii) a 2024 K-bar placeholder of $31 million, which includes the approved 2024 ROE of 9.28%; and (iii) a net collection of $10 million reflecting adjustments for various Y factor amounts, including the incorporation of a one-time collection of approximately $10 million attributable to the ECM, inclusive of income tax gross-up.

Type 1 Capital Tracker Application
In October 2024, the Corporation submitted an application (Proceeding 29513) seeking approval for Type 1 Capital Tracker treatment and associated funding for its advanced metering infrastructure and forestry protection programs. If approved, Type 1 Capital Tracker revenue will be subject to true-up for actual capital expenditures, the final I-X escalation incorporated in base rates and K-bar, the actual cost-of-debt used to finance the capital expenditures, and the final approved ROE. The Corporation has requested approval for interim Type 1 Capital Tracker revenue of $8 million for 2025, $17 million for 2026, $28 million for 2027 and $38 million for 2028.

In November 2024, the AUC bifurcated the proceeding into two modules. The first module will determine whether the criteria established in Decision 27388-D01-2023 for Type 1 Capital ("Type 1 Capital Criteria") have been met. If the AUC determines that one or both of the applied-for programs meet the Type 1 Capital Criteria, it will proceed to Module 2 where it will assess the reasonableness of the 2025-2028 forecast Type 1 capital revenue requirement for those programs. The Corporation expects a decision on the first module of its Type 1 Capital Tracker application in the first half of 2025.

2025 Annual Rates Application
In September 2024, the Corporation submitted its 2025 Annual Rates Application. In doing so, the Corporation also requested approval of a placeholder for additional revenues applied-for as part of its Type 1 capital tracker application. The applied-for 2025 PBR rates were subsequently updated in November 2024 to incorporate the AUC's approved ROE for 2025.

The AUC declined to approve the Corporation's applied-for Type 1 capital tracker placeholder amount. However, a $nil placeholder was approved as part of the Corporation's 2025 Annual Rates Application to permit rates to be adjusted in the event that FortisAlberta's Type 1 capital tracker application is approved, in part or as-filed.

In December 2024, the AUC issued Decision 29297-D01-2024 approving the Corporation's 2025 rates and riders, on an interim basis for January 1, 2025, including an average increase of approximately 2.8% to the distribution component of customer rates. The increase in the distribution component of customer rates reflected:

i. A collection of $5 million to reflect the increase in the Corporation's interim 2023 going-in revenue requirement;

ii. 2024 true-ups inclusive of:

- a collection of $5 million to reflect the impact of the updated interim 2023 going-in revenue requirement on 2024 base rates;
- a refund of $6 million to reflect the impact of a decrease of 0.82% in the 2024 placeholder I-X escalation, inclusive of the X factor premium, to 2.80% on 2024 base rates; and
- a collection of $6 million for the true-up of the placeholder 2024 K-bar to reflect the updated 2024 placeholders for I-X escalation and cost of debt;

iii. 2025 distribution rates inclusive of:

- an I-X escalation of 2.80%, inclusive of the X factor premium of 0.03%;
- an ROE of 8.97% for 2025 as approved in Decision 29586-D01-2024, which was issued in the fourth quarter of 2024 in accordance with the AUC's Generic Cost of Capital decision as described below;
- a 2025 K-bar placeholder of $31 million; and
- a net collection of Y factor amounts of $1 million.

Generic Cost of Capital ("GCOC") Proceeding for 2024 and Beyond
In January 2022, the AUC initiated a two-stage GCOC proceeding to establish the cost of capital parameters for (i) 2023, and (ii) 2024 and beyond. In March 2022, the AUC issued Decision 27084-D01-2022 confirming that the 8.50% ROE and 37% equity thickness approved for 2022 would be extended on a final basis for the duration of 2023.

In June 2022, the AUC commenced the second stage of the GCOC proceeding, which explored a formula-based approach to cost of capital for 2024 and beyond. Specifically, the AUC identified the following topics to be explored: (i) a formula-based approach to determine ROE; (ii) the initial numerical variables to be used in the formula; (iii) the process to calculate ROE in future test years; and (iv) the future process or threshold which would trigger a review of the approach if necessary. The record of this proceeding closed in June 2023.

In October 2023, the AUC issued Decision 27084-D02-2023 for the determination of cost of capital parameters for 2024 and beyond. This decision also confirmed an equity thickness of 37% for all electric distribution utilities and approved the implementation of a formulaic Automatic Adjustment Mechanism ("AAM") for the annual determination of ROE. The AAM will adjust a notional going-in ROE of 9.0% by 50% of the difference between the forecasted long-term Government of Canada bond yield compared with the base value of 3.1% and 50% of the difference between the utility bond yield spread compared with the base value of 1.58%. Base values were established as at February 2023. The calculation is as follows:

$$ROE_t = 9.0\% + 0.5 \times (YLD_t - 3.10\%) + 0.5 \times (SPRD_t - 1.58\%)$$

YLD_t = forecast 30 year Government of Canada Bond Yield

$SPRD_t$ = the difference between the 30-year A-rated Canadian Utility Bond Yield and the 30 year Government of Canada Bond Yield over the October period of each preceding year

The AUC's AAM does not incorporate a minimum value or floor for the approved ROE in any given year. However, the AUC has committed to evaluating the effectiveness of its formula on a five year cadence, and is willing to permit mid-term re-openers of the AAM's operation at any time if a compelling reason to do so can be identified by a stakeholder, including the AUC. The approved AAM is used to set an adjusted ROE for the following year using data available in the fourth quarter of the preceding year. This approach will be used in each year of the 2024-2028 PBR term.

In November 2023, the AUC issued Decision 28585-D01-2023 approving a 9.28% ROE for Alberta utilities, effective January 1 to December 31, 2024.

Similarly, in November 2024, the AUC issued Decision 29586-D01-2024 approving a 8.97% ROE for Alberta utilities, effective January 1 to December 31, 2025. The Corporation's 2025 Annual Rates Filing was subsequently updated in November 2024 to incorporate the AUC's approved ROE for 2025.

Appeal of Generic Cost of Capital Decision for 2024 and Beyond
In November 2023, the Corporation sought permission to appeal Decision 27084-D02-2023 to the Court. FortisAlberta alleges that the AUC erred in its decision to not adjust the Corporation's ROE, deemed equity ratio, or both, to address the incremental business risk resulting from increased competition from REAs located in the Corporation's service area, as well as heightened regulatory risk, as evidenced by the revenue removal directed in the AUC's 2022 Phase II Distribution Tariff Application decision, as discussed below. In April 2024, the Court granted the Corporation's application for permission to

appeal the AUC's Generic Cost of Capital decision for 2024 and beyond. The Corporation expects that its full appeal of the decision will be completed during the first quarter of 2025.

Phase II Distribution Tariff Application ("DTA")

A Phase II DTA is undertaken periodically to propose revisions to rate design and rate class cost allocations and to determine how much of the Corporation's revenue requirement will be recovered from each customer rate class. The DTA also establishes the billing determinants that will apply to each rate class. The Corporation filed a Phase II DTA in October 2020 proposing a revised rate design intended to achieve improved alignment between revenues collected from, and costs assigned to, specific rate classes.

During the process, the AUC also considered the allocation of costs attributable to the use of the Corporation's distribution system by REAs. These costs had historically been recovered from the Corporation's load customers under FortisAlberta's regulated tariff. As part of the Phase II proceeding, the AUC determined that REAs are not captured in the definition of "customer" contained in the *EUA* for purposes of application of the Corporation's regulated tariff. In the same decision, the AUC held that costs attributable to REAs cannot be recovered from the Corporation's load customers. As a result, costs allocated to REAs were ordered removed from the Corporation's 2023 revenue requirement. The Corporation incorporated the financial impact of this decision in its 2023 COS Application, removing revenue of approximately $10 million and thereby reducing the forecasted 2023 COS revenue requirement to $660 million. The revenue removal will be incorporated into PBR3 base distribution rates annually through the I-X mechanism.

In February 2022, the Court granted the Corporation permission to appeal the REA cost recovery aspect of the AUC's 2022 Phase II DTA decision to a full panel of the Court. The subject of this appeal was whether the AUC erred in preventing the Corporation from recovering upstream distribution costs properly allocatable to REAs from its own ratepayers to the extent that these costs cannot be recovered directly from REAs. This appeal was heard in December 2022. On April 28, 2023, the Court of Appeal of Alberta dismissed the Corporation's appeal of a prior AUC ruling preventing the recovery of distribution costs from REAs under FortisAlberta's regulated tariff. The Court's decision necessitates that the Corporation pursue other means, including the passing of legislative amendments, to recover these costs directly from these entities.

Tariff Recovery Mechanism for AESO Customer Contributions

In 2021, the AUC issued Decision 24932-D01-2020, which directed a prospective change to the distribution facility owner ("DFO") tariff recovery mechanism applicable to payments required to be made by DFOs ("AESO contributions") under the AESO Customer Contribution Policy ("ACCP"). The new tariff recovery mechanism provides that AESO contributions required to be made by DFOs under the policy are to be expensed and collected from customers as a flow-through and that DFOs are no longer permitted to recover an equity return on these amounts. The AUC confirmed that any AESO contributions made prior to the release of the decision were to be treated as rate base additions in accordance with past practice, attracting both an equity and debt return.

In 2022, the Court of Appeal of Alberta, after considering applications that were brought by various parties in 2021, granted leave to appeal Decision 24932-D01-2020. The hearing of the appeal took place in February 2023 and a decision was issued in November 2023. The Court found that the AUC breached its duty to ensure procedural fairness during the process that led to the issuance of the decision and, therefore, remanded the entire matter back to the AUC for reconsideration.

In the second quarter of 2024, the AUC initiated a proceeding (Proceeding 29006) to reconsider matters related to the ACCP. On October 15, 2024, the AUC confirmed that the issues list for this proceeding would consist of: (i) is the long-established Commission customer contribution policy lawful? (ii) is the Commission compelled by the legislation to allow transmission system owners to pay or repay the Contributions in Aid of Construction, include the resulting costs in their capital base and earn a return on the expenditure? (iii) are Contributions in Aid of Construction to be treated as expenditures, rather than as capital amounts on which some component of the utility system is entitled to earn a rate of return?

On December 20, 2024, the Corporation made a submission to the AUC confirming FortisAlberta's position that the ACCP is lawful. As part of the same process, AltaLink Management Ltd., a transmission facility owner, disputed the legality of the ACCP and took the position that all unamortized Contributions in Aid of Construction provided by FortisAlberta should be repaid to the Corporation and funded by AltaLink Management Ltd.

A determination in this proceeding may have an impact on the Corporation's going-in rates and K-bar amounts for the third PBR term. A decision is expected in 2025.

Electric Distribution System Transfer

If the Corporation and a municipality or a REA come to an agreement to transfer electric distribution system assets to the Corporation, the transfer and purchase is subject to regulatory oversight. The municipality or REA is required to apply to the AUC to cease and discontinue its operations. Concurrently, the Corporation is required to apply to the AUC to alter its electric service area to include the electric service area of the municipality or REA and obtain approval of the purchase price for the distribution system assets and the related rate treatment.

In the fourth quarter of 2023, the Tomahawk Rural Electrification Association Ltd.("TREA") membership approved the sale and transfer of the TREA electric distribution system and related assets (the "system") to the Corporation for $11 million. In April 2024, TREA and the Corporation filed applications with the AUC seeking all regulatory approvals required to complete the transfer of TREA's distribution assets to FortisAlberta. For the interim period, the Corporation entered into an operating agreement with TREA to oversee and maintain its electric distribution system. On July 9, 2024, the AUC issued Decision 28988-D01-2024 approving TREA's application to cease and discontinue operations and FortisAlberta's application for approval to accept a transfer of distribution assets from TREA. On August 8, 2024, the Corporation paid $11 million to TREA in consideration of the distribution system transfer. The amount to be included in the Corporation's rate base is still subject to a prudence review by the AUC, which is expected to be concluded in the first half of 2025.

RESULTS OF OPERATIONS

	Three months ended December 31,			Twelve months ended December 31,		
($ millions)	**2024**	**2023**	**Variance**	**2024**	**2023**	**Variance**
Total revenues	229	209	20	901	814	87
Cost of sales	75	72	3	279	257	22
Depreciation	68	62	6	266	244	22
Amortization	6	5	1	25	21	4
Other income	2	2	—	11	6	5
Interest expense	34	33	1	135	125	10
Income before income tax	48	39	9	207	173	34
Income tax expense	6	4	2	26	12	14
Net income	42	35	7	181	161	20

The following table outlines net income and significant variances in the Results of Operations for the three months ended December 31, 2024, as compared to December 31, 2023:

Item	Increase *($ millions)*	Explanation
Net income	7	The increase was primarily due to: • formulaically-determined PBR revenue that incorporates (i) higher regulated rate base, to fund incremental depreciation, interest expense and income tax (ii) customer additions, (iii) true-ups and adjustments related to the 2022 rate base and 2023 revenue requirement, and (iv) an increase in the GCOC-determined ROE from 8.50% in 2023 to 9.28% in 2024; partially offset by: • higher operating costs attributable to expanded operational requirements driven by customer growth and emerging industry trends, including higher labour costs.
Total revenues	20	The increase was primarily due to: • formulaically-determined PBR revenue that incorporates (i) higher regulated rate base, to fund incremental depreciation, interest expense and income tax, resulting from the operation of the K-bar funding mechanism, (ii) customer additions, (iii) true-ups and adjustments related to the 2022 rate base and 2023 revenue requirement, and (iv) an increase in the GCOC-determined ROE from 8.50% in 2023 to 9.28% in 2024. The increase in revenue also included higher franchise fees, which are flowed through to customers and do not affect net income.
Cost of sales	3	The increase was primarily due to expanded operational requirements driven by customer growth and emerging industry trends, including higher labour costs, as well as higher franchise fees which are flowed through to customers and do not affect net income.
Depreciation	6	The increase was primarily due to a higher depreciable asset base compared to the prior period driven by continued execution of the Corporation's capital expenditure program.

The following table outlines net income and significant variances in the Results of Operations for the twelve months ended December 31, 2024, as compared to December 31, 2023:

Item	Increase *($ millions)*	Explanation
Net income	20	The increase was primarily due to: • formulaically-determined PBR revenue that incorporates (i) higher regulated rate base to fund incremental depreciation, interest and income tax expense, (ii) customer additions and commercial and industrial demand, (iii) true-ups and adjustments related to the 2022 rate base and 2023 revenue requirement, and (iv) an increase in the GCOC-determined ROE from 8.50% in 2023 to 9.28% in 2024; partially offset by: • higher operating costs attributable to expanded operational requirements driven by customer growth and emerging industry trends, including higher labour costs; and • higher income tax expense due to higher income before taxes and changes in tax timing differences associated with property, plant and equipment.
Total revenues	87	The increase was primarily due to: • formulaically-determined PBR revenue that incorporates (i) higher regulated rate base to fund incremental depreciation, interest and income tax expense, (ii) customer additions and commercial and industrial demand, (iii) true-ups and adjustments related to the 2022 rate base and 2023 revenue requirement, and (iv) an increase in the GCOC-determined ROE from 8.50% in 2023 to 9.28% in 2024. The increase in revenue also included higher franchise fees, which are flowed through to customers and do not affect net income.
Cost of sales	22	The increase was primarily due to expanded operational requirements driven by customer growth and emerging industry trends, including higher labour costs, as well as higher franchise fees which are flowed through to customers and do not affect net income.
Depreciation	22	The increase was primarily due to a higher depreciable asset base compared to the prior period driven by execution of the Corporation's capital expenditure program.
Interest expense	10	The increase was primarily due to higher borrowings to support continued execution of the Corporation's capital expenditure program.
Income tax expense	14	The increase was primarily due to higher income before taxes and changes in tax timing differences associated with property, plant and equipment.

SUMMARY OF QUARTERLY RESULTS

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

($ millions)	Total Revenues	Net Income
December 31, 2024	229	42
September 30, 2024	230	54
June 30, 2024	224	40
March 31, 2024	218	45
December 31, 2023	209	35
September 30, 2023	209	45
June 30, 2023	198	41
March 31, 2023	198	40

Changes in total revenues and net income quarter over quarter are a result of factors including, but not limited to, electricity deliveries, number of customer sites, regulatory decisions, ongoing investment in the distribution grid, inflation, and changes in income tax. While approximately 85% of the Corporation's distribution revenue is derived from largely fixed non-energy billing determinants, seasonality can affect the revenue recognized in the Corporation's quarterly operations.

December 31, 2024 / 2023
Net income for the three months ended December 31, 2024 increased $7 million compared to the same period in 2023. The increase was primarily due to formulaically-determined PBR revenue that incorporates (i) higher regulated rate base, to fund incremental depreciation, interest expense and income tax, (ii) customer additions, (iii) true-ups and adjustments related to the 2022 rate base and 2023 revenue requirement, and (iv) an increase in the GCOC-determined ROE from 8.50% in 2023 to 9.28% in 2024. This was partially offset by higher operating costs attributable to expanded operational requirements driven by customer growth and emerging industry trends, including higher labour costs.

September 30, 2024 / 2023
Net income for the three months ended September 30, 2024 increased $9 million compared to the same period in 2023. The increase was primarily due to formulaically-determined PBR revenue that incorporates changes in billing determinants, other adjustments that result from the operation of the K-bar funding mechanism, and true-ups and adjustments related to 2022 rate base and 2023 revenue requirements; higher revenue from (i) regulated rate base growth, which funds incremental depreciation, interest expense and income tax and (ii) customer additions; and an increase in the GCOC-determined ROE from 8.50% in 2023 to 9.28% in 2024. This was partially offset by higher income tax expense due to higher income before taxes and changes in tax timing differences associated with property, plant and equipment; and higher operating costs attributable to inflationary increases and labour costs.

June 30, 2024 / 2023
Net income for the three months ended June 30, 2024 decreased $1 million compared to the same period in 2023. This was primarily due to (i) the timing of income tax expense due to changes in tax timing differences associated with property, plant and equipment and (ii) higher operating costs attributable to inflationary increases, higher labour costs and timing of expenses. This was partially offset by (i) an increase in the GCOC-determined ROE from 8.50% in 2023 to 9.28% in 2024; (ii) higher revenue from regulated rate base growth, which funds incremental depreciation, interest expense and income tax; and (iii) formulaically-determined PBR revenue that incorporates changes in billing determinants, other adjustments that result from the operation of the K-bar funding mechanism, and true-ups and adjustments related to 2022 and 2023 rate base amounts.

March 31, 2024 / 2023
Net income for the three months ended March 31, 2024 increased $5 million compared to the same period in 2023. The increase was primarily due to higher revenues from (i) an increase in the GCOC-determined ROE from 8.50% in 2023 to 9.28% in 2024; (ii) regulated rate base growth, which funds incremental depreciation, interest expense and income tax; (iii) an increase from customer additions and higher industrial and commercial demand; (iv) an increase relating to a non-recurring adjustment to 2022 rate base and income taxes as a result of the approval of the 2024 compliance filing and annual rates filing; and (v) an increase in allowance for funds used during construction. This was partially offset by increases in operating costs attributable to higher labour costs.

FINANCIAL POSITION

The following table outlines the significant changes in the balance sheet between December 31, 2024 and December 31, 2023:

Item	(Decrease)/ Increase *($ millions)*	Explanation
Assets:		
Cash and cash equivalents	(77)	The decrease was primarily due to carrying a higher cash balance in the prior year given the timing of the AESO payment for customer transmission charges.
Accounts receivable	(6)	The decrease was primarily driven by the volume and timing of collections for transmission-related amounts from customers that the Corporation administers on behalf of the AESO and flows through to customers, partially offset by the timing of collection of distribution revenue from customers.
Regulatory assets (current and long-term)	40	The increase was primarily due to a change in the regulated asset associated with the deferred income tax liability and the timing of collection of PBR-related amounts.
Property, plant and equipment, net	244	The increase was primarily due to continued investment associated with the Corporation's capital expenditure program, partially offset by depreciation and customer contributions.
Intangible assets, net	12	The increase was primarily due to continued investment in computer software, partially offset by amortization.
Liabilities and Shareholder's Equity:		
Accounts payable and other current liabilities	(57)	The decrease is primarily due to higher amounts payable to the AESO for customer transmission charges, partially offset by increased payables associated with the Corporation's capital expenditure program.
Regulatory liabilities (current and long-term)	(26)	The decrease was primarily due to a lower AESO charges deferral balance, partially offset by higher future costs of removal.
Deferred income tax	27	The increase was primarily due to higher deductible temporary differences related to capital asset expenditures and changes in regulatory deferral amounts.
Debt (including short-term borrowings)	173	The Corporation issued $300 million of long-term debt in May 2024 to fund the Corporation's capital expenditure program and the repayment of $150 million of maturing debt in September 2024.
Total shareholder's equity	106	The increase was due to earnings of $181 million and an equity contribution of $40 million, less dividends paid of $115 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

Cash Flow Requirements and Liquidity

The Corporation expects that operating costs, interest expense, and other working capital will generally be paid out of operating cash flows. Cash flow is also required to fund capital expenditure programs and it is expected that these will be financed from a combination of cash flows from operations, borrowings under the credit facility, equity contributions from Fortis via FAHI, long-term debenture issuances, and borrowing of demand notes from Fortis, as required.

The Corporation's ability to service its debt obligations and pay dividends is dependent on the financial results of the Corporation. Depending on the timing of cash payments, borrowings under the Corporation's credit facility, or demand notes from Fortis may be periodically required to support the servicing of working capital deficiencies. The Corporation may rely upon the proceeds of new debenture issuances to meet its principal obligations when they become due.

	Three months ended December 31,			Twelve months ended December 31,		
($ millions)	2024	2023	Variance	2024	2023	Variance
Cash and cash equivalents, beginning of period	78	10	68	77	—	77
Cash and cash equivalents from (used in):						
Operating activities	(12)	192	(204)	303	532	(229)
Investing activities	(132)	(139)	7	(478)	(548)	70
Financing activities	66	14	52	98	93	5
Cash and cash equivalents, end of period	—	77	(77)	—	77	(77)

Operating Activities

For the three months ended December 31, 2024, net cash provided from operating activities decreased by $204 million compared to the same period in 2023. This was due to differences between the timing of the collection of accounts receivable from retailers for distribution revenue, including customer transmission amounts, and the remittance of transmission-related charges to the AESO, partially offset by higher net income after non-cash adjustments. For the year ended December 31, 2024, net cash provided from operating activities decreased by $229 million compared to the same period in 2023. This was due to timing differences in the AESO charges deferral, partially offset by higher net income after non-cash adjustments.

Investing Activities

For the three and twelve months ended December 31, 2024, net cash used in investing activities decreased by $7 million and $70 million, respectively, compared to the same period in 2023. The decrease in investing activities was primarily due to the timing of executing the capital expenditure program, changes in working capital and an increase in customer contributions. For the year ended December 31, 2024, the Corporation incurred expenditures of approximately $8 million (2023 - $15 million) for distribution infrastructure to facilitate the interconnection of distributed energy resources, such as solar photovoltaic and wind, including independent power producers. The cost of these distribution assets was offset by customer contributions.

Financing Activities

For the three and twelve months ended December 31, 2024, cash from financing activities increased by $52 million and $5 million, respectively, primarily to support the Corporation's capital expenditure program. For the three and twelve months ended December 31, 2024, the Corporation paid dividends of $29 million and $115 million, respectively, (December 31, 2023 - $26 million and $105 million) to its parent company FAHI, and received an equity contribution of $40 million (December 31, 2023 - $nil).

PROJECTED CAPITAL EXPENDITURES

The Corporation's 2025 projected gross capital expenditures (excluding customer contributions) are approximately $590 million, inclusive of an allowance for funds used during construction, capitalized overheads, and changes in working capital. The 2025 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, ability to procure materials and engage contractors, and other factors that could cause actual results to differ from forecast. Included in the 2025 projected gross capital expenditure program are approximately $16 million of expenditures to support the ongoing connection of distributed energy resources, such as solar photovoltaic and wind, to its electric distribution system, and advance its distribution voltage management program to manage line losses and provide support for existing and new DG sites.

CONTRACTUAL OBLIGATIONS

The Corporation's contractual obligations as at December 31, 2024 were as follows:

($ millions)	Total	2025	2026	2027	2028	2029	> 2029
Principal payments on debt (1)	2,950	115	—	—	—	—	2,835
Interest payments on debt	2,764	131	131	131	131	131	2,109
Other commitments (2)(3)	51	5	5	5	2	2	32
Total	5,765	251	136	136	133	133	4,976

(1) *Payments are shown exclusive of discounts.*

(2) *The Corporation and an Alberta transmission service provider have entered into an agreement to allow for joint attachments of distribution facilities to the transmission system. The agreement remains in effect, in perpetuity, until the Corporation no longer has attachments to the transmission system. Due to the unlimited duration of this contract, the calculation of future payments after year 2029 includes payments to the end of 20 years. However, the payments under this agreement may continue for an indeterminable period.*

(3) *Other contractual obligations include performance and restricted share unit obligations and defined benefit pension contributions.*

CAPITAL MANAGEMENT

The Corporation's objective when managing capital is to ensure ongoing access to the capital required to build and maintain its electric distribution facilities. 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 FAHI.

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

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

Summary of Capital Structure

As at:	December 31, 2024		December 31, 2023	
	$ millions	%	$ millions	%
Total debt	2,935	61.4	2,762	61.4
Shareholder's equity	1,846	38.6	1,740	38.6
	4,781	100.0	4,502	100.0

The Corporation has externally imposed capital requirements by virtue of its Trust Indenture and committed credit facility such that consolidated debt cannot exceed 75% of the Corporation's consolidated capitalization ratio, which is based on the Corporation's total capital structure. As at December 31, 2024, the Corporation was in compliance with these externally imposed capital requirements.

Debentures
On May 27, 2024, the Corporation issued $300 million of senior unsecured debentures, by private placement, at a rate of 4.897%, to be paid semi-annually, and mature in 2054. The net proceeds of the issuance were used for general corporate purposes, to finance the Corporation's capital expenditures and to repay the Series 14-2 unsecured debentures of $150 million, which matured on September 30, 2024.

Credit Facilities
As at December 31, 2024, the Corporation had an unsecured committed credit facility with an available amount of $250 million that matures in August 2029. Borrowings on the committed credit facility are available by way of prime loans, Canadian Overnight Repo Rate Average loans and letters of credit. Letters of credit are provided by the lender of the Corporation's unsecured committed credit facility, with a one year expiry date. The weighted average effective interest rate for the twelve months ended December 31, 2024 on the committed credit facility was 6.0% (2023 - 6.3%).

The table below summarizes the credit facilities unutilized as at December 31, 2024, and 2023:

($ millions)	**2024**	**2023**
Total credit facility	250	250
Credit Facility utilized:		
Draws on credit facility	(115)	(95)
Letters of credit outstanding	(2)	(2)
Credit facility unutilized	133	153

OFF-BALANCE SHEET ARRANGEMENTS

Except for letters of credit outstanding, the Corporation had no off-balance sheet arrangements as at December 31, 2024.

CREDIT RATINGS

Debentures issued by the Corporation are rated by Morningstar DBRS and Standard and Poor's ("S&P"). The ratings assigned to the debentures issued by the Corporation are reviewed by these agencies on an ongoing basis.

The table below summarizes the ratings assigned to the Corporation's debentures as at December 31, 2024:

Rating Agency	Credit Rating	Type of Rating	Outlook
Morningstar DBRS	A (low)	Senior Unsecured Debt	Stable
S&P	A-	Senior Unsecured Debt	Negative

During the fourth quarter of 2024, both Morningstar DBRS and S&P issued updated credit reports confirming the Corporation's credit ratings and outlooks. In 2023, S&P had changed the Corporation's outlook from "stable" to "negative" based on its view that FortisAlberta faces increasing wildfire-related risks.

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.

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:

($ millions)	December 31, 2024	December 31, 2023
Accounts payable and other current liabilities (1)	2	3

(1) *Includes charges from related parties for information technology services and other general operating expenses.*

The Corporation invoices related parties on terms and conditions consistent with invoices issued to all other third parties, which require amounts to be paid on a net 30 days basis with interest on overdue amounts. Terms and conditions on amounts invoiced 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:

($ millions)	December 31, 2024	December 31, 2023
Included in other revenue (1)	—	1
Included in cost of sales (2)	6	5

(1) *Includes services provided to related parties for information technology, material sales and intercompany employee services.*
(2) *Includes charges from related parties for corporate governance and other general operating expenses.*

During the year, the Corporation paid $1 million to a related party for information technology services that were recognized as an intangible asset.

All services provided to, or received from, related parties are billed on a cost-recovery basis.

FINANCIAL INSTRUMENTS

The following table represents the fair value measurements of the Corporation's financial instruments:

Senior Unsecured Debentures ($ millions)	December 31, 2024	December 31, 2023
Fair value (1)	2,816	2,667
Carrying value (2)	2,834	2,684

(1) *The fair value of the senior unsecured debentures was estimated using level 2 inputs and calculated using indicative prices provided by a third party for the same or similarly rated issues of debt with similar maturities.*
(2) *Carrying value is presented gross of debt issuance costs.*

The fair value of the Corporation's financial instruments reflects 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.

SUMMARY OF SELECTED ANNUAL FINANCIAL INFORMATION

The following table sets forth selected annual financial information of the Corporation that is derived from audited financial statements and are not indicative of results for any future period and should not be relied upon to predict future performance or results.

($ millions)	2024	2023	2022
Total revenues (1)	901	814	750
Net income (1)	181	161	151
Assets (2)	6,182	5,962	5,547
Non-current liabilities (2)	3,902	3,543	3,433
Dividends (2)	115	105	100

(1) See Results of Operations for commentary on the change in total revenues and net income for 2024 as compared to 2023.
(2) See Financial Position for a discussion of significant changes in assets, non-current liabilities, including long-term debt and shareholder's equity for 2024 as compared to 2023.

2023 / 2022
Total Revenues increased $64 million and net income increased $10 million in 2023 compared to 2022. The increase in revenues and net income was primarily due to an increase in regulated rate base; an increase in customer additions and higher industrial and commercial demand; alternative revenue from the ECM earned in the second term of PBR and recognized in 2023, for which there was no equivalent amount recognized in 2022; the recovery of income tax expense in customer rates beginning in 2023; and an increase in franchise fees, which are flowed through to customers and do not affect net income. These were partially offset by the $10 million in uncollectible revenue associated with incurred costs attributable to REAs' use of the Corporation's distribution system that the AUC has determined are unrecoverable from customers under the Corporation's distribution tariff. The increase in total assets was primarily due to the continued execution of the Corporation's capital expenditure program. The increase in non-current liabilities was primarily due to the issuance of $200 million of senior unsecured debentures during the second quarter of 2023, partially offset by the reclass to current liabilities of $150 million of senior unsecured debentures that matured in September 2024.

From 2022 to 2024, dividends were paid to assist in maintaining the approved capital structure of 37 percent equity.

CRITICAL ACCOUNTING ESTIMATES

General
The preparation of the 2024 Annual Financial Statements required management to make estimates and judgments that affect the reported amounts of, and disclosures related to, assets, liabilities, revenues, expenses, gains, losses, and contingencies. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time they are made, with any adjustments recognized in the period they become known. Actual results may differ significantly from these estimates.

Regulation
Generally, the accounting policies of the Corporation are subject to examination and approval by the AUC. The timing of recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that otherwise expected for entities not subject to rate regulation. Certain estimates are necessary since the regulatory environment in which the Corporation operates often requires amounts to be recorded at estimated values until finalization and adjustment, if any, are determined pursuant to subsequent regulatory decisions or other regulatory proceedings. The final amounts approved by the AUC for deferral as regulatory assets and liabilities and the approved recovery or settlement periods may differ from those originally expected. Any resulting adjustments to original estimates are recognized in the period they become known.

Revenue Recognition
Revenues are recognized as earned, at AUC approved rates where applicable, including amounts recognized on an accrual basis for services rendered but not yet billed. The unbilled revenue accrual at the end of each period is based on the difference between the forecast revenue and the actual amounts billed. The development of the revenue forecast is based upon numerous assumptions such as energy deliveries, customer demand, customer sites, economic activity, and weather conditions.

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. Management annually assesses if updates are required to depreciation and amortization rates based on changes in capital asset balances and new information related to the service life of assets.

Income Tax

Income tax is determined based on estimates of the Corporation's current income tax and estimates of deferred income tax resulting from temporary differences between the carrying value of assets and liabilities in the financial statements and their income tax values. A deferred income tax asset or liability is determined for each temporary difference based on enacted income tax rates and laws in effect when the temporary differences are expected to be recovered or settled. Uncertainty associated with the application of tax statutes and regulations, and the outcome of tax audits and appeals, requires that judgments and estimates be made in the accrual process and in the calculation of effective tax rates.

Income tax benefits associated with positions taken, or expected to be taken, on an income tax return are recognized only when the more likely than not threshold is met. Income tax benefits are measured at the largest amount of benefit that is greater than 50% likely of being realized upon settlement. Unrecognized tax benefits are evaluated quarterly, and changes are recorded based on new information, including issuance of relevant guidance by the courts or tax authorities and developments occurring in examinations of the Corporation's tax returns. Administrative actions of the tax authorities, changes in tax law or regulation, and the uncertainty associated with the application of tax statutes and regulations could change the Corporation's estimate of income taxes, including the potential for elimination or reduction to realize tax benefits.

Pension and Other Post-Employment Benefits

The Corporation's defined benefit pension plans and the other post-employment benefit plan are subject to judgments utilized in the actuarial determination of the expense and the related obligation. The primary assumptions utilized by management in determining the expense and obligation are the discount rate and the expected long-term rate of return on plan assets. Other assumptions utilized are the average rate of compensation increase, average remaining service life of the active employee group, employee and retiree mortality rates, extended health care trend rate and dental care cost trend rate. All assumptions are assessed and concluded on, in consultation with the Corporation's external actuarial advisor.

Discount rates, which are used to determine the projected benefit obligation, reflect market interest rates on high quality bonds with cash flows that match the timing and amount of expected pension benefit payments. This methodology is consistent with that used to determine the discount rates in the previous year.

Consistent with prior years, the Corporation's third-party actuary provides a range of expected long-term pension asset returns based on the actuary's internal modeling. The expected long-term return on pension plan assets used falls within a normal range as provided by the actuary.

Goodwill

The Corporation is required to perform, at least on an annual basis, an impairment test for goodwill, and any impairment provision has to be charged to earnings. In addition, the Corporation also performs an impairment test if any event occurs or if circumstances change that would indicate that the fair value was below its carrying value. No such event or change in circumstances occurred during 2024 or 2023.

During 2024, the Corporation performed an annual assessment of goodwill and concluded that it is more likely than not that the fair value of the reporting unit was greater than the carrying value and that goodwill was not impaired.

Contingencies

The Corporation is subject to various legal proceedings and claims that arise in the ordinary course of business operations. It is management's judgment that the amount of liability, if any, from these actions would not have a material effect on the Corporation's financial statements.

CHANGES IN ACCOUNTING POLICIES

Accounting Standards Updates ("ASU") 2023-07 Segment Reporting (Topic 280), *Improvements to Reportable Segment Disclosures*, was adopted for the year ended December 31, 2024. This is consistent with note 3 of the audited financial statements for the year ended December 31, 2024.

FUTURE ACCOUNTING PRONOUNCEMENTS

The Corporation considers the applicability and impact of all 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 not expected to have a material impact on the financial statements.

Income Tax Disclosures
ASU 2023-09 *Income Taxes (Topic 740)*, *Improvements to Income Tax Disclosures*, is effective on January 1, 2025 on a prospective basis, with retrospective application and early adoption permitted. The ASU requires additional disclosure of income tax information by jurisdiction to reflect an entity's exposure to potential changes in tax legislation and associated risks and opportunities. The Corporation does not expect that the adoption of this update will have a material impact on its disclosures.

Disaggregation of Income Statement Expenses
ASU 2024-03 *Income Statement (Subtopic 220-40), Reporting Comprehensive Income, Expense Disaggregation Disclosures*, was issued in November 2024, is effective January 1, 2027 and will be applied on a prospective basis. This ASU requires additional disclosure of specific cost and expense information in the notes to the financial statements. The Corporation is assessing the impact of adoption.

GOVERNMENT POLICY DEVELOPMENTS

Government Policies Impacting the Electricity Industry
The regulatory framework under which the Corporation operates is impacted by significant shifts in government policy and/or changes in government, which creates uncertainty about public policy priorities and directions, particularly around electricity and environmental issues.

Government of Alberta Review of the Regulated Rate Option ("RRO") Electricity Rates
In anticipation of increased energy usage and cost during the cold winter months, the Government of Alberta temporarily capped the RRO electricity rate at 13.5 cents/kWh from January to March 2023 for eligible RRO customers. The cap was put in place to reduce billing impacts for Albertans struggling with an elevated cost of living and was implemented as part of the Government of Alberta's Affordability in Action plan.

On April 1, 2023, the RRO rate cap was lifted. Customers remaining on the RRO are once again being billed on the uncapped RRO rate. Any costs above the RRO electricity rate of 13.5 cents/kWh were deferred and will be repaid between April 2023 to December 2024. EPCOR Utilities Inc., as the appointed provider of the Corporation's RRO services, has assumed the contractual obligations, including financial consequences, related to the RRO rate cap. As a pure-play electric distribution utility, the Corporation was, therefore, unaffected by the RRO rate cap.

In 2023, the Government of Alberta initiated a broader review of the RRO as part of its stated mandate to explore ways to improve affordability and rate stability for Albertans.

In April and September 2024, the Government of Alberta enacted changes to the existing RRO legislation and regulations, respectively, which came into effect January 1, 2025. The key changes are: (i) the rebranding of the RRO as the Rate of Last Resort ("ROLR"); (ii) the implementation of a two-year fixed-price model that includes a cap on annual increases; (iii) the incorporation of a consumer awareness surcharge to fund an initiative to inform regulated rate customers about their electricity service options; and (iv) a requirement for ROLR providers to enhance information for customers on monthly bills.

On December 20, 2024, the AUC issued Decision 29692-D01-2024 approving the amended agreement between FortisAlberta and EPCOR Energy Alberta GP ("EEA") to reflect the rebranding of the RRO as ROLR. Effective January 1, 2025, EEA will provide ROLR and default rate service to eligible customers in FortisAlberta's distribution service area, consistent with the original terms of the agreement.

Government of Canada Clean Electricity Regulations ("CERs")
On January 1, 2023, the Government of Canada passed the CERs in connection with its goal of achieving net-zero emissions by 2035. The CERs impose emission standards on technologies used in the generation of electricity. On December 17, 2024, the Government of Canada issued its finalized CERs with an updated goal of achieving net-zero emissions by 2050, including interim targets beginning in 2035. While the Corporation is not involved in the generation of electricity, FortisAlberta

considers that the implementation of the CERs in their current form may have implications for the affordability of electricity and overall economic growth in Alberta.

Restructured Energy Market ("REM")
On March 11, 2024, the Government of Alberta directed the AESO to work with industry and stakeholders to design and submit a draft REM design with the stated objectives of (i) generation reliability; (ii) customer affordability; (iii) decarbonization by 2050; and (iv) reasonable implementation. Industry and stakeholder consultations will incorporate the following topics: (i) day-ahead market; (ii) market power mitigation; (iii) pricing and reserve market; (iv) market clearing; (v) intertie participation; and (vi) shorter settlement. The Government of Alberta has directed that the REM be implemented by January 1, 2027. While the Corporation is not involved in the generation of electricity, FortisAlberta considers that the REM may have implications for the affordability of electricity in Alberta.

OTHER DEVELOPMENTS

Collective Agreement
The Corporation entered into a three-year Collective Agreement with the United Utility Workers Association that was ratified on February 3, 2023, and expires on December 31, 2025.

Corporate Income Tax Audit
The Corporation is currently undergoing a corporate income tax audit of its 2020 tax year by the Canada Revenue Agency ("CRA"). The audits of the 2016, 2017, 2018 and 2019 tax years are generally complete, notwithstanding a limited number of pending tax matters. The Corporation is continuing to work with the CRA and the Alberta provincial tax authority towards the resolution of the tax matters identified in those audit years. As at December 31, 2024, there were no significant changes to the Corporation's existing tax positions. The Corporation will continue to assess whether there are material impacts to the financial statements as future processes unfold with the respective tax authorities.

BUSINESS RISK MANAGEMENT

Regulatory
The Corporation is subject to the uncertainties routinely faced by regulated utility companies. These uncertainties include whether customer rates approved by the AUC will provide the Corporation with a reasonable opportunity to recover its prudently incurred costs of providing utility service, including a fair return on the equity and debt capital used to fund investments in regulated assets.

The Corporation's regulated rate base, including the cost of replacement or upgrades to existing facilities and the addition of new facilities, continue to require the approval of the AUC. There is no assurance that the Corporation will receive regulatory orders in a timely manner, and may incur costs prior to having approved rates. A failure to obtain approval of capital expenditures may adversely affect the Corporation's results of operations or financial position. In the interest of regulatory efficiency, the AUC can employ generic proceedings to address regulatory matters that impact multiple utilities. While generic proceedings allow for regulatory efficiencies, there is the risk that a collective result will not adequately address individual utility circumstances.

Cost of Capital
The AUC establishes a regulated cost of capital for the Corporation and other utilities in litigated proceedings. The fair return standard requires the AUC to establish ROEs and deemed capital structures that will enable utilities to: (i) provide a risk-adjusted return on equity to investors that approximates the required return for a comparable investment; (ii) continue to attract capital on reasonable terms; and (iii) preserves the utilities' financial integrity. The Corporation's finances could be negatively affected if the AUC's method of determining the Corporation's cost of capital that does not meet the fair return standard.

The GCOC-determined ROE, calculated on an annual basis, is an integral driver of the Corporation's financial results and is determined on long-term Government of Canada bond yields and utility bond yield spreads. As such, the Corporation's financial position can be impacted by changes in interest rates.

Timely Recovery of Prudently Incurred Costs
The fundamental risk faced by all regulated utilities is that approved rates will not provide sufficient revenue to recover the prudently incurred costs associated with providing utility services. This risk may present differently, and be heightened, in a PBR ratemaking framework that intentionally delinks rate revenue and the costs of providing utility service over an extended term.

The AUC's third generation PBR plan is based on a formula that will determine annual customer rates, and as such it may expose the Corporation to the following specific risks: (i) that the Corporation will experience inflationary increases in excess of the inflationary factor approved by the AUC in the formula; (ii) that the Corporation will be unable to achieve the productivity improvements incented by the X factor; (iii) that the costs related to the Corporation's operational and capital expenditures will be in excess of those provided for in the base formula and any incremental capital funding mechanism; and (iv) that material unforeseen costs will be incurred and that they will not qualify, or be approved, for recovery as a Z factor adjustment.

Recovery of Costs Related to Emerging Technologies
The AUC may not approve investments in emerging technologies, such as non-wires alternatives, for inclusion in the Corporation's rate base. As technology-related electrical distribution and generation infrastructure evolves, the Corporation may also be subject to a risk that customers may defect from the distribution grid. The loss of customers would result in a decrease in revenue, put upward pressure on remaining customer rates, and may impact the overall recoverability of on-going distribution costs.

Utility Asset Disposition ("UAD")
The Corporation is exposed to the risk that the unrecovered costs associated with utility assets subsequently deemed by the AUC to have been subject to an extraordinary retirement as contemplated by the AUC's Decision 2013-417, including removals from service resulting from sudden obsolescence, will not be recoverable from customers. Currently, the Corporation has no asset retirements considered to be extraordinary.

In early 2023, the Court of Appeal of Alberta granted an appeal brought by ATCO Electric Ltd. that alleged that the AUC had committed an error of law when it previously prohibited ATCO Electric Ltd. from recovering the remaining net book value of utility assets destroyed by wildfires in the Wood Buffalo region of Alberta in 2016. In a court ordered reconsideration, the AUC reversed its prior finding that the principles described in its UAD line of cases mandated this outcome and, instead, held that the regulatory treatment applicable to casualty losses of this kind must be based on a balancing of the interests of the utility and its customers. Consistent with this finding, the AUC held that ATCO Electric Ltd. was permitted to recover the remaining net book value of the destroyed assets in customer rates. FortisAlberta considers this recent refinement of UAD principles, as they relate to casualty losses, to represent an incremental decrease to the regulatory risk previously associated with losses of assets characterized as extraordinary retirements.

The Rate of Last Resort, formerly the Regulated Rate Option
As an owner of an electricity distribution network under the EUA, the Corporation is required to act, or to authorize a substitute party to act, as a provider of electricity services, including the wholesale purchase and retail sale of electricity, to eligible customers under a regulated rate and to appoint a retailer as default supplier to provide electricity services to customers otherwise unable to obtain electricity services. In order to remain solely a distribution utility, the Corporation appointed EPCOR as its regulated rate and default provider. As a result of this appointment, EPCOR assumed all of the Corporation's contractual rights and obligations in respect of the provision of these services.

If the number of ROLR customer sites is significantly reduced or increased on a long-term basis during the term of the contract with EPCOR, the consideration associated with the contract may be subject to adjustment and could have a financial impact on the Corporation. In the event that EPCOR is unable or unwilling to act as regulated rate provider or as default supplier, and no other party is willing to act as regulated rate provider or as default supplier, the Corporation would be required under the EUA to act as a provider of electricity services to eligible customers under a regulated rate or to provide electricity services to customers otherwise unable to obtain electricity services. If the Corporation could not secure outsourcing for these functions, the Corporation would be required to administer these responsibilities by adding staff, facilities, and/or equipment, as necessary.

Economic Conditions
Alberta's economy is impacted by a number of factors, including the level of oil and gas exploration and production activity in the province, which is influenced by commodity prices, government mandated oil production limits, and the ability to import from, export to, and access other markets. A general and extended decline in Alberta's economy would be expected to have the effect of reducing requests for electricity service over time and may increase the number of salvaged sites. Significant reductions in customer requests for interconnection, reduced demand from existing customers, or both, could materially reduce the Corporation's revenues.

In addition, the Corporation's business could be negatively affected if import and export duties, tariffs, barriers, or other protectionist measures were imposed or increased, especially with respect to the United States. Any change in export or import regulations, tariffs or other protectionist measures, or related legislation, or shift in the enforcement or scope of existing regulations, could adversely impact the Corporation's customer base and Alberta's economic activity and conditions generally, which could further impact the Corporation's business and financial results.

The Corporation's customer base includes oil and gas and large industrial customers, and the effect of government policy and energy transition plans could have an effect on customers' future consumption patterns, which could impact the Corporation's future revenues, investments in electrical distribution infrastructure and earnings.

Changes in governmental health policies in response to evolving health risks could lead to volatility in capital markets and adversely impact economic activity and conditions around the world. Potential risks include, but are not limited to, availability of personnel, energy usage and revenues, customer retention, the timing of capital expenditures, the amount and timing of operating and maintenance expenses, timing of regulatory filings and accounts receivable valuation.

Counterparty risk with retailer billings is mitigated through the Corporation obtaining an acceptable form of prudential, which includes a cash deposit, a letter of credit, an investment grade credit rating from a major rating agency, or a financial guarantee from an entity with an investment grade credit rating. The Corporation deals with reasonable credit-quality institutions in accordance with established credit approval practices. In the event of non-performance by counterparties, there could be an adverse effect on the Corporation's results of operations and financial position.

Interest Expense
The Corporation is exposed to interest expense risks associated with its credit facility and the refinancing of its long-term debt. As part of the third generation PBR plan, interest *rate* variances are flowed-through customer rates, however the utility assumes interest risk associated with variances in the *volume* of short-term and long-term debt issued as compared to the levels assumed in PBR rates. If the Corporation is required to incur a level of capital investment that is in excess of what is assumed in PBR rates, there would be an increase in the volume of debt which could have an effect on the Corporation's results of operations and financial position.

Taxation
Earnings could be impacted by changes in income tax rates and other tax legislation federally and provincially. The nature, timing or impact of changes in tax laws cannot be predicted and could have an effect on the Corporation's results of operations and financial position. Although income taxes are generally recovered in customer rates, tax-related regulatory lag can result in recovery delays or non-recovery for certain periods and changes in tax legislation could effect the after-tax cost of existing and future debt that may not be recoverable in customer rates.

For regulatory reporting purposes, the income tax value of certain property, plant and equipment of the Corporation is higher than for statutory corporate income tax purposes. In a future reporting period, the difference may result in higher corporate income tax expense than that recognized for regulatory purposes and collected in customer rates.

Supply Chain Risk
The Corporation is exposed to supply chain disruptions that can impact its ability to operate and maintain its system and execute its capital plan. Supply chain disruption can result from a variety of factors, including labour shortages, material shortages, increased demand from the utility industry, adverse weather events that impact the transportation of goods and the crystallization of geopolitical risks, and the effect of tariffs or other protectionist measures that are imposed or increased, especially with respect to the United States. If the Corporation is unable to procure the required materials in a timely manner and at reasonable cost, its financial performance may be negatively impacted.

Reduction in Customer Base
The Corporation carries out regulated operations in a geographically-defined service area that is approved by the AUC, pursuant to the HEEA. The Corporation has a statutory obligation, and right, to serve all members of the public residing in its service area who are not customers of a municipal utility or are not members of an REA. The boundaries of the Corporation's service area are subject to change upon the occurrence of certain events, which may result in a decrease in the Corporation's customer base.

Municipal Annexations
If a municipality that owns an electricity distribution system expands its boundaries, an annexation can result in the municipality acquiring the Corporation's assets situated in the annexed area. In such circumstances, the HEEA provides that the AUC may determine the amount of compensation from the municipality to the Corporation for any facilities transferred, which is generally based on a replacement cost less depreciation valuation method. Given the historical population and economic growth of Alberta and its municipalities, the Corporation is occasionally affected by these types of transactions.

Municipal Franchise Agreements

The Corporation has entered into franchise agreements with several municipalities in its service area. Franchise agreements provide the Corporation with the exclusive right to serve sites located in the municipalities' corporate limits in consideration of the remittance of franchise fees paid by customers. The agreements, which have a maximum duration of 20 years, are required to provide the municipalities with an option to repurchase distribution facilities from the Corporation upon renewal dates that occur at 10-, 15- and 20-year anniversaries. Should a municipality opt to repurchase distribution assets, the Corporation would be required to transfer them to the municipality at a price to be determined, based on a suitable valuation approach. If such a transfer is required to be completed, the corresponding assets would be removed from the Corporation's rate base negatively impacting the Corporation's revenues.

Competition with REAs

The Corporation is statutorily obligated to provide ongoing System Access Service ("SAS") to both its customers and REAs that operate in, or adjacent to, its approved service area. Operational relationships between the Corporation and REAs are governed by individual operating agreements (variously referred to as "Wire Owner Agreements" or "Integrated Operations Agreements"). The Corporation broadly classifies REAs as being either "traditional" or "non-traditional" depending on their business models. Traditional REAs, many of which are directly operated by the Corporation, limit their membership to agricultural sites consistent with REAs' historical mandate in Alberta. In contrast, non-traditional REAs market their services broadly to attract new members from various sources, including the Corporation's current residential, commercial and industrial customer base, which creates a competitive environment in service areas shared with the Corporation. REA tariffs and any included rates are not subject to review or approval by the AUC. If non-traditional REAs successfully attract sufficient numbers of new connections and transfers of existing customers to their memberships, the Corporation may be negatively affected by the associated loss of revenues and a requirement to sell facilities associated with the transferring site(s).

The Government of Alberta has approved legislation and orders in council to amend the Rural Utilities Act and Regulations in order to facilitate the: (i) purchase of one REA by other REAs and (ii) expansion of REA services into additional business lines. This may result in increased competition for FortisAlberta with the REAs.

Capital Resources and Liquidity

The Corporation's financial position could be adversely affected if it fails to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and the repayment of maturing debt. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including regulatory approvals, the results of operations and financial position of the Corporation and Fortis, conditions in the capital and bank credit markets, the ratings assigned by credit rating agencies, and general economic conditions. The Corporation actively monitors the debt markets to appropriately plan, access and execute financing options.

Insurance Coverage

The Corporation maintains insurance coverage with respect to certain potential liabilities and the accidental loss of value of certain of its assets, in amounts and with such insurers, as it considers appropriate, taking into account relevant factors, including the practices of owners of similar assets and operations. However, the Corporation's distribution assets are not covered by insurance, as is customary in North America.

It is anticipated that existing insurance coverage will be maintained. However, there can be no assurance that the Corporation will be able to obtain or maintain adequate insurance in the future at rates it considers reasonable or that insurance will continue to be available on terms as favourable as the Corporation's existing arrangements, or that insurance companies will meet their obligation to pay claims. Further, there can be no assurance that available insurance will cover all losses or liabilities that may arise in the conduct of the Corporation's business. The occurrence of a significant uninsured claim, a claim in excess of the insurance coverage limits maintained by the Corporation, or a claim that falls within a significant self-insured retention could have a material adverse effect on the Corporation's results of operations, cash flow, and financial position.

Continued Reporting in Accordance with US GAAP

In May 2022, the Alberta Securities Commission (ASC) approved the extension of the Corporation's exemptive relief order which permits the Corporation to continue reporting in accordance with US GAAP rather than IFRS Accounting Standards, until the earlier of January 1, 2027; and the later of (i) the effective date prescribed by the IASB for the mandatory application of a standard within IFRS Accounting Standards specific to entities with activities subject to rate regulation or (ii) two years after the IASB publishes the final version of a mandatory rate-regulated standard.

In January 2021, the IASB issued an Exposure Draft which is expected to result in a permanent mandatory standard specific to entities with activities subject to rate regulation. If ASC relief does not continue as detailed above, the Corporation would then be required to become a United States Securities and Exchange Commission registrant in order to continue reporting under US GAAP, otherwise the Corporation would be required to adopt IFRS Accounting Standards. The IASB completed its redeliberations during 2024, however the timing around the issuance of, and the effective date for, a permanent standard, based on the IASB Exposure Draft, is not yet known. The ultimate impact of a requirement to adopt IFRS Accounting Standards for external financial reporting purposes is not yet known.

Safety and Operations

The Corporation is required to operate and maintain its electric distribution system in a manner that enables the provision of safe and reliable utility service to customers, including the development and application of appropriate standards, systems and processes to ensure the safety of employees, contractors and the general public. An inability to discharge these responsibilities may result in material adverse consequences for the Corporation.

Operating and Maintenance

The Corporation's distribution assets require normal course maintenance, improvement and replacement in accordance with applicable standards. The Corporation determines expenditures that must be made to maintain and replace equipment to ensure the continued safe and reliable operation of its distribution assets. An inability on the part of the Corporation to perform required work in a timely manner may result in increased costs and service disruptions for customers.

Longer-term shifts in climate patterns are expected to impact system and operational planning. Operationally, long-term changes in climate patterns may negatively impact asset performance, which in turn, could negatively impact reliability.

Permits and Rights-of-Way

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

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

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

Environmental

The Corporation is subject to numerous laws, regulations and guidelines governing the generation, management, storage, transportation, recycling and disposal of hazardous substances and other waste materials, and otherwise relating to the protection of the environment. Environmental damages and associated costs could arise due to a variety of events, including the impact of severe weather on the Corporation's facilities, human error or misconduct, or equipment failure. Costs arising from compliance with such environmental laws, regulations and guidelines may become material to the Corporation. Expenditures related to environmental compliance are anticipated to increase in the future. In particular, the management of Greenhouse Gases ("GHG") emissions is a global concern due to new and emerging GHG laws, regulations, and guidelines. The Corporation continues to develop compliance strategies and assess the impact of emerging legislative changes, however significant uncertainties remain.

In addition, the process of obtaining environmental permits and approvals, including any necessary environmental assessments, can be lengthy, contentious and expensive. The Corporation would seek to recover the costs associated with environmental protection, compliance and damage in customer rates; however, there is no assurance that such costs will be recoverable through rates and, if substantial, unrecovered costs may have a material adverse effect on the Corporation's results of operations, cash flow and financial position.

The Corporation is also subject to the risk of contamination of air, soil and water primarily related to the use and/or disposal of petroleum-based products, mainly transformer, hydraulic and lubricating oil, in the day-to-day operating and maintenance activities. Contamination typically occurs through the accidental release of transformer or lubricating oils either through equipment failure, human error or damages caused by the public. The Corporation could be found to be responsible for remediation of contaminated properties, whether such contamination was actually caused by the Corporation. Environmental laws make owners, operators and senior management subject to prosecution or administrative action for breaches of environmental laws, including the failure to obtain regulatory approvals. Changes in environmental laws governing contamination could lead to significant increases in costs to the Corporation.

Weather Variability and Climate Change
The Corporation's physical assets are exposed to the effects of severe weather conditions and other acts of nature, some of which could be caused by climate-change. Although the physical assets have been constructed and are operated and maintained to withstand severe weather and other acts of nature, there is no assurance that they will successfully do so in all circumstances. Many of the physical assets are in remote areas that makes it difficult to perform maintenance and repairs if such assets are damaged. Losses resulting from repair costs and lost revenues could substantially exceed insurance coverage. Adverse weather conditions and climate change may impact operations, potentially affecting the distribution of electricity to customers. The Corporation's liability for any such interruptions is limited as per the approved Terms and Conditions.

Wildfire
Electric distribution facilities have the potential to cause fires because of equipment failure, trees falling on and lightning strikes to distribution lines or equipment, and other causes. Risks associated with fire damage are related to weather, the extent of forestation and grassland cover, habitation and third-party facilities located on or near the land on which the facilities are situated. Future climate change scenarios suggest that changes in precipitation that result in droughts could increase the risk of wildfires. The Corporation may become liable for fire suppression costs, regeneration and timber value costs, and third-party claims in connection with fires on land where its facilities are located if it is found that such facilities were the cause of a fire and the Corporation was found to be negligent in its wildfire risk mitigation practices. The resulting liabilities could be material.

The Corporation has a Wildfire Control Agreement with the Government of Alberta (the "Crown"), which limits the Corporation's liability for the Crown's forest fire suppression costs in the forest protection area. The agreement allows the Corporation to limit its liability to 25% of the fire suppression costs to a maximum of $100,000 per incident, following approval by the Crown of the Corporation's annual wildfire management plan for wildfire prevention. In the absence of this approval or work not completed as per the annual wildfire management plan, the Corporation's liability is limited to 50% of the fire suppression costs to a maximum of $100,000 per incident. The Corporation's wildfire management plan is presented for approval annually, prior to the wildfire season, with the most recent approved in March 2024.

The Corporation maintains insurance for fire suppression costs and liability for third-party claims. The insurance is subject to coverage limits as well as time-sensitive claims discovery and reporting provisions. Therefore, there can be no assurance that the liabilities that may be incurred by the Corporation will be covered by its insurance.

Cybersecurity, Information and Operations Technology
The Corporation's ability to operate effectively is dependent upon developing and maintaining information systems and infrastructure that support the operation of its distribution facilities, provide the electricity market with billing and load settlement information, and support the financial and general operating aspects of the business.

Exposure of the Corporation's information and operations technology systems to external threats poses a risk to the security of these systems and information. Such cybersecurity threats include unauthorized access to information and operations technology systems due to hacking, ransomware, viruses and other causes that can result in service disruptions, acts of war or terrorism, system failures and the deliberate or inadvertent disclosure of confidential business, employee and customer information.

Cybersecurity breaches, acts of war or terrorism, grid disturbances or security breaches involving the misappropriation of sensitive, confidential and proprietary customer, employee, financial or system operating information could significantly disrupt the Corporation's business operations and have an adverse effect on its reputation. The Corporation assessed its cybersecurity measures and continues to strengthen and protect the Corporation's technological infrastructure from potential malicious attacks and risks.

Labour Relations

Approximately 74% of the employees of the Corporation are members of the UUWA. The Corporation considers its relationship with the UUWA to be satisfactory; however, there can be no assurance that current relations will not be impacted in future collective bargaining processes. The inability to maintain a collective bargaining agreement on acceptable terms could result in increased labour costs or costs associated with service interruptions arising from labour disputes not provided for in customer rates, which could have a material adverse effect on the Corporation’s results of operations, cash flow, and financial position.

Human Resources

The Corporation’s ability to deliver service in a cost-effective manner is dependent on the ability of the Corporation to attract, develop and retain a skilled workforce. Given the demographics of the Corporation’s workforce, there may be an increase in retirement of critical workforce segments in future years. Meeting the Corporation's capital expenditure program and customer expectations could be challenging if the Corporation does not continue to attract, develop and retain qualified personnel.

Note: Additional information, including the Corporation’s Annual Information Form and Audited Financial Statements, is available on SEDAR+ at www.sedarplus.ca*. The information contained on, or accessible through, this website is not incorporated by reference into this document.*