AltaLink, L.P.

Management's Discussion and Analysis
February 24, 2025

ALTALINK
A BERKSHIRE HATHAWAY ENERGY COMPANY

Sustainable Electricity Leader
Chef de file en matière d'électricité durable

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Management's Discussion and Analysis

This Management's Discussion and Analysis (MD&A) reflects events known to us as at February 24, 2025. This MD&A is intended to provide you with an understanding of our business, our strategy, our performance, our expectations for the future, and how we manage risk and financial resources. The Board of Directors approved this MD&A on February 19, 2025, based on the recommendation of the Audit Committee, which reviewed this MD&A in accordance with its terms of reference.

You should read this MD&A in conjunction with our legal advisory on Forward-Looking Information, which we have included at the end of this MD&A, our audited consolidated financial statements for the years ended December 31, 2024 and 2023 (the consolidated financial statements), and the notes thereto.

The financial information in this MD&A is in Canadian dollars, our functional currency.

Unless otherwise noted, references in this MD&A to "we", "us", "our", "AltaLink" or "the Partnership" mean AltaLink, L.P. together with its subsidiary entities, PiikaniLink, L.P. and KainaiLink, L.P., references to a "quarter" and "year" refer to the three-month and the twelve-month periods ended December 31, 2024, respectively. Additionally, "AESO" refers to the Alberta Electric System Operator, "AFUDC" refers to Allowance for Funds Used During Construction, "AHLP" refers to AltaLink Holdings, L.P., "AIES" refers to the Alberta Interconnected Electric System, "AILP" refers to AltaLink Investments, L.P., "AIML" refers to AltaLink Investment Management Ltd., "ALP" refers to AltaLink, L.P., "AML" refers to AltaLink Management Ltd., "AUC" refers to the Alberta Utilities Commission, "BHE" refers to Berkshire Hathaway Energy Company, "BHEA" refers to BHE AltaLink Ltd., "CWIP" refers to Construction Work-In-Progress, "DACDA" refers to Direct Assigned Capital Deferral Account, "DBRS" refers to DBRS Limited, "ESG" refers to Environmental, Social, and Governance, "EH&S" refers to Environment, Health, and Safety, "FFO" refers to Funds from Operations, "GAAP" refers to Generally Accepted Accounting Principles, "GCOC" refers to Generic Cost of Capital, "GTA" refers to General Tariff Application, "IFRS Accounting Standards" refers to International Financial Reporting Standards as issued by the International Accounting Standards Board, "KLP" refers to KainaiLink, L.P., "NID" refers to Needs Identification Document, "PLP" refers to PiikaniLink, L.P., and "S&P" refers to Standard & Poor's Global Ratings.

Additional information relating to our business, including our Annual Information Form for the year ended December 31, 2023 is available on SEDAR+ at www.sedarplus.ca.

Executive Summary

2024 Highlights

AltaLink's safe delivery of affordable and reliable electricity for its customers is highlighted in its 2024 results:

- Our employee safety performance as measured by total recordable injury frequency rate was 0.32, representing two injuries, compared to three injuries in 2023. In November 2024, for the eighth consecutive year, we received the Electricity Canada President's Award for Safety Excellence as the best performing transmission company with 300 to 1,500 employees in 2023.
- Our customer average outage duration improved to 8.9 minutes compared to 9.2 minutes in 2023, establishing a new best-ever annual performance result in 2024.
- We achieved a customer satisfaction average score of 9.70 out of 10 compared to 9.59 in 2023. Our 2024 results are our best-ever annual results achieved to date.
- We are extending our commitment to customers and Albertans by keeping our annual revenue requirements below the 2018 level of $904.0 million for another two years in 2024 and 2025; a total of seven years from 2019 to 2025. Our 2025 transmission tariffs of $905.3 million includes the revenue requirements of $897.0 million and a recovery of $8.3 million for 2023 wildfire damage restoration costs directed by the AUC.
- We received approval from the AUC to no longer pre-collect the funds used for salvage activities in our revenue requirements moving forward, which resulted in a reduction of our revenue requirements by approximately $29 million over 2024 and 2025.
- The AUC approved our project financing from the Canada Infrastructure Bank for the Central East Transfer-Out project. This project financing will save Alberta ratepayers approximately $60 million over the 30-year financing of the project.
- The AESO approved a project change proposal for a high-capacity conductor that provides approximately 50% additional capacity on the Central East Transfer-Out transmission line while only increasing the project investment by approximately 4%. This increase in project investment is approximately $8 million with a total project investment of $207.0 million.
- We were named in Forbes Canada's best employers list for 2024.
- We received the Workplace Excellence Award from the United Way of Calgary and Area, for our 2023 campaign which raised $804,496. The award honors workplace campaigns that exhibit strong employee engagement, leadership support, and a best-practice approach. In 2024, our employees raised $867,318 for the United Way after the dollar-for-dollar match by AltaLink, bringing our total to more than $12.1 million since 2002.
- S&P reaffirmed its issuer credit rating and senior secured rating on AltaLink at "A-" with a stable outlook. DBRS reaffirmed its ratings on AltaLink including the Issuer, Medium-Term Note (Secured), and Senior Secured Note ratings at "A", as well as the Commercial Paper rating at R-1 (low), all with stable trends. "A" and "A-" ratings allow us to keep debt financing costs low for our customers.
- The AUC issued an order approving 8.97% as the final return on equity for 2025 for Alberta utilities using its formula-based approach and prescribed bond yields and utility credit spread inputs.
- Our comprehensive income of $330.1 million increased compared to $297.8 million in 2023 mainly due to increased revenue from the regulatory generic cost of capital decision.
- We invested $356.0 million in capital assets compared to $279.0 million in 2023 to ensure continued electric transmission system safety and reliability, and to connect generation.

Strategic Highlights

- We continue to work collaboratively with our customers to safely deliver affordable, reliable, and sustainable electricity. Our reliability statistics as reported by Electricity Canada retained our ranking in the top quartile of Canadian electric utilities for outage duration, outage frequency, and restoration time. We continued to implement leading practices and to invest in wildfire mitigation which protects Albertans and customer businesses. We strengthened our efforts to keep rates affordable for customers through innovation and controlling our costs.

- Delivering affordable rates and cost savings for customers allowed us to meet our commitment to Albertans by keeping our annual revenue requirements below the 2018 level of $904.0 million for six years from 2019 to 2024 and to extend our commitment for a seventh year to 2025.

- We connected new generation supply to support Alberta's economy to enable lower prices through competition of multiple sources of generation. We will play a critical role in restoring the Alberta-British Columbia intertie improving reliability and enabling the import and export of more electricity. We also worked with our customers to develop interconnections for new load projects and the electrification of our customers' facilities. In support of an affordable electricity system, we promote the use and optimization of existing transmission assets wherever appropriate as it requires less incremental investment.

- We build positive, respectful, trusting relationships with local Indigenous communities as the foundation for successful project outcomes and collaborative partnerships. We consult with Indigenous communities in ways that add value to both the community and our business. Our long-term partnerships with the Piikani Nation and the Kainai-Blood Tribe continue to hold transmission investments and provide the First Nations with 51% of the net income from PiikaniLink, L.P. and KainaiLink, L.P.

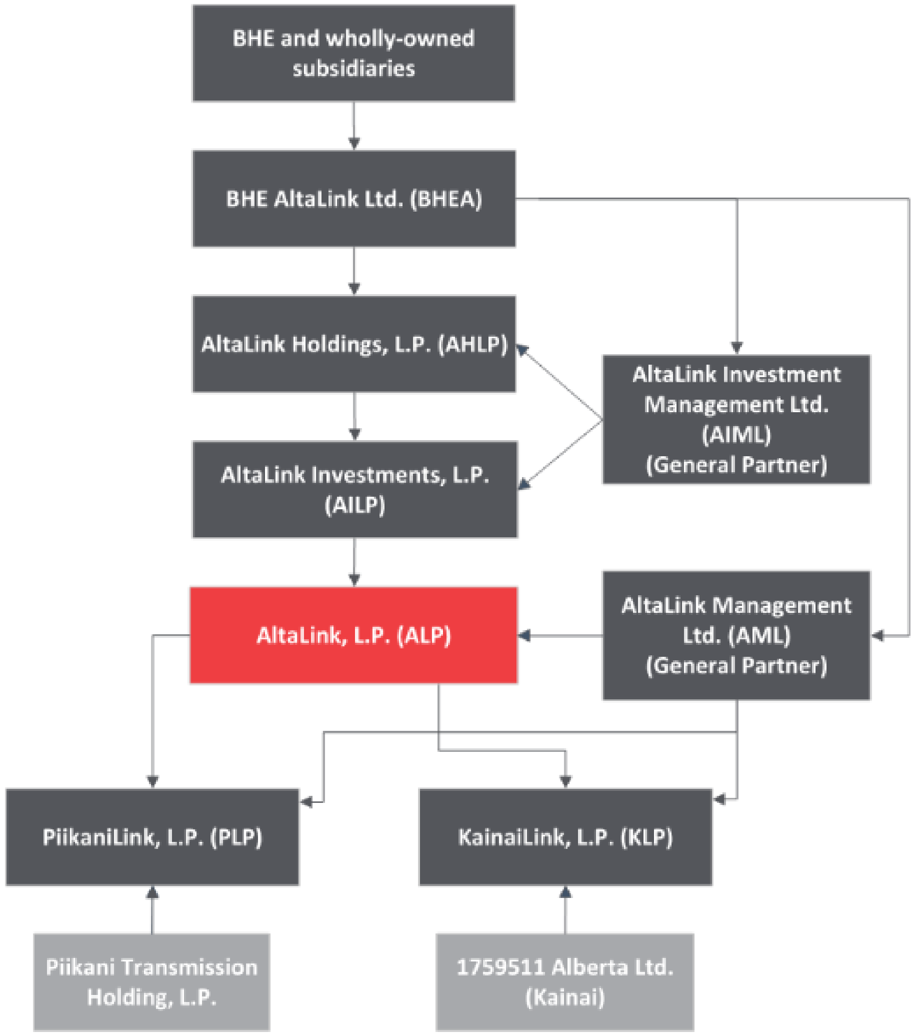
- We continue to advance our commitment to operate our business in a sustainable and socially responsible manner as well as maintaining our Sustainable Electricity Company designation from Electricity Canada which we first obtained in 2014. Our annual Sustainability Reports highlight the Environmental, Social, and Governance objectives we are working to meet, including a greenhouse gas management plan.

Our Ownership Structure

ALP is a limited partnership formed under the laws of Alberta on July 3, 2001, pursuant to the Limited Partnership Agreement between AML, as general partner, and AILP, as the sole limited partner. The general partner manages the regulated electricity transmission facilities that we own and operate in the Province of Alberta.

AILP and AHLP were formed within a group structure to issue debt and own regulated entities. AIML manages both AILP and its sole limited partner, AHLP. AHLP is wholly owned by BHEA, which itself is a wholly owned, indirect subsidiary of BHE.

Our operations and headquarters are in Alberta, where we provide reliable, safe, and efficient service to Albertans. We are regulated by the AUC and the AESO directs both the operation of the interconnected electrical system and our new capital projects.



Our Business and Strategies

We build, own, and operate regulated electricity transmission facilities in the Province of Alberta. Through our transmission facilities, we deliver electricity safely, reliably, and efficiently to approximately 85% of Alberta's population to meet continuously changing customer needs under all operating conditions. We connect generation plants to major load centres, cities, and large industrial plants throughout our 226,000 square kilometre service area, which covers a diverse geographic area, including most major urban centres in central and southern Alberta. Our transmission facilities comprise approximately half of the total kilometres in the Alberta Interconnected Electric System, including interconnections with British Columbia's transmission system that link Alberta with the North American Western Interconnection system.

Our Vision and Core Principles

Our vision is to be the best energy company in serving customers, while delivering sustainable energy solutions. Our six core principles further define our values, strategies, and vision:

We use certain measures to determine whether we are meeting our goals and the needs of our customers. Our performance continues to compare favourably to other Canadian transmission facility owners in terms of reliability, safety, customer satisfaction, and cost-effectiveness.

Customer Service

We are focused on delivering reliability, dependability, low prices, and exceptional service to our customers. We are committed to providing innovative solutions that customers want and need.

Customer performance

Customer feedback is essential to improving the customer service experience. Our customer service representatives pride themselves in understanding customer requirements, especially through times of change. They achieve this through planned touch point meetings throughout the year. Additionally, we host an annual "Let's Connect" event to update customers on industry trends and our key customer service initiatives.

We measure customer service performance through a third-party survey process, using the resulting feedback to establish specific initiatives aimed at improving our customers' experience. We use the average survey score out of 10 as the measure of customer satisfaction. Our average customer satisfaction score for 2024 improved compared to prior years.

The following chart summarizes our strong customer service performance.

Our average customer satisfaction score was 9.70 in 2024 compared to 9.59 in 2023 and 9.57 in 2022. Our 2024 results were our best-ever annual results achieved to date.

Employee Commitment

We equip employees with the resources and support they need to be successful. We encourage teamwork and provide a safe, rewarding, and inclusive work environment. We make no compromise when it comes to safety and security.

Our employees' knowledge and dedication to "keeping the lights on" through operational excellence is key to successfully delivering customer requirements. We aim to provide a clear link between each employee's total direct compensation to both business performance and their own individual performance. In particular, each employee's incentive pay is dependent on AltaLink's actual performance compared to previously established goals and targets in alignment with customer interests. Additional information on our incentive plans is included in our Annual Information Form available on SEDAR+ at www.sedarplus.ca.

Diversity and inclusion (D&I)

We believe in an inclusive environment, in building spaces of mutual respect and trust. Our D&I Plan stresses the importance of frequent communication to foster a culture of awareness and understanding within AltaLink. The plan also includes training and resources for leaders and employees, D&I events, and Employee Resource Groups to actively engage employees. To date, Employee Resource Groups include Women+Power (Alberta-based network for women in energy), BEAUTIE (Black Employees and Allies United to Inspire Equity), InspirAsian (Asian and Pacific Islander employees and allies), Pride Connection (LGBTQ2+ employees and allies), and Our Familia (Latino, Latina and Latinx employees and allies).

In February 2024, we issued a *Celebrating Our Differences Report*. This report is a helpful resource for employees to better understand what we are trying to achieve, why D&I is a business priority, and what ongoing work is occurring. Our goal is to ensure that all employees feel physically and psychologically safe as well as have a sense of belonging at work. We continue to spend a significant amount of time listening, educating, and implementing best practices in this area.

In our 2024 pulse survey, we had an 83% participation rate and continued to see strong results relating to AltaLink actively supporting diversity and inclusion, being a welcoming workplace climate, and leadership that fosters an inclusive environment. For the first time in 2024 we also provided an option for self-identification for those who were interested in doing so, as a means of better understanding our current state and informing 2025 D&I planning.

In the second quarter of 2023, we conducted our second D&I survey. We had a 74% participation rate, and the survey results indicated steady progress from our first D&I survey in 2021. Top rated items were that AltaLink actively supported diversity and inclusion; had a welcoming workplace climate; and leadership that fosters an inclusive environment.

Employee engagement and support to the community

We continuously strive to attract, retain, and develop a high-quality, diverse workforce. Our workforce enables us to sustain our business, and to remain at the forefront of innovation and continuous improvement. We employ approximately 690 skilled and dedicated employees who maintain and operate our facilities and deliver on the capital transmission projects. Using an independent third party, we regularly conduct employee engagement surveys with all employees. Employee surveys will continue to be conducted each year on varied topics as employee expectations continue to evolve.

In January 2024, AltaLink was named in Forbes Canada's best employers list for 2024.

In the third quarter of 2024, we conducted a pulse survey with an 83% participation rate from employees. Overall employee engagement improved compared to our 2023 employee engagement survey.

In the third quarter of 2023, we conducted an employee engagement survey with an 82% participation rate from employees. Overall employee engagement improved compared to our 2022 summer pulse survey. Workplace safety and our hybrid work model were the most highly rated areas in the 2023 survey.

We continue to provide employees with flexibility through hybrid work arrangements. In addition, we continue to provide enhanced wellness and mental health support to our employees.

AltaLink and its employees support the communities in which we live through community investment and as employees volunteer throughout the year. In 2024, our employees raised $867,318 for the United Way after the dollar-for-dollar match by AltaLink, bringing our total to more than $12.1 million since 2002. AltaLink and its employees donate their time through our Global Days of Service program and United Way Days of Caring events, contributing hundreds of hours to organizations across Alberta. AltaLink is also the presenting sponsor of the Rogers Birdies for Kids program at the Rogers Charity Classic PGA Champions golf tournament. In 2024, the program raised over $25.4 million for 293 youth-based charities in Alberta.

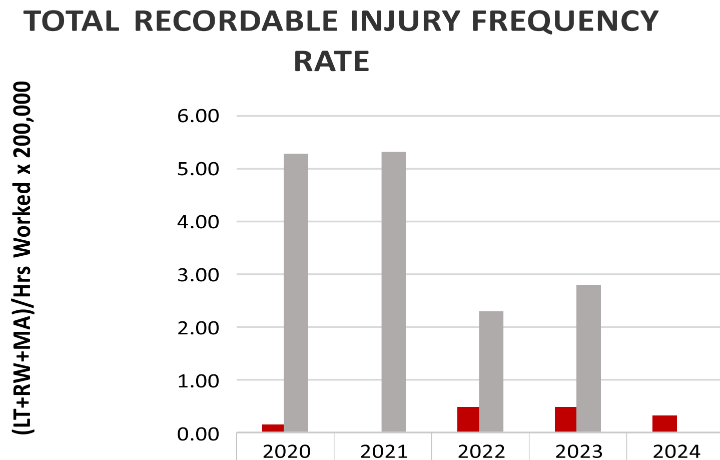
In March 2024, we received the Workplace Excellence Award from the United Way of Calgary and Area, for our 2023 campaign. The award honours workplace campaigns that exhibit strong employee engagement, leadership support, and a best-practice approach.

Safety

The safety and security of our employees, customers, and the general public is our top priority. Our monthly environmental, health, and safety business review provides management guidance and oversight with respect to safety. Our safety management initiatives encompass all aspects of our safety systems, focussing our entire organization on building a culture of safety accountability and responsibility. We strive to continuously improve our safety performance through focused training and ongoing commitment to our safety culture and safety management processes.

We attain strong safety metrics, and our employee injury frequency rate is better than those of our peers, as reported by Electricity Canada for transmission employees.

Our safety statistics measured by total recordable injury frequency rate include all lost time (LT), restricted work (RW) and medical aid (MA) incidents per 200,000 exposure hours worked by employees. The following chart summarizes our strong safety performance.



	2020	2021	2022	2023	2024
AltaLink Employees	0.15	0.00	0.48	0.48	0.32
Electricity Canada	5.28	5.32	2.30	2.80	N/A (1)

1. *Electricity Canada Transmission Employees injury frequency rate is not available at this time.*

Our total recordable injury frequency rate for employees was 0.32 in 2024, representing two injuries, and 0.48 in 2023 compared to the 2.80 average reported by Electricity Canada for 2023.

In November 2024, for the eighth consecutive year, we received the Electricity Canada President's Award of Safety Excellence as the best performing transmission company with 300 to 1,500 employees in 2023.

Safety codes

We are committed to public safety and are accredited by the Alberta Safety Codes Council. To maintain our accreditation, we must adhere to a Quality Management Plan that requires us to ensure that all our substations and transmission lines meet Alberta Electric Utility Code requirements. Alberta Safety Codes Council monitors all accredited companies for compliance with their Quality Management Plans and safety codes.

Environmental Respect

We are committed to using natural resources wisely and protecting our environment for the benefit of future generations. Our Environmental RESPECT Policy details this commitment in the areas of Responsibility, Efficiency, Stewardship, Performance, Evaluation, Communication, and Training.

We believe responsible environmental management is good business; it benefits our customers and improves the quality of the environment in which we live.

We modelled our environmental management system after the International Organization for Standardization (ISO) requirements and the ISO 14001:2015 standard. The environmental management system is a framework for systematically managing environmental risks and improving environmental performance.

Corporate sustainability is important to our overall business strategy, which collectively considers environmental, social, and economic aspects in our business planning, decision making, and governance. On June 27, 2024, we released our 2023 Sustainability Report, which is available at www.altalink.ca.

We strive to be leaders in environmental best practices and provide environmental leadership through innovative practices and sound risk management. In designing and constructing new transmission facilities, as well as operating and maintaining our existing facilities, we consider ways to reduce land use impacts and improve efficiency. We also promote sustainable energy and actively work to connect sustainable energy generation facilities to our transmission grid.

We are maintaining our accreditation from the Right-of-Way Stewardship Council for our sustainable integrated vegetation management practices. We were the first utility in Canada to receive this third-party independent confirmation, indicating that our practices for environmental management of our transmission rights-of-way meet industry standards of excellence.

Regulatory Integrity

We adhere to a policy of strict regulatory compliance and pursue frequent, open communication with stakeholders regarding our business performance.

As a transmission facility owner, the AUC regulates us pursuant to the *Electric Utilities Act* (Alberta), the *Public Utilities Act* (Alberta), the *Alberta Utilities Commission Act* (Alberta), and the *Hydro and Electric Energy Act* (Alberta). Through various regulatory decisions, these statutes and their respective regulations impact our tariffs, construction, operations, and financing.

The AESO determines whether an expansion or enhancement of the transmission system is required and directs us to enhance and expand the transmission system. We and other transmission facility owners are permitted to charge tariffs for the use of our transmission facilities. The AUC regulates all tariffs under the provisions of the *Electric Utilities Act* (Alberta) in respect of rates and terms and conditions of service. We receive all regulated transmission tariffs, including settlements of deferral and reserve accounts, from the AESO.

We developed a Code of Ethics and Business Conduct for how we conduct business and a Compliance Plan to achieve the purposes of the Inter-Affiliate Code of Conduct, as ordered by our regulator. We seek to promote integrity and transparency in all aspects of conducting our business and in our relations with our colleagues, customers, shareholders, business partners, and other stakeholders. We are committed to ethical practices with policies in place to ensure we operate at the highest standard for our customers. Every year, we require employees to acknowledge and sign-off on their commitment to our Code of Ethics and Business Conduct and our associated policies.

Operational Excellence

Together with our employees, we pride ourselves on excellence in every aspect of our work. Our high standards for operations and system maintenance enable us to meet and exceed our customers' expectations, perform our work safely, and preserve our assets.

We focus on "keeping the lights on" for Albertans and are committed to reinforcing and maintaining Alberta's transmission infrastructure to ensure that the province's electricity grid can enable economic growth and support the energy transition. Our focus on continuous improvement and operational excellence covers our operating, maintenance, project execution, work planning, and scheduling activities.

We strive to continuously implement business improvements across our organization to deliver reliable, affordable, and safe transmission service to our customers.

Operations and asset management

We design and implement operational, maintenance and information technology capital investments to fulfil our commitment to the safe, reliable, and cost-effective operation of our transmission business. Our program-based maintenance activities cover a broad functional spectrum of the transmission business, including transmission lines, substations, telecommunications, meters, vehicles, buildings, tools, control centre, information technology and safety management improvements. We use life extension and risk-based asset replacement programs to ensure timely and effective replacement of assets that have reached the end of their useful lives.

Wildfires and storm emergency response

In May and June 2023 wildfires in Alberta burned more than 1.9 million hectares of land, the most in Alberta's history, after an extraordinarily dry and hot spring. Our transmission system was impacted by wildfires in the Edson, Drayton Valley, and Brazeau areas of Alberta. None of these fires initiated from our operations. We restored service to all customers impacted from these wildfires by July 3, 2023, and completed all structure repairs by August 10, 2023. The restoration of the damaged transmission lines cost $22.4 million.

Further to the wildfires, on June 19, 2023, a portion of our transmission system experienced a spring snowstorm with heavy wet snow and winds. We restored service to all impacted customers by June 30, 2023. The restoration of the damaged transmission lines cost $2.3 million.

These wildfire and snowstorm events resulted in our largest restoration effort in our history. Please refer to the "2023 Wildfire and Storm Cost Recovery Application" section of this MD&A.

Wildfire mitigation plans

We developed and implemented detailed wildfire mitigation plans for our service territory since 2019. We submit these plans to the AUC for approval as part of our GTA process. We received approval for our wildfire mitigation plan in the 2019-2021, 2022-2023, and 2024-2025 GTA periods. These plans include improvements in situational awareness, meteorological systems, and risk modelling; investments in asset hardening and vegetation management; and our ongoing elevated wildfire risk operating practices and policies, which include inspections, recloser blocking procedures, wildfire encroachment procedures, and public safety power shutoff (PSPS).

Asset hardening and vegetation management

We continue to invest in specific asset improvements to reduce the risk of wildfire ignition from our operations. These hardening efforts reduce the likelihood of our transmission lines igniting a wildfire at locations of high fire risk. Investments are primarily focused on targeted transmission structure or transmission line upgrades or identified right-of-way improvements to remove hazardous vegetation to reduce fire ignition risk.

Situational awareness, meteorology, and risk modelling

We use available integrated meteorology, fire monitoring and camera systems available from the Alberta Government. Additionally, we installed incremental weather and camera stations in support of improvements to our situational awareness. This weather information, combined with expert third-party assessment, provides weather and fire risk forecasting daily for our service territory. We also established a Daily Hazard Forecast Report, which is provided to the organization and field crews, and implemented an information portal in the control room. We initially completed our fire risk modelling and HRFA mapping in 2020 and are planning to complete an update of the static risk modelling in 2025. We implemented further enhancements to our fire weather modelling tools in 2024. We complete regular periodic policy updates and training regarding field operations and contractor crew fire management and preventive practices.

Asset inspection program

We complete asset inspections for all our facilities on an at least an annual basis. For lines located in HRFAs, inspection frequencies are twice per year to review structure and vegetation conditions.

Public safety power shutoffs and wildfire encroachment policy

A PSPS is an operating protocol used as a preventative measure of last resort during periods of extreme wildfire risk. It involves de-energizing a transmission line or lines proactively under certain conditions to reduce the risk of wildfire ignition. In determining whether to initiate a PSPS, we work with local public safety authorities and consider data from our wildfire risk forecasting tools and meteorological systems. If the forecast exceeds thresholds, escalating action is taken proactively starting from the seven-day forecast outlook. We continue to conduct stakeholder engagement and exercises related to our PSPS process. To mitigate the risk of secondary ignitions from fires on the landscape as well as safety risks to fire fighters on scene, we also have a wildfire encroachment policy to either disable reclosers or proactively de-energize transmission lines. These measures aim to reduce the risk to public safety.

Capital projects

We energized or completed $266.9 million of capital project additions in the year ended December 31, 2024 (2023 - $231.5 million). Please refer to the "Major Capital Projects" section of this MD&A.

Reliability

A strong, efficient, and reliable transmission system ensures Albertans have access to multiple generation resources from across the province. A reliable transmission system also ensures that all generators can compete, enabling access to low-cost generation, which includes sustainable energy generation for customers.

We operate our transmission system to minimize disruption of service to our customers. Severe weather and other unplanned events cause service disruptions to which we respond as quickly as possible. Our proactive operating practices and capital investments have delivered a long-term trend of improved reliability. Our reliability statistics are consistently above the national average, as reported by Electricity Canada, who has ranked us in the top quartile of Canadian electric utilities for outage duration, outage frequency, and restoration time. In November 2023, we received the Electricity Canada 2023 Reliability and Resiliency Award which recognizes a utility that has showcased dedication in asset management, innovation in reliability, outage communications, and overall reliability and resiliency management as evaluated by an external panel of experts.

On November 20, 2024, the AESO held an annual information session to update industry stakeholders on power system planning and reliability initiatives. The session provided updates on the Reliability Requirements Roadmap, announced a Climate Resiliency White Paper scope of work, as well as updates on several power system planning initiatives. Please refer to the "Major Capital Projects" section of this MD&A for further details on the system planning initiatives.

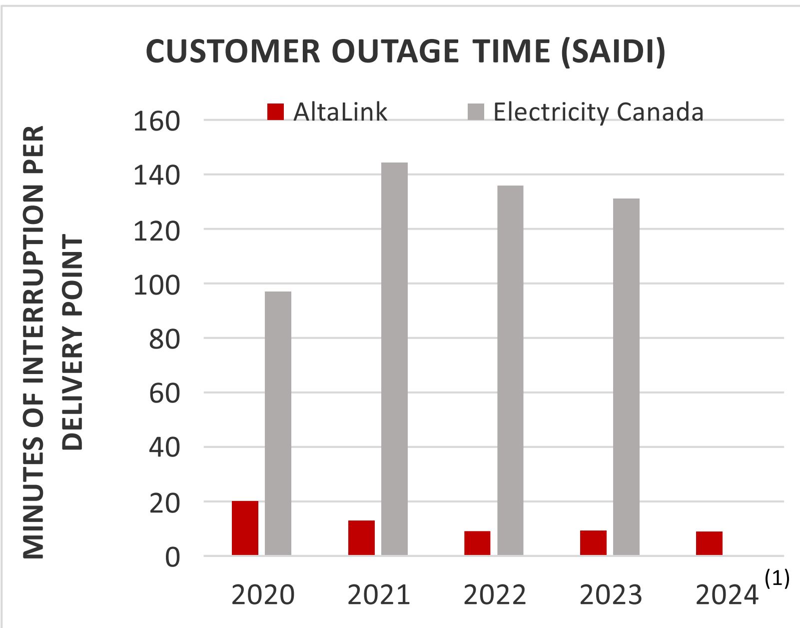
Regarding the Reliability Requirements Roadmap, the AESO provided an update on items completed from the first version of the roadmap and indicated that it is planning to issue a revision to the roadmap in the first quarter of 2025. Indications were for continued focus on the implementation of new ancillary services and fast frequency response in support of increasing AIES intertie capabilities as well as supporting the Alberta Restructured Energy Market initiative.

In the November 20, 2024 session, the AESO also announced they are undertaking the development of a Climate Resiliency White Paper to raise awareness and provide stakeholders with an understanding of the importance of system resiliency due to extreme weather events. This is due to the increased frequency and rising effects of extreme weather events on the AIES. The AESO advised that the matters within the scope of the consultation are system resiliency and actions stakeholders can take to become more resilient. We provided requested stakeholder feedback on the scope of the whitepaper in January 2025.

On March 10, 2023, the AESO released the Reliability Requirements Roadmap, providing an analysis of Alberta grid reliability based on changes in energy supply mix arising from the energy transition. The AESO identified three emerging reliability challenges: frequency stability, system strength, and flexibility capability. The AESO continues to progress and consult with industry on improvement plans in these areas. We continue to collaborate with the AESO on solutions.

Our reliability of service continues to be strong. Our 2024 average customer outage duration improved compared to our 2023 results, establishing a new best-ever annual performance result, primarily due to fewer outages affecting customers related to equipment malfunction and reduced impacts from weather. We continue to work on improvement plans and coordination with customers and other transmission operators to prevent outages by efficiently directing maintenance to high-risk assets and ensuring efficient restoration efforts when outages occur. Our ongoing focus on capital maintenance investments, operating maintenance activities, and initiatives to reduce restoration times continues to provide strong power system reliability in support of our customers.

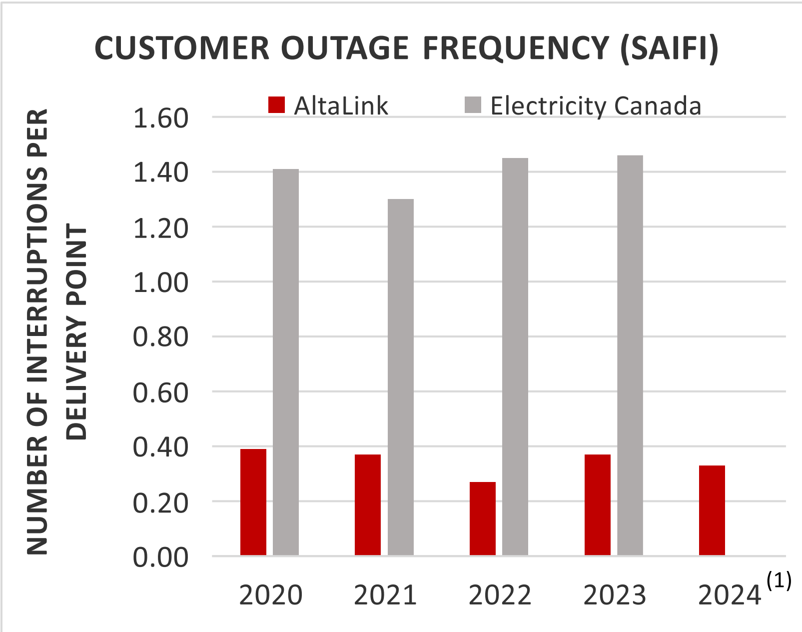
The charts that follow summarize our reliability performance for the past five years, showing continued favourable trends and comparisons to the latest information reported by Electricity Canada. Our 2023 customer reliability performance was impacted by the major wildfire and snowstorm events and due to the size and nature of the events, the customer interruptions qualify as a major event under Electricity Canada guidelines and are excluded from the historic reliability performance metrics.



Our average customer outage duration time was 8.9 minutes in 2024 and 9.2 minutes in 2023 compared to the 131.0 minute average reported by Electricity Canada for 2023. Our 2024 results were our best-ever annual results achieved to date.

1. *Electricity Canada customer outage time numbers are not available at this time.*

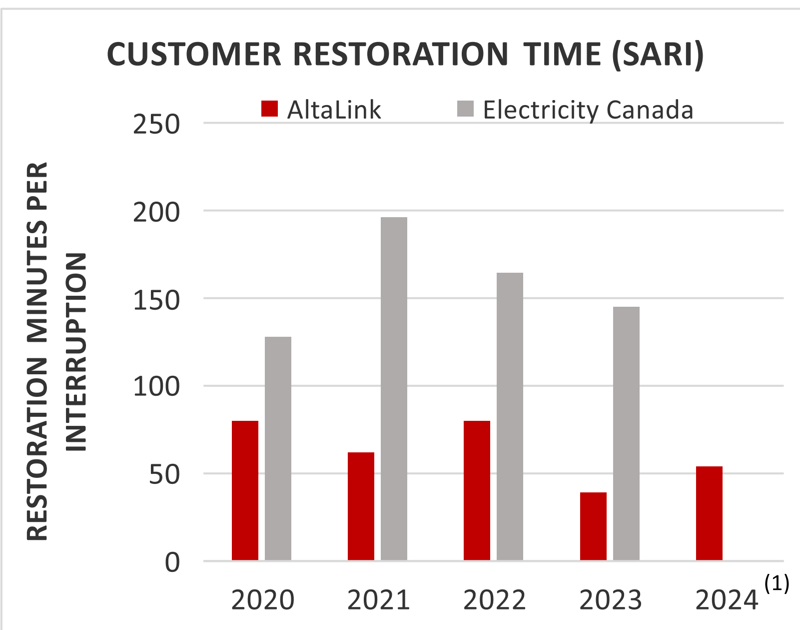
System Availability Interruption Duration Index (SAIDI) is the average number of interruption minutes per delivery point.



Our customer outage frequency was 0.33 in 2024 and 0.37 in 2023 compared to the 1.46 average reported by Electricity Canada for 2023.

1. *Electricity Canada customer outage frequency numbers are not available at this time.*

System Availability Interruption Frequency Index (SAIFI) is the average number of interruptions per delivery point.



Our customer restoration time was 54 minutes in 2024 and 39 minutes in 2023 compared to the 145 minute average reported by Electricity Canada for 2023.

1. *Electricity Canada customer restoration time numbers are not available at this time.*

System Average Restoration Index (SARI) is the average number of interruption minutes per sustained interruption.

Cyber and physical security

Our cyber and physical security management system is modelled based on ISO requirements and the 27000 family of standards and it helps us to identify and use best practices to keep the grid secure. As part of our ongoing efforts to enhance our cyber security preparedness, we underwent an external audit conducted by the British Standards Institute in September 2024 and recertified our information security management system in accordance with ISO 27001:2022. In addition, we are audited by the AESO every three years against the Alberta Reliability Standards (ARS) including Critical Infrastructure Protection (CIP) standards. These standards are closely aligned with the North American Electric Reliability Corporation CIP standards. Compliance with the CIP standards is critical to mitigating cybersecurity risks to Alberta's bulk electric system. The ARS CIP standards provide a comprehensive list of security controls to help utilities effectively and securely operate Alberta's bulk electric system.

In 2024, we continued to upgrade our cyber security preparedness by adding controls to meet compliance requirements and to keep up with best practices.

Physical attacks on critical infrastructure in the United States have been on the rise and continue to highlight the vulnerability of utility infrastructure to such attacks. Given this trend, we requested, and the AUC approved additional funding for incremental investment in physical security measures at key locations in 2024 and 2025. These investments are planned to continue through to 2029 pending ongoing AUC approval.

We have also been working closely with federal and provincial government security agencies and industry partners to implement additional security controls. We continue to monitor security developments and threats closely.

Financial Strength

We are excellent stewards of our financial resources. Backed by BHE, we invest in hard assets and focus on long-term opportunities that will contribute to our future strength.

We align our financing strategy with the AUC-approved regulated debt and equity capital structure and with targets for our key financial metrics. We finance our operations and maintenance capital expenditures from operating cash flows, and we intend to fund growth capital expenditures from the balance of our operating cash flows, additional borrowings under our capital markets platform and, if required, equity contributions from our limited partner, AILP.

AltaLink's Senior Debt has an "A" and "A-" credit rating from DBRS and S&P, respectively. On July 9, 2024, DBRS reaffirmed its ratings on AltaLink including the Issuer, Medium-Term Note (Secured), Senior Secured Note ratings at "A", as well as the Commercial Paper rating at R-1 (low), all with stable trends. On April 26, 2024, S&P reaffirmed its issuer credit rating and senior secured rating on AltaLink at "A-" with a stable outlook. The financial strength demonstrated through "A" and "A-" credit ratings allow us to keep debt financing costs low for our customers. In 2024, our weighted average cost of long-term debt was 4.25% (2023 – 4.03%).

Return on capital investment

Continued investment in our regulated capital assets provides reliability of supply of transmission service to our customers and is one of our indicators of future revenue streams. As a regulated utility, we earn most of our net income from allowed returns on equity invested in our regulated capital assets.

On November 8, 2024, the AUC issued its decision on the Generic Cost of Capital for 2025 for Alberta's regulated electric and gas utilities. The AUC set a return on equity of 8.97% for 2025 for Alberta utilities using the formula and the prescribed bond yields and utility spread inputs. In 2023, the AUC issued its decision on the GCOC for 2024 and beyond for Alberta's regulated electric and gas utilities, approving a set equity ratio and a formula to determine return on equity. The AUC set a deemed equity ratio of 37% and increased return on equity from 8.5% to a notional 9.00%, which is subject to formulaic adjustments using 30-year Government of Canada bond yields and Canadian utility spreads. On November 20, 2023, under the approved formula, the AUC issued an order approving 9.28% as the final return on equity for 2024 for Alberta utilities. The AUC approved an equity return of 8.5% and an equity ratio of 37% for 2023.

We calculate our allowed returns on equity by multiplying our mid-year investments in rate base and CWIP by the equity ratio and rate of return approved by the AUC. Our operating cash flow relates primarily to (i) the return on equity on our rate base; and (ii) recovery of depreciation on our rate base assets.

The table below summarizes our mid-year rate base and CWIP:

(in millions of dollars)	**2024**	2023	2022
Mid-year rate base including minority interests	**$ 7,479.6**	$ 7,434.3	$ 7,510.9
Mid-year CWIP	**201.9**	149.7	138.0

For the year ended December 31, 2024, our capital program included approximately $215.8 million of capital replacement and upgrade projects, $68.2 million of growth projects directly assigned to us by the AESO, and $32.0 million of information technology and corporate facilities projects.

Environmental, Social, and Governance

ESG Strategy

As a regulated transmission provider, ESG is integrated in our vision to be the best energy company in serving customers while delivering sustainable energy solutions. Our transmission system is critical infrastructure that connects businesses, industries, and 85% of Alberta's population to the electricity generated across the province. Our ESG strategies are embedded within our six core principles with objectives associated with each ESG element.

ESG Objectives
Environmental We are committed to delivering long-term sustainable solutions to our customers. We seek opportunities to avoid or minimize environmental impacts, to reclaim and restore where impacts are unavoidable, and maintain a responsible approach to resource consumption.
Social Our commitment to the communities we serve includes the delivery of safe, reliable, and affordable transmission services; our community investment strategy; and meaningful consultation practices. We are dedicated to creating a diverse and inclusive workforce and make no compromises when it comes to providing a healthy and safe work environment.
Governance We are fair and transparent in everything we do. We are committed to being ethical and have policies in place to ensure we operate at the highest standard for our customers.

Our core principles guide our business and support our commitment to sustainability. For more details regarding our six core principles, please refer to "Our Vision and Core Principles" section of this MD&A.

As an electric transmission company, we play an important role in enabling electric generating companies to transition to a low-carbon economy. We have made key investments in our infrastructure, and we continue to enable the connection of renewable energy generation around the province. Our ESG opportunities are driven by operational excellence strategies and the energy transition to enable the connection of renewable electricity generation as described in the "Major Capital Projects" section of this MD&A.

AltaLink's Board of Directors approves management's strategy and response to EH&S climate-related risks, including compliance with applicable legislation, regulatory requirements, and industry standards.

We manage ESG risks by following our Enterprise Risk Management Framework and program, which was modelled after the ISO 31000 standard for risk management. A primary goal of our program is to provide uniform processes to identify, analyze, evaluate, report, and mitigate our key risks for the benefit of our customers and shareholders, including ESG risks. We analyze all risks using our risk severity scale which includes ESG impacts and not just financial impacts. Please refer to the "Risk Management" section of this MD&A for further information on our framework and processes and our ESG risks. Our ESG risks include environment, health and safety, climate change, wildfires, transmission reliability, cyber and physical security, labour relations, and electric and magnetic fields.

We modelled our EH&S management system after the ISO 14001:2015 requirements, the international standard for environmental management systems, and ISO 45001, the international standard for occupational health and safety management systems. We support the day-to-day management and enhance the effectiveness of our system through appropriate reporting, record keeping, training, and audit processes.

Sustainable Electricity Leader | Chef de file en matière d'électricité durable

Our commitment to sustainability is important to our overall business strategy and is part of our business planning, decision making, and governance. Every decision and every plan considers environmental, social, and governance impacts now and for the future. Since 2014, when we first received the Electricity Canada's Sustainable Electricity Leader designation, we have made a commitment to operate our business sustainably and affordably. In 2019, we became the first Canadian utility to be re-designated as a **Sustainable Electricity Leader ™**. We have continued to build on our practices to ensure sustainability is a driving force in our work every day.

Our commitment to strong ESG performance has long been core to how we do business. Our current ESG programs and initiatives include:

- Environmental RESPECT policy
- Oil-filled equipment polychlorinated biphenyls (PCBs) and spill management
- Greenhouse gas reduction program
- Right-of-way management programs
- Recycling and waste management programs
- Avian protection program
- D&I, hybrid work, and employee wellbeing programs
- Community investment program
- Indigenous relations program
- Cyber and physical security management system
- Sustainable procurement initiative
- Wildfire mitigation and management program
- Integrated EH&S management system

We report information on our ESG programs, performance metrics and trends in our annual Sustainability Report. The Global Reporting Initiative Standards continue to inform the content of our annual Sustainability Report. On June 27, 2024, we released our 2023 Sustainability Report, which is available at www.altalink.ca in the Sustainability section.

Our Commitment to the Environment

We are committed to meeting or surpassing all environmental legislation and regulations and implementing good environmental management practices. The Board of Directors reviews our environmental management quarterly, including our response to environmental, health and safety issues, compliance with applicable legislation, regulatory requirements and industry standards.

All aspects of our transmission business are subject to one or more levels of environmental legislation and regulations. Although primarily regulated at the provincial level, jurisdiction over the environment is also shared by federal agencies and local managing authorities. Federal legislation is the primary regulating authority in situations involving federal lands (e.g. National Parks, First Nations' lands), navigable waters, trans-boundary environmental impacts (e.g. ozone depleting substances), issues of national concern (e.g. hazardous substances such as PCBs) and migratory birds. Provincial legislation applies to all aspects of the construction, operation, and maintenance of our transmission facilities (e.g. the *Environmental Protection and Enhancement Act* (Alberta), the *Water Act* (Alberta), the *Wildlife Act* (Alberta), the *Public Lands Act* (Alberta), the *Historical Resources Act* (Alberta)). In 2024, we spent approximately $9.3 million (2023 – $5.3 million) to manage environmental aspects of our business, mainly for environmental assessments for new and upgraded transmission facilities.

Oil-filled equipment, PCBs and spill management system

The primary risk associated with oil-filled equipment, including PCBs, at our facilities is the potential for releases of transformer insulating oil.

Our EH&S management system defines control procedures and is designed to identify risks along with proposed mitigation. Our standards, procedures, and management practices are comprehensive. Examples include:

- We have a Spill Prevention and Response Standard, a PCBs Handling Standard and Procedure, and we have provided related training to field personnel and contractors;
- We have installed secondary oil containment features at all new transformer locations, as required in our containment design standard;
- We monitor and analyze transformer oil for PCBs content; and
- We track and manage incidents through an incident management database.

Greenhouse gas reduction

Part of the greenhouse gas reduction program is currently focused on preventing releases from sulfur hexafluoride (SF6) gas filled equipment and improving our fleet vehicle fuel efficiency.

SF6 is a potent greenhouse gas that is used in electrical equipment. We monitor our SF6 gas filled equipment and prioritize the repair of leaking equipment to minimize impacts to the environment. We have a SF6 Reporting Standard and Handling Procedure and have provided training to field personnel.

Using data gathered over previous years, we were able to work with vehicle operators to reduce overall consumption of fuel and reduce idle times. This allowed us to reduce our greenhouse gas emissions associated with operation of our fleet and reach internal fuel efficiency targets for the year. We are also reducing our footprint by adding five new electric and hybrid vehicles to our fleet in 2024.

Rights-of-way management

Tree contacts with transmission lines create both a safety risk and a fire hazard. We use an integrated approach to manage vegetation on rights-of-way, including annual patrols to monitor vegetation growth and assess maintenance requirements.

We maintain our accreditation from the Right-of-Way Stewardship Council for our sustainable integrated vegetation management practices and successfully completed a full site re-certification in 2022.

Recycling and waste management

We encourage the reduction, reuse and recycling of wastes through recycling programs, including used transformer insulating oil, salvaged wood poles, paper, aluminum and copper wire, general scrap metal, and battery recycling. General waste and construction waste is delivered to municipal landfill sites through waste service companies.

We developed a process to recycle large transformers, which may contain trace amounts of PCBs. We ensure salvaged metals are clean of any trace amounts of PCBs prior to recycling. In 2024, we recycled five large transformers compared to nine in 2023.

Avian protection

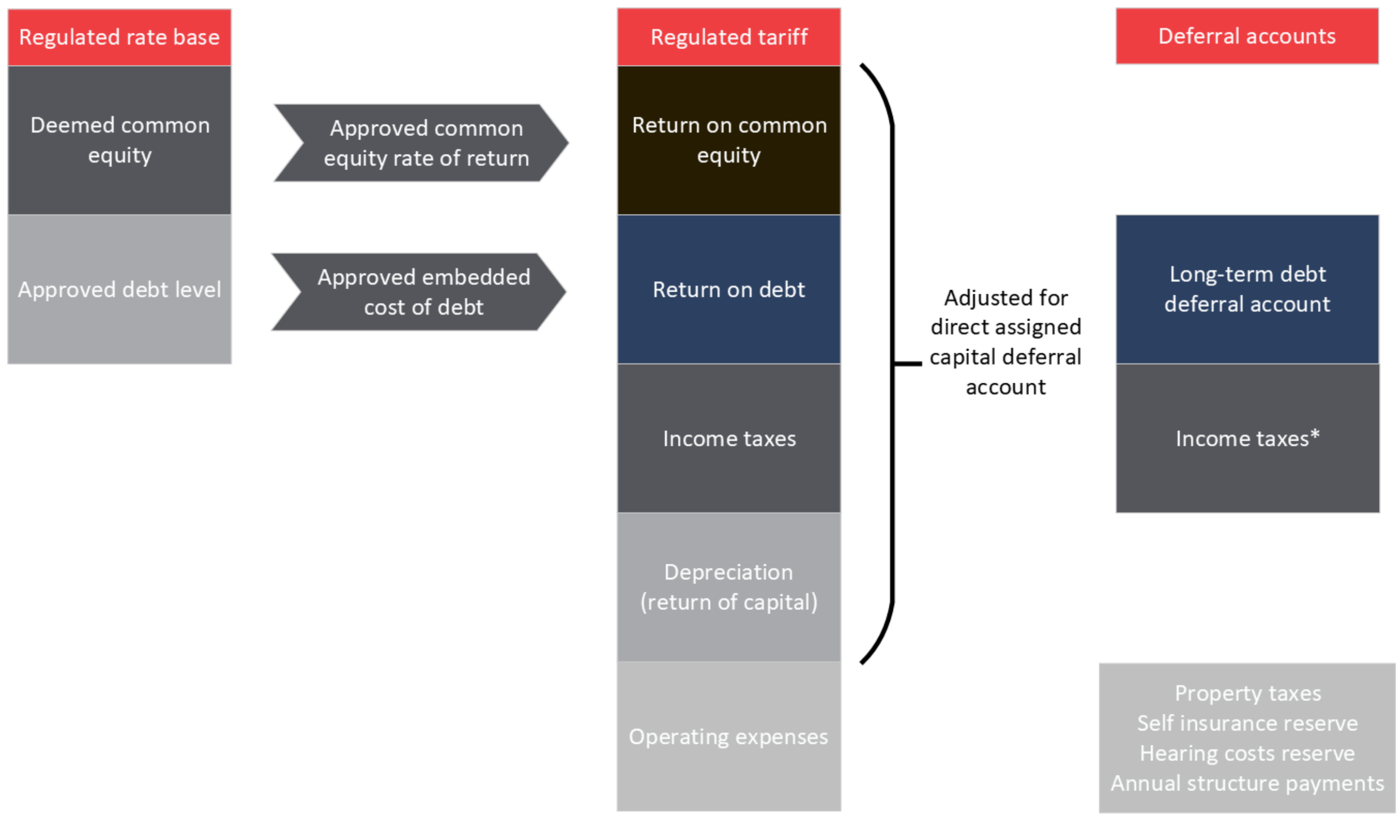
Our Avian Protection Plan is designed to reduce the impact transmission facilities have on birds. The plan includes set standards and processes for preventing collisions by installing bird markers that make power lines more visible to birds in flight. The plan reduced bird collisions with our transmission facilities between 60% and 90%. In 2024, we had 35 incidents of bird collisions with our transmission facilities compared to 42 incidents in 2023.

Transmission Tariffs

Overview

Under the *Electric Utilities Act* (Alberta), we prepare and file applications with the AUC for approval of tariffs to be paid by the AESO for the use of our transmission facilities, and the terms and conditions governing the use of those facilities. The AUC reviews and approves such tariff applications based on a cost-of-service regulatory model under a forward test year basis. Under this model, the AUC provides us with a reasonable opportunity to (i) earn a fair return on equity; and (ii) recover our forecast costs, including operating expenses, depreciation, borrowing costs and taxes (including deemed income taxes) associated with our regulated transmission business. The AUC must approve tariffs that are just, reasonable, and not unduly preferential, arbitrary or unjustly discriminatory. Our transmission tariffs are not dependent on the price or volume of electricity transported through our transmission system. We receive our annual transmission tariffs from the AESO in equal monthly instalments, based on the amounts approved by the AUC for the applicable year. We and the AESO settle amounts owing or due in respect of deferral and reserve accounts after the AUC issues its decision on these matters. Tariff adjustments arising from deferral and reserve accounts relate to services we provided in past periods and their settlement is not contingent on providing future services.

The following diagram outlines the principal components of our transmission tariff revenue:



* We will recover income taxes through regulated tariffs in future years when the taxes are deemed to be paid using the flow-through calculation method.

The AESO is responsible for directing the safe, reliable, and economic operation of the AIES, including long-term transmission system planning. To meet long-term planning needs, the AESO directs us to expand and reinforce the AIES within the area in which we operate. We are obligated to fulfil these directions pursuant to the *Transmission Regulation*.

Interim tariffs

On December 5, 2024, the AUC approved final transmission tariffs for AltaLink, including monthly tariffs for PLP and KLP, of $98.4 million for December 2024, and $75.4 million per month for 2025. On December 1, 2023, the AUC approved 2024 interim refundable transmission tariffs for AltaLink, including monthly tariffs for PLP and KLP, of $73.6 million per month effective January 1, 2024. On August 17, 2022, the AUC approved revised final transmission tariffs for AltaLink, including monthly tariffs for PLP and KLP, of $73.6 million per month for 2023.

2024-2025 General Tariff Application

We are extending our commitment to customers and Albertans by keeping our annual revenue requirements below the 2018 level of $904.0 million for another two years in 2024 and 2025; a total of seven years from 2019 to 2025. On December 5, 2024, the AUC approved AltaLink's 2025 revenue requirements including PLP and KLP, of $897.0 million.

On November 14, 2024, the AUC approved AltaLink's 2024 revenue requirement including PLP and KLP, of $902.5 million. On November 25, 2024, AltaLink filed post-disposition documents reflecting the 2025 approved return on equity of 8.97%.

On August 12, 2024, AltaLink filed its compliance filing application to reflect the directions from the AUC decision with respect to AltaLink's 2024-2025 GTA. In its compliance filing, AltaLink commenced capitalization of salvage costs as part of the previously approved salvage methodology. As a result, the forecast pre-collection of salvage included in AltaLink's original application is no longer necessary.

On June 19, 2024, the AUC issued Decision 28174-D02-2024 with respect to AltaLink's 2024-2025 GTA, providing its reasons for the approval of the negotiated settlement and its findings on the matters excluded from the negotiated settlement. Specifically, the AUC:

- approved the previously denied $98.9 million actual salvage costs incurred from 2019 to 2021 and the 2022-2025 salvage expenditures of $124.3 million, subject to changes arising from revised wildfire mitigation capital expenditures. The AUC also approved AltaLink's transition to the capitalization of site preparation or salvage costs for capital replacement projects starting in 2024. However, the AUC did not approve the recovery of $11 million of debt and equity returns for 2022-2023 related to the previously denied $98.9 million salvage costs;
- approved $29.1 million of forecast capital expenditures, including capitalized salvage, related to AltaLink's 2024-2025 Wildfire Mitigation Plan, which is generally consistent with the approved wildfire capital expenditures in AltaLink's 2022-2023 Wildfire Mitigation Plan. The AUC did not approve AltaLink's request, filed on August 31, 2023, for an incremental $46.3 million in forecast wildfire mitigation capital expenditures; and
- denied AltaLink's proposed wildfire related third-party damages deferral account stating that AltaLink currently has multiple layers of protection to address the risk of liability for wildfire related third-party damages. The AUC confirmed the layers include AltaLink's capital replacement and upgrade program, AltaLink's Wildfire Mitigation program, protection under Section 90 of the *Electric Utilities Act* (Alberta), commercial insurance and the regulatory self-insurance reserve account.

The 2024-2025 GTAs for PLP and KLP were approved as filed.

The AUC directed AltaLink to file a compliance filing on or before August 12, 2024, to reflect its directions in Decision 28174-D02-2024, as well as Decision 28750-D01-2024 with respect to the 2023 Wildfire and Storm Cost Recovery Application.

In February and March 2024, information responses, rebuttal evidence, oral argument, and reply argument were filed and an oral hearing was held.

On December 12, 2023, AltaLink advised the AUC that it reached a negotiated settlement with customer groups on the majority of its 2024-2025 GTA. On December 19, 2023, AltaLink filed the agreement with the AUC for approval. On February 12, 2024, the AUC issued Decision 28174-D01-2024 with respect to AltaLink's 2024-2025 GTA, approving the negotiated settlement agreement as filed. Under the agreement, AltaLink reduced its applied-for operating expenses by $7.0 million and sustaining capital expenditures by $38.8 million for the 2024-2025 test period. The agreement did not include AltaLink's proposed wildfire deferral account, certain components of the wildfire mitigation plan, and actual and forecast salvage expenditures from the 2019-2023 GTA and the 2024-2025 GTA, respectively. AltaLink's total revised revenue requirements adjusted for the negotiated settlement were $891.4 million for 2024 and $903.7 million for 2025.

On August 31, 2023, AltaLink refiled its 2024-2025 GTA, which included amendments to its planned Wildfire Mitigation Plan capital expenditures from $16.0 million to $38.5 million in 2024 and from $14.6 million to $38.4 million in 2025. At that time, AltaLink's total amended revenue requirements for 2024 and 2025 were $895.3 million and $911.9 million, respectively. In its application, AltaLink included a new request for a wildfire damages deferral account.

On July 5, 2023, AltaLink requested the AUC to suspend the schedule for its 2024-2025 GTA until August 31, 2023. AltaLink required the schedule delay to amend its application. The amendment was in response to the unprecedented wildfire events that AltaLink experienced in the areas of Edson, Drayton Valley, and Brazeau in May and June 2023. On July 11, 2023, the AUC allowed AltaLink to refile its application and directed AltaLink to limit its application updates to its Wildfire Mitigation Plan and related wildfire references.

On April 28, 2023, AltaLink filed its 2024-2025 GTA with the AUC. Our revenue requirements at that time were $894.1 million and $908.6 million for 2024 and 2025, respectively. The application also requested the approval of $98.9 million of salvage costs incurred from 2019 to 2021 based on additional information filed.

The table below summarizes the 2024 and 2025 transmission tariffs approved on December 5, 2024, and the 2023 transmission tariff approved on August 17, 2022.

(in millions of dollars)	2025 Approved	2024 Approved	2023 Approved
Return on equity	$ 234.0	$ 234.2	$ 231.7
Return on debt	195.9	194.2	180.6
Operating costs	179.4	176.9	168.6
Depreciation and amortization	302.3	289.7	302.3
Miscellaneous revenue offset	(7.5)	(7.5)	(8.2)
Revenue requirement as amended August 31, 2023 – ALP	**904.2**	**887.5**	**875.0**
Forecast operating expense reductions	(4.5)	(2.5)	—
Forecast tariff reductions resulting from capital expenditure reductions	(3.7)	(1.3)	—
Revenue requirement as filed December 19, 2023 – ALP	**896.0**	**883.7**	**875.0**
Pre-collection of salvage removed due to capitalization	(17.9)	(11.1)	—
Net impact of excluded matters	(2.2)	(0.7)	—
Adjustment to return on equity from 8.5% to 9.28%	21.4	21.6	—
Impact of 2023 wildfire and storm cost recovery	0.6	1.1	—
Revised revenue requirement as filed August 12, 2024 – ALP	**897.8**	**894.6**	**875.0**
Revised revenue requirement as filed August 12, 2024 – PLP	4.7	4.8	4.9
Revised revenue requirement as filed August 12, 2024 – KLP	3.0	3.1	3.1
Revised revenue requirement as filed August 12, 2024	**905.6**	**902.5**	**883.0**
Adjustment to return on equity from 9.28% to 8.97%	(8.6)	—	—
Total revenue requirement as approved December 5, 2024	**897.0**	**902.5**	**883.0**
Funding of 2023 spring wildfire and snow events	8.3	8.3	—
Other transmission tariff adjustments	—	(2.9)	—
Total transmission tariffs as approved December 5, 2024	**$ 905.3**	**$ 907.8**	**$ 883.0**

* Totals may not add due to rounding

The table below summarizes the GTA forecasted gross capital expenditures for 2023, 2024 and 2025.

(in millions of dollars)	2025 Approved	2024 Approved	2023 Approved
Gross capital expenditures	**$ 360.0**	**$ 369.2**	**$ 196.5**

2023 Wildfire and Storm Cost Recovery Application

On July 31, 2024, the AUC approved, on a placeholder basis, the recovery of $18.5 million of expenditures through the self-insurance reserve over the 2024 and 2025 period. The AUC did not approve capitalization of the expenditures to rate base. The AUC also approved $6.2 million of salvage expenditures, on a placeholder basis, through the net salvage reserve account.

On May 1, 2024, AltaLink and interveners provided final argument and reply argument to this application. On March 28, 2024, AltaLink filed responses to information requests with the AUC.

On December 20, 2023, AltaLink filed an application with the AUC to recover all costs incurred as a result of the May and June 2023 wildfire and storm events. AltaLink requested AUC approval of $18.5 million of capital expenditures relating to the repair and replacement of damaged or destroyed transmission facilities, and $6.2 million of salvage expenditures relating to the removal of damaged or destroyed transmission facilities. AltaLink also requested AUC approval to include the capital expenditures in its 2024 opening rate base and the salvage expenditures in its net salvage reserve account effective December 31, 2023.

Canada Infrastructure Bank Debt Financing Application

On January 14, 2025, AltaLink applied to the AUC to amend the existing approval of its debt application to reflect a revised outside date of March 31, 2025, for the issuance of the bond securing the facility. Upon receiving AUC approval, AltaLink will proceed with formal amendments to the credit facility. AltaLink expects its first drawdown under the credit facility will occur in the first quarter of 2025.

AltaLink and the Canada Infrastructure Bank have entered into a credit agreement whereby low-cost, 30-year, amortizing financing will be available to AltaLink in connection with the construction and development of AltaLink's portion of the Central East Transfer-Out project (please refer to the "Major Capital Projects" section of this MD&A) as well as two other transmission infrastructure projects for which facility applications are yet to be filed. The Central East Transfer-Out project financing is expected to save Alberta ratepayers approximately $135 million for the entire project, including $60 million for AltaLink's portion of the project over the 30-year financing term. The availability of the Canada Infrastructure Bank credit facility remains subject to AltaLink's satisfaction of various conditions, including obtaining regulatory approvals. On September 4, 2024, AltaLink filed an application seeking AUC approval in connection with AltaLink's incurrence of indebtedness under the Canada Infrastructure Bank credit agreement and granting of security in respect of such indebtedness, including $128.5 million for the Central East Transfer-Out project. On October 18, 2024, the AUC approved AltaLink's project financing.

Generic Cost of Capital Proceeding

On November 8, 2024, the AUC issued its decision on the GCOC for 2025 for Alberta's regulated electric and gas utilities. The AUC set a deemed equity ratio of 37% and a return on equity of 8.97% for 2025 for Alberta utilities.

On November 20, 2023, under the approved formula, the AUC issued an order approving 9.28% as the final return on equity for 2024 for Alberta utilities. On October 9, 2023, the AUC issued its decision on the GCOC for 2024 and beyond for Alberta's regulated electric and gas utilities, approving a set equity ratio and a formula to determine return on equity. The AUC set a deemed equity ratio of 37% and set a notional return on equity of 9.00%, which is subject to formulaic adjustments using 30-year Government of Canada bond yields and Canadian utility spreads.

	Approved 2025	Approved 2024	Approved 2023
Deemed capital structure			
Common equity ratio	**37.00%**	**37.00%**	**37.00%**
Debt ratio	**63.00%**	**63.00%**	**63.00%**
Generic return			
Return on equity	**8.97%**	**9.28%**	**8.50%**

2021-2022 Deferral Accounts Reconciliation

On December 5, 2024, the AUC in Decision 28174-D01-2024 authorized AltaLink to invoice the AESO a one-time charge of $3.4 million for returns of and on capital investment, pursuant to the AUC's approval of the 2021-2022 Deferral Accounts Reconciliation Application.

On February 12, 2024, the AUC issued Decision 28174-D01-2024 with respect to AltaLink's 2024-2025 GTA. The AUC approved the negotiated settlement agreement as filed. This includes approval of AltaLink's 2021-2022 deferral accounts reconciliation, which was filed along with its 2024-2025 GTA.

On April 28, 2023, AltaLink filed its 2021-2022 deferral accounts reconciliation along with its 2024-2025 GTA. The reconciliation included 25 projects with total gross capital additions of $155.7 million for 2021 and 2022, as well as AltaLink's other deferral accounts for taxes other than income taxes, long-term debt, and annual structure payments.

Alberta Electric System Operator Tariff Decision - Distribution Facility Owners Contribution

On September 27, 2024, AltaLink and other parties filed an agreed statement of facts and law with the AUC. On October 15, 2024, the AUC issued direction to parties in the proceeding including the issues list and process schedule for the proceeding. The AUC established that the issues to be determined in the proceeding are: (i) whether the long-established AUC customer contribution policy is lawful; (ii) whether the AUC is compelled by the legislation to allow transmission system owners to pay or repay the Contributions in Aid of Construction; and (iii) whether Contributions in Aid of Construction are 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. With respect to process, evidence from all parties was due December 20, 2024. The AUC, as well as all registered parties to the proceeding, had the opportunity to ask information requests by January 20, 2025. Information responses were due January 31, 2025, followed by rebuttal evidence on February 28, 2025. Written argument and reply argument will be filed March 19 and April 23, 2025, respectively.

On April 26, 2024, the AUC initiated the proceeding to reconsider distribution facility owner payments under the Independent System Operator tariff customer contribution policy. On June 7, 2024, AltaLink and other participants filed written submissions with respect to proceeding process and the specific issues that should be addressed in the proceeding, followed by reply comments on the other parties' written submissions filed on June 28, 2024.

The Alberta Court of Appeal heard the appeal February 8, 2023, and issued its decision on November 14, 2023. In its decision, the Court overturned the AUC's decisions regarding the legality of the current customer contribution regime and the AUC's ability to deny a utility its return on investment. In its decision, the allocation issue (between transmission facility owners and distribution facility owners, who is entitled to the investment) as well as the fair return issue (no one is allowed to earn a return on the investment) were returned to the AUC for rehearing and reconsideration on the basis that the AUC did not provide adequate notice that it was considering disallowing any utility from earning a fair return on the investment. The Court remitted the fair return issue and the allocation issue back to the AUC so that the appellants had an opportunity to present their case fully and fairly. The Court offered guidance on what the AUC may wish to consider and made several statements that were supportive of AltaLink's position, including: (i) the Court noted that a distribution facility owner may provide the initial contribution and the transmission facility owner can then rebate the contribution; (ii) the option of a transmission facility owner repaying the distribution facility owner to assume total ownership may be a viable alternative.

On January 12, 2022, the Alberta Court of Appeal heard AltaLink's permission to appeal the AUC's decisions regarding the legality of the current customer contribution regime and the AUC's ability to deny a utility its return on investment. The AUC responded that its ruling on the return issue was within its discretion and within its public interest mandate. On January 19, 2022, the court granted permission to appeal.

On May 25, 2021, AltaLink filed its application for permission to appeal AUC Decision 26061-D01-2021 with the Alberta Court of Appeal. As a result of the multiple appeals and the combination of all appeals, the Alberta Court of Appeal moved the hearing from October 2021 to January 2022.

On April 23, 2021, the AUC issued Decision 26061-D01-2021 in respect of its separate AESO customer contribution proceeding, as initiated in November 2020. The AUC ruled that (i) the current policy is legal, but stated that it sends the wrong price signals to distribution facility owners to prefer an investment in transmission; (ii) FortisAlberta can keep its existing investment and can continue to earn a return on its existing investment; and (iii) it is not in the public interest for either a distribution facility owner or a transmission facility owner to earn a return on AESO customer contributions on a go-forward basis. All utilities launched appeals regarding the ability of the AUC to deny a return on an investment that is required by a private utility to serve its customers.

On December 4, 2020, AltaLink filed its application for permission to appeal AUC Decision 24932-D01-2020 with the Alberta Court of Appeal.

On November 10, 2020, the AUC initiated a separate proceeding to (i) examine the legal basis of the current AESO customer contribution policy as it pertains to all transmission facility owners and distribution facility owners, (ii) consider whether there is a need for a new policy, including consideration of AltaLink's proposed policy, and (iii) if approved, set the date on which any new policy would commence. On December 2, 2020, AltaLink filed its submissions in this proceeding, stating that the current customer contribution policy was contrary to business principles as it allows a distribution facility owner to earn a return on assets that are owned, operated, and maintained by a transmission facility owner who has all the risk of ownership, and contrary to the legislative scheme in Alberta, which delineates the ownership of transmission and distribution assets. AltaLink also stated that it disagrees with the AUC's Decision 24932-D01-2020 and that it intends to file an appeal.

On November 4, 2020, the AUC issued Decision 24932-D01-2020 with respect to FortisAlberta's review and variance proceeding. In its decision, the AUC rescinded its findings from the original decision which directed FortisAlberta to transfer the unamortized balance of its AESO contributions as of December 31, 2017, of approximately $375 million to AltaLink, and that AltaLink's proposed new contribution policy be applied effective January 1, 2018. The AUC's decision was based on two main areas: (i) if the original decision was confirmed, FortisAlberta would incur incremental income tax, carrying costs and debt restructuring costs of at least $117 million that would be required to be recovered from ratepayers; and (ii) the AUC determined that a majority of the approximately $40 million in savings to ratepayers on which the hearing panel relied as the basis for their original decision can be achieved by directing FortisAlberta to adjust the applicable amortization rate for its AESO contributions to match the service lives of the transmission assets.

In July 2020, AltaLink and FortisAlberta filed expert tax evidence on three areas of disagreement as requested by the AUC in May 2020:

- The effect of the AESO's contribution on AltaLink's income tax expense for the years 2018-2022;
- The limitation on the number of prior years for which tax returns can be refiled; and
- Support for the respective positions of FortisAlberta and AltaLink on the amount of the undepreciated capital cost allowance available to FortisAlberta to shield incremental income tax that may be triggered by the transfer of AESO contributions from FortisAlberta to AltaLink.

In December 2019, the AUC reopened the review and variance proceeding record and in January 2020, it issued specific information requests for clarification on the previously filed evidence to both FortisAlberta and AltaLink. AltaLink and FortisAlberta filed responses to the AUC information requests at the end of January 2020.

On September 22, 2019, the AUC issued Decision 22942-D02-2019 with respect to the 2018 AESO tariff. As part of this decision, the AUC approved AltaLink's proposal to refund contributions made by distribution facility owners relative to transmission projects built and owned by transmission facility owners on the basis that it provided benefit to rate payers but rejected AltaLink's argument that the current customer contribution regime that allowed distribution facility owners to earn returns on transmission facility owner assets was contrary to the legislation. The proposal would benefit distribution customers by flowing through the lower cost of capital of the transmission facility owner rather than the higher cost of capital of the distribution facility owner. As directed by the AUC, AltaLink would pay the unamortized contribution balance of approximately $375 million and add the amount to AltaLink's rate base. The AUC directed the AESO to consult with AltaLink to provide a joint proposal to implement AltaLink's contribution proposal. In September 2019, FortisAlberta filed a review and variance application with the AUC requesting the AUC re-evaluate its findings with respect to AltaLink's customer contribution proposal as it relates to distribution facility owners. In October 2019, the AUC granted FortisAlberta's request to proceed to a review and variance with the close of record in November 2019 after submissions from FortisAlberta, AltaLink and other interested parties. FortisAlberta has also sought a stay of the AUC's decision. On October 25, 2019, the AUC granted FortisAlberta's stay application. AltaLink filed for permission to appeal the portion of the decision rejecting AltaLink's argument that the current customer contribution regime was contrary to the legislation. FortisAlberta also filed for permission to appeal the decision with the Court of Appeal.

Our Transmission Facilities

The AIES is a network or grid of transmission facilities operating at high voltages ranging from 69 to 500 kilovolts. The grid delivers electricity from generating units across the province representing 20,777 megawatts of available generation capacity through approximately 26,000 kilometres of transmission lines and over 600 substations. The AIES is interconnected to British Columbia's transmission system through a 500-kilovolt circuit and two 138-kilovolt circuits that we own and operate. The AIES is also interconnected to Saskatchewan's transmission system via a 150-megawatt direct current converter station owned by ATCO Electric Ltd. (ATCO Electric) and to Montana's transmission system via a 230-kilovolt transmission line owned by MATL Canada L.P., a related party.

Our transmission facilities are an integral part of the AIES, as our service area covers 226,000 square kilometres and we service approximately 85% of Alberta's population. We own approximately 13,400 kilometres of transmission lines and 310 substations which we manage and operate through our control centre and telecommunications network. Our transmission system includes a 342-kilometre high voltage direct current transmission link, to facilitate power transfer, grid resiliency and reduce power system losses for the benefit of customers. Our transmission lines are comprised of wood or metal support structures, conductors, foundations, insulators, connecting hardware and grounding systems. Our substations are comprised of high-voltage power transformers, power circuit breakers, switches, capacitor and reactor banks, protection and control systems, metering and monitoring systems, buildings and security systems. Our substations integrate the transmission lines into a network and transform the voltage of electricity to meet the requirements of generators and customers. We accept electricity into our system at our generator interconnection substations and deliver power to distribution facility owners and wholesale customers at our customer supply substations. Where the transmission system connects to a distribution network, transmission substations step down the voltage to distribution level voltages. The high voltage direct current transmission link includes solid state power electronic equipment (valves), converter transformer, cooling systems and control systems used in the direct current conversion process.

Our real-time control centre and telecommunications system enable us to continuously monitor, control and manage our transmission facilities and coordinate with the AESO and other transmission facility owners. Our telecommunications system includes microwave radio, fibre optic cable, power line carrier and mobile radio systems. To further support the maintenance and operation of our transmission facilities, we own and operate office and service buildings, transport and work equipment, and information technology assets.

Most of our transmission facilities are situated on lands owned by private landowners, railway companies, industrial customers, and federal and provincial governments, for which we have obtained appropriate land use rights through utility right-of-way agreements, crossing agreements, land easements, permits, licences and other agreements. We also own land, office and storage space used in connection with our operations. In addition, we lease office space and rent storage space on customary terms and at market rates.

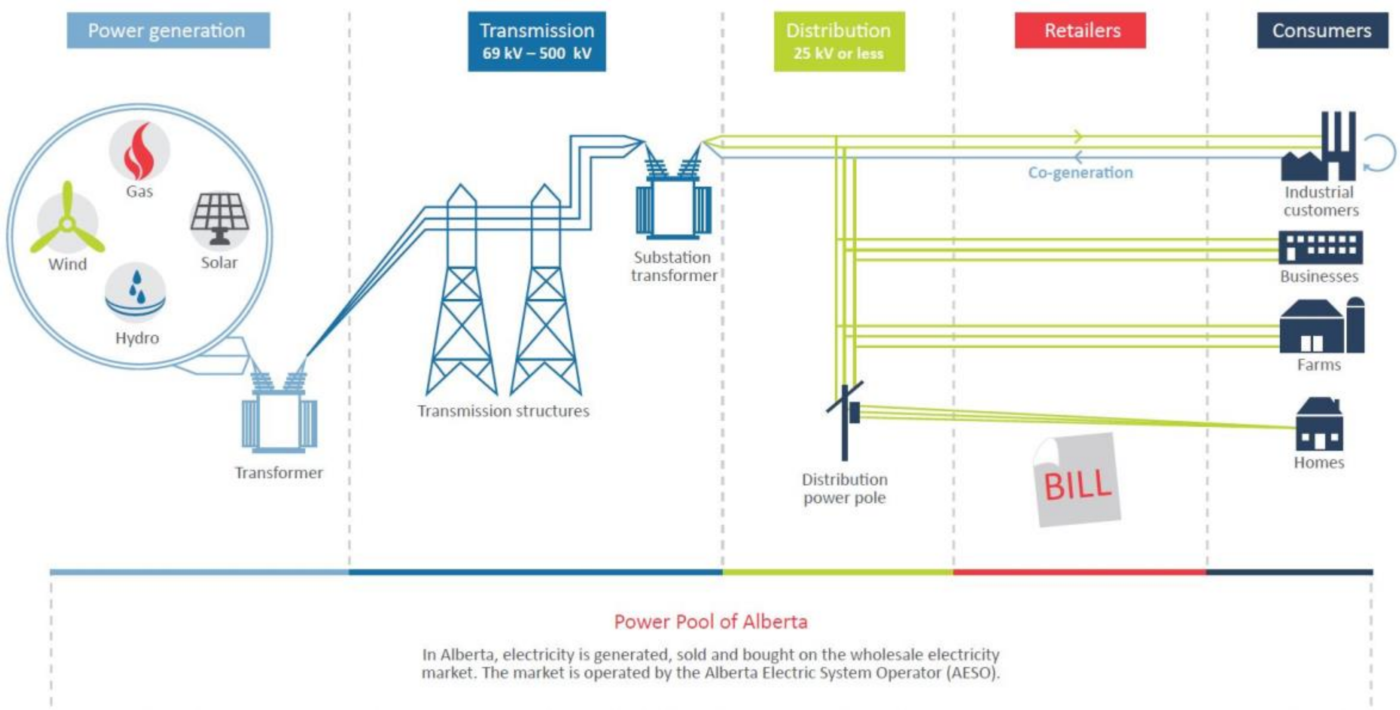
Overview of Electricity Industry in Alberta

The electricity industry in Alberta consists of four principal segments:

- **Generation** is the production of electric power. Generators sell wholesale power into the Power Pool (wholesale electricity market) operated by the AESO or through direct contractual arrangements. Most of the power produced in Alberta is generated using natural gas as the fuel source, with wind, solar and hydro power adding the majority of the remaining supply.
- **Transmission** is the conveyance of electricity at high voltages. Alberta's transmission system or grid is operated by transmission facility owners, which are regulated by the AUC, and is composed of high voltage power lines and related facilities which transmit electricity from generating facilities to distribution networks and directly connected end-users.

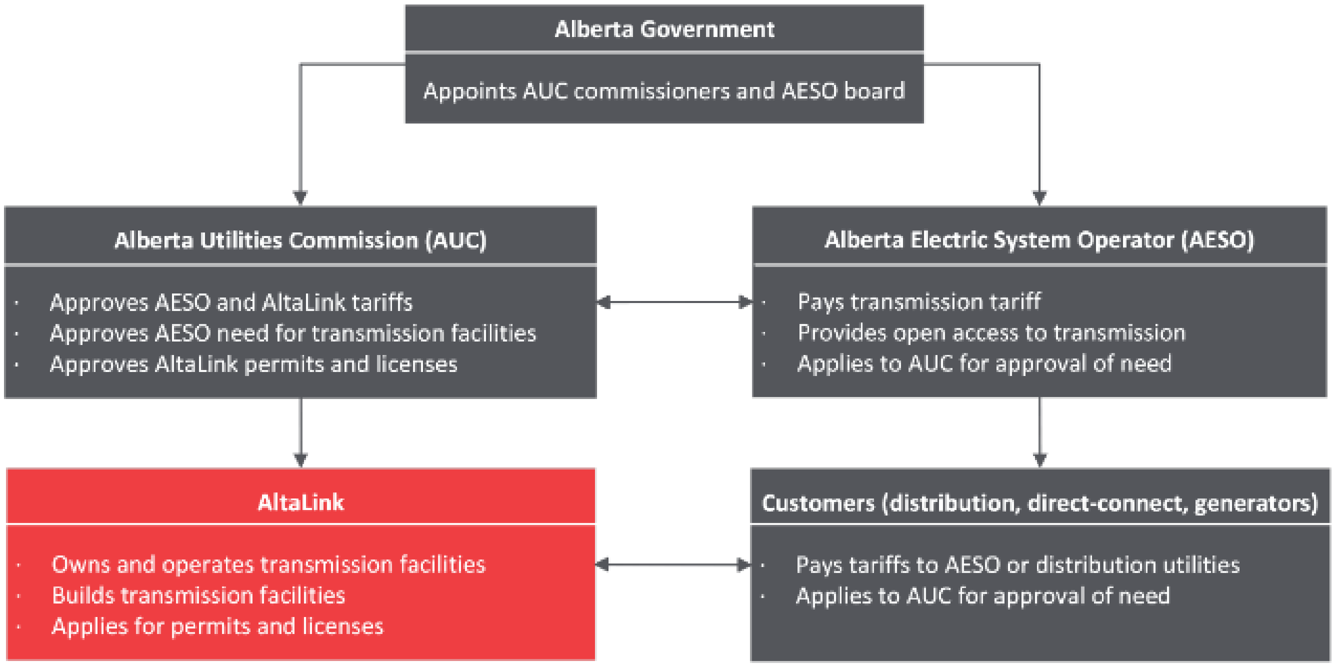
- **Distribution** is the conveyance of electricity at lower voltages. Distribution facility owners are regulated by the AUC and are responsible for arranging for, or providing, regulated rate and regulated default supply services to convey electricity from transmission systems and distribution-connected generators to end-use customers. Distribution facility owners are responsible for (i) providing non-discriminatory distribution access and arranging for transmission access for end-use electricity customers, and (ii) constructing and upgrading electricity distribution systems to deliver electricity safely, reliably and efficiently.
- **Retail** is the offering for sale or selling of electricity to end-use customers. In Alberta, retailers can procure energy through the Power Pool, through direct contractual arrangements with energy suppliers or ownership of generation facilities and arrange for its distribution to end-use customers. Retailers often bundle the sale of electricity with other services and products. Retailers include "self-retailers" who perform the retailing function on their own behalf. Self-retailers interact with other participants in the Alberta electricity industry, such as distribution utilities, in the same manner as other retailers.

In Alberta's electricity marketplace, market participants interact in several ways. The following diagram represents an overview of this interaction:



We and other transmission facility owners in Alberta are regulated by the AUC as utilities, primarily under the *Electric Utilities Act* (Alberta) and the *Public Utilities Act* (Alberta). Under the *Electric Utilities Act* (Alberta), we must operate and maintain our transmission facilities in a manner that is consistent with the safe, reliable and economic operation of the transmission system; assist the AESO in carrying out its duties, responsibilities and functions; and provide the AESO with use of our transmission facilities to carry out its duties, responsibilities and functions.

The following diagram outlines our relationships with the AUC, the AESO and other participants in the electricity industry:



Alberta Utilities Commission

The AUC is an independent, quasi-judicial agency established by the Alberta Government to regulate and oversee Alberta's electricity industry. The AUC is responsible for ensuring that electrical utility services are delivered fairly, responsibly and in the public interest. In doing so, its duties include:

- **Adjudication and Regulation** - The AUC regulates and adjudicates issues related to the operation of electric utilities within Alberta;
- **General Tariff and Other Applications** - The AUC processes and approves general tariff applications relating to revenue requirements, capital expenditure prudency, and sets rates of return for regulated utilities. The AUC also processes deferral account applications, which include the review of prudency for all costs related to direct assigned capital projects. In determining tariffs, the AUC ensures utility rates are just and reasonable;
- **Facilities Applications** - The AUC approves new electricity transmission facilities and issues permits to build and licences to operate electricity transmission facilities;
- **Enforcement** - The AUC reviews operations and accounts of electric utilities and conducts on-site inspections to ensure compliance with industry regulations and standards. The AUC adjudicates enforcement issues and may impose administrative penalties when market participants contravene or fail to comply with: (i) any provision of the *Alberta Utilities Commission Act* (Alberta), or any other enactment under the AUC's jurisdiction, including the *Electric Utilities Act* (Alberta), and the *Hydro and Electric Energy Act* (Alberta), and any regulations made thereunder; (ii) any AUC decision, order or rule; or (iii) AESO rules or reliability standards; and
- **Information and Knowledge** - The AUC collects, stores, analyzes, appraises, and disseminates information to fulfil its duties.

Alberta Electric System Operator

The Alberta Electric System Operator is an independent system operator that oversees the AIES and its wholesale electricity market (the Power Pool). The AESO is responsible for directing the safe, reliable and economic operation of the AIES, including long-term transmission system planning.

The system operators at the AESO's control centre monitor and operate the AIES to keep the power grid physically stable and balanced by: (i) dispatching electric power generation in Alberta; (ii) scheduling electricity flow within interconnected power grids; and (iii) coordinating real-time operations with transmission facility owners. The physical operation of our transmission facilities can only be performed through our control centre. By law, we must comply with directions from the AESO's control centre unless we consider that there is a real and substantial risk of damage to our transmission facilities or risk to the safety of our employees, the public, or the environment. The AESO also contracts with generation and distribution companies and large industrial consumers of electricity to provide system access services to the AIES.

As operator of the Power Pool, the AESO receives electricity supply offers and demand bids, sets the schedule for dispatching generating plants, reports the Power Pool price for each hour, carries out financial settlement for the electricity exchanged through the Power Pool, and schedules generating plants to provide system support services, such as operating reserve. All electricity entering or leaving the AIES, including electricity imported into and exported from Alberta, is exchanged through the Power Pool. The AESO recovers the cost of market operations through a charge on all megawatt hours traded therein.

We and other transmission facility owners receive all our transmission tariff revenues from the AESO. The AESO, in turn, charges wholesale tariffs, approved by the AUC, in a manner that promotes fair and open access to the AIES and facilitates a competitive market for the purchase and sale of electricity. The AESO aggregates tariffs paid to all transmission facility owners, costs associated with transmission losses, system support services and other operating costs.

The AESO tariff must ensure that the just and reasonable costs of the transmission system are charged to distribution companies; customers who are industrial systems; customers who have an interval meter, receive electricity directly from the transmission system and have arranged for system access service; and exporters. Except as otherwise provided by the *Transmission Regulation*, line losses caused by the transmission of electricity are location-based and assessed against suppliers. The AESO's wholesale tariffs are based on the following principles:

- **Customer Rates** - All end-users (or load customers) are charged the same "postage stamp" tariff for transmission service, regardless of where they are located in Alberta.
- **Supplier Rates** - All suppliers are charged the same "postage stamp" tariff for transmission service in addition to an adjustment for losses which are location specific.
- **Import/Export Rates** - All importers or exporters are charged the same "postage stamp" tariff for transmission service in addition to an adjustment for losses which are location specific.

Alberta Reliability Standards

The AESO continues to introduce mandatory Alberta Reliability Standards for planning and operating the AIES and its interties to other jurisdictions. Alberta Reliability Standards are the planning and operating rules that electric utilities follow to ensure reliable systems.

In Alberta, the AESO recommends reliability standards for approval by the AUC. The AESO monitors compliance with approved reliability standards, which are binding and enforced by the Market Surveillance Administrator. The Market Surveillance Administrator may impose penalties on transmission facility owners, including AltaLink, for non-compliance with approved ARS.

Alberta Reliability Standards include Critical Infrastructure Protection standards. We completed our triannual AESO audit of ARS for the audit period from July 1, 2020, to June 30, 2023, and continue to progress resolution of the findings from the audit. We also continue to work with the AESO and the Market Surveillance Administrator on the implementation of ongoing improvements and new standards.

Transmission Planning and Development

The AESO directs us and other transmission facility owners to upgrade and expand the transmission system consistent with:

- The *Transmission Regulation*;
- The *Electric Utilities Act and Hydro and Electric Energy Act*, as amended; and
- The AESO's Long-Term Transmission Plans.

The AESO's responsibilities include long-term transmission planning and management, including assessing the current and future needs of market participants, and planning the capability of the transmission system to meet those needs. Except for critical transmission infrastructure, designated under the *Electric Utilities Act* (Alberta), the AESO determines whether an expansion or enhancement of the transmission system is required. If so, the AESO must file a need application with the AUC for approval. A need application is not required for maintenance upgrades, enhancements or other modifications to existing transmission facilities if it improves efficiency or operation of the transmission facility but does not materially affect capacity.

As a result of the Alberta Transmission Policy review conducted by the Government of Alberta on December 10, 2024, the AESO was directed to implement changes to its current transmission planning framework, and specifically, to move away from the current zero-congestion transmission planning standard to an optimally planned transmission planning standard. The AESO has initiated a stakeholder consultation to support development of an optimally planned transmission framework which will commence in 2025, move through regulatory processes in 2026, and be implemented by the first quarter 2027 via the 2027 Long-Term Transmission Plan. We are participating in this stakeholder engagement process.

The AESO directs us to prepare and submit facility applications to the AUC for permits to construct and licences to operate the transmission facilities to meet the identified need. In some cases, the AESO and AltaLink may jointly file need applications and facility applications. Except for critical transmission infrastructure, the AESO generally determines whether we are eligible to prepare and submit facility applications based on the geographic area in which we operate. In addition, the Lieutenant Governor in Council may make regulations respecting the determination of who may apply for construction or operation of transmission facilities, including determining who may apply based on a competitive process. Under the *Transmission Regulation*, the AESO has established rules or practices respecting competitive tenders, the preparation of cost estimates, project scope documents and schedule documents for projects.

In 2014, the Government of Alberta amended the *Transmission Regulation* and enacted a new regulation - the Transmission Deficiency Regulation. The *Transmission Regulation* amendments are technical amendments concerning changes in timing and authority for certain components of the transmission facility approval process, including the legislative requirement for a Needs Identification Document.

The Transmission Deficiency Regulation implemented the province's Market Participant Choice and Approved Cost Estimate initiatives. These initiatives were later added into the AUC and AESO's processes and procedures. Market Participant Choice allows a Market Participant to construct their own interconnection to the grid in certain circumstances. After an agreed upon period of time, the Market Participant must transfer ownership of the interconnection to the transmission facility owner in whose service territory it is located. The Market Participant remains responsible for any costs incurred by the transmission facility owner because of actions taken by the user during design or construction of the interconnection facility.

The Approved Cost Estimate provisions require a transmission facility owner to submit a cost estimate for designated projects to the AUC for approval after obtaining a permit to construct. The AUC may make rules for the Approved Cost Estimate process and may approve an amount higher or lower than the estimate submitted by the transmission facility owner. Actual project costs must be considered prudent if the costs are equal to or less than the Approved Cost Estimate. Since the implementation of the Approved Cost Estimate provision into Regulation, the AUC has not required AltaLink or other transmission facility operators to utilize the process.

Cost Estimates

Prior to filing a facility application with the AUC, we provide the AESO with a service proposal that includes our initial cost estimate for the project, which reflects our proposed route, preliminary design and other information available to us at the time.

After the AESO accepts our service proposal, we include the initial cost estimate as part of our facility application with the AUC. The AUC's process to review and approve facility applications may take up to two years or more from the date of filing, depending on the complexity of the project and other factors. On all system projects, six months after the AUC issues a permit and licence pursuant to an approved facility application, we are required to provide the AESO with a post permit and licence estimate. The timing of the updated cost estimate may be as long as three years after our service proposal and may vary materially from the initial cost estimate. The updated cost estimate reflects a significant amount of additional information that typically includes the AUC's approved route, contracted construction labour and material pricing, geotechnical information, scope changes from detailed design, and any other material information that may impact the final project cost.

Once the project is completed, we include the final costs in our DACDA application to the AUC where we seek approval to include our final and prudently incurred costs of the project into our rate base.

Electricity Policy Review

Deregulation and restructuring of parts of Alberta's electricity industry began in 1996 and continues to evolve. We are subject to changing political conditions and changes in provincial regulations and permitting requirements.

Alberta Transmission Policy Review

On March 6, 2024, the Government of Alberta announced the proclamation of Bill 22 the *Electricity Statutes (Modernizing Alberta's Electricity Grid) Amendment Act, 2022*, which had previously received royal assent on May 31, 2022. Key changes enabled through the legislation and enabling regulations include a formal definition for energy storage in Alberta's legislative and regulatory framework, the ability for distribution and transmission utilities to own and/or operate energy storage assets under specific conditions, and enabling the use of competitive models to procure non-wires distribution and transmission services from market participants. The legislation also includes a definition of self-supply with export and includes exemptions to broadly enable market participants to choose self-supply and export, while also ensuring these facility owners pay their fair share of system costs through the AESO tariff. The legislation also sets the stage to establish a framework for long-term planning of Alberta's electric distribution system, which includes requiring distribution companies to prepare system plans according to regulations.

On July 11, 2024, the Government of Alberta announced its congestion and cost allocation policy direction and upcoming changes to the *Transmission Regulation* as a result of a stakeholder engagement process completed following release of the discussion green paper titled *Transmission Policy Review: Delivering the Electricity of Tomorrow* in November 2023.

Key foundational principles confirmed include maintaining regulated transmission as a monopoly service with planning conducted by the AESO, maximizing the efficiency of the current transmission system by optimizing its use, ensuring that new transmission is only built when necessary, and maximizing the efficient use of the new transmission expansion.

Changes to the *Transmission Regulation* include the replacement of the zero-congestion policy standard, which required the development of new transmission infrastructure where a generator chose to locate, with an optimally planned transmission standard. On a go forward basis, the cost of new transmission system infrastructure will be assigned to generation developers on a cost-causation basis. Ancillary services which are procured by the AESO to ensure the reliability of the electricity system will also be allocated on a cost-causation basis.

On December 10, 2024, the Government of Alberta issued a direction letter to the AESO to further guide the AESO's responsibilities for transmission planning and the Independent System Operator Tariff under the *Transmission Regulation*. In 2025, the government will bring forward the legislative tools and amendments necessary to implement updated transmission policies as noted below:

- Implement a cost allocation framework for new transmission infrastructure based on cost-causation principles by requiring new generators to contribute to transmission infrastructure costs by replacing the Generating Unit Owner's Contribution with an upfront and non-refundable Transmission Reinforcement Payment. These payments will have no upper limit, a floor of $0 per megawatt, and will apply to both transmission-connected and distribution-connected generators. The Transmission Reinforcement Payment rates will be calculated as a function of the supplier's proximity to transmission capacity, their technical attributes and characteristics, and the cost of reinforcing the transmission system and will be defined by a future Alberta Electric System Operator Tariff process.
- Recover line losses through a system-wide average starting on January 1, 2027.
- Require the AESO to file a NID for the Alberta Intertie Restoration project by December 31, 2026, to restore the Alberta-British Columbia intertie to or near to 950 megawatts.
- Require the AESO to procure and maintain high levels of ancillary services to support full import flows on the Alberta-British Columbia Intertie and the Montana Alberta Tie Line.
- Require the AESO to increase the path rating of the Alberta-Saskatchewan Intertie as part of the McNeill Converter's end-of-life replacement to leverage the use of the existing transmission capacity in the region.
- Remove the competitive procurement requirement for upgrades or enhancements to the path rating of interties.

Energy market design

On July 1, 2024, the Government of Alberta implemented two interim regulations, the *Market Power Mitigation Regulations*, and the *Supply Cushion Regulations*, to address the impacts of economic and physical withholding. The regulations will expire November 30, 2027.

On July 11, 2024, the Government of Alberta announced the policy framework for the Restructured Energy Market based on recommendations from the Alberta Market Surveillance Administrator and the AESO. In September 2024, the AESO initiated a stakeholder consultation to complete detailed design of the Restructured Energy Market, which is to be completed by the end of 2025. The market will be designed to encourage increased competition, improve reliability, and make utility bills more affordable. Legislative and regulatory changes will proceed in 2025, are focused on generation, and include:

- Introduction of a mandatory day-ahead market;
- Allowing the price of energy to be determined by the strategic offers of market participants, while using market mitigation to limit the potential for excessive exercise of market power;
- Maintaining a province-wide uniform price for electricity;
- Implementing Security Constrained Economic Dispatch;
- Implementing shorter settlement periods;
- Review of the price floor and ceiling;
- Co-optimization of energy and ancillary services; and
- Enabling intertie market participation.

On December 10, 2024, the Government of Alberta issued a direction letter to the AESO to further guide the ongoing technical design of the Restructured Energy Market. In 2025, the government will bring forward the legislative tools and amendments necessary to implement the market policies as noted below:

- Develop a market-based congestion management mechanism that recognizes incumbency, provides impacted generators with a means of managing the dispatch risk arising from congestion constraints, and considers the participation of controllable load and energy storage. Any revenue generated from this mechanism will be applied towards the cost of transmission projects prioritizing congested areas of the province.
- Continue to have robust engagement with stakeholders on the development of the design and the Independent System Operator Rules that will implement the Restructured Energy Market while ensuring alignment with the government's objectives of reliability, affordability, investment certainty, economic efficiency, and sustainability.
- Develop an energy pricing framework in accordance with guidance that will be provided within legislation.
- Collaborate in an AUC-led initiative to implement five-minute settlement for transmission-connected loads, generators, and interties by 2032 and for all loads by 2040.

The government confirmed that the Independent System Operator Rules required for the Restructured Energy Market to be implemented will be enacted through legislation, instead of the previously understood AUC process. Following the implementation of the new market, an interim period will commence with a process established for the AESO to correct possible technical deficiencies in an expeditious manner. At the end of the interim period and beyond, any proposed amendments to the rules will require AUC approval in accordance with the established process for Independent System Operator Rules.

On December 13, 2024, the AESO released its Restructured Energy Market High Level Design document for stakeholder review. The document provides an overview of the latest proposed design elements including:

- Financial day-ahead markets to allow participants to firm up pricing a day in advance to inform operation decisions, with day-ahead commitment to ensure adequate resources are available and deliverable in real time.
- New ancillary services to meet reliability requirements, including a day-ahead commitment product and ramping products to ensure sufficient resources are available for real-time needs.
- New market tools and co-optimization of energy and ancillary services to enhance its ability to operate a system with transmission congestion and variability and ensure the lowest cost solution is dispatched to meet system needs.
- Updated pricing to send appropriate signals to resources in times of supply scarcity and supply surplus through an increase in the price cap, lowering of the price floor, and including price signals for energy and required ancillary services to compensate resources in advance of supply scarcity situations.
- Appropriate guardrails to provide protection for consumers against excessive exercise of market power without interfering with investment signals.
- Shorter settlement Intervals to encourage quicker response to variability on the AIES.

Renewable energy development

On February 28, 2024, the Government of Alberta announced new policy changes impacting renewable energy development in the province, and confirmed the pause on project approvals implemented August 3, 2023, would be lifted the following day as committed. These policy changes were implemented as a result of recommendations from the AUC as follows:

- Implementing an "agriculture first" approach in evaluating best use of agricultural lands proposed for renewables development, requirements to provide a bond or security for future reclamation costs, implementation of a buffer zone around identified protected areas and restrictions for future wind development within the zone, and development on Crown lands on a case-by-case basis.
- Other proposed developments located within the buffer zones may be subject to a further visual impact assessment prior to approval.
- The AUC undertaking a review of *Rule 007 (Applications for Power Plants, Substations; Transmission Lines, Industrial Systems Designations, Hydro Developments and Gas Utility Pipelines)*.
- Municipalities are automatically granted the right to participate in AUC hearings and are eligible to request cost recovery for participation, and a review of rules related to municipal submission requirements will be completed.
- The Government of Alberta also confirmed renewable project owners should expect changes in how transmission costs are allocated in the future.

On December 6, 2024, amendments were enacted to the *Alberta Utilities Commission Act* (Alberta) and the *Environmental Protection and Enhancement Act* (Alberta) to implement policy direction established on February 28, 2024. The changes introduced in the regulations include:

- Amendments to the Activities Designation Regulation and Conservation and Reclamation Regulation providing clarity for renewable energy developers on new and existing environmental protections which will create consistent reclamation requirements across all forms of renewable energy operations, including a mandatory reclamation security requirement including for projects located on private lands. The reclamation security will either be provided directly to the province or may be negotiated with landowners if sufficient evidence is provided to the AUC.

- The new Electric Energy Land Use and Visual Assessment Regulation follows an agriculture first approach. Renewable energy developments will no longer be permitted on Class 1 and 2 lands unless the proponent can demonstrate the ability for both crops and/or livestock to coexist with the renewable generation project. In some cases, an irrigability assessment must be conducted by proponents and considered by the AUC.
- The new Electric Energy Land Use and Visual Assessment Regulation also ensures pristine viewscapes are conserved through the establishment of buffer zones and visual impact assessment zones as designated by the province. New wind projects will no longer be permitted within specified buffer zones and other proposed electricity developments located within the buffer zones will be required to submit a visual impact assessment before approval.

Data centre development

On December 4, 2024, the Government of Alberta unveiled its data centre attraction strategy with the goal of positioning Alberta as North America's destination of choice for Artificial Intelligence data centre investment. The strategy identifies three foundational pillars supporting Alberta's perceived competitive advantage in the global landscape including power capacity, sustainable cooling, and economic diversification. Moving forward the government will look to implement additional policy and regulatory changes to fully optimize this economic growth initiative.

Ministry of Affordability and Utilities mandate

On July 19, 2023, the Government of Alberta released the Mandate Letter for the Minister of Affordability and Utilities which included:

- Pushing back against any federal regulation requiring a net-zero power grid by 2035, and instead developing and implementing a comprehensive plan to achieve a carbon-neutral power grid by 2050 that is reliable, affordable, and uses small modular reactors, carbon capture utilization and storage, and other emission-reduction technologies;
- Reviewing the operations, policies, and mission of the ministries agencies including the AUC and the AESO, and recommending ways to improve their operations and align their mission with the government's goal of a carbon-neutral power grid by 2050; and
- Reviewing Alberta's electricity pricing system with the goal of reducing transmission and distribution costs for Albertans.

Net-Zero Electricity Policy

On December 18, 2024. the final federal *Clean Electricity Regulations* were published in the Canada Gazette II and came into force on January 1, 2025.

Following consultations with stakeholders, additional flexibilities were adopted in the final regulations based on the release of a February 16, 2024, discussion paper on the proposed Regulations titled *"Public Update: 'What We Heard' during consultations and directions being considered"*.

We participated in these engagements and filed submissions on March 15, 2024, and November 2, 2023. The design of the Clean Electricity Regulations drives progress toward a net zero electricity grid by 2050 by moving to low and non-carbon emitting electricity sources. The final Regulations include:

- An effective date of 2035, with an extension to the timeline required to achieve a net-zero grid from 2035 to 2050.
- The extension of the inflight project demarcation to December 31, 2025.
- The allowable emissions limit has been shifted from a fixed emissions intensity standard of 30 tonnes per gigawatt hour to an annual emissions limit based on 65 tonnes per gigawatt hour, with an additional 35 tonnes per gigawatt hour enabled with the use of offsets.
- Existing natural gas units will have 25 years after the date they are commissioned before needing to comply with the annual emissions limit.
- Emission associated with on-site electricity for existing behind the fence co-generation units will be excluded until 2050.
- The ability to transfer or "pool" compliance credits among electricity units within a province for a combined emissions limit.
- The allowance of electricity units to "bank" compliance credits for use in future years.
- The allowance of units to operate over their emissions limit through the remission of carbon offsets.

- The ability for electricity system operators to direct units to provide electricity in order to respond to an emergency situation. The resulting emissions can be exempt from the emissions limit, without needing to seek prior federal approval, for a period of 30 days.
- An exemption for small units of less than 25 megawatts and regions that are not connected to a grid regulated by the North American Electric Reliability Corporation.
- The option for provinces and territories to enter into equivalency agreements that would stand down the federal Regulations if the province has adopted rules that deliver a level of emission reductions equivalent to Canada's Clean Electricity Regulations.

On December 17, 2024, the Government of Alberta issued a statement calling on the federal government to completely abandon any attempt to regulate or otherwise interfere with Alberta's governance over its provincial power grid. It also confirmed that Alberta is preparing an immediate court challenge of the Clean Electricity Regulations.

On April 19, 2023, the Government of Alberta released its Emissions Reduction and Energy Development Plan which includes as aspiration to achieve a carbon neutral economy by 2050, and to do so in an affordable and reliable way that ensures energy security. In the electricity sector, the plan commits to the following:

- Continuing to support new technologies including energy storage;
- Exploring diversification of low-emitting technologies in Alberta, including carbon capture utilization and storage, hydrogen, and small modular nuclear reactors;
- Considering energy management supports to continue driving energy efficiency and emissions reduction projects in industrial and commercial facilities;
- Advocating for federal financial support to maintain affordable electricity; and
- Reviewing Alberta's distribution and transmission policies to ensure ongoing reliability, affordability, and coordinated efforts to increase efficiency.

Major Capital Projects

The AESO mandate, defined in the *Electric Utilities Act* (Alberta) and its regulations, requires the AESO to assess both current and future needs of the AIES.

On January 31, 2025, the AESO released its 2025 Long-Term Transmission Plan (LTP). The LTP identifies three areas of planning: load growth, generation growth and intertie development. The LTP was developed under Alberta's current zero-congestion policy and acknowledges that the current workstream to develop and implement the AESO's Optimal Transmission Planning framework will impact generation growth driven transmission projects. The Optimal Transmission Planning framework seeks to optimize the use of the existing transmission system, while planning the development of new transmission; altogether it ensures a safe and reliable electricity system that enables a fair, efficient, and openly competitive electricity market. The Optimal Transmission Planning framework is not anticipated to impact transmission system projects driven by load growth and by intertie development. The LTP identifies approximately $2,100 million of generation driven projects and $150 million of Intertie driven projects in AltaLink's service territory with in-service dates before 2030.

On May 15, 2024, the AESO released its 2024 Long-Term Outlook. The reference case was consistent with the Government of Alberta's target to achieve decarbonization by 2050. The alternatives focused on the following three scenarios:

- Decarbonization by 2035: a scenario which assumes a linear decline in emissions from 2030 to 2035 based on federal Clean Electricity Regulations;
- Alternative Decarbonization: a scenario which explores the effect of increasing intertie connections in 2035 and anticipates technological cost declines as well as delays in development of carbon capture, utilization and storage, nuclear small modular reactors and hydrogen; and
- High Electrification: a scenario which anticipates higher load growth from increased electric vehicles, electrification of building heating and cooling as well as additional industrial load due to electrification and carbon capture, utilization and storage adoption.

The scenarios allow the AESO to consider possible future states of the Alberta market. The AESO had delayed its LTP until January 2025 due to the evolving carbon policies and regulations which impact the development of the grid.

On September 1, 2023, the AESO initiated its cluster study interconnection process for generators and energy storage projects. On October 1, 2023, the AESO reported approximately 40,000 megawatts of generation in the queue related to approximately 140 projects initially in the first cluster. The completion of the first set of cluster studies was November 29, 2024, and approximately one-third of projects accounting for roughly 5,800 megawatts continued to the next stage of the interconnection process. The second cluster commenced in October 2024, with approximately 17,000 megawatts of new generation to be studied in 2025.

Projects Overview

The following is an overview of the main system projects in various stages of development:

Central East Transfer-Out

The proposed Central East Transfer-Out development will enable sustainable energy generation integration, and its planned execution contains two stages. Stage 1 will consist of a new 240-kilovolt transmission line approximately 135 kilometres long. AltaLink will construct 50 kilometres of the line and ATCO Electric Ltd. (ATCO Electric) will construct the other 85 kilometres. Stage 2 will add a second planned circuit to the 240-kilovolt transmission line to enable more capacity for incremental generation in Alberta's central east and southeast areas. The project received permit and licence on August 10, 2021.

On December 1, 2022, the AESO issued direction to AltaLink and ATCO Electric to commence Stage 1 construction on the project. Both AltaLink and ATCO Electric updated the estimated cost to reflect current market conditions. On October 5, 2023, the AESO formally approved the revised total cost estimated at $489 million, with AltaLink's share of project costs estimated at $223 million. The previous total cost estimate was $310 million, with AltaLink's share of project costs estimated at $159 million.

On February 2, 2024, the AESO submitted a reaffirmation study to the AUC which confirmed that congestion is forecast to occur greater than 0.5% of the time annually, meeting the trigger established to proceed with Stage 2 construction. On February 14, 2024, the AUC issued a letter that indicated their agreement with the AESO's assessment and confirmed that the construction milestone for Stage 2 was met.

On February 22, 2024, the AESO approved a project change proposal for AltaLink to spend an additional $8 million for a high-capacity conductor that provides approximately 50% additional capacity on the line. This equates to an approximately 4% project cost increase for more than a 50% capacity increase. ATCO Electric's portion is estimated to be $12 million for a high-capacity conductor for their section of line.

On December 18, 2024, the AESO approved AltaLink's project change proposal which reduced AltaLink's portion of the project by $22.2 million. This change resulted in AltaLink's share of the project cost being $207.0 million. The reduction is attributed to lower escalation for transmission lines materials and construction contracts.

AltaLink and ATCO Electric commenced transmission line foundation construction in fall 2024. Currently, AltaLink is forecasting an in-service date in the second quarter of 2026 aligning with the LTP. As at December 31, 2024, AltaLink invested $59.7 million on the project.

Vauxhall Area Transmission Development

To enable sustainable energy generation integration and manage congestion in the Taber area, the proposed Vauxhall Area Transmission development includes the construction of a new 138-kilovolt transmission line approximately 14 kilometres long and the uprate of an existing line. The AESO and AltaLink filed a joint NID and facility application on December 9, 2022. The AUC oral regulatory hearing for the project was held in June 2023. The project received permit and licence on September 19, 2023. The 879L portion of the project, which was an uprate to the line, was energized in November 2024. The 610L portion, which is a new construction line, is forecast to be energized in March 2025. The current estimated cost of the project is $20.6 million. As at December 31, 2024, we invested $15.3 million on the project.

Southeast Development and Southwest Development

The AESO is developing a Southeast transmission plan in response to strong interest in renewable development in the Southeast region of Alberta. The aggregate capacity of proposed generation projects exceeds the current transmission capacity, and the AESO is exploring potential solutions. To address short-term requirements, the AESO issued a Project Assistance Direction to AltaLink in August 2022 to assist in the study of voltage support alternatives in the Cassils-Bowmanton-Whitla area. On February 9, 2023, the AESO hosted the Cassils-Bowmanton-Whitla Path Congestion presentation for stakeholders. The presentation described longer term requirements to include the addition of new double circuit 240-kilovolt transmission lines. AltaLink provided the AESO with estimates for multiple alternatives, which the AESO is assessing. The LTP identified this project as a generation growth driven project which will be impacted by the Optimal Transmission Planning framework. As a result, the timing of this project is uncertain. The current AESO cost estimate for the new transmission lines is $650 million, with a forecasted in-service date of 2029-2030. As at December 31, 2024, we invested $0.1 million on the project.

On March 22, 2023, the AESO filed a Notice of Consideration for an Abbreviated Need Approval Process with the AUC for the Bowmanton 244S Substation Voltage Support project. The Abbreviated Need Approval Process closed April 6, 2023, and permit and licence was received June 6, 2023. The Bowmanton 244S Substation Voltage Support project is estimated at $10.7 million and was energized in February 2025. As at December 31, 2024, we invested $10.0 million on the project.

In addition, the AESO indicated that a Southwest Development project adjacent to the Southeast Development would be required. This Southwest Development project would continue to enable generation in the south part of the province and direct power flows to the load centre of Calgary. AltaLink provided NID estimates on multiple alternatives. The project is currently paused while the AESO is reviewing connection options. As at December 31, 2024, we invested $0.6 million on the project.

Provost to Edgerton and Nilrem to Vermilion Transmission Development

The Provost to Edgerton and Nilrem to Vermilion transmission development involves constructing two new transmission lines in the Central East area to support the integration of new sustainable energy generation and load growth. The lines will initially be energized at 138 kilovolts, with the option of increasing the voltage to 240 kilovolts in the future by upgrading the termination substations. The total cost estimate for the Provost to Edgerton and Nilrem to Vermilion Project is $294 million, with our portion estimated at $238 million and ATCO Electric portion estimated at $56 million. In 2019, the AUC approved the NID filed by the AESO with construction being triggered based on certain load and congestion triggers being met.

The Provost to Edgerton Development is a 48-kilometre transmission line located in AltaLink's service territory. The Provost to Edgerton Development is estimated at $125 million, with the first stage estimated at $58 million and the second stage estimated at $67 million. AltaLink filed the facility application for the Provost to Edgerton Development on December 11, 2020. The project received permit and licence on August 26, 2021.

The Nilrem to Vermilion Development consists of a new transmission line with approximately 80 kilometres in AltaLink's service territory and 13 kilometres in ATCO Electric's service territory. AltaLink's section of the Nilrem to Vermilion Development is estimated at $113 million and ATCO Electric's section is estimated at $56 million. We filed the facility application for the Nilrem to Vermilion Development on December 4, 2020. On September 23, 2021, the AUC denied AltaLink's and ATCO Electric's facility applications for the Nilrem to Vermilion Development. Some of the reasons cited by the AUC included incomplete and insufficient route information and insufficient coordination between us and ATCO Electric on the overall route. AltaLink awaits next steps from the AESO.

In November 2021, the AESO directed AltaLink to uprate an existing transmission line to reduce congestion in the area. We completed the construction on the line in October 2022. This uprate defers the Provost to Edgerton and Nilrem to Vermilion Project to a later in-service date which is expected to be further impacted by the Optimal Transmission Planning framework. As at December 31, 2024, we invested $23.1 million on the project.

Alberta – British Columbia Intertie Restoration

The Alberta Intertie Restoration project was included in the AESO's 2025 LTP, which aligns with the Government of Alberta's direction letter to the AESO dated December 10, 2024. The AESO estimates this project to cost $150 million.

On April 26, 2024, the AESO directed AltaLink to evaluate three scope items required to restore the capacity of the Alberta-British Columbia intertie including transformers with higher emergency ratings, the location of series compensation and line clearance mitigations. We provided the updated scope information to the AESO in October 2024. As at December 31, 2024, we invested $5.1 million on the project.

Chapel Rock to Pincher Creek

The Chapel Rock to Pincher Creek development in Southwest Alberta will enable the integration of future sustainable energy generation and enhance the transfer-out capability in the area, contributing to the restoration of the Alberta and British Columbia intertie capability to 1,200 megawatts. This development consists of a new 240-kilovolt transmission line approximately 40 kilometres long between the Pincher Creek area and a new 500-kilovolt Chapel Rock substation. The current total estimated capital additions are $350-400 million. The AESO indicated in their LTP that the timing for this project will depend on the pace at which sustainable energy generation commits to connecting to the transmission system in the southwest part of the province and the outcome of the Optimal Transmission Planning framework. The AESO plans to file the NID approximately four years before the forecasted congestion occurs. We are waiting for further direction from the AESO on the timing of the project prior to completing a service proposal and facility application. As at December 31, 2024, we invested $31.2 million on the project.

Battery Energy Storage System Installation Feasibility Project

On February 14, 2024, the AESO provided direction for assistance to complete a transmission battery energy storage system feasibility assessment. The direction includes environmental and land use effects evaluations, high-level facility designs, and investigating the ability to potentially improve power system performance. AltaLink has provided high level estimate information and is working with the AESO to determine the next steps in the assessment.

The estimated cost of the feasibility study project is approximately $3 million, of which Emissions Reduction Alberta will contribute 50% ($1.5 million). As at December 31, 2024, we invested $0.2 million on the project.

Non-GAAP Financial Measures

We use certain financial metrics that are not defined under accounting principles generally accepted in Canada, i.e., IFRS Accounting Standards. Such non-GAAP financial measures provide our management and our investors with additional insight into our financial performance and financial condition, expanding on the information that we provide in our consolidated financial statements. In particular, our investors, lenders, and credit rating agencies use certain non-GAAP financial measures to calculate debt covenants and financial ratios.

We believe earnings before interest and taxes (EBIT) and earnings before interest, taxes, depreciation, and amortization (EBITDA) are useful supplemental measures to analyse our operating performance and to provide indications of the results generated by our principal business activities prior to the consideration of certain expenses. We use EBITDA to measure our operating performance, before considering our financing strategy or recognizing costs for the consumption and replacement of our capital assets.

FFO represents earnings before depreciation and amortization, finance costs, non-controlling interests, actuarial gains or losses, and losses on the disposal of assets less interest paid. FFO should not be considered an alternative to, or more meaningful than, "cash provided by operating activities". We believe that FFO is a useful supplemental measure in analyzing our ability to generate cash flow to fund capital investment and working capital requirements.

References to "earnings" in this section of the MD&A denote comprehensive income before losses on the disposal of assets.

These non-GAAP financial measures do not have standardized meanings and are therefore unlikely to be comparable to similar measures presented by other companies.

Financial Position and Cash Flows

Financial Position

In the following table, we discuss material changes (over $50.0 million) in our statement of financial position during the year ended December 31, 2024:

(in millions of dollars)	Increase/(Decrease)		Explanation
Other non-current assets [note 11]	$	94.3	The increase is primarily due to higher receivables for the recovery of deemed future income taxes.
Long-term debt maturing in less than one year [note 13]	$	(350.0)	The decrease is due to the repayment of $(350.0) million Medium-Term Notes in June 2024.
Long-term debt [note 13]	$	323.2	The increase is primarily due to the issuance of $325.0 million of Senior Secured Notes in May 2024 to contribute to the repayment of $350.0 million Medium-Term Notes in June 2024.
AltaLink, L.P. equity	$	78.1	The increase is primarily due to generated comprehensive income of $330.1 million, partially offset by the distribution of $(252.1) million to AILP and AML.

Cash Flows

	Quarter ended December 31,				Year ended December 31,			
(in millions of dollars)	**2024**		2023		**2024**		2023	
Cash, beginning of period	**$**	**0.2**	$	1.6	**$**	**6.8**	$	0.1
Cash flow provided by (used in):								
Operating activities		**186.4**		50.2		**558.2**		431.6
Investing activities		**(85.7)**		(48.0)		**(305.0)**		(198.5)
Financing activities		**(100.8)**		3.0		**(259.9)**		(226.4)
Cash, end of period	**$**	**0.1**	$	6.8	**$**	**0.1**	$	6.8

Operating activities

For the quarter and year ended December 31, 2024, our cash flow from operating activities increased by $136.2 million and $126.6 million, respectively, compared to the same periods in 2023. The changes are primarily due to 13 monthly tariffs collected in 2024 and 11 monthly tariffs collected in 2023.

Investing activities

For the quarter and year ended December 31, 2024, our cash flow used in investing activities increased by $37.7 million and $106.5 million, respectively, compared to the same periods in 2023. The changes are primarily due to higher capital project activity, including the capitalization of site preparation costs for replacement projects, lower third-party contributions, and lower vendor refunds received.

Financing activities

For the quarter ended December 31, 2024, our cash flows used in financing activities increased by $103.8 million compared to the same period in 2023. The change is primarily due to issuing $500.0 million less Senior Secured Notes, having $103.8 million more of net repayment of commercial paper and distributing $2.8 million more to AILP and AML. These changes are partially offset by repaying $(500.0) million less Medium-Term Notes.

For the year ended December 31, 2024, our cash flows used in financing activities increased by $33.5 million compared to the same period in 2023. The change is primarily due to issuing $175.0 million less of Senior Secured Notes and distributing $26.7 million more to AILP and AML. These changes are partially offset by repaying $(150.0) million less of Medium-Term Notes and having $(17.8) million more of net issuances of commercial paper.

Commitments

		Payments due by periods			
(in millions of dollars)	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Long-term debt excluding interest	**$ 4,725.0**	**$ —**	**$ 350.0**	**$ —**	**$ 4,375.0**

We have contractual commitments to repay long-term debt of $4,725.0 million (December 31, 2023 – $4,750.0 million), as disclosed in our annual audited consolidated financial statements in note 13 - Scheduled principal repayments.

We are committed to lease payments of $61.7 million (December 31, 2023 – $64.3 million), as disclosed in our annual audited consolidated financial statements in note 15 - Lease liabilities.

We also have contractual commitments associated with the construction of new facilities as at December 31, 2024 of $180.3 million (December 31, 2023 – $140.1 million), as disclosed in our annual audited consolidated financial statements in note 26 - Commitments.

Liquidity and Capital Resources

Liquidity

We generally issue commercial paper to finance our day-to-day cash requirements. The commercial paper program, together with our lines of credit and anticipated long-term debt issuance, provides us with sufficient liquidity to finance our planned operations and capital projects.

The aggregate of our bank and inter-affiliate credit facilities as at December 31, 2024 was $725.0 million (December 31, 2023 – $725.0 million). On December 16, 2024, we extended the maturity dates for our bank credit facilities to December 14, 2029 to increase the term and reduce pricing risk. The $500.0 million facility provides support to our commercial paper program, under which $153.0 million of commercial paper was outstanding as at December 31, 2024 (December 31, 2023 – $129.0 million). AltaLink may use the $500.0 million and $75.0 million bank credit facilities for general corporate purposes. On March 31, 2023, we added a $150.0 million inter-affiliate revolving credit facility from AILP to provide additional liquidity for ALP and on December 20, 2024, we extended its maturity date to March 31, 2027. We have not drawn any amount on the AILP inter-affiliate credit facility as at December 31, 2024. As at December 31, 2024, we had $569.9 million of liquidity remaining under those facilities (December 31, 2023 – $594.9 million). We consider our liquidity arrangements adequate to accommodate our expected capital expenditures and working capital requirements over the next few years.

On October 31, 2023, we entered into a credit agreement with the Canada Infrastructure Bank to provide debt financing for up to 50% of eligible costs on AltaLink's Central East Transfer-Out Project, Southeast Development and Southwest Development Projects. Total borrowing under the credit facility is capped at $604.3 million with a final maturity date of December 31, 2065. All borrowings under the credit facility are subject to a fixed repayment schedule. On October 18, 2024, the AUC approved the credit facility. We expect our first drawdown under the credit facility to be in the first quarter of 2025.

We plan to finance our projected capital investments, working capital requirements and any maturities of long-term debt through a prudent combination of cash flow from operating activities, new long-term debt, and equity contributions from AILP.

We use short-term interest-bearing instruments issued by highly rated counterparties to invest temporary cash balances and amounts we receive from customers in advance of construction of facilities. We remit to the individual customers all investment income related to deposits received from those customers for construction projects and we use the investment income earned on deposits received from customers for future operating and maintenance costs.

Liquidity, coverage and capital ratios[1]

(in millions of dollars)	Twelve months ended December 31, **2024**	2023
Comprehensive income	**$ 330.1**	$ 297.8
Actuarial loss	**0.5**	0.3
Non-controlling interests	**1.7**	1.7
Loss on disposal of assets	**7.9**	8.4
Finance costs	**204.2**	197.2
EBIT	**544.4**	505.4
Depreciation and amortization	**301.2**	293.9
EBITDA	**845.6**	799.3
Interest paid	**(223.1)**	(176.9)
Standby fees	**(1.0)**	(1.0)
FFO	**$ 621.5**	$ 621.4

(in millions of dollars)	Twelve months ended December 31, **2024**	2023
Net cash provided by operating activities	**$ 558.2**	$ 431.6
Change in non-cash working capital	**(49.1)**	51.3
Third-party contributions revenue	**28.5**	27.2
Change in financial assets and liabilities related to regulated activities, non-current	**91.7**	82.3
Change in deferred revenue for salvage	**10.0**	9.5
Change in other	**(17.8)**	19.5
FFO	**$ 621.5**	$ 621.4

(in millions of dollars)	As at December 31, **2024**	2023
Letters of credit	**$ 2.1**	$ 1.1
Less: cash	**(0.1)**	(6.8)
Other post-employment benefit obligations[2]	**4.2**	3.6
Short-term debt (excluding outstanding cheques)	**153.0**	129.0
Long-term debt	**4,695.6**	4,722.4
Lease liabilities	**47.7**	48.7
Total debt	**4,902.5**	4,898.0
Cash	**0.1**	6.8
Accrued interest on debt	**31.4**	48.1
Financing fees, premiums, and discounts	**29.5**	27.6
Less: other post-employment benefit obligations[2]	**(4.2)**	(3.6)
Total debt as per Master Trust Indenture and bank credit facilities	**4,959.3**	4,976.9
Total equity including non-controlling interests	**3,847.3**	3,769.3
Less: AltaLink equity investment in subsidiaries	**(15.9)**	(15.9)
Total capitalization	**$ 8,790.7**	$ 8,730.3

	Twelve months ended December 31, 2024	2023
Interest paid	**$ 223.1**	$ 176.9
Interest expense[3]	**$ 208.5**	$ 200.4
EBIT interest expense coverage[4]	**2.61X**	2.52X
EBITDA interest expense coverage[5]	**4.06X**	3.99X
FFO interest paid coverage[6]	**3.79X**	4.51X
FFO/Debt[7]	**12.68%**	12.69%
Total debt/total capitalization as per Master Trust Indenture[8]	**56.42%**	57.01%
Total debt/total capitalization as per bank credit facilities[9]	**56.42%**	57.01%

1. Please refer to the "Non-GAAP Financial Measures" section of this MD&A for further information concerning the non-GAAP financial measures used in this table.
2. For the purposes of calculating total debt, other post-employment benefit obligations of $5.5 million as at December 31, 2024 were adjusted to reflect an after-tax amount equal to $4.2 million using an income tax rate of 23% (December 31, 2023 – $4.7 million was adjusted to $3.6 million).
3. Interest expense is calculated as the sum of interest expense, amortization of deferred financing fees, standby fees, and interest expense on lease liabilities.
4. EBIT interest expense coverage is calculated as EBIT divided by interest expense.
5. EBITDA interest expense coverage is calculated as EBITDA divided by interest expense.
6. FFO interest paid coverage is calculated as the sum of FFO and interest paid divided by interest paid.
7. FFO/Debt is calculated as FFO divided by total debt.
8. The AltaLink Master Trust Indenture contains a debt to total capitalization covenant with a limit of 75%.
9. AltaLink's credit facilities contain a debt to total capitalization covenant with a limit of 75%. The calculation includes required adjustments for both non-recourse debt and equity contributions in Permitted Joint Arrangement Subsidiaries.

We align our regulatory debt to total capitalization with the capital structure approved by the AUC and with corresponding targets for our overall key financial metrics.

Working capital

At December 31, 2024, our working capital deficiency was $157.5 million (December 31, 2023 – $462.0 million). The working capital deficiency includes trade and other payables, drawn commercial paper and bank credit facilities, long-term debt maturing in less than one year, and the current portion of deferred revenue. Considering AltaLink's aggregate available credit facilities, the current working capital deficiency is manageable.

We fund our working capital requirements from cash provided by operating activities, and to the extent necessary, through equity injections from AILP and borrowings under our commercial paper program or drawings on our committed bank credit facilities and new long-term debt.

Earnings Coverage

	Year ended December 31,		
	2024	2023	2022
Earnings-to-interest coverage on total debt[1,2]	**2.51X[2,3,4]**	2.29X[2,3,4]	2.51X[2,3,4]

1. Earnings-to-interest coverage on total debt is a non-GAAP financial measure. As a result of having distributed securities by way of a medium-term note program using the debt shelf procedures, we must include updated earnings coverage ratios in conjunction with our consolidated financial statements. Please refer to the "Non-GAAP Financial Measures" section of this MD&A for further information concerning the non-GAAP financial measures used in this MD&A.
2. Earnings-to-interest coverage on total debt equals pro-forma earnings before interest and income taxes divided by pro-forma interest requirements on short and long-term debt. We calculate this ratio by giving pro-forma effect to any long-term debt issued during the period and the use of the proceeds from such long-term debt issues.
3. Our pro-forma earnings before interest and income tax for the 12 months ended December 31, 2024, for the purposes of calculating this ratio, was $538.7 million (December 31, 2023 – $498.2 million). Our pro-forma interest requirement on short and long-term debt for the 12 months ended December 31, 2024 was $214.5 million (December 31, 2023 – $217.7 million).
4. Our pro-forma earnings before interest and income tax for the 12 months ended December 31, 2024 and 2023 is calculated as: comprehensive income of $330.1 million (December 31, 2023 – $297.8 million) plus finance costs of $204.2 million (December 31, 2023 – $197.2 million) plus capitalized borrowing costs of $4.4 million (December 31, 2023 – $3.2 million) plus income taxes of $nil (December 31, 2023 – $nil). Our pro-forma interest requirement on short and long-term debt for the 12 months ended December 31, 2024 and 2023 is calculated as: finance costs of $204.2 million (December 31, 2023 – $197.2 million) plus capitalized borrowing costs of $4.4 million (December 31, 2023 – $3.2 million) plus the net pro-forma effect of interest expense of $5.9 million on the May 22, 2024 issuance of $325.0 million of Series 2024-1 Senior Secured Notes (December 31, 2023 – $17.3 million on the October 11, 2023 issuance of $500.0 million of Series 2023-1 Senior Secured Notes).

Credit Ratings

We strive to maintain an "A" category credit rating to enable credit market access during periods of market turmoil and to minimize financing costs for ratepayers. The AUC in its GCOC Decision 27084-D02-2023 reaffirmed its support for this approach.

	As at December 31,		
	2024	2023	2022
DBRS – Commercial Paper[1]	**R-1 (low)**	R-1 (low)	R-1 (low)
DBRS – Medium-Term Notes (Secured) and Senior Secured Notes [1]	**A**	A	A
S&P – Medium-Term Notes (Secured) and Senior Secured Notes [2]	**A-**	A-	A

1. On July 9, 2024, DBRS reaffirmed the existing ratings with Stable trends. On August 16, 2024, DBRS publicly released a new combined AltaLink, L.P. and AltaLink Investments, L.P. credit rating report.
2. On April 5, 2023, S&P reaffirmed its issuer credit rating and senior secured rating on AltaLink at "A" with a stable outlook. On June 23, 2023, S&P reaffirmed its issuer credit rating and senior secured rating on AltaLink at "A", but revised its outlook from stable to negative due to the potential that BHE's business or financial risk could weaken over the next 24 months if BHE-owned PacifiCorp faces significantly increased liabilities related to the 2020 wildfires. On November 21, 2023, S&P downgraded the credit ratings of AltaLink by one notch from "A" to "A-" with a stable outlook. The ratings downgrade reflects S&P's view using their group ratings methodology that BHE will not provide extraordinary support to its subsidiaries under all foreseeable circumstances. On April 26, 2024, S&P reaffirmed its issuer credit rating and senior secured rating on AltaLink at "A-" with a stable outlook.

Results of Operations

Revenue

(in millions of dollars)	Quarter ended December 31, **2024**	2023	2022
Operations	**$ 256.2**	$ 253.3	$ 246.7
Other	**16.5**	11.2	9.6
	$ 272.7	$ 264.5	$ 256.3

(in millions of dollars)	Year ended December 31, **2024**	2023	2022
Operations	**$ 1,021.4**	$ 976.5	$ 952.8
Other	**49.8**	39.2	36.2
	$ 1,071.2	$ 1,015.7	$ 989.0

Revenue from operations

Revenue from operations includes all revenue earned from providing electricity transmission services, including future income tax revenue. The principal components of our transmission tariffs include recovery of forecast operating costs, deemed income taxes, depreciation and amortization expenses, and debt and equity rate base returns.

For the quarter ended December 31, 2024, our revenue from operations increased by $2.9 million or 1.1% compared to the same period in 2023. The change is primarily due to higher debt and equity returns on rate base, partially offset by recovery of lower revenue related to salvage expenses. For the year ended December 31, 2024, our revenue from operations increased by $44.9 million or 4.6% compared to 2023. The change is primarily due to higher debt and equity returns on rate base. Higher recovery of other allowable costs of transmission services, including the recovery of costs related to our 2023 wildfire restoration work which was approved by the AUC on July 31, 2024 as a self-insurance account item were offset by lower salvage recovery. On June 19, 2024, the AUC approved the collection of costs of site preparation for capital replacement projects over the average useful lives of the related replacement assets starting January 1, 2024. As a result, the Partnership now capitalizes these costs.

For the quarter and year ended December 31, 2023, our revenue from operations increased by $6.6 million or 2.7% and $23.7 million or 2.5%, respectively, compared to the same periods in 2022. The changes are primarily due to recovery of higher allowable costs of transmission services, partially offset by the returns on a lower rate base.

Other revenue

Other revenue includes the amortization of third-party contributions and revenue for construction services provided to third parties including other utilities on a cost recovery basis.

Our other revenue for the quarter and year ended December 31, 2024 increased by $5.3 million and $10.6 million, respectively, compared to the same periods in 2023. These changes are primarily due to higher cost recovery revenue from other utilities and third parties and higher amortization of third-party contributions, partially offset by lower revenue from related parties.

Our other revenue for the quarter and year ended December 31, 2023 increased by $1.6 million and $3.0 million, respectively, compared to the same periods in 2022. These changes are primarily due to higher amortization of third-party contributions and interest revenue on cash deposits.

Operating expenses excluding disallowed capital costs

(in millions of dollars)	**2024**	2023	2022
Quarter ended December 31,	**$ 37.0**	$ 23.6	$ 21.5
Year ended December 31,	**122.5**	104.8	99.1

Our operating expenses include salaries and wages, contracted labour, and general and administration costs.

Our operating expenses for the quarter and year ended December 31, 2024 increased by $13.4 million and $17.7 million, respectively, compared to the same periods in 2023. These changes are primarily due to higher employee salaries and benefits, contracted labour, and general operating expenses including costs of services provided to other utilities and third parties.

Our operating expenses for the quarter and year ended December 31, 2023 increased by $2.1 million and $5.7 million, respectively, compared to the same periods in 2022. These changes are primarily due to higher software license and subscription fees, higher legal and insurance costs, higher salaries and benefits, and market inflation on utilities and other general operating expenses.

Disallowed capital costs

(in millions of dollars)	**2024**	2023	2022
Quarter ended December 31,	**$ —**	$ —	$ —
Year ended December 31,	**—**	—	1.5

On January 19, 2022, the AUC issued its decision on AltaLink's 2022-2023 GTA. The AUC disallowed $1.5 million of capital replacement and upgrade project additions related to our Wildfire Mitigation Plan.

Property taxes, salvage and other

(in millions of dollars)	**2024**	2023	2022
Quarter ended December 31,	**$ 20.7**	$ 30.5	$ 26.1
Year ended December 31,	**103.1**	111.6	98.4

Property taxes, salvage and other expenses are recovered dollar for dollar through regulated deferral and reserve account mechanisms and includes property taxes, salvage expenses, self-insurance expenses, annual structure payments, and hearing expenses. To the extent that actual costs vary from amounts approved in our tariffs, the difference is refunded to or collected from the AESO and included in Revenue from operations.

Property taxes, salvage, and other expenses for the quarter and year ended December 31, 2024 decreased by $9.8 million and $8.5 million, respectively, compared to the same periods in 2023. These changes are primarily due to a decrease in salvage expense as a result of the AUC approving the collection of costs of site preparation for capital replacement projects over the average useful lives of the related replacement assets starting January 1, 2024. As a result, the Partnership now capitalizes these costs. This variance was partially offset by recognizing $18.5 million of self-insurance expense related to the 2023 wildfire and snow events. Expenses associated with the 2023 wildfire and snow events were originally capitalized but were denied capitalization in the AUC's decision received on July 31, 2024, and instead approved to be recovered through the self-insurance reserve account.

For more details of these costs, please see note 21 - Expenses in our annual audited consolidated financial statements.

Property taxes, salvage, and other expenses for the quarter and year ended December 31, 2023 increased by $4.4 million and $13.2 million, respectively, compared to the same periods in 2022. These changes are primarily due to an increase in salvage expense due to higher salvage activities and higher property taxes.

Depreciation and amortization

(in millions of dollars)	**2024**	2023	2022
Quarter ended December 31,	**$ 77.8**	$ 76.3	$ 74.8
Year ended December 31,	**301.2**	293.9	287.0

We calculate depreciation and amortization on a straight-line basis using various AUC-approved rates.

Depreciation and amortization for the quarter and year ended December 31, 2024 increased by $1.5 million and $7.3 million, respectively, compared to the same periods in 2023. These changes are primarily a result of capital projects that have been completed and added to our property, plant and equipment and intangible assets compared to lower asset retirements.

Depreciation and amortization for the quarter and year ended December 31, 2023 increased by $1.5 million and $6.9 million, respectively, compared to the same periods in 2022. These changes are primarily a result of capital projects we completed and added to our property, plant and equipment and intangible assets compared to lower asset retirements.

Finance costs

(in millions of dollars)	**2024**	2023	2022
Quarter ended December 31,	**$ 52.0**	$ 52.1	$ 49.0
Year ended December 31,	**204.2**	197.2	188.9

Finance costs include interest expense on short-term debt, long-term debt, and lease liabilities as well as amortization of deferred financing fees less capitalized borrowing costs.

For the quarter and year ended December 31, 2024 our weighted average cost of long-term debt was 4.29% and 4.25%, respectively (December 31, 2023 – 4.11% and 4.03%, respectively, and December 31, 2022 – 3.93% and 3.91%, respectively).

Our finance costs for the quarter ended December 31, 2024 decreased by $0.1 million compared to the same period in 2023 primarily due to a lower weighted average cost of short-term debt partially offset by a higher weighted average cost of long-term debt. Our finance costs for the year ended December 31, 2024 increased by $7.0 million compared to 2023 primarily due to a higher weighted average cost of long-term debt.

Our finance costs for the quarter and year ended December 31, 2023 increased by $3.1 million and $8.3 million, respectively, compared to the same periods in 2022. These changes are primarily due to a higher weighted average cost of short-term and long-term debt.

EBITDA

(in millions of dollars)	**2024**	2023	2022
Quarter ended December 31,	**$ 214.9**	$ 210.5	$ 208.7
Year ended December 31,	**845.6**	799.3	789.9

Our EBITDA for the quarter and year ended December 31, 2024 increased by $4.4 million and $46.3 million, respectively, compared to the same periods in 2023. These changes are primarily due to higher revenue and lower property taxes, salvage and other expenses, partially offset by higher operating expenses.

Our EBITDA for the quarter and year ended December 31, 2023 increased by $1.8 million and $9.4 million, respectively, compared to the same periods in 2022. These changes are primarily due to higher revenue, partially offset by higher salvage expenses, higher operating costs and lower revenue on equity returns on a lower rate base.

Please refer to the *"Liquidity"* section of this MD&A for more information on how we calculate EBITDA.

Comprehensive income

(in millions of dollars)	**2024**	2023	2022
Quarter ended December 31,	**$ 79.9**	$ 76.4	$ 84.4
Year ended December 31,	**330.1**	297.8	311.2

Our comprehensive income for the quarter and year ended December 31, 2024 increased by $3.5 million and $32.3 million, respectively, compared to the same periods in 2023. The changes are primarily due to increased revenue from the regulatory generic cost of capital decision, and a higher recovery of interest as a result of increased approved short-term interest rates, partially offset by higher operating costs.

Our comprehensive income for the quarter and year ended December 31, 2023 decreased by $8.0 million and $13.4 million, respectively, compared to the same periods in 2022. The changes are primarily due to higher interest rates on short-term debt, higher operating costs mainly as a result of inflation, an actuarial loss compared to an actual gain in 2022, and lower revenue on equity returns on a lower rate base.

Selected financial information derived from our consolidated financial statements

	December 31, 2024	December 31, 2023	December 31, 2022
Net income per partnership unit ($/unit)	**0.996**	0.898	0.932
Comprehensive income per partnership unit ($/unit)	**0.995**	0.897	0.938
Distributions per partnership unit ($/unit)	**0.760**	0.679	0.738
Total assets (in millions of dollars)	**10,134.5**	10,017.3	9,897.8
Short and long-term debt (in millions of dollars)[1]	**4,873.7**	4,874.3	4,867.8

1. The balance before deducting deferred financing fees, which we offset against this amount in the consolidated financial statements, in accordance with IFRS Accounting Standards.

Summary of quarterly financial information

Quarter ended	Revenue ($ millions)	Net income ($ millions)	Units outstanding (millions)	Net income per unit ($/unit)
December 31, 2024	**272.7**	**80.4**	**331.9**	**0.242**
September 30, 2024	277.8	83.7	331.9	0.252
June 30, 2024	251.5	83.9	331.9	0.253
March 31, 2024	269.2	82.6	331.9	0.249
December 31, 2023	264.5	76.7	331.9	0.231
September 30, 2023	252.2	74.6	331.9	0.225
June 30, 2023	252.8	74.1	331.9	0.223
March 31, 2023	246.2	72.8	331.9	0.219
December 31, 2022	256.3	82.3	331.9	0.248
September 30, 2022	243.6	74.5	331.9	0.225
June 30, 2022	242.6	77.0	331.9	0.232
March 31, 2022	246.5	75.3	331.9	0.227

Risk Management

Our transmission business is subject to risks and uncertainties like those described below. Our goal is to manage these risks to reasonably protect us from unacceptable outcomes including undesirable financial results. The reader should carefully consider these risk factors and uncertainties in addition to the other information contained in this MD&A, our corresponding consolidated financial statements, Annual Information Form, press releases, material change reports and other continuous disclosure documents available on SEDAR+ at www.sedarplus.ca.

Risk Controls and Other Mitigating Measures

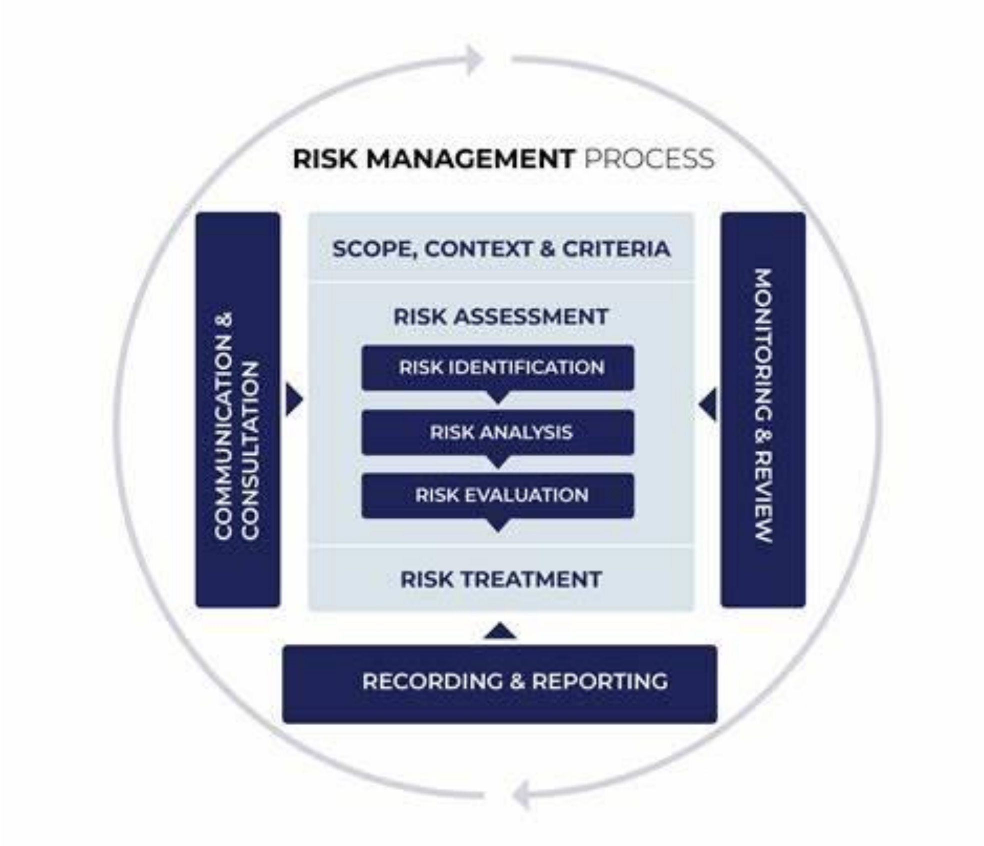
We maintain controls and other mitigating measures to manage the risks we face. Under our risk management program, we conduct quarterly risk evaluations to identify and assess our most significant risks and the strategies through which we manage them.

Our Approach to Enterprise Risk Management

We use an enterprise-wide portfolio approach to manage key business risks. These risks stem from the uncertainty that permeates our business. Managing these risks successfully requires a systematic, structured and timely approach. To achieve this, we have developed an enterprise risk management policy which has been approved by our Board of Directors. We have also defined an Enterprise Risk Management Framework and developed an enterprise risk management program modelled after the ISO 31000 standard. A primary goal of our enterprise risk management program is to provide uniform processes to identify, analyze, evaluate, treat and report our key risks for the benefit of our customers and shareholders. By strengthening our risk management practices, enterprise risk management supports the corporate governance needs of our Board of Directors and the due diligence responsibilities of senior management.

We integrate risk management with our strategic planning and business planning processes to promote and facilitate proactive management of risks and opportunities that may impact our strategic and business objectives.

The following diagram depicts our enterprise risk management process:



Risk Assessments

Risk assessments involve identifying, analyzing and evaluating the risks we face. Some of the methods we use to identify risks and opportunities include management interviews, facilitated risk workshops, and stakeholder discussions. Under our enterprise risk management program, we conduct quarterly risk assessments to identify and analyze our most significant risks and opportunities and the existing controls which manage them. Risk owners are defined for all our key risks. We then combine quantitative and qualitative methods to analyze the residual likelihood and potential impact associated with the risks and opportunities.

We use a heat map as a tool to document residual risk levels for our most significant risks and opportunities. For the top strategic and operational risks, key risk indicators are tracked, and risk treatment plans are in place.

Our risk management program includes management's quarterly review and update of current and emerging risks or opportunities against our approved risk criteria.

Risk treatment involves making decisions as to the appropriate course of action to increase or decrease risk to target levels. Risk treatment approaches may include avoiding the risk by discontinuing activities, taking an appropriate amount of additional risk to pursue opportunities, taking actions to modify the likelihood or consequence of the risk, sharing or outsourcing the risk, or making an informed choice to retain the risk at the already appropriate level. Management updates assessments of residual risks on a quarterly basis and reports these assessments to the Board of Directors. Monitoring of risks against risk tolerances, key risk indicators, and the status of ongoing controls and risk treatment plans are reported to the Board of Directors annually.

Insurance and Statutory Liability Protection

Our current insurance policies provide coverage for a variety of losses and expenses that could impact our business. This insurance coverage includes general liability, physical loss of or damage to property, boiler, and machinery (including substations), property terrorism, directors' and officers' liability, fiduciary liability, employment practices liability, crime, non-owned aircraft liability, remotely piloted aircraft systems liability, and vehicle liability. We believe the extent of this coverage is prudent in the context of our transmission business and utility industry practice, and we anticipate maintaining this coverage.

Consistent with certain past AUC decisions, we do not carry insurance for physical loss of, or damage to, transmission lines, towers, poles, or physical damage to certain owned vehicles. We do carry insurance for all other assets and $400 million in general liability insurance. General liability insurance provides coverage for third-party bodily injury or property damage resulting from our operations or premises for which we are legally obligated to pay. This coverage includes, but is not limited to, fire suppression costs and damages resulting from wildfires. It is not always possible or economically feasible to insure against all risks on our assets or for other exposure to liabilities, and we may decide not to carry insurance against certain risks for several reasons including high premiums. In accordance with past prudent industry practice and certain AUC directives, we self-insure against certain risks for which commercial insurance is not acquired. In the event of an uninsured loss greater than $100,000, we may apply to the AUC to recover the loss through increased funding to our self-insurance reserve or through increased tariffs. Costs claimed through the self-insurance reserve are subject to AUC approval and we cannot predict with certainty how related AUC decisions could adversely impact us. We cannot predict if the regulator may find we have acted imprudently, and consequently deny the recovery of damages through rates. In Decision 2013-417 (Utility Asset Disposition), the AUC determined that in the case of an extraordinary retirement of a regulated asset, any under or over recovery of capital investment is allocated to the utility and its shareholders. We do not carry insurance for this risk.

The *Electric Utilities Act* (Alberta) and the Liability Protection Regulation limits our liability by excluding liability for a third-party's loss of profits, loss of revenue, loss of production, loss of earnings, loss of contract or any other indirect, special, or consequential loss or damage arising out of or in any way connected with an Independent System Operator act. Our liability is therefore confined to a third-party's direct loss or damage resulting from our negligence, wilful misconduct or breach of contract while performing our legislative duties, responsibilities and functions.

Risk Factors and Uncertainties

Despite our risk management initiatives, we have no assurance that an individual risk or multiple risks will not adversely affect our business. If we are unable to adequately control or mitigate their effects, such risks could adversely affect our results of operations, financial position and performance and, accordingly, the value of our outstanding securities.

The following are the more significant risks that have an impact on our financial position and results of our operations:

Regulatory Risks

Regulated financial risk

As a regulated transmission facility owner in Alberta, we are subject to the risks normally faced by companies that are regulated. These risks relate to the AUC directing the amendment of our applied for tariffs or revenue requirements, which permit a reasonable opportunity to recover on a timely basis the estimated costs of providing service, including a fair return on rate base. In addition, these risks include the disallowance by the AUC of costs incurred. Our ability to recover the actual costs of providing service and to earn the approved rates of return depends on achieving our forecasts and demonstrating the prudency of the incurred costs in the rate-setting process.

Actual costs could exceed the approved forecast costs if, for example, we incur operational, maintenance and administration costs above those included in our approved revenue requirement, higher expenses due to maintenance capital expenditures being at levels above those provided for in the tariff decisions, or additional financing charges because of increased debt balances or higher interest rates. The AUC also reviews the prudency of our capital costs. We cannot predict how AUC decisions may adversely affect us and there can be no assurance that we can entirely recover the actual costs of capital work through the revenue requirement. Substantial unrecovered costs could have a material adverse effect on our financial condition and results of operations.

The AUC also authorizes placeholders for key assumptions within the GTA and DACDA processes. These assumptions are subject to change during the regulatory process, which may lead to retroactive adjustments for prior periods. The inability to obtain acceptable tariff decisions or to otherwise recover any significant difference between forecast and actual expenses, or changes in key assumptions in a timely manner, could adversely affect our financial condition and results of our operations. Management can do less to mitigate this risk when regulatory decisions are made after the start of the period to which they apply. Regulatory decisions can also delay our recovery of balances owed to us for deferral accounts.

Utility asset disposition

As a regulated transmission facility owner, we are subject to the risk that transmission infrastructure assets could be retired before they are fully depreciated. We cannot predict with certainty how AUC decisions could adversely impact us; thus, we neither have nor offer the assurance that we can entirely recover the net book value of assets through the AUC-approved revenue requirement. If the AUC determined a loss was "extraordinary", this could negatively impact us as the AUC has, in the past, decided that utility shareholders bear extraordinary losses.

We continue to monitor decisions from the AUC and the Alberta courts regarding utility asset dispositions and address any resulting increased risks.

Transmission system cost bypass by load customers

Our customers may be impacted by load customers bypassing transmission system costs as it could increase costs for remaining load customers. Although we do not have any direct volume or price risk, there is potential for continuous and increasing cross-customer cost subsidization because of the existing design of the AESO tariff. Future regulatory or government policy decisions may result in changes that could adversely affect our financial results by an allocation of these costs to the utility. It is anticipated that cost bypass will be a significant part of the ISO tariff re-design in the AESO's next tariff application in January 2027.

Government policies impacting the electricity industry

Deregulation and restructuring of parts of Alberta's electricity industry began in 1996 and continues to evolve. We are subject to risks associated with changing political conditions and changes in provincial regulations and permitting requirements. It is not possible to accurately predict changes in political conditions, laws or regulations that could impact our operations. The continuing restructuring of the Alberta electricity industry, including the regulatory environment, could have a material adverse effect on our financial condition and results of our operations. Please refer to the "Electricity Policy Review" section of this MD&A.

Financial Risks

Credit ratings

Our credit ratings are not recommendations to purchase, hold or sell our debt securities in that such ratings do not comment as to market price or suitability for a particular investor. AltaLink cannot give assurance that any credit rating will remain in effect for any given period or that our credit ratings will not be revised or withdrawn entirely in the future by the respective credit rating agencies if in their judgment circumstances so warrant. Our credit ratings may not reflect the potential impact of all risks related to our business or our debt securities. In addition, real or anticipated changes in our credit ratings will generally affect the market value of our debt securities.

Previously we faced higher levels of construction investment, as the AESO directly assigned the construction of large multi-year transmission facility projects to us. We experienced increased debt service obligations because of significantly increased debt capital levels necessary to fund their construction, but without corresponding additions to our rate base assets during the construction period for such capital projects. During this time, the AUC supported us by providing credit metric support through both CWIP in rate base and the recovery of provincial and federal future income taxes in our revenue requirement. When we emerged from the period of higher investment, the AUC approved our application to discontinue this credit metric support to lower our tariffs for our customers.

Although the AUC provided credit metric support, there can be no assurance that we will receive the regulatory support necessary to mitigate evolving financial risk as needed. Without this regulatory support we anticipate that, among other things, the ratings of our debt securities may be downgraded.

If the credit ratings of our debt securities were downgraded, then we would expect that our access to the necessary capital to finance transmission projects may be adversely impacted and the cost of capital available to us would likely be increased.

Competition

In Alberta, our industry has generally operated on the premise that transmission facility owners provide most of the facilities and services required within their respective geographic service territories. However, changes to legislation were made where the assigning of critical transmission projects may be made through competitive tender regardless of historical service area. In addition, the Lieutenant Governor in Council may make regulations respecting the determination of who may apply for construction or operation of transmission facilities, including determining who may apply based on a competitive process or some other method or process. The AESO applied to the AUC for approval of its proposed framework for competitive bidding. The AUC approved the AESO's application, with conditions. There can be no assurance that any competition related to the provision of transmission services will not have a material adverse effect on our financial condition and results of our operations.

Capital resources and liquidity

Our financial position could be adversely affected if we fail to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and the repayment of maturing debt. Funds generated from our operations after payment of our expenses (including interest payments on debt) may not be sufficient to fund the repayment of all existing debt when due and anticipated capital expenditures. There may be limitations on the levels of equity capital available to us from our partners. We are substantially wholly owned by AILP and do not use our equity securities as a primary source of capital. Our ability to arrange sufficient and cost-effective debt financing could be affected by numerous factors, including the regulatory environment in Alberta, the results of our operations and financial position, conditions in the capital and bank credit markets, our credit ratings, and general economic conditions. The inability to access sufficient capital for our operations could have a material adverse effect on our financial condition and results of our operations.

Annual impairment tests

Any write-down in the value of goodwill or other assets because of an annual impairment test would result in a non-cash charge that reduces our reported earnings. A write-down of any material amount could have an adverse effect on our compliance with any debt to total capitalization tests under our credit facilities or trust indentures. If our credit metrics were adversely impacted, then we anticipate that, among other things, the credit ratings of our debt securities may be downgraded, our access to the necessary capital to finance transmission projects may be adversely impacted and the cost of capital available to us may be increased.

Operational Risks

Wildfires

Alberta has experienced a heightened incidence of wildfires and wildfire severity due to climate change and other factors. We cannot predict how the AUC will respond to such heightened incidence, or how the AUC might treat recovery of our past investment or the cost of restoration assets.

Electricity transmission facilities may also start wildfires as a result of causes such as equipment operation or failure, and objects including trees contacting transmission assets. We have a robust set of procedures to address wildfire risk. We review and update these procedures based on the practices in other jurisdictions. We apply to the AUC for approval for funds to implement these procedures and mitigation investments. Additional requirements may be imposed by the regulator or legislators in response to heightened risk.

Despite these actions, we may be liable for firefighting costs, damages to personal property, structures, and natural resources, fines, and third-party claims including for personal injuries in connection with such fires. These costs could substantially exceed insurance coverage, if any, and such amounts may not be approved by the AUC for recovery, in whole or in part, through increased tariff revenues. Substantial unrecovered costs could have a material adverse effect on our financial condition and results of our operations.

Cyber and physical security

We rely on information technology in virtually all aspects of our business. A significant disruption or failure of our information technology systems by physical or cyber attack could result in service interruptions, outages, safety failures, security violations, regulatory compliance failures, an inability to protect corporate information assets against intruders, and other operational difficulties. Attacks perpetrated against our information systems could result in loss of assets and critical information and expose us to remediation costs, damages, fines, and reputational damage.

Although we have taken steps intended to mitigate these risks, including business continuity planning, compliance with Critical Infrastructure Protection Standards, disaster recovery planning, implementing a comprehensive cyber security program, and business impact analysis, a significant disruption or cyber intrusion could lead to misappropriation of assets or data corruption and could adversely affect our results of our operations, financial condition or liquidity. We also engage the services of external experts to evaluate the security of our information technology infrastructure and controls. Additionally, if we are unable to maintain, acquire or implement new technology that is up to date with cyber security requirements, this could have an adverse effect on our results of our operations, financial condition or liquidity. Cyber or physical attacks could further adversely affect our ability to operate facilities, information technology and business systems, or compromise confidential customer and employee information. In addition, physical or cyber attacks against key suppliers or service providers could have a similar effect on us.

Transmission reliability

The reliability of our transmission facilities is critical to the customers who depend upon them. Our transmission assets require maintenance, improvement and replacement to help ensure their reliable performance. We continually develop capital expenditure programs and assess current and future operating and maintenance requirements for our facilities.

Our ability to reliably deliver power is subject to the risk of service interruptions from factors that include equipment failure, accidents, climate change, severe weather conditions and other acts of nature, operator error, labour-related actions, vandalism, sabotage, cyber attacks or terrorism. As a result, our ability to deliver an acceptable level of reliability to our customers may be adversely impacted.

We base our upgrade and maintenance programs on assumptions as to costs of services and equipment, regulatory requirements, revenue requirement approvals, and other matters which are not certain. The inability to obtain AUC recognition (in connection with determining our revenue requirements) of expenditures which we believe are necessary to maintain, improve, or replace our transmission assets, the failure to carry out these upgrade and maintenance programs on a timely basis, or the occurrence of significant unforeseen equipment failures or damage could have a material adverse effect on us. The costs of repairing or replacing damaged assets, or responding to customer claims, could substantially exceed insurance coverage, if any, and such amounts may not be approved by the AUC for recovery, in whole or in part, through increased tariff revenues. While we may be liable for direct damages to third parties as a result of our negligence, willful misconduct or breach of contract, we expect that the Liability Protection Regulation shields us from most claims for indirect damages, such as loss of profit or revenue. The effectiveness, however, of this liability protection is subject to the court's interpretation of the regulation, which has not yet occurred.

Legislation and the AESO's reliability standards and rules set out requirements with which we must comply as well as penalties for non-compliance. We expect to recover the costs of implementing and complying with requirements through our tariffs. Non-compliance penalties after investigations may be substantial, and we may not be able to recover these costs through our tariffs. Such penalties may have a material adverse effect on our financial condition and results of our operations.

In addition, we have a facility acceptance process for new assets as they become energized and integrated into our asset base. Material, equipment, engineering or construction deficiencies may be found following acceptance and energization of new assets, prior to expiration of warranty periods. Claims processes are in place to seek recovery of deficiencies found within the warranty periods. Arbitration or litigation may occur in relation to any claims process, which may result in litigation by or against us. Any substantial unrecovered warranty claims or costs incurred beyond the warranty period or costs above the warranty cap could have a material adverse effect on our financial condition and results of our operations.

Climate change
As a transmission facility owner and operator, we are subject to uncertainties caused by climate change and severe weather conditions. These uncertainties include, but are not limited to, the following potential impacts of climate change:

- Customer legal claims due to not being able to reliably transmit power due to service disruptions caused by severe weather;
- Not being able to recover investments in assets or costs related to the repair or replacement of assets damaged by severe weather or required by new environmental laws or regulations;
- Penalties for not being able to comply with laws, regulations, rules, or reliability standards;
- Wildfire, flood, wind, or other damages as a result of more extreme weather;
- Demands on our transmission system due to electric vehicles, charging stations, the transitioning to clean energy generation, and extreme temperatures; or
- Government policy or legislative changes or customer preferences for electrical generation using lower carbon fuels causing certain transmission assets to become stranded and our recovery of the related investments impaired and our reputation negatively impacted.

Potential effects of pathogens, or similar crises
Our business could be adversely affected by the outbreak of pathogens or similar crises, through new legislation or regulatory directives limiting our operations or by disruptions to our supply chains, which could adversely impact our ability to transmit reliable electricity or delay certain of our construction and other capital expenditure projects. Delays of our capital projects could result in increased costs which we may not be able to fully recover through the regulatory process. Such disruptions could adversely affect our consolidated financial results and our ability to service our long-term debt.

In addition, the government and regulators could impose other requirements on our business that could have an adverse financial impact on our results or operations. Further, we could be adversely impacted if we experience material payment delays or defaults by the AESO or other customers to which we provide services.

Project execution
We manage multiple capital projects to support our operations and the growth of our transmission system. Our ability to execute capital projects depends upon numerous factors that are normally faced by companies executing large construction projects. These factors include, but are not limited to, changes in project scope, the availability and timeliness of regulatory approvals and other required permits, skilled labour availability and productivity, staff resourcing, availability, quality, and cost of material and services, design and construction errors, the ability of contractors to deliver on project commitments, and the availability and cost of financing.

Some of these typical project risks may be more pronounced for our transmission facility projects. They include the risks associated with the regulatory approval process, which can involve significant landowner opposition and be delayed due to challenges in areas such as route selection, landowner consultation, compliance (including receiving the required environmental or other permits, approvals and certificates from federal, provincial or municipal agencies), and litigation.

These project risks can translate into performance issues and project delays, which under traditional regulatory accounting would delay the receipt of expected cash flows related to a project. Delays in receiving cash flows for large projects could have an adverse impact on our credit metrics, which are considered by debt rating agencies in assigning a particular rating to our debt securities.

Project risks including inflation can also translate into additional actual project costs. We are dependent upon AUC decisions for recovery of the actual project costs of constructing our facilities. We maintain a capital deferral account that is intended to capture the difference between our forecast costs and the actual costs of capital projects for directly assigned projects. The AUC reviews all project costs recorded in our capital deferral account to determine whether the actual costs of projects were prudently incurred. There can be no assurances that all the actual costs of capital projects will be recovered through an increased revenue requirement approved by the AUC or that a previously approved revenue requirement will not be reduced through the review process. We cannot predict with certainty how AUC decisions may adversely impact us and there can be no assurance that we can entirely recover the actual costs of directly assigned capital projects through the revenue requirement approved by the AUC. Substantial unrecovered costs could have a material adverse effect on our financial condition and results of our operations.

Labour relations

On May 6, 2024, AltaLink and the United Utility Workers' Association (UUWA) reached a four-year collective agreement. The term of the agreement is January 1, 2024, to December 31, 2027.

On December 23, 2024, AltaLink and the International Brotherhood of Electrical Workers (IBEW) ratified a collective bargaining agreement which is effective January 1, 2025, to December 31, 2028 (previous four-year collective agreement term expired on December 31, 2024).

These four-year term collective agreements will provide our business and our people with stability.

Approximately 57% of our employees are unionized (361 UUWA employees and 28 IBEW employees). The provisions of collective agreements affect the flexibility and efficiency of our business. We consider our relationship with these labour union groups to be collaborative; however, there can be no assurances that current relations will not be affected throughout future collective bargaining processes.

Environment, health, and safety

We are subject to regulation relating to the protection of the environment, health and safety, under a variety of federal, provincial and municipal laws and regulations (collectively, EH&S regulation). Among other things, spills and leaks can occur in the operation of electric transmission facilities, including accumulations of fluids containing hydrocarbons, PCBs and other contaminants in soil and gravel at substation and pole sites. Electricity transmission itself has inherent potential risks to safety.

Complying with EH&S regulation may require significant expenditures, including costs for cleanup and damages due to contaminated properties, and costs for implementing appropriate training and work safety programs. Failure to comply with EH&S regulation may result in fines and penalties and regulatory authorities may also seek or order the recovery of natural resource damages, injunctive relief or the imposition of stop work orders. We are also exposed to civil and criminal liability for EH&S matters.

Although we do not expect that the costs of complying with EH&S regulation or dealing specifically with environmental liabilities, as they are known today, will have a material adverse effect on our financial condition or results of our operations, we have no assurance that the costs of complying with future EH&S regulation will not have a material effect.

Electric and magnetic fields

Scientists and public health experts in Canada, the United States and other countries continue to study the possibility that exposure to electric and magnetic fields from power lines, household appliances and other electricity sources may cause health problems. If it were to be concluded that electric and magnetic fields present a health hazard, we may face litigation and be required to take mitigation measures. The costs of any litigation, damages awarded, and mitigation measures could have a material adverse effect on our financial condition and results of our operations.

Transactions with Related Parties

Throughout our normal course of business, we enter into various transactions with related parties. We record these transactions at exchange values based on normal commercial rates. AML employs all staff who provide administrative and operational services to our business on a cost reimbursement basis. We indemnified AML for employment associated expenses of $32.0 million and $135.4 million, for the quarter and year ended December 31, 2024, respectively, (December 31, 2023 – $31.5 million and $129.0 million, respectively) and liabilities of $27.0 million as at December 31, 2024 (December 31, 2023 – $24.9 million).

On March 31, 2023, we added a $150.0 million inter-affiliate revolving credit facility from AILP to provide additional liquidity for ALP.

For more details, please refer to note 18 - Related party transactions in our annual audited consolidated financial statements.

Legal Proceedings and Contingencies

We are subject to legal proceedings, investigations, assessments, and claims throughout our ordinary course of business. AltaLink was sued by third parties who seek compensation for damages in respect of certain operating, capital or other activities performed by AltaLink or its contractors. We intend to defend ourselves vigorously against these claims. These contingencies depend on future legal proceeding results and the likely outcomes are not determinable.

We found equipment, engineering or construction deficiencies following acceptance and energization of certain assets. We have claims processes in place to seek recovery for such deficiencies. We intend to vigorously pursue these claims.

In one instance, we had claimed that specific equipment had inherent design, manufacturing, and other defects that created a risk of personal injury and property damage. On September 27, 2023, through a judicial dispute resolution process led by a justice of the Court of King's Bench (Alberta), all parties agreed to settle the claim in respect of this equipment. We are passing along all benefit of recovery to customers by lowering rate base, as previously directed by the AUC. The cash recovery was used to pay down debt and return equity to shareholders. There was no gain or loss from this settlement.

Off-Balance Sheet Arrangements

All off-balance sheet arrangements such as transactions, agreements or contractual arrangements with unconsolidated entities, structured finance entities, special purpose entities or variable interest entities reasonably likely to materially affect liquidity or the availability of, or requirements for, capital resources require disclosure. We currently have no such off-balance sheet arrangements. For details regarding our commitments, please refer to note 26 - Commitments in our annual audited consolidated financial statements.

Critical Accounting Estimates

We make estimates and assumptions that affect amounts reported in the consolidated financial statements and accompanying notes. The more significant estimates impacting our financial condition and the results of our operations are disclosed in note 2 - Basis of preparation in our annual audited consolidated financial statements.

Accounting Changes

Rate-regulated project

At the International Accounting Standards Board (IASB) meetings in July 2015, the IASB determined that understanding the following three inter-connected relationships is key to developing a standard for the recognition of rate-regulated activities:

- The rate-regulated entity and its customers
- The rate-regulated entity and the regulators
- The rate-regulator and the entity's customers

The IASB met several times from 2016 to 2020 for discussions regarding a new accounting model for rate-regulated activities and to explore how to amend IFRS Accounting Standards to reflect the effects of rate regulation. On January 28, 2021, the IASB published an exposure draft of a new IFRS Accounting Standard on regulatory assets and regulatory liabilities with comments requested by July 30, 2021. We provided our comments as part of a comment letter submitted by Electricity Canada. In July 2024, following completion of the redeliberation of the proposals in the Exposure Draft, the IASB confirmed it was satisfied that applicable due process requirements have been complied with and sufficient consultation and analysis were undertaken to begin the process for balloting the new IFRS Accounting Standard. The IASB expects to publish the new Standard in the second half of 2025. The new Standard will replace IFRS 14 *Regulatory Deferral Accounts.* This new Standard is not expected to have a material impact to our consolidated financial statements as we were able to recognize financial assets and liabilities related to regulated activities when we adopted IFRS in 2010.

Forward-Looking Information

This MD&A contains certain statements or disclosures that may constitute forward-looking information under applicable securities laws. All statements and disclosures, other than those of historical fact, which address activities, events, outcomes, results or developments that AltaLink anticipates or expects may or will occur in the future (in whole or in part) should be considered forward-looking information. In some cases, forward-looking information can be identified by terms such as “anticipate”, “believe”, “contemplate”, “continue”, “could”, “enable”, “expect”, “forecast”, “future”, “intends”, “may”, “plan”, “potential”, “will” or other comparable terminology. Forward-looking information presented in such statements or disclosures may, without limitation, relate to: applications to the AUC for approval of, among other things, AltaLink's revenue requirements (including deferral and reserve accounts; capital structure and return on equity; financing plans; treatment of costs for applicable test periods including income taxes, operating expenses, depreciation, capital costs for direct assigned projects and maintenance programs, financing costs related to long-term debt and short-term borrowing, and projected growth in AltaLink's rate base and assets under construction); transmission system expansion forecasts; the anticipated direct assignment of transmission development projects to AltaLink from the AESO pursuant to approved Need Applications or competitive bidding processes; the timing and development of transmission projects and the anticipated capital costs of such projects; business strategy, plans and objectives of management for future operations; forecast business results; the achievement of certain operational and performance measures and the resulting effect on compensation of executive officers; and the anticipated financial performance or condition of AltaLink.

Various factors or assumptions are typically applied in drawing conclusions or making the forecasts or projections set out in forward-looking information. These factors and assumptions include but are not limited to:

- no changes in the legislative and operating framework for Alberta's electricity market that are adverse to AltaLink (refer to "Transmission Tariffs" and "Overview of Electricity Industry in Alberta" sections of this MD&A, for examples);
- decisions from the AUC concerning outstanding tariff and other applications that are consistent with past regulatory practices and decisions and are obtained in a timely manner (refer to "Transmission Tariffs" and "Major Capital Projects" sections of this MD&A, for examples);
- approved rates of return and deemed capital structures for AltaLink's transmission business that are sufficient to foster a stable investment climate (refer to "Transmission Tariffs" section of this MD&A, for examples);
- a stable competitive environment;
- AltaLink obtaining sufficient capital on acceptable terms to finance its transmission system expansion and to pay maturing debt; and
- no significant event occurring outside the ordinary course of business such as a natural disaster, pandemic or other calamity.

These assumptions and factors are based on information currently available to AltaLink including information obtained by AltaLink from third-party industry analysts. In some occurrences, material assumptions and factors are presented or discussed elsewhere in this MD&A and in the Annual Information Form in connection with the statements or disclosures containing the forward-looking information. AltaLink cautions readers that the foregoing list of material factors and assumptions is not exhaustive.

The forward-looking information in statements or disclosures in this MD&A is based (in whole or in part) upon factors which may cause actual results, performance or achievements of AltaLink to differ materially from those contemplated (whether expressly or by implication) in the forward-looking information. These factors are based on information currently available to AltaLink including information obtained by AltaLink from third-party industry analysts. Actual results may differ materially from those predicted by such forward-looking statements. While AltaLink does not know what impact any of these differences may have, its business, results of operations, financial condition and its credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- the risks associated with being subject to extensive regulation, including risks associated with AUC action or inaction;
- the risk that the AUC does not provide specific levelization to sustain AltaLink's credit metrics over a growth period characterized by large multi-year transmission facility projects;

- the risk that transmission projects are not directly assigned to AltaLink by the AESO or that AltaLink is not designated for filing a facility application;
- the risk that AltaLink is not able to arrange sufficient cost-effective financing to repay maturing debt and to fund capital expenditures and other obligations;
- the risk that system expansion plans are delayed or changed;
- the risks that the actual costs of completing a transmission project significantly exceed estimated costs, or that the AUC determines actual costs of completing a project were not prudently incurred or may be otherwise retroactively denied;
- the risks to AltaLink's facilities and services posed by climate change, severe weather, wildfires, other natural disasters or catastrophic events, including pandemics, and the limitations on AltaLink's insurance coverage or self-insurance regulated by the AUC for losses or recovery of net book value resulting from these events;
- the potential for service disruptions and increased costs if AltaLink fails to maintain and improve its aging asset base or experiences a cyber or physical attack;
- the risks associated with forecasting AltaLink's revenue requirements and the possibility that AltaLink could incur operational, maintenance or administrative costs above those included in AltaLink's approved revenue requirement;
- the risk that transmission system expansion costs that are directed to AltaLink by the AESO or costs incurred by AltaLink in maintaining or upgrading the existing system become stranded and AltaLink's recovery of the related costs is impaired;
- the risk that transmission system costs bypassed through distribution-connected generation, onsite generation by load customers and net metering practices results in decreased use of system facilities or billing determinant erosion and therefore increased cost of service for remaining system users or an allocation of those costs to the utility; and
- the risk that the level of transmission system expansion or replacement may be impacted as a result of general regulatory or government policies intended to minimize the construction of and costs associated with new transmission. These include, amendments to the *Transmission Regulation* to move away from congestion-free transmission planning and the introduction of a Transmission Reinforcement Payment for generation-driven transmission development and the introduction of a Restructured Energy Market in 2027, the promotion of distributed-connected generation, distributed energy resources, behind-the-meter generation, self-supply and export and non-wires services, and the implementation of Alberta's Bill 22, *Electricity Statutes (Modernizing Alberta's Electricity Grid) Amendment Act*.

AltaLink cautions readers that the above list of risk factors is not exhaustive. Other factors, which could cause actual results, performance or achievements of AltaLink to differ materially from those contemplated (whether expressly or by implication) in the forward-looking statements or other forward-looking information, are disclosed in the section entitled “Risk Management” in this MD&A, including the subsection entitled “Risk Factors and Uncertainties”. Risk factors that could lead to such differences include, without limitation, legislative and regulatory developments that could affect costs or revenues, the speed and degree of competition entering the market, global capital markets conditions and activity, timing and extent of changes in prevailing interest rates, currency exchange rates, inflation levels and general economic conditions in geographic areas where AltaLink operates, results of financing efforts, changes in counterparty risk, and the impact of accounting standards issued by standard setters.

All forward-looking information is given as at February 24, 2025. AltaLink is not obligated to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required by applicable laws. Because of these risks, uncertainties, and assumptions, readers should not place undue reliance on these forward-looking statements. Any forward-looking information contained herein is expressly qualified by this statement.