AltaLink, L.P.

Management's Discussion and Analysis

August 5, 2025

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 August 5, 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 July 28, 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 unaudited consolidated condensed interim financial statements for the three and six months ended June 30, 2025 and 2024 (the second quarter consolidated financial statements), 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 period ended June 30, 2025 and the twelve-month period 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, 2024, is available on SEDAR+ at www.sedarplus.ca.

Executive Summary

Quarter Highlights

- We achieved a customer satisfaction average score of 9.73 out of 10 compared to 9.71 for the same quarter in 2024.

- We had one employee injury, representing a total recordable injury frequency rate of 0.61, matching our performance for the same quarter in 2024.

- Our customer average outage duration increased to six minutes compared to four minutes for the same quarter in 2024. Performance was impacted by wildfire activity that required de-energization of seven transmission lines across four different fire events. These wildfire de-energizations contributed three of the six average outage duration minutes in the quarter. Excluding the impact of wildfires, our reliability performance improved compared to the same quarter in 2024.

- On May 28, 2025, we activated our emergency response plan due to an out-of-control wildfire in the Lac La Biche area of Alberta. We quickly installed fire-resistant pole wrap on structures to help protect our assets where possible. This wildfire impacted four of our transmission lines. On June 10, 2025, we completed repairs and restored transmission service to our industrial customers in the area.

- On May 15, 2025, we filed our 2026-2027 GTA, 2023-2024 Deferral Accounts Reconciliation Application, and the 2026-2027 GTAs on behalf of PLP and KLP. On July 15, 2025, we filed an amended application and are seeking approval of total amended revenue requirements of $929.0 million and $975.5 million for 2026 and 2027, respectively.

- On July 10, 2025, the Transmission Amendment Regulation was enacted through Order in Council. The updated regulation, along with the May 15, 2025, implementation of Bill 52, the *Energy and Utilities Statutes Amendment Act,* makes several legislative and regulatory amendments to transmission policy. The focus of the legislation and regulation is on strengthening reliability, lowering and stabilizing Alberta utility bills and encouraging investment in the province.

- In July 2025, with the release of our 2024 Sustainability Report, AltaLink continued to demonstrate its commitment to sustainability as it operates the transmission system that supplies millions of Albertans with electricity.

- We earned net and comprehensive income of $82.6 million compared to $83.9 million for the same quarter in 2024. Our income decreased mainly due to decreased revenue from a lower approved return on equity of 8.97% in 2025 versus 9.28% in 2024, partially offset by one-time utility right-of-way revenue.

- In May 2025, S&P reaffirmed its issuer credit rating and senior secured rating on AltaLink at "A-" with a stable outlook. In July 2025, 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.

- We invested $112.1 million in capital assets compared to $96.0 million for the same quarter in 2024 to ensure continued electric transmission system safety and reliability, to replace transmission assets damaged by wildfires, and to connect customers.

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 confirmed our ranking in the top quartile of Canadian electric utilities for transmission outage duration and outage frequency. 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 by 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 the end of 2025.

- We connect new generation supply to support Alberta's economy and 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 PLP and KLP.

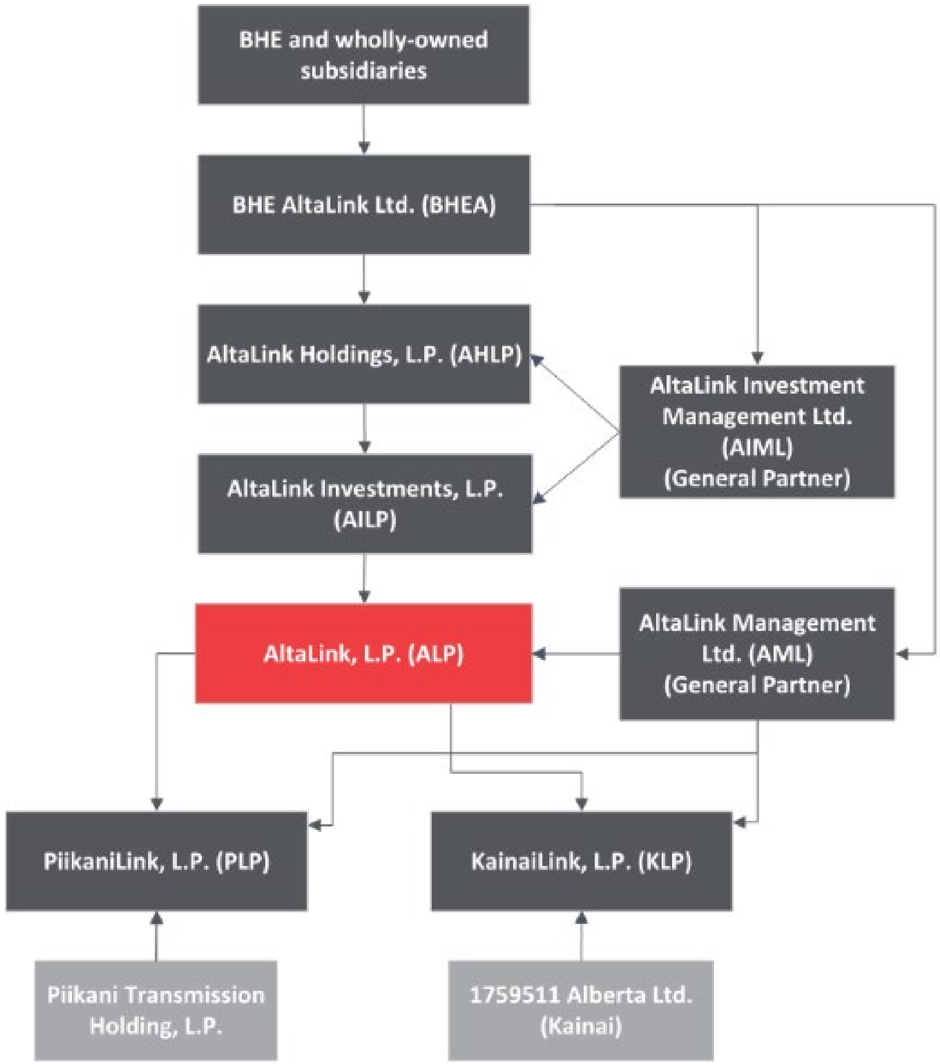
- We continue to advance our commitment to operate our business in a sustainable and socially responsible manner as well as maintaining our Sustainable Electricity Company designation from Electricity Canada which we first obtained in 2014. Our annual Sustainability Report highlights the Environmental, 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.

For more details regarding our business and strategies, please refer to "Our Business and Strategies" section of our MD&A for the year ended December 31, 2024.

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 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 the 12 months ended June 30, 2025 improved compared to the same period in 2024.

The table below summarizes our strong customer service performance.

	Twelve months ended June 30,				
	2025	2024	2023	2022	2021
Average customer satisfaction score	**9.72**	9.62	9.57	9.48	9.21

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, our 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 (LGBTQ+ 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 D&I, 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 D&I planning.

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 680 skilled and dedicated employees who maintain and operate our facilities and deliver on 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 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.

We support eligible employees with flexible work hours or compressed work weeks. This approach balances employee well-being, teamwork and collaboration. 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.

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.

The table below summarizes our strong safety performance.

	Twelve months ended June 30,				
	2025	2024	2023	2022	2021
Total recordable injury frequency rate[1]	**0.32**	0.48	0.48	0.16	0.00

1. Number of all lost time, restricted work, and medical aid incidents per 200,000 exposure hours worked by employees.

We experienced two employee injuries resulting in a total recordable injury frequency rate of 0.32 for the twelve months ended June 30, 2025.

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.

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 July 14, 2025, we released our 2024 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 transmission 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 transmission tariffs for the use of our transmission facilities. The AUC regulates all transmission 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.

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.

The North American Electric Reliability Corporation issued its 2025 Summer Reliability Assessment which states that wildfires are a threat to system reliability, particularly in Alberta. This risk was not listed as a risk in the 2024 Summer Reliability Assessment.

Wildfires emergency response

On May 28, 2025, we activated our emergency response plan due to an out-of-control encroaching wildfire in the Lac La Biche area of Alberta. We quickly installed fire-resistant pole wrap on structures to help protect our assets where possible. On May 30, 2025, the wildfire reached our assets and impacted four of our transmission lines. On June 10, 2025, we completed repairs and restored transmission service to our industrial customers in the area. Overall, 21 wood structures were damaged by this wildfire. The restoration of the damaged transmission lines, which is estimated to cost approximately $6 million, was challenging due to the assets being in remote, hard to access, forested muskeg.

During the same emergency response plan, we de-energized an additional two transmission lines on May 31, 2025, and June 7, 2025, under our encroachment policy. Neither of these events resulted in damage to our assets. We returned our emergency response to normal on June 23, 2025, when fire risk conditions subsided.

We continue to monitor the active wildfires in this area and continue to engage with Alberta Wildfire to assess wildfire threats.

Capital projects

We energized or completed $77.2 million of capital project additions in the second quarter of 2025 (2024 – $53.7 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 transmission outage duration and outage frequency.

In the second quarter of 2025 the AESO provided updates regarding the Reliability Requirements Roadmap confirming continued focus on implementing new ancillary services and fast frequency response in support of grid reliability, supply adequacy and intertie capabilities.

On May 26, 2025, the AESO posted a finalized scope of work for the Climate Resiliency White Paper with stakeholder consultation expected to start in 2026. The scope of the White Paper is to cover issues directly related to system resiliency, such as AESO plans and activities to maintain and enhance system resiliency, and a review of best practices for stakeholders as guidance to become more resilient. Issues related to climate change, Independent System Operator rules, policy, legislation, and regulatory frameworks are not in scope.

In the November 20, 2024, session, the AESO 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 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.

Our reliability of service continues to be strong. Our average customer outage duration for the 12 months ended June 30, 2025, increased compared to the same period in 2024, primarily due to the requirement to de-energize transmission lines experiencing encroachment from wildfires. Based on fire activity and risk in the Sturgeon County region in May 2025, we proactively de-energized one transmission line, directly impacting one industrial customer and increasing the average customer outage duration by 1.33 minutes. In addition, a large wildfire in the Lac La Biche area required us to de-energize four transmission lines but had no customer impacts as our industrial customers in the area had already begun halting their processes or were able to remain connected through other transmission lines in the region. A wildfire in the Edson area also encroached one of our transmission lines resulting in us de-energizing this line on May 31, 2025. This event also did not result in any customer impacts due to other available transmission lines in the region. Lastly, in June 2025 a wildfire in the Edson area encroached on another one of our transmission lines which we de-energized, impacting one industrial customer with an outage duration impact of 1.62 minutes. Throughout all these wildfire events, we engaged customers to coordinate outages to reduce the impact to their operations, wherever possible. Excluding these wildfire events, our customer outage duration improved for the quarter as compared to the same quarter in 2024.

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 table below summarizes our reliability performance from 2021 to 2025. Our customer reliability performance was impacted by the major wildfire and snowstorm events that occurred in the second quarter of 2023. 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.

	Twelve months ended June 30,				
	2025	2024[4]	2023	2022	2021
Duration of outages (SAIDI)[1]	**10.8**	10.1	8.8	8.3	16.0
Frequency of outages (SAIFI)[2]	**0.30**	0.29	0.33	0.28	0.42
Restoration time (SARI)[3]	**68.4**	69.1	40.1	63.8	66.0

1. System Availability Interruption Duration Index is the average number of interruption minutes per delivery point.
2. System Availability Interruption Frequency Index is the average number of interruptions per delivery point.
3. System Average Restoration Index is the average number of interruption minutes per sustained interruption.
4. These customer reliability metrics were adjusted to include a June 28, 2024, substation outage event that was previously recognized in July 2024.

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 and ISO 27019:2017. In addition, we complete an annual self-certification and 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 reliability 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.

Physical attacks on critical infrastructure in Canada and 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 transmission facilities in 2024 and 2025. On March 10, 2025, AltaLink was issued a new list of critical facilities from the AESO that must comply with CIP-014-AB-2 Physical Security requirements, which included five additional transmission facilities and removed one facility previously included. Ongoing investments to implement countermeasures and mitigations to these risks are planned to continue through 2032 pending 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, 2025, 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. On May 1, 2025, 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. For the six months ended June 30, 2025, our weighted average cost of long-term debt was 4.27% (June 30, 2024 – 4.20%).

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% until otherwise changed 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 table below summarizes our return on equity from 2021 to 2025.

	2025 Approved	2024 Approved	2023 Approved	2022 Approved	2021 Approved
Return on equity	**8.97%**	9.28%	8.50%	8.50%	8.50%

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.

Transmission Tariffs

Overview

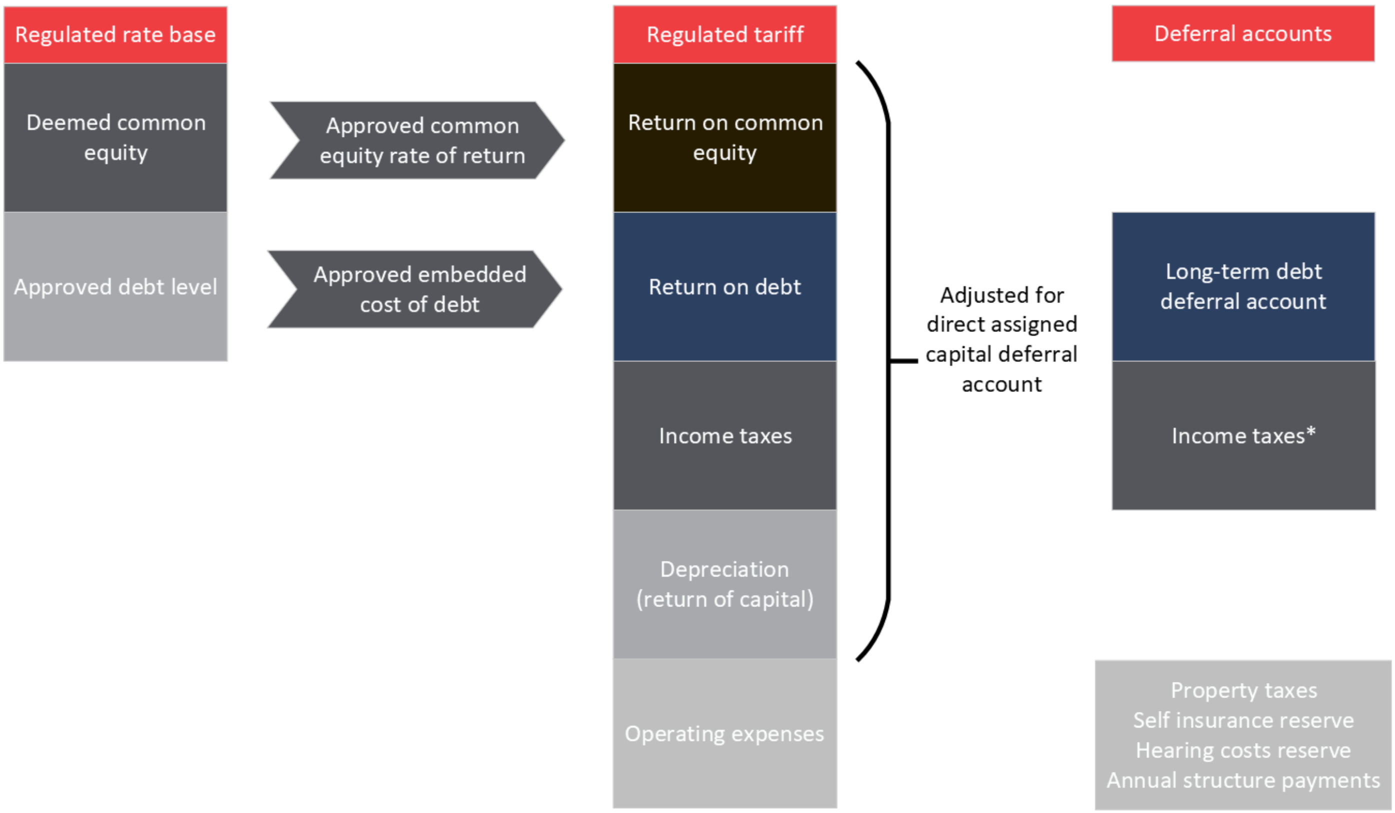
Under the *Electric Utilities Act* (Alberta), we prepare and file applications with the AUC for approval of transmission tariffs to be paid by the AESO for the use of our transmission facilities, and the terms and conditions governing the use of those facilities. The AUC reviews and approves our revenue requirements in our general tariff applications based on a cost-of-service regulatory model under a forward test year basis.

We met 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 extended our commitment for a seventh year to the end of 2025.

The table below summarizes our revenue requirements from 2021 to 2025.

(in millions of dollars)	**2025 Approved**	2024 Approved	2023 Approved	2022 Approved	2021 Approved
Revenue requirements	**$ 897.0**	$ 902.5	$ 883.0	$ 878.9	$ 873.3

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



* We will recover income taxes through regulated transmission tariffs following AUC approval beginning in 2026 when the taxes are deemed to be paid using the flow-through calculation method.

For more details regarding our transmission tariffs, please refer to the "Transmission Tariffs" section of our MD&A for the year ended December 31, 2024.

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 transmission tariffs

On December 5, 2024, the AUC approved final transmission tariffs for AltaLink, including monthly transmission 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 transmission tariffs for PLP and KLP, of $73.6 million per month effective January 2024.

2026-2027 General Tariff Application

On July 14, 2025, AltaLink filed responses to information requests from the AUC and interveners. On July 15, 2025, AltaLink filed an amendment to its 2026-2027 GTA with total amended revenue requirements including PLP and KLP of $929.0 million and $975.5 million for 2026 and 2027 million, respectively.

AltaLink filed its 2026-2027 GTA and 2023-2024 Deferral Accounts Reconciliation Application with the AUC on May 15, 2025. AltaLink also filed the 2026-2027 GTAs on behalf of PLP and KLP. Our total revenue requirements including PLP and KLP are $939.1 million and $995.6 million for 2026 and 2027, respectively. Key components and highlights of the GTAs included:

- Total transmission tariffs (net of adjustments) of $936.3 million and $995.6 million in 2026 and 2027, respectively;
- We anticipate energizing the Central East Transfer-Out project in 2026 with an estimated capital investment of $207 million;
- A $19.5 million increase for AltaLink's Systems, Applications, and Products for Phase 1 of the SAP End-of-Support Transition program;
- A $20.0 million increase in capital expenditures for AltaLink's wildfire mitigation plan, which is primarily related to wildfire mitigation work in the Bow Valley region; and
- A $44.2 million increase in capital expenditures for the capital replacement and upgrade program from 2025 to 2026, primarily due to an increased volume of required substation major equipment replacements and transmission line wood structure replacements due to the condition of long service assets. These replacements are required to meet AltaLink's statutory obligations to provide safe, reliable, and economic service.

The table below summarizes the 2026 and 2027 transmission tariffs applied for on May 15, 2025 and amended on July 15, 2025, and 2025 transmission tariffs approved on December 5, 2024.

(in millions of dollars)	2027 Applied for	2026 Applied for	2025 Approved
Return on equity	$ 252.5	$ 248.5	$ 245.4
Return on debt	207.4	202.5	194.9
Operating costs	195.0	189.3	174.9
Depreciation and amortization	297.6	288.5	281.7
Miscellaneous revenue offset	(7.4)	(7.5)	(7.5)
Income tax	43.0	10.1	—
Revenue requirements as filed May 15, 2025 – ALP	**988.0**	**931.4**	**889.3**
Amendment adjustments	(20.1)	(10.1)	—
Revenue requirements as amended July 15, 2025 - ALP	**967.9**	**921.3**	**889.3**
Other adjustments	—	(2.8)	8.3
Transmission tariffs as amended July 15, 2025 – ALP	**967.9**	**918.5**	**897.6**
Transmission tariffs as filed May 15, 2025 – PLP	4.6	4.7	4.7
Transmission tariffs as filed May 15, 2025 – KLP	3.0	3.0	3.0
Total transmission tariffs as filed May 15, 2025 and amended July 15, 2025	**$ 975.5**	**$ 926.2**	**$ 905.3**

* Totals may not add due to rounding

The table below summarizes the GTA forecasted gross capital expenditures for 2025, 2026 and 2027.

(in millions of dollars)	2027 Applied for	2026 Applied for	2025 Approved
Gross capital expenditures	$ 423.4	$ 426.8	$ 360.0

AUC Enforcement Proceeding

On May 29, 2025, Enforcement staff of the AUC publicly commenced an enforcement application against AltaLink (the Application), recommending that the AUC establish a proceeding to determine whether AltaLink contravened section 39 of the *Electric Utilities Act (Alberta)* and section 41(1)(b) of the *Hydro and Electric Energy Act (Alberta)* because of AltaLink's selection, installation and use of certain equipment on some of its transmission lines and alleged deficiencies in AltaLink's quality management system. The Application follows an 18-month investigation by Enforcement staff and is available online through the AUC's e-Filing portal. In the Application, Enforcement staff seek administrative monetary penalties of $18 million and operational remedies against AltaLink that include replacement of the equipment in certain areas of its service territory and operational audits. The AUC has commenced a proceeding to consider the Application and established a process schedule, with an oral hearing anticipated in November 2025.

AltaLink has actively disputed and continues to dispute Enforcement staff's allegations and intends to vigorously defend them on the basis that they are unsubstantiated and inaccurate, and that the equipment and AltaLink's practices comply with all relevant safety codes. See also the “Risk Management" and "Forward-Looking Information" sections in our MD&A for the year ended December 31, 2024, and the "Risk Factors" and "Forward-Looking Information" sections of our most recently filed Annual Information Form.

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. These expenditures related to the May and June 2023 wildfire and storm events. 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.

Canada Infrastructure Bank Debt Financing Application

AltaLink and the Canada Infrastructure Bank 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 the Southeast Alberta Transmission Development and Southwest Alberta Transmission Development 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 approximately $60 million for AltaLink's portion of the project over the financing term.

The availability of the credit facility for projects other than the Central East Transfer-Out project remains subject to AltaLink's satisfaction of various conditions, including obtaining regulatory approvals. If approved, AltaLink's project financing from the Canada Infrastructure Bank for the Southeast Alberta Transmission Development and Southwest Alberta Transmission Development projects is expected to save Alberta ratepayers approximately $185 million over the financing terms.

AltaLink completed the first draw-down of $37.6 million in respect of the Central East Transfer-Out project on March 27, 2025, after the AUC approved AltaLink's amended debt application. The fixed 31-year interest rate of 2.17% is approximately 227 basis points lower than a conventional 30-year AltaLink bond offering. All Central East Transfer-Out project borrowings under the credit facility will be repaid by June 30, 2056.

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 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% until otherwise changed 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.

2023-2024 Deferral Accounts Reconciliation Application

AltaLink filed its 2023-2024 Deferral Accounts Reconciliation Application along with its 2026-2027 GTA on May 15, 2025. The reconciliation included 22 projects with total gross capital additions of $76.7 million for 2023 and 2024, 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 July 22, 2025, the AUC issued its decision on the lawfulness and treatment of distribution facility owner (DFO) contributions in aid of construction (CIAC) under the AESO's Independent System Operator tariff. This proceeding had been remitted to the AUC following a decision of the Alberta Court of Appeal on November 14, 2023, where 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.

The AUC found that neither DFOs nor transmission facility owners (TFOs) are entitled to earn a return on CIAC. The AUC's findings on each issue considered in the proceedings are described below:

- The AESO is permitted under the *Electric Utilities Act* and *Transmission Regulation* to establish a customer contribution policy requiring DFOs to pay CIACs in relation to transmission facility construction or upgrades triggered by system access service requests.
- The AUC is not compelled by legislation to require TFOs to pay or repay CIACs, to include these amounts in their capital base, or to earn a return on such expenditures.
- It is lawful to treat CIACs paid by DFOs as expenditures rather than as capital amounts entitled to a return. CIACs are not investments in utility-owned assets by either DFOs or TFOs and thus do not qualify for a return under Section 122(1)(a) of the *Electric Utilities Act*. Instead, CIACs are payments to secure transmission access from another utility.

To address the potential rate shock arising from a large or lumpy CIAC due to the AUC's finding that CIACs paid by DFOs should be treated as expenditures rather than as capital amounts, the AUC approved the use of deferral accounts and amortization, consistent with the approach established in Decision 26521-D01-2021.

Following its determination of the legal issues, the AUC provided its observations on the usefulness of CIAC as a continuing regulatory instrument, including the following:

- The AUC advised that the NID and facility approval process are insufficient safeguards to ensure economic discipline or fair cost allocation. The AUC noted that its ability to assess the need and drivers for transmission infrastructure, and effectiveness of price signals through the NID and facility approval process, is limited;
- While acknowledging that price signals may be weaker in the context of DFO-driven projects to address general load growth, the AUC advised that eliminating the DFO CIAC entirely would remove an important economic price signal and exacerbate incentives for utilities to pursue capital-intensive, transmission-biased solutions without considering non-wires solutions. The AUC advised that concerns with weakened price signals can be addressed through policy refinement, not wholesale abandonment;
- A proper and well-designed customer contribution policy ensures cost responsibility aligns with cost causation, discourages inefficient investments, encourages system optimization, and maintains fairness for all customers within Alberta's electricity system. Future contribution policies should reflect broader system planning objectives, including fairness, investment and economic discipline, and alignment of risk with ownership and control; and
- Future iterations of the customer contribution policy should focus less on theoretical price signals and more on practical cost accountability, equity across customer classes, and incentives that support cost-effective, economic and optimized system development.

The AUC then encouraged the AESO to consider the following as part of its next Independent System Operator tariff review:

- Whether the current CIAC framework continues to align with system realities;
- How contribution policies might better support the evaluation and use of non-wires alternatives and system optimization;
- The extent to which cost causation and accountability can be preserved under generalized load growth scenarios; and
- Whether policy clarity could be improved by simplifying or standardizing treatment across project types.

Independent System Operator Tariff Redesign

In March 2025, the AESO published its 2025 engagement plan regarding the Independent System Operator Tariff Redesign, as well as the Restructured Energy Market and Optimal Transmission Planning. Details with respect to Restructured Energy Market and Optimal Transmission Planning are provided in the Transmission Planning and Development section below. With respect to the Independent System Operator Tariff Redesign, the AESO's stated objective is to implement policy-driven cost allocation and address rate issues within the Independent System Operator tariff.

On March 5, 2025, the AESO kicked off the Independent System Operator Tariff Redesign, identifying six work streams within the engagement process:

1. Ancillary Services Cost Allocation: new products (including Restructured Energy Market) and current products;
2. Transmission Reinforcement Payments and Supply System Access Service: Optimal Transmission Planning and transmission cost allocation;

3. Amendments for the AESO Connection Process: Improved efficiency of the AESO Connection Process and other clarity and administrative changes;
4. Internal Demand Rates: Rate Demand Transmission Service (Bulk and Regional), self-supply; and non-firm demand services;
5. Tariff Treatment of Intertie Transactions: import and export Supply System Access Service; and
6. Connection and Costs Allocation and Investment Policy: AESO contribution policy and participant-funded costs.

The AESO also indicated its intention to file with the AUC in 2026 its proposed tariff redesign regarding work streams 1 to 3. Work streams 1 and 3 are anticipated to be filed in the third quarter of 2026 while work stream 2 may be filed at the end of the first quarter or early in the second quarter of 2026. Work streams 4 to 6 will be filed with the AUC in 2027.

In the first half of 2025, the AESO held stakeholder sessions and sought written feedback on several of the workstreams. Throughout the engagement process AltaLink has identified Ancillary Service Reallocation, Transmission Reinforcement Payments, and Cost Shifting as high priority topics for review. AltaLink also proposed that a cost-of-service study, cost-shifting study, and grid value study be completed by the AESO in the process. The AUC deadline for the AESO to file the bulk and regional rate updates is January 31, 2027, with new rates expected to take effect in 2029 following the AUC review process. AltaLink continues to engage fully in the Independent System Operator Tariff Redesign given the importance of the AESO transmission tariff in respect of AltaLink's rates and terms and conditions of service.

Transmission Planning and Development

For details on transmission planning and development in Alberta, please refer to the "Overview of the Electricity Industry in Alberta", "Transmission Planning and Development", "Our Transmission Facilities", and "Major Capital Projects" sections of our MD&A for the year ended December 31, 2024.

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.

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 July 10, 2025, the Transmission Amendment Regulation was enacted through Order in Council. The updated regulation, along with the May 15, 2025, implementation of Bill 52, the *Energy and Utilities Statutes Amendment Act,* makes several legislative and regulatory amendments to transmission policy. The focus of the legislation and regulation is on strengthening reliability, lowering and stabilizing Alberta utility bills and encouraging investment in the province.

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. The AESO is no longer obligated to plan transmission for removal of all transmission constraints, and they must ensure the timely implementation of required transmission expansions and enhancements in a manner that maintains system reliability and can reasonably be expected to maximize economic efficiency. Detailed updates to the Transmission Regulation include:

- On a go forward basis, ancillary services which are procured by the AESO to ensure the reliability of the electricity system will be allocated on a cost-causation basis and may be recovered from market participants or classes of market participants, through transmission rates or a fee administered by the AESO, to be defined by a future AESO Tariff process.

- Implementation of a new transmission system cost allocation framework 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 new transmission-connected and distribution-connected generators and energy storage resources. The Transmission Reinforcement Payment rate will be defined by a future AESO Tariff process, and payments received will be used for the sole purpose of reducing the AESO's annual transmission costs.
- Confirmation that the AUC review of the AESO tariff ensures that just and reasonable costs of the transmission system are wholly charged to distribution facility operators, customers who operate industrial systems, transmission-connected industrial customer and exporters.
- Requires the AESO file a NID for the Alberta Intertie Restoration project by December 31, 2026, to restore the Alberta-British Columbia intertie to 950 megawatts and develop a plan and make arrangement to restore the line to 1200 megawatts.
- Requires 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.
- Requires 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.
- Removes the competitive procurement requirement for upgrades or enhancements to the path rating of interties and requires the AESO establish a competitive process to determine who is eligible to apply to construct and operate a new regulated intertie, which must not exclude a transmission facility operator.

On June 18, 2025, the AESO released a report titled "*Rationale for Ancillary Service procurement for Intertie Restoration: Fast Frequency Response Plus*". The AESO is proposing to procure up to 750 megawatts of highly available fast frequency response (non-wires) services through medium term (7-10 years) and long-term (20 years) ancillary service contracts. The contract capacity will also be used to provide other reliability services. The rationale for this procurement is to meet the AESO's obligations under the Transmission Regulation to restore intertie capability and support import flows of 800 megawatts on the Alberta-British Columbia intertie and up to 300 megawatts on the Montana Alberta Tie Line intertie. The AESO initiated a stakeholder consultation process in July 2025 and plans to release the Request for Proposals in mid-2026 with proposals due in late 2026.

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*. Key changes included 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 included a definition of self-supply with export and included 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.

Optimal Transmission Planning

In July 2025, the Minister of Affordability and Utilities confirmed direction to the AESO to prepare a list of priority transmission projects to support investor certainty.

On March 31, 2025, the AESO released its Optimal Transmission Planning Framework Options Paper and launched its formal stakeholder consultation process. The engagement process is currently underway, expected to conclude in the third quarter of 2025, and will be followed by the drafting and review of new Independent System Operator Rules. The AESO is planning to initiate the AUC review process for the new Independent System Operator Rules in the first quarter of 2026 and implement the new optimal transmission planning framework by the first quarter of 2027. AltaLink continues to engage fully in development of the new planning framework.

Under the framework, new transmission investments would only be triggered when the additional benefits from increased transmission expansion outweigh their additional costs, or transmission investments are required to satisfy reliability requirements. Included in the framework is a new cost–benefit assessment methodology applicable to projects that are not driven by reliability or legislative requirements. Projects driven by reliability and legislative requirements will continue to use least-cost criteria. The AESO confirmed it is using the Federal Energy Regulatory Commission Order No. 1920 and other jurisdictions that use Optimal Transmission Planning in their planning practice as a starting point in development of the Alberta design.

Energy market design

On July 15, 2025, the Minister of Affordability and Utilities sent a direction letter to the AESO about the Restructured Energy Market design. The direction confirmed uniform pricing for load while adopting a locational marginal pricing framework for generators and transmission-connected loads who elect a locational price. Recovery of line losses from generator resources will be through the location marginal price. Incumbent generators, those who are in service or have made a final investment decision prior to July 9, 2025, will be allocated financial transmission rights upon energization of their facilities. The financial transmission rights will be granted to a generating unit for the lesser of eight years or when the asset retires, beginning with the launch of the Restructured Energy Market (targeted to be 2027). The Government of Alberta will bring in the necessary legislation to enact these decisions by early 2026, and the AESO will continue to work with stakeholders to develop a long-term congestion management approach that supports ongoing investability in the market.

On May 15, 2025, Bill 52, the *Energy and Utilities Statutes Amendment Act, 2025* received royal assent. As a result, several legislative and regulatory amendments to support updates to power market rules have been enabled.

Key foundational elements included replacing the power pool with a market for reliability products and a real-time market, co-optimization of energy and ramping services, a wider real-time price range to send more dynamic signals to the market, congestion pricing in coordination with Optimal Transmission Planning to manage congestion within the market, implementation of shorter settlement intervals, and market power mitigation measures to provide guardrails against excessive exercise of market power.

The legislation allows for the Independent System Operator Rules required for the Restructured Energy Market to be implemented by Ministerial direction. 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.

As a result of the legislative direction, on May 22, 2025, the AESO released an update to its Restructured Energy Market High Level Design document, previously released on December 13, 2024, for stakeholder review. The most significant change is the removal of the previously proposed day-ahead commitment market and day-ahead scheduling market. The updated design includes:

- Market-based congestion management through the implementation of a Locational Marginal Price for energy, allowing the price of energy to vary based on the value of the energy produced at different locations.
- Implementation of a new ancillary service ramping product to ensure resources are available for real-time needs.
- Updated pricing ($1,500 per megawatt hour and a further increase to $2,000 per megawatt hour in 2032) 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 to negative $100 per megawatt hour in 2032, 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 through implementation of a secondary offer cap.
- Enhanced day-ahead reliability market for operating reserves to ensure more competitive outcomes from the products needed to meet reliability needs.
- An updated reliability unit commitment process based on a supply-cushion threshold.

On March 11, 2024, the Government of Alberta implemented two interim regulations, the *Market Power Mitigation Regulation* and the *Supply Cushion Regulation*, to address the impacts of economic and physical withholding. The regulations will expire November 30, 2027, as the requirements of the interim regulations are integrated into the new Restructured Energy Market design.

Renewable energy development

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 included:

- Clarity for renewable energy developers on environmental protections to create consistent reclamation requirements across all forms of renewable energy operations, including a mandatory reclamation security requirement. 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.
- Renewable energy developments will no longer be permitted on some lands unless the proponent can demonstrate the ability for both crops and/or livestock to coexist with the renewable generation project.
- Ensuring 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 July 9, 2025, the Government of Alberta launched a consultation on a potential Data Centre Levy to ensure the sector contributes fairly to the province's economic and infrastructure needs and gives Albertans a fair return from data centre investments. The consultation process will conclude on August 18, 2025.

On May 20, 2025, the AESO announced its phased approach to enable data center integration. The AESO confirmed its approach will prioritize projects that are well advanced in the AESO connection process to enable large load development by 2027 or 2028 without negatively impacting grid reliability. On June 4, 2025, the AESO gave a presentation outlining the approach for Phase I and Phase II. To facilitate Phase I, the AESO set a 1,200-megawatt reliability-based cumulative grid limit for large loads and also established a method to assign the 1,200 megawatts to existing large load developers. Phase II involves establishing an enhanced long-term framework for connecting large loads in alignment with government policy including the development of new or updated rules and the adoption of North American Electric Reliability Corporation Large Load Standards. Updates to the large load connection process are anticipated to achieve their goals of a safe, reliable and affordable grid. Engagement on Phase II is planned in the second half of 2025.

To provide locational signals for data centre developers, an updated load Capability Map is expected to be published by the AESO in the third quarter of 2025. Prior to 2027, the AESO will also establish an enhanced long-term framework for connecting large loads in alignment with government policy including the development of new or updated rules and the adoption of North American Electric Reliability Corporation Large Load Standards. If necessary, the AESO will adjust the large load connection process as needed to achieve their goals of a safe, reliable and affordable grid.

On March 20, 2025, the AESO released an update on data centres, emphasizing the importance of maintaining a safe, reliable, and affordable grid while accommodating the growing demand from data centres. The AESO created a list of additional facility and operating details that will be required as the project progresses through Stage 3 of the connection process and posted these requirements on their website in April 2025.

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. 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

In March 2025, the AESO released its analysis of the final federal *Clean Electricity Regulations*, which came into force January 1, 2025, and concluded that they pose a significant risk to the reliability and affordability of Alberta's electricity system in the coming years. The AESO's assessment concluded that the Regulations will fail to deliver meaningful reductions in carbon emissions in Alberta. To make up for restrictions on natural gas generation resulting from the regulations, the AESO forecasts $30 billion in additional capital and operating costs from 2024 to 2049. They also forecast that between 2035 and 2050, the Regulations will result in wholesale electricity prices 35% higher than they would otherwise be.

On March 6, 2025, the Government of Alberta issued a statement calling on the federal government to reverse course on the Regulations and confirmed they are preparing a court challenge.

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 included an effective date of 2035, a 25-year provision for existing natural gas units to comply with the annual emissions limit, an exemption for behind-the-fence cogeneration until 2050, an exemption for small units less that 25 megawatts and regions not connected to a grid regulated by the North American Electric Reliability Corporation, and the options for provinces and territories to enter into equivalency agreements that would stand down the federal Regulations with equivalent levels of emission reductions.

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 allowed the AESO to consider possible future states of the Alberta market.

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 the fall of 2024. Project construction is on track, with foundations and stringing construction on schedule at the end of the second quarter of 2025. The project remains on budget and AltaLink is forecasting to achieve an in-service date in the second quarter of 2026 which aligns with the AESO LTP. As at June 30, 2025, AltaLink had invested $117.3 million in 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 reconfigured transmission line, was energized in March 2025. The current estimated cost of the project is $23.3 million. As at June 30, 2025, we had invested $22.3 million in the project.

Southeast Alberta Transmission Development and Southwest Alberta Transmission 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 June 30, 2025, we had invested $0.1 million in 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 April 2025. As at June 30, 2025, we had invested $10.1 million in the project.

In addition, the AESO indicated that a Southwest Alberta Transmission Development project adjacent to the Southeast Alberta Transmission Development project will be required. This Southwest Alberta Transmission Development project would continue to enable generation in the southern 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 June 30, 2025, we had invested $0.6 million in 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, where Stage 1 of the project was to be completed by 2023 and Stage 2 by 2025.

On December 21, 2023, the AUC approved an extension to Stage 1 for completion by 2027. On March 13, 2025, AltaLink applied for a time extension to Stage 2 until 2029 given that the milestone trigger was not met. The AESO files annual milestone updates on the Provost to Edgerton and Nilrem to Vermilion NID proceeding. AltaLink updated its project schedule after discussions with the AESO.

On April 1, 2025, the AUC granted the extension to Stage 2 for completion to 2027. The AUC stated that subsequent time extensions will require compelling support that demonstrates the project is likely to move forward, and that AltaLink has considered how impacts to stakeholders or environment may have evolved since initial project approval. The AESO will work with AltaLink to determine next steps for this project.

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 June 30, 2025, we had invested $24.0 million in the project.

Alberta – British Columbia Intertie Restoration

The Alberta Intertie Restoration project was included in the 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. On March 27, 2025, the AESO directed AltaLink to assist the AESO with its NID development by preparing an environmental and land use evaluation report of options under consideration. In addition, AltaLink is to provide a cost estimate report consisting of cost estimates for each of these options. Completion of this direction is required by September 20, 2025. As at June 30, 2025, we had invested $5.4 million in 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 June 30, 2025, we had invested $32.4 million in the project.

Battery Energy Storage System Installation Feasibility

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 $0.3 million, of which Emissions Reduction Alberta will contribute 50%. As at June 30, 2025, we had invested $0.2 million in the project.

Southeast System Strength

The AESO is developing a Southeast System Strength project to reinforce the 240-kilovolt transmission system between Cassills 324S substation, Bowmanton 244S substation and Whitla 251S substation, in the Southeast region of Alberta. The AESO identified potential system strength limitations in this area. The AESO is exploring potential solutions which include either a synchronous condenser or a battery energy storage system. On February 22, 2024, the AESO issued a project assistance direction to AltaLink to provide cost estimates for each option. AltaLink provided these estimates on August 24, 2024. The AESO is assessing the options before filing a NID application. The high-level cost estimates for this system reinforcement project range from $150 million to $300 million. We expect the AESO to make a technology decision and issue direction in the fourth quarter of 2025, with a forecasted in-service date in the 2029 to 2030 timeframe. As of June 30, 2025, we had invested $0.1 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 $25.0 million) in our statement of financial position as at June 30, 2025, compared to December 31, 2024:

(in millions of dollars)	Increase/(Decrease)		Explanation
Property, plant, and equipment [note 8]	$	57.4	The increase is primarily due to investing $202.0 million in capital assets and construction work-in-progress, partially offset by $139.8 million in depreciation.
Third-party deposits and Third-party deposits liability [note 9]	$	28.2	The increase is primarily due to receiving $56.9 million of customer contributed funds and using $28.6 million of these funds on related capital projects.
Other non-current assets [note 6]	$	35.5	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 11]	$	350.0	The increase is due to reclassifying $350.0 million of Medium-Term Notes maturing in May 2026 from non-current.
Long-term debt [note 11]	$	(312.1)	The decrease is primarily due to reclassifying $350.0 million of Medium-Term Notes maturing in May 2026 to current, partially offset by borrowing $37.6 million of long-term debt in March 2025 to fund the Central East Transfer-Out project.
AltaLink, L.P. equity	$	60.9	The increase is primarily due to generating net and comprehensive income of $162.8 million, partially offset by distributing $101.8 million to AILP and AML.

Cash Flows

	Three months ended June 30,				Six months ended June 30,			
(in millions of dollars)	**2025**		2024		**2025**		2024	
Cash, beginning of period	**$**	**2.9**	$	0.1	**$**	**0.1**	$	6.8
Cash flow provided by (used in):								
Operating activities		**74.2**		104.5		**254.9**		303.9
Investing activities		**(93.1)**		(84.4)		**(188.1)**		(147.0)
Financing activities		**16.2**		(20.1)		**(66.7)**		(163.6)
Cash, end of period	**$**	**0.2**	$	0.1	**$**	**0.2**	$	0.1

Operating activities

For the three months ended June 30, 2025, our cash flow from operating activities decreased by $(30.3) million compared to the same period in 2024. The change is primarily due to higher interest payments as a result of the timing of when coupon payments were due.

For the six months ended June 30, 2025, our cash flow from operating activities decreased by $(49.0) million compared to the same period in 2024. The change is primarily due to the timing of transmission tariff receipts. Specifically, we had one additional month of transmission tariff of $73.6 million outstanding from the AESO as at December 31, 2023 which we collected in January 2024.

Investing activities

For the three and six months ended June 30, 2025, our cash flow used in investing activities increased by $(8.7) million and $(41.1) million, respectively, compared to the same periods in 2024. The changes are primarily due to higher capital project activity, including the capitalization of site preparation costs for replacement projects.

Financing activities

For the three months ended June 30, 2025, our cash flows used in financing activities decreased by $36.3 million compared to the same period in 2024. This change is primarily due to repaying $350.0 million of Medium-Term Notes in 2024 and distributing $9.5 million less to AILP and AML in 2025. These changes are partially offset by issuing $(325.0) million of Senior Secured Notes in 2024.

For the six months ended June 30, 2025, our cash flows used in financing activities decreased by $96.9 million compared to the same period in 2024. This change is primarily due to repaying $350.0 million of Medium-Term Notes in 2024 and distributing $35.1 million less to AILP and AML in 2025. These changes are partially offset by issuing $(287.4) million less of Senior Secured Notes in 2025 and repaying $(3.1) million more of commercial paper in 2025.

Commitments

(in millions of dollars)	Remaining six months 2025	2026	2027	2028	2029	2030	2031 and thereafter	**Total as at June 30, 2025**
Long-term debt								
Principal repayments	$ —	$ 350.2	$ 0.8	$ 0.8	$ 0.8	$ 225.8	$ 4,184.2	**$ 4,762.6**
Interest payments	100.7	196.7	191.9	174.2	209.4	191.8	2,953.2	**4,017.9**
	$ 100.7	$ 546.9	$ 192.7	$ 175.0	$ 210.2	$ 417.6	$ 7,137.4	**$ 8,780.5**

We have contractual commitments to repay long-term debt and to pay related interest which totals $8,780.5 million (December 31, 2024 – $8,825.0 million), as disclosed in our second quarter consolidated financial statements in note 11 – Debt.

We are committed to lease payments of $59.5 million (December 31, 2024 – $61.7 million), as disclosed in our second quarter consolidated financial statements in note 13 - Lease liabilities.

We also have contractual commitments associated with the construction of new facilities as at June 30, 2025 of $222.9 million (December 31, 2024 – $180.3 million), as disclosed in our second quarter consolidated financial statements in note 19 - 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 June 30, 2025 was $725.0 million (December 31, 2024 – $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 June 30, 2025 (December 31, 2024 – $153.0 million). AltaLink may use the $500.0 million and $75.0 million bank credit facilities for general corporate purposes. On December 20, 2024, we extended the $150.0 million inter-affiliate revolving credit facility from AILP to March 31, 2027. To date, we have not drawn on the AILP inter-affiliate credit facility. As at June 30, 2025, we had $570.0 million of liquidity remaining under these facilities (December 31, 2024 – $569.9 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, AltaLink 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, Southeast Alberta Transmission Development and Southwest Alberta Transmission Development projects. Total borrowing under the credit facility is capped at $604.3 million with a final maturity date of December 31, 2065. On October 18, 2024, the AUC approved the credit facility. The remaining availability of the credit facility as at June 30, 2025 is $566.7 million (December 31, 2024 – $604.3 million). All borrowings under the credit facility are subject to a fixed repayment schedule. The borrowings under the credit facility as at June 30, 2025 and December 31, 2024 were $37.6 million and $nil, respectively.

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.

Liquidity, coverage, and capital ratios[1]

	Twelve months ended June 30,	
(in millions of dollars)	**2025**	2024
Comprehensive income	**$ 326.4**	$ 317.4
Actuarial loss	**0.5**	0.3
Non-controlling interests	**1.7**	1.7
Loss on disposal of assets	**7.5**	9.3
Finance costs	**204.2**	201.4
EBIT	**540.3**	530.1
Depreciation and amortization	**303.7**	297.5
EBITDA	**844.0**	827.6
Interest paid	**(225.0)**	(180.7)
Standby fees	**(0.9)**	(0.9)
FFO	**$ 618.1**	$ 646.0

	Twelve months ended June 30,	
(in millions of dollars)	**2025**	2024
Net cash provided by operating activities	**$ 509.3**	$ 504.5
Change in non-cash working capital	**6.6**	(9.7)
Third-party contributions revenue	**28.9**	28.0
Change in financial assets and liabilities related to regulated activities, non-current	**83.8**	89.5
Change in deferred revenue for salvage	**7.5**	13.3
Change in other	**(18.0)**	20.4
FFO	**$ 618.1**	$ 646.0

(in millions of dollars)	As at June 30, **2025**	2024
Letters of credit	**$ 2.0**	$ 1.8
Less: cash	**(0.2)**	(0.1)
Other post-employment benefit obligations[2]	**4.4**	3.7
Short-term debt (excluding outstanding cheques)	**503.0**	131.0
Long-term debt	**4,383.5**	4,695.3
Lease liabilities	**46.4**	48.8
Total debt	**4,939.1**	4,880.5
Cash	**0.2**	0.1
Accrued interest on debt	**30.8**	48.5
Financing fees, premiums, and discounts	**29.1**	29.7
Less: other post-employment benefit obligations[2]	**(4.4)**	(3.7)
Total debt as per Master Trust Indenture and bank credit facilities	**4,994.8**	4,955.1
Total equity including non-controlling interests	**3,908.3**	3,798.9
Less: AltaLink equity investment in subsidiaries	**(15.9)**	(15.9)
Total capitalization	**$ 8,887.2**	$ 8,738.1

	Twelve months ended June 30, **2025**	2024
Interest paid	**$ 225.0**	$ 180.7
Interest expense[3]	**$ 209.4**	$ 205.1
EBIT interest expense coverage[4]	**2.58X**	2.58X
EBITDA interest expense coverage[5]	**4.03X**	4.04X
FFO interest paid coverage[6]	**3.75X**	4.57X
FFO/Debt[7]	**12.51%**	13.24%
Total debt/total capitalization as per Master Trust Indenture[8]	**56.20%**	56.71%
Total debt/total capitalization as per bank credit facilities[9]	**56.20%**	56.71%

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 $5.7 million as at June 30, 2025 were adjusted to reflect an after-tax amount equal to $4.4 million using an income tax rate of 23% (June 30, 2024 – $4.8 million was adjusted to $3.7 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 our current capital structure of 37% equity and 63% debt approved by the AUC and with corresponding targets for our overall key financial metrics.

Working capital

At June 30, 2025, our working capital deficiency was $497.7 million (December 31, 2024 – $157.5 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

	Twelve months ended June 30,	
	2025	2024
Earnings-to-interest coverage on total debt[1,2]	**2.57X[2,3,4]**	2.31X[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 June 30, 2025, for the purposes of calculating this ratio, was $535.8 million (June 30, 2024 – $522.5 million). Our pro-forma interest requirement on short and long-term debt for the 12 months ended June 30, 2025 was $208.9 million (June 30, 2024 – $226.4 million).
4. Our pro-forma earnings before interest and income tax for the 12 months ended June 30, 2025 and 2024 is calculated as: comprehensive income of $326.4 million (June 30, 2024 – $317.4 million) plus finance costs of $204.2 million (June 30, 2024 – $201.4 million) plus capitalized borrowing costs of $5.2 million (June 30, 2024 – $3.7 million) plus income taxes of $nil (June 30, 2024 – $nil). Our pro-forma interest requirement on short and long-term debt for the 12 months ended June 30, 2025 and 2024 is calculated as: finance costs of $204.2 million (June 30, 2024 – $201.4 million) plus capitalized borrowing costs of $5.2 million (June 30, 2024 – $3.7 million) plus the net pro-forma effect of interest expense of $(0.5) million on the March 27, 2025 issuance of $37.6 million of Canada Infrastructure Bank debt financing (June 30, 2024 – $21.3 million on the May 22, 2024 issuance of $325.0 million of Series 2024-1 Senior Secured Notes and 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 June 30,	
	2025	2024
DBRS – Commercial Paper[1]	**R-1 (low)**	R-1 (low)
DBRS – Medium-Term Notes (Secured) and Senior Secured Notes [1]	**A**	A
S&P – Medium-Term Notes (Secured) and Senior Secured Notes [2]	**A-**	A-

1. On July 9, 2025, DBRS reaffirmed the existing ratings with Stable trends.
2. On May 1, 2025, 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)	Three months ended June 30, 2025	2024	Six months ended June 30, 2025	2024
Operations	**$ 246.5**	$ 239.6	**$ 492.8**	$ 499.1
Other	**17.3**	11.9	**29.4**	21.6
	$ 263.8	$ 251.5	**$ 522.2**	$ 520.7

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 three months ended June 30, 2025, our revenue from operations increased by $6.9 million compared to the same period in 2024. The change is primarily due to higher revenue related to a salvage recovery reduction in June 2024 as a result of the AUC's June 19, 2024, approval of the capitalization of site preparation costs for replacement projects effective January 1, 2024, partially offset by lower equity returns on rate base in 2025 due to a lower approved return on equity of 8.97% versus 9.28% in 2024.

For the six months ended June 30, 2025, our revenue from operations decreased by $6.3 million compared to the same period in 2024. The change is primarily due to lower revenue as a result of lower equity returns on rate base in 2025 due to a lower approved return on equity of 8.97% versus 9.28% in 2024.

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 three and six months ended June 30, 2025 increased by $5.4 million and $7.8 million, respectively, compared to the same periods in 2024. These changes are primarily due to higher cost recovery revenue from other utilities and third parties and one-time revenue from the City of Calgary to access our utility right-of-way.

Operating expenses

(in millions of dollars)	Three months ended June 30, 2025	2024	Six months ended June 30, 2025	2024
Operating expenses	**$ 33.6**	$ 29.7	**$ 63.6**	$ 59.3

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

Our operating expenses for the three and six months ended June 30, 2025 increased by $3.9 million and $4.3 million, respectively compared to the same periods in 2024. These changes are primarily due to higher costs of services provided to other utilities and third parties which are recovered in other revenue as noted above.

Property taxes, salvage, and other expenses

(in millions of dollars)	Three months ended June 30, 2025	2024	Six months ended June 30, 2025	2024
Property taxes, salvage, and other expenses	**$ 19.2**	$ 10.2	**$ 40.3**	$ 41.5

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 transmission 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 three months ended June 30, 2025 increased by $9.0 million compared to the same period in 2024. The change is primarily due to the AUC's June 19, 2024, approval of the capitalization of site preparation costs for replacement projects effective January 1, 2024, resulting in a reduction to salvage expense in June 2024.

Property taxes, salvage, and other expenses for the six months ended June 30, 2025 decreased by $1.2 million compared to the same period in 2024. The change is primarily due to a decrease in salvage expense.

Depreciation and amortization

(in millions of dollars)	**Three months ended June 30, 2025**	2024	**Six months ended June 30, 2025**	2024
Depreciation and amortization	**$ 75.5**	$ 74.3	**$ 151.0**	$ 148.4

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

Depreciation and amortization for the three and six months ended June 30, 2025 increased by $1.2 million and $2.6 million, respectively, compared to the same periods in 2024. These changes are primarily a result of capital projects that have been completed and added to our property, plant and equipment and intangible assets.

Finance costs

(in millions of dollars)	**Three months ended June 30, 2025**	2024	**Six months ended June 30, 2025**	2024
Finance costs	**$ 50.4**	$ 50.8	**$ 100.5**	$ 100.5

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 three and six months ended June 30, 2025, our weighted average cost of long-term debt was 4.26% and 4.27%, respectively (June 30, 2024 – 4.21% and 4.20%, respectively).

Our finance costs for the three months ended June 30, 2025 decreased by $0.4 million compared to the same period in 2024. This change is primarily due to a lower weighted average cost of short-term debt, partially offset by a higher volume of short-term debt and a higher weighted average cost of long-term debt.

Our finance costs for the six months ended June 30, 2025 was consistent compared to the same period in 2024.

EBITDA

(in millions of dollars)	Three months ended June 30, **2025**	2024	Six months ended June 30, **2025**	2024
EBITDA	**$ 211.0**	$ 211.6	**$ 418.3**	$ 419.9

Our EBITDA for the three and six months ended June 30, 2025 decreased by $0.6 million and $1.6 million, respectively, compared to the same periods in 2024. These changes are primarily due to lower operating revenue from a lower approved return on equity of 8.97% in 2025 versus 9.28% in 2024, partially offset by one-time utility right-of-way revenue and higher recovery of depreciation and amortization.

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

Net and comprehensive income

(in millions of dollars)	Three months ended June 30, **2025**	2024	Six months ended June 30, **2025**	2024
Net and comprehensive income	**$ 82.6**	$ 83.9	**$ 162.8**	$ 166.5

Our net and comprehensive income for the three and six months ended June 30, 2025 decreased by $1.3 million and $3.7 million, respectively compared to the same periods in 2024. These changes are primarily due to decreased revenue from a lower approved return on equity of 8.97% in 2025 versus 9.28% in 2024, partially offset by one-time utility right-of-way revenue.

Selected financial information derived from our consolidated financial statements

	Three months ended June 30, **2025**	2024	Six months ended June 30, **2025**	2024
Net and comprehensive income per partnership unit ($/unit)	**0.249**	0.253	**0.490**	0.502
Distributions per partnership unit ($/unit)	**0.108**	0.137	**0.307**	0.412
Total assets (in millions of dollars)	**10,273.6**	10,043.5	**10,273.6**	10,043.5
Short and long-term debt (in millions of dollars)[1]	**4,911.2**	4,852.4	**4,911.2**	4,852.4

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)
June 30, 2025	**263.8**	**82.6**	**331.9**	**0.249**
March 31, 2025	258.4	80.2	331.9	0.242
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

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. For more details regarding our material risk factors, please refer to the "Risk Management" and "Forward-Looking Information" sections of our MD&A for the year ended December 31, 2024, and the "Risk Factors" and "Forward-Looking Information" sections of our most recently filed Annual Information Form.

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.

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 transmission 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. When determining a just and reasonable transmission tariff, the AUC may decide that any under or over recovery of capital investment that occurs upon the retirement of a regulated asset 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 material risks that may have an impact on our financial position and results of our operations are:

Regulatory Risks

- Regulated financial risk
- Utility asset disposition
- Transmission system cost bypass by load customers
- Government policies impacting the electricity industry

Financial Risks

- Credit ratings
- Competition
- Capital resources and liquidity
- Annual impairment tests

Operational Risks

- Wildfires
- Cyber and physical security
- Transmission reliability
- Climate change
- Potential effects of pathogens or similar crises
- Labour relations
- Environment, health, and safety
- Electric and magnetic fields

We updated the project execution risk disclosure as detailed below:

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 stakeholder 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 and trade tariffs can also translate into additional actual project costs. To mitigate the risk associated with trade tariffs, we enter long-term contracts and diversify our procurement to consider vendors in countries without trade tariffs, where possible. We are dependent upon AUC decisions for recovery of the actual project costs of constructing our facilities. We maintain a direct assigned capital deferral account that is intended to capture the difference between our forecast costs and the actual costs of capital projects for AESO directly assigned projects. The AUC reviews all capital project costs including those recorded in our direct assigned 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 capital costs 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.

For more details regarding our material risk factors, please refer to the "Risk Management" and "Forward-Looking Information" sections of our MD&A for the year ended December 31, 2024, and the "Forward-Looking Information" and "Risk Factors" sections of our most recently filed Annual Information Form.

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 $36.2 million and $73.7 million, respectively, for the three and six months ended June 30, 2025 (June 30, 2024 – $35.0 million and $71.4 million, respectively), and liabilities of $25.5 million as at June 30, 2025 (June 30, 2024 – $20.9 million).

On March 31, 2023, we added a $150.0 million inter-affiliate revolving credit facility from AILP to provide additional liquidity for ALP. On December 20, 2024, we extended the maturity date to March 31, 2027.

For more details, please refer to note 14 - Related party transactions in our second quarter consolidated financial statements.

Legal Proceedings and Contingencies

We are subject to legal proceedings, investigations, assessments, and claims throughout our ordinary course of business.

- On May 29, 2025, Enforcement staff of the AUC commenced an enforcement application against AltaLink, recommending that the AUC establish a proceeding to determine whether AltaLink contravened certain sections of legislation because of AltaLink's use of certain equipment on some of its transmission lines and alleged deficiencies in AltaLink's quality management system. In the Application, Enforcement staff seek administrative monetary penalties of $18 million and operational remedies. AltaLink has actively disputed and continues to dispute Enforcement staff's allegations. The AUC has commenced a proceeding to consider the Application, including penalties, if any.
- 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.

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 19 - Commitments in our second quarter 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 second quarter 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 met in May 2025 to discuss issues identified in drafting the prospective IFRS Accounting Standard *Regulatory Assets and Regulatory Liabilities.* 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 transmission 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 requirements;
- 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.

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" and in the "Risk Factors" and "Forward-Looking Information" sections of our most recently filed Annual Information Form. 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 August 5, 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.