CU INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE YEAR ENDED DECEMBER 31, 2025

This Management's Discussion and Analysis (MD&A) is meant to help readers understand key operational and financial events that influenced the results of CU Inc. (our, we, us, or the Company) during the year ended December 31, 2025.

This MD&A was prepared as of February 25, 2026, and should be read with the Company's audited consolidated financial statements (2025 Consolidated Financial Statements) for the year ended December 31, 2025. Additional information, including the Company's Annual Information Form (2025 AIF) that will be filed on March 31, 2026, is available on SEDAR+ at www.sedarplus.ca.

The Company is controlled by Canadian Utilities Limited (Canadian Utilities or CU), which in turn is controlled by ATCO Ltd. (ATCO) and its controlling share owner, Sentgraf Enterprises Ltd. and its controlling share owner, the Southern family.

Terms used throughout this MD&A are defined in the Glossary at the end of this document.

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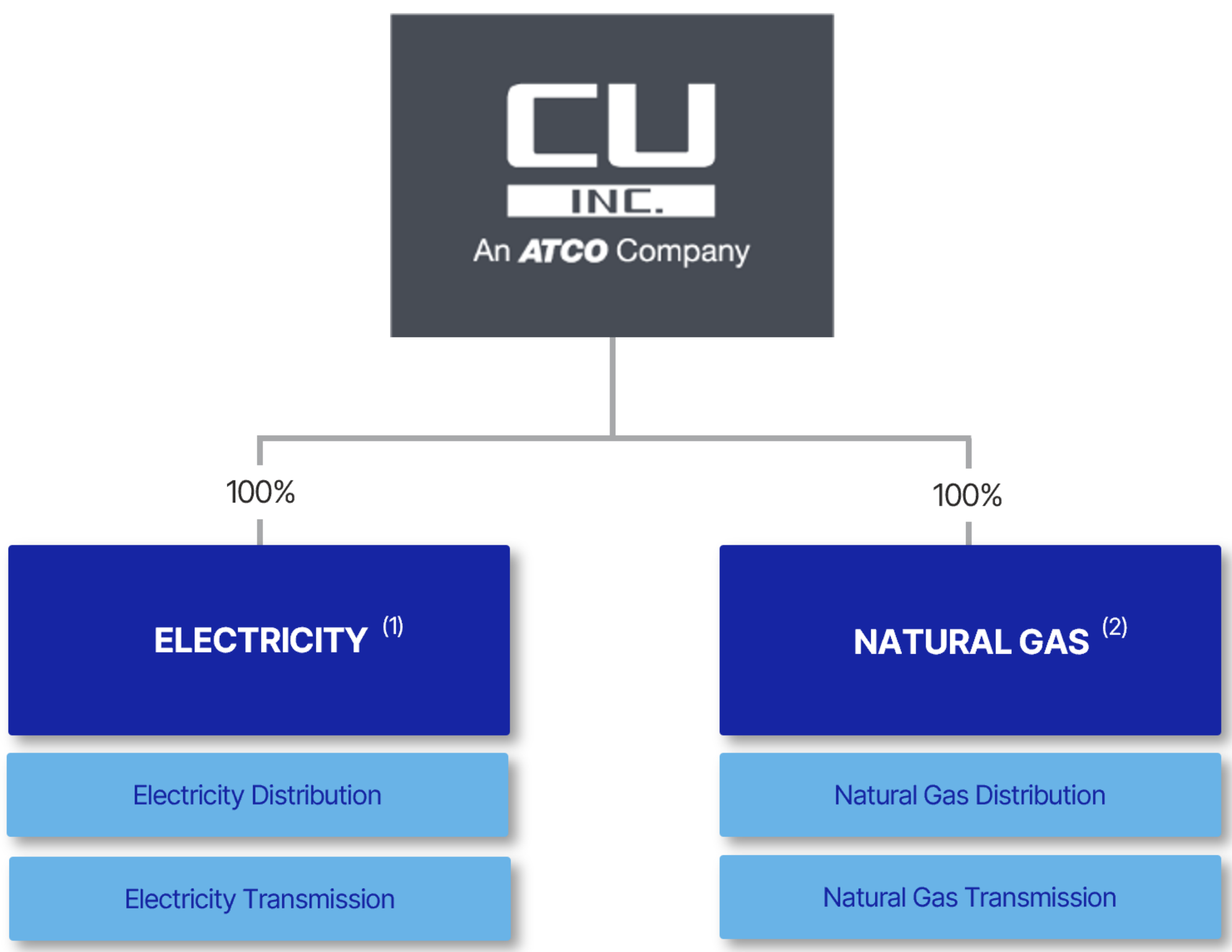
OUR COMPANY

CU Inc. is a wholly-owned subsidiary of Canadian Utilities Limited, an ATCO Company. CU Inc. is an Alberta-based corporation with approximately 3,600 employees and assets of $20 billion comprised of rate-regulated utility operations in electricity and natural gas distribution and transmission. More information about CU Inc. can be found on the Canadian Utilities Limited website at www.canadianutilities.com.

THE UTILITIES

The Company's activities are conducted through regulated businesses in two Business Units within western and northern Canada: Electricity, which includes Electricity Distribution and Electricity Transmission, and Natural Gas, which includes Natural Gas Distribution and Natural Gas Transmission.

SIMPLIFIED ORGANIZATIONAL STRUCTURE



(1) The Electricity segment includes ATCO Electric Transmission and ATCO Electric Distribution.

(2) The Natural Gas segment includes ATCO Gas and ATCO Pipelines.

The 2025 Consolidated Financial Statements include the accounts of CU Inc. and all of its subsidiaries. The 2025 Consolidated Financial Statements have been prepared in accordance with International Financial Reporting Standards (IFRS) and the reporting currency is the Canadian dollar.

OUR BUSINESSES

The Company's activities are conducted through regulated businesses in two Business Units within western and northern Canada: Electricity and Natural Gas.

ELECTRICITY

FAST FACTS

75,000 KM	263,613	240
Powerlines (Owns and Operates)	Average monthly customers in 2025	Communities served in Alberta

Our Electricity business unit is comprised of two regulated businesses: Electricity Distribution and Electricity Transmission.

Electricity Distribution provides regulated electricity distribution and distributed generation mainly in northern and central east Alberta, the Yukon, the Northwest Territories, and in the Lloydminster area of Saskatchewan. Electricity Transmission provides electricity transmission mainly in northern and central east Alberta, and in the Lloydminster area of Saskatchewan. Electricity Transmission has a 35-year contract, which commenced in 2019, to be the operator of Alberta PowerLine, a 500-km electricity transmission line between Wabamun, near Edmonton, and Fort McMurray, Alberta.

NATURAL GAS

FAST FACTS

51,600 KM	1,337,232	100+
Pipelines (Owns and Operates)	Average monthly customers in 2025	Years of operations

Our Natural Gas business unit is comprised of two regulated businesses: Natural Gas Distribution and Natural Gas Transmission.

Natural Gas Distribution serves municipal, residential, commercial, and industrial customers throughout Alberta and in the Lloydminster area of Saskatchewan. Natural Gas Transmission receives natural gas on its pipeline system from various gas processing plants as well as from other natural gas transmission systems and transports it to end users within the province of Alberta or to other pipeline systems.

SHAPING THE FUTURE: CU INC.'S AMBITIONS

CREATING PROSPERITY AND OPPORTUNITY FOR GENERATIONS TO COME

CU Inc. is a modern, customer-focused, diversified energy company with a relentless drive for growth, simplicity and safety. We are committed to a bright, bold future which creates prosperity and opportunity for generations to come.

OUR CORE VALUES

Our actions reflect our core values of safety, integrity, agility, caring, and collaboration. These core values guide us as we balance the short- and long-term economic, environmental and social considerations of our businesses.

Innovation, growth and financial strength provide the foundation from which we built our Company. Our long-term success depends on our ability to continue offering our customers exceptional, comprehensive and integrated solutions to meet their evolving needs.

CU INC.'S STRATEGY

CU Inc. has three key pillars that support our long-term strategy: **Growth and Prosperity**, **Operational Excellence** and **Financial Leadership**.

Growth and Prosperity

Our exceptional foundation of regulated electric and natural gas utilities; dedicated and highly skilled people; and diverse relationships position us to capitalize on strategic opportunities driving our next phase of growth and prosperity.

We are focused on unlocking near term growth while charting a resilient path for the future within our fundamental Canadian utility businesses. To achieve this we are focused on successfully executing essential capital projects that create value and facilitate economic growth while safely delivering reliable, resilient and affordable energy to our customers.

Our five-year regulated utility capital plan (2026-2030) that is outlined below is the most ambitious regulated utility plan our Company has announced in recent years. Our confidence in this plan lies in our robust project pipeline that currently includes the Yellowhead Pipeline (Yellowhead) and the Central East Transfer Out (CETO) projects. Additionally, we have identified other utility capital spending that is expected to proceed during the 5-year forecast period associated with customer growth, system reliability and safety, climate and technology, and other program and system investments.

The economic drivers within Alberta are fundamental to our growth. Alberta continues to lead population growth in Canada, and in mid-2025, Alberta’s population reached five million people, up 2.5 per cent year-over-year. As a provider of essential energy services, CU Inc. plays a critical role in enabling population, business and industrial growth within its operating regions. CU Inc.'s utility assets are part of the economic backbone of Alberta and northern Canada.

Operational Excellence

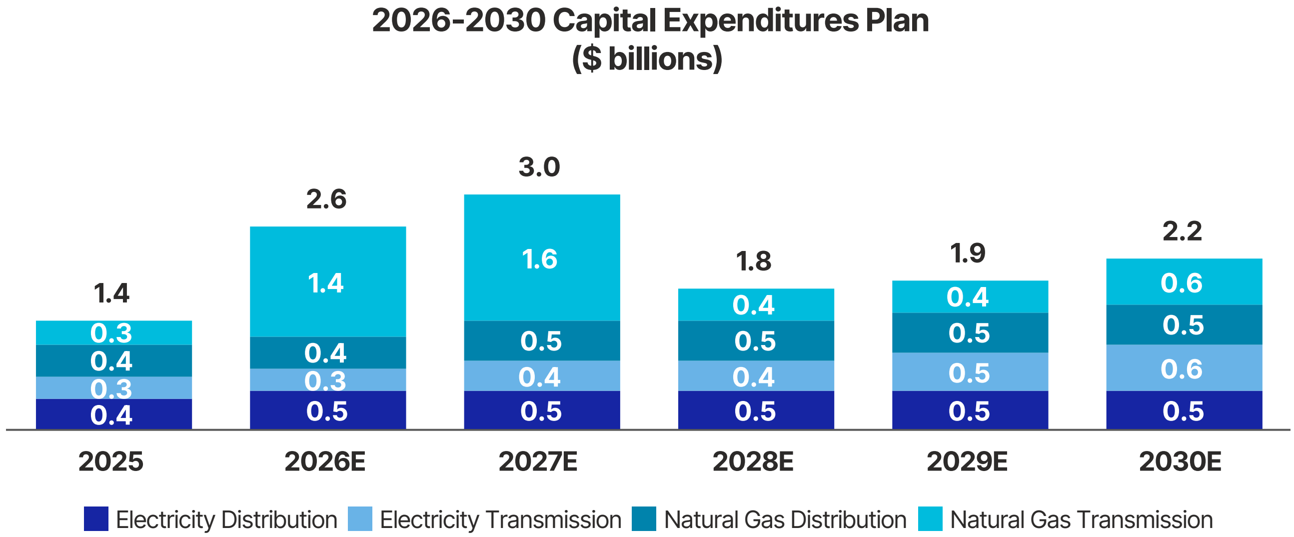
Operational Excellence is anchored in safety, reliability, resiliency, and operational performance. Safety is a foundational imperative and our number one operational priority. By continuing to foster a strong safety culture, CU Inc. ensures that operational efficiency, reliability, and resilience are achieved without compromise through company-wide collaboration and championing workplace safety across the business. From a performance perspective, our businesses are known for their ability to drive operational efficiencies.

Financial Leadership

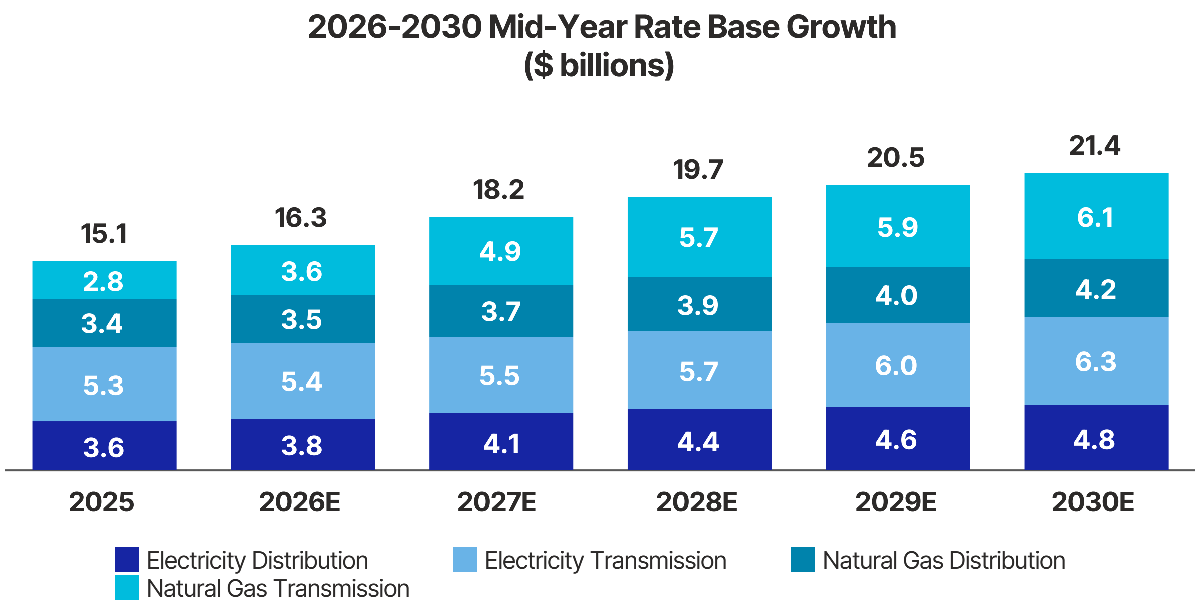
CU Inc. is charting a path for sustainable, long-term growth. Our Company was built on an unwavering commitment to financial strength. This continues today with our focus on growing earnings and cash flow, maintaining strong investment grade credit ratings, and prudently sourcing capital to fund growth.

CAPITAL EXPENDITURE PLAN

The five-year (2026-2030) capital expenditure plan anticipates approximately $11.5 billion of capital spending to support the evolving needs of our customers throughout the regulated jurisdictions in which we operate. These capital projects will be aligned with customer growth, system reliability and safety, climate adaptation and resilience, new technologies and energy transition initiatives. Additionally, Yellowhead supports the expansion of natural gas transmission in Alberta, relieving capacity constraints and supporting economic growth within Canada. In the latter years of the forecast period, we anticipate customer growth, system reliability and safety, and climate adaptation and resilience to continue to be strong investment themes. Additional natural gas transmission and distribution projects and Alberta Electric System Operator (AESO)-directed electric transmission and distribution projects are anticipated to be de-risked and come into view as further economic growth puts new pressures on our regulated systems. Following the completion of Yellowhead, our capital forecast continues to project higher annual capital spending than experienced over the past few years with an anticipated mid-year rate base [1] CAGR [2] in the range of 5-7 per cent over the longer term. See Appendix 2 for more information on our five-year (2026-2030) capital expenditure plan.



Mid-year rate-base [1] growth is a leading indicator of a regulated utility's earnings trend. This level of anticipated capital expenditures over the five-year forecast would support a mid-year rate base CAGR [1] of approximately seven per cent from 2026 to 2030.



Rate base is a measure specific to rate-regulated utilities and is used by regulatory authorities. The Company finances infrastructure investments, referred to as rate base, through a combination of equity and debt. Regulatory proceedings establish the approved rate of return on equity (ROE) and the equity ratio – the proportion of utility investments financed with equity, with the remainder financed by debt. Both the ROE and the equity ratio are determined based on the concept of "fair

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(1) *Mid-year rate base is a non-GAAP financial measure and mid-year rate base CAGR is a non-GAAP ratio (each as defined in National Instrument 52-112 - Non-GAAP and Other Financial Measures Disclosure (NI 52-112)). Mid-year rate base and mid-year rate base CAGR are not standardized measures under the reporting framework used to prepare the Company's financial statements and may not be comparable to similar measures disclosed by other issuers. The most directly comparable measures to mid-year rate base reported in accordance with International Financial Reporting Standards (IFRS) are property, plant and equipment and intangible assets. See "Other Financial and Non-GAAP Measures" and "Reconciliation of Rate Base and Mid-Year Rate Base to Property, Plant and Equipment and Intangible Assets" in this MD&A.*

(2) *CAGR means compound annual growth rate.*

return," which includes three main components: (i) comparability, (ii) financial integrity, and (iii) financial attractiveness. The costs of equity and debt are included in the amounts collected as revenues. More information about rate base is described in the "Reconciliation of Rate Base and Mid-Year Rate Base to Property, Plant and Equipment, and Intangible Assets" section in this MD&A.

Capital expenditures are approved by the regulator through rate applications. The five-year capital forecast includes capital expenditures that extend beyond currently approved rate applications. These capital expenditures will require approval by the regulator in future rate applications.

UTILITIES PERFORMANCE

REVENUES

Revenues of $803 million in the fourth quarter of 2025 were $19 million lower than the same period in 2024. Lower revenues were mainly due to the commencement of refunds of $35 million and $36 million to the customers of Electricity Distribution and Natural Gas Distribution, respectively, over the September 1, 2025 to February 28, 2026 period, resulting from the Alberta Utilities Commission's (AUC's) Second Generation Performance Based Regulation (PBR2) re-opener Phase II Decision rendered in the second quarter of 2025. The Company has been granted leave to appeal this decision, which will be heard by the Alberta Court of Appeals in April 2026.

Revenues of $3,080 million in the full year of 2025 were $37 million higher than the same period in 2024. Higher revenues were mainly due to growth in rate base. Higher revenues were partially offset by a decrease in the approved ROE following the annual update of the AUC approved ROE formula, which set the 2025 ROE at 8.97 per cent compared to the 2024 rate of 9.28 per cent, and the completion of Efficiency Carry-Over Mechanism (ECM) funding of up to 0.5 per cent additional ROE in 2024 for Electricity Distribution and Natural Gas Distribution. In addition, higher revenues were partially offset by the commencement of the PBR2 re-opener refund.

ADJUSTED EARNINGS

	Three Months Ended December 31			Year Ended December 31		
($ millions)	**2025**	**2024**	**Change**	**2025**	**2024**	**Change**
Electricity						
Electricity Distribution [1]	**36**	46	(10)	**153**	150	3
Electricity Transmission [1]	**44**	47	(3)	**177**	190	(13)
Total Electricity [1]	**80**	93	(13)	**330**	340	(10)
Natural Gas						
Natural Gas Distribution [1]	**73**	69	4	**143**	142	1
Natural Gas Transmission [1]	**28**	28	—	**109**	95	14
Total Natural Gas [1]	**101**	97	4	**252**	237	15
Financing & Other and Intersegment Eliminations [1]	**—**	(5)	5	**(1)**	(20)	19
Total Utilities [2]	**181**	185	(4)	**581**	557	24

(1) Non-GAAP financial measures (as defined in NI 52-112). The most directly comparable measure reported in accordance with IFRS is Earnings for the Period. Adjusted earnings is not a standardized financial measures under IFRS and may not be comparable to similar financial measures disclosed by other issuers. See "Other Financial and Non-GAAP Measures" and "Reconciliation of Adjusted Earnings to Earnings for the Period" in this MD&A.

(2) Total of segments measure (as defined in NI 52-112). The most directly comparable measure reported in accordance with IFRS is Earnings for the Period. See "Other Financial and Non-GAAP Measures" and "Reconciliation of Adjusted Earnings to Earnings for the Period" in this MD&A.

Utilities adjusted earnings of $181 million in the fourth quarter of 2025 were $4 million lower than the same period in 2024 mainly due to a decrease in 2025 ROE which was set at 8.97 per cent compared to the 2024 rate of 9.28 per cent, and the completion of ECM funding of up to 0.5 per cent additional ROE in 2024 for Electricity Distribution and Natural Gas Distribution, partially offset by growth in rate base and cost efficiencies. Additionally, lower earnings were partially due to tax adjustments recorded in the fourth quarter of 2024 in Electricity Distribution.

Utilities adjusted earnings of $581 million in the full year of 2025 were $24 million higher than the same period in 2024 mainly due to growth in rate base and cost efficiencies. Higher earnings were partially offset by a decrease in 2025 ROE which was set at 8.97 per cent compared to the 2024 rate of 9.28 per cent, and the completion of ECM funding of up to 0.5 per cent additional ROE in 2024 for Electricity Distribution and Natural Gas Distribution.

Detailed information about the activities and financial results of the Utilities business segments is provided in the following sections.

Electricity Distribution

Electricity Distribution provides regulated electricity distribution and distributed generation mainly in northern and central east Alberta, the Yukon, the Northwest Territories, and in the Lloydminster area of Saskatchewan.

Electricity Distribution adjusted earnings of $36 million in the fourth quarter of 2025 were $10 million lower than the same period in 2024 mainly due to tax adjustments recorded in 2024, the completion of ECM funding in 2024, and lower ROE in 2025, partially offset by growth in rate base and cost efficiencies.

Electricity Distribution adjusted earnings of $153 million in the full year of 2025 were $3 million higher than the same period in 2024 mainly due to growth in rate base and cost efficiencies, partially offset by the completion of ECM funding in 2024 and lower ROE in 2025.

Electricity Transmission

Electricity Transmission provides electricity transmission mainly in northern and central east Alberta, and in the Lloydminster area of Saskatchewan. Additionally, Electricity Transmission has a 35-year contract to be the operator of Alberta PowerLine, a 500-km electricity transmission line between Wabamun, near Edmonton, and Fort McMurray, Alberta.

Electricity Transmission adjusted earnings of $44 million and $177 million in the fourth quarter and full year of 2025 were $3 million and $13 million lower than the same periods in 2024 mainly due to lower ROE in 2025.

Natural Gas Distribution

Natural Gas Distribution serves municipal, residential, commercial, and industrial customers throughout Alberta and in the Lloydminster area of Saskatchewan.

Natural Gas Distribution adjusted earnings of $73 million and $143 million in the fourth quarter and full year of 2025 were $4 million and $1 million higher than the same periods in 2024 mainly due to the growth in rate base and cost efficiencies in 2025, partially offset by completion of ECM funding in 2024 and lower ROE.

Natural Gas Transmission

Natural Gas Transmission receives natural gas on its pipeline system from various gas processing plants as well as from other natural gas transmission systems and transports it to end users within the province of Alberta or to other pipeline systems.

Natural Gas Transmission adjusted earnings of $28 million in the fourth quarter of 2025 were comparable to the same period in 2024.

Natural Gas Transmission adjusted earnings of $109 million in the full year of 2025 were $14 million higher than the same period in 2024 mainly due to growth in rate base and cost efficiencies, partially offset by lower ROE in 2025.

FINANCING & OTHER AND INTERSEGMENT ELIMINATIONS

Including intersegment eliminations, Financing & Other adjusted earnings in the fourth quarter and full year of 2025 were $5 million and $19 million higher than the same periods in 2024 mainly due to higher interest income from cash investments.

2025 DEVELOPMENTS

Yellowhead Pipeline Project (Yellowhead)

Yellowhead consists of approximately 235 kilometres of high-pressure natural gas pipeline with the projected spend estimated at $2.9 billion, a Class III estimate with an expected accuracy of +/-20 per cent. The pipeline is 100 per cent contracted with customers, and is on track for construction to commence in 2026, subject to both AUC and corporate approvals. In the third quarter of 2025, the AUC approved the Need Assessment Application for the project. As one of two key regulatory filings that require approval from the AUC to advance, this approval marks a major milestone in the development of Alberta's energy infrastructure. The Company filed a separate facility application on November 4, 2025, to seek AUC approval for construction and operation of the physical infrastructure. The AUC is expected to render a decision on this application in the third quarter of 2026.

The Company expects to fund Yellowhead's development according to their regulated capital structure, which is 63 per cent regulated debt and 37 per cent regulated equity. The regulated debt is expected to be funded with debenture issuances throughout 2026 and 2027. The regulated equity is expected to be funded with internally generated cash flows, equity contributions from Canadian Utilities and Indigenous partnerships are expected to contribute up to 30 per cent of the equity. In 2025, CU Inc. raised $500 million fixed to fixed rate subordinate notes and $200 million preferred shares to substantially pre-fund its equity contribution.

Central East Transfer Out (CETO) Project

CETO consists of a 135-km 240kV transmission line, of which Electricity Transmission is building 85-km of the transmission line and AltaLink LP is constructing the remaining 50-km. Electricity Transmission completed the winter season construction in the first quarter of 2025, including substation tendering for civil, structural and electrical works, began fall season construction in the third quarter of 2025, and continues to progress on target timelines. Electricity Transmission's 85-km of the transmission line is on track to be energized by June 2026 with an approximate $255 million project spend. CETO will support renewable energy integration in Alberta and transport electricity in the counties of Red Deer, Lacombe and Stettler, supplying more than 1,500-MW of electricity to Alberta's grid.

REGULATORY INFORMATION

REGULATED BUSINESS MODELS

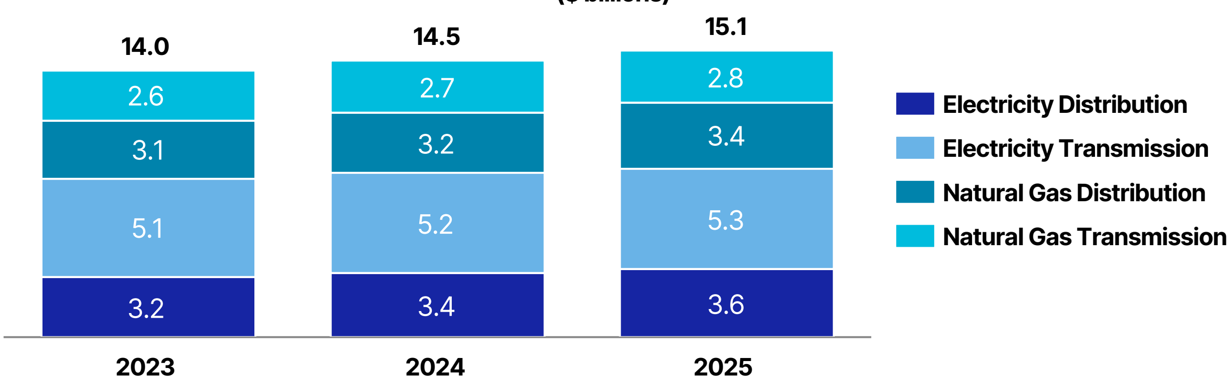
Regulated Business Models

The Alberta business operations of Electricity Distribution, Electricity Transmission, Natural Gas Distribution, and Natural Gas Transmission are regulated mainly by the AUC. The AUC administers acts and regulations covering such matters as rates, financing and service area.

Natural Gas Transmission and Electricity Transmission operate under Cost of Service (COS) regulation. Under this model, the regulator establishes the revenues to provide for a fair return on utility investment using mid-year calculations of the total investment less depreciation, otherwise known as mid-year rate base. Growth in mid-year rate base is a leading indicator of the business' earnings trend, depending on changes in the approved equity component of the mid-year rate base and the rate of return on common equity.

Natural Gas Distribution and Electricity Distribution operate under Performance Based Regulation (PBR). Under PBR, revenue is determined by a formula that adjusts customer rates for inflation less an estimated amount for productivity improvements. The AUC reviews the utilities' results annually to ensure the rate of return on common equity is within certain upper and lower boundaries. To complete these calculations, the AUC uses mid-year rate base. For this reason, growth in mid-year rate base can be a leading indicator of the business' earnings trend, depending on the ability of the business to maintain costs based on approved going-in rates and on the formula that adjusts rates for inflation and productivity improvements.

Mid-Year Rate Base [(1)]
($ billions)



(1) *Mid-year rate base is a non-GAAP financial measure. See "Other Financial and Non-GAAP Measures" and "Reconciliation of Rate Base and Mid-Year Rate Base to Property, Plant and Equipment, and Intangible Assets" in this MD&A.*

PERFORMANCE BASED REGULATION

The Natural Gas Distribution and Electricity Distribution businesses moved to a third generation of PBR (PBR3) for the years 2024 to 2028.

On October 4, 2023, the AUC issued its decision regarding the parameters of the PBR3 plans that set rates for the distribution utilities for the years 2024 to 2028. The AUC approved continuation of the incremental capital funding mechanism based on historical five years of actual capital spend as well as the ability to seek additional funding for capital that meets certain eligibility criteria. The AUC also introduced a new productivity factor premium and an asymmetric, two-tiered Earnings Sharing Mechanism. The AUC did not include an ECM for PBR3, however, 2023 and 2024 had ECM revenue related to the second PBR term.

	PBR THIRD GENERATION
Timeframe	2024 to 2028
Inflation Adjuster (I Factor)	Inflation indices (FWI and CPI) adjusted annually with a true up applied
Productivity Adjuster (X Factor)	0.40% (includes 0.3% for productivity factor premium)
O&M	Based on 2023 approved COS Applications; inflated by I-X through the PBR term
Return on Operating Cost Investment	Ability to apply for return on operating solutions
Treatment of Capital Costs	a. Recovered through going-in rates inflated for I-X and a K Bar (the AUC allowance for capital additions under PBR) that is based on inflation adjusted average historical capital costs for the period 2018-2022. The K Bar is calculated annually and adjusted for the actual weighted average cost of capital (WACC) b. Significant extraordinary capital costs not previously incurred, required by a third party or directly caused by applicable law related to net-zero objectives recovered through a "Type I" K Factor
Return On Equity (ROE)	a. Based on the established Generic Cost of Capital (GCOC) formula (results released November of each year) b. + 0.5% ROE ECM achieved from PBR Second Generation added to 2023 and 2024
Earnings Sharing Mechanism (ESM)	Two-tiered, asymmetric ESM; • the utilities retain 100% of the first 200 bps of earnings above the authorized ROE • a 60/40 utility/customer split for the next 200 bps of earnings, and • a 20/80 utility/customer split for any earnings over 400 bps
Reopener	+/- 300 bps of the approved ROE for two consecutive years or +/- 500 bps of the approved ROE for any single year
ROE Used for Reopener Calculation	• 2024: Based on the GCOC formula excluding impact of ECM • 2025-2028: Based on the GCOC formula
Quantification and Tracking of Efficiencies	Utility must report a select set of operational metrics annually to the AUC

REGULATORY UPDATES

COMMON MATTERS

2026 Return on Equity

On November 12, 2025, the AUC issued a decision setting the 2026 ROE at 9.02 per cent. The ROE determination utilized the approved formula set in the 2023 Generic Cost of Capital proceeding. The 2026 ROE of 9.02 per cent is slightly higher than the 2025 ROE of 8.97 per cent, due to favourable bond and utility spreads.

Third Generation PBR (PBR3) Decision Permission to Appeal

On March 12, 2025, the Alberta Court of Appeal granted ATCO Electric Permission to Appeal (PTA) a decision of the AUC that established the parameters of the PBR3 plan that will apply to the Alberta Electric and Gas Distribution utilities for the period 2024 to 2028 (PBR3 Decision).

The PTA was granted to ATCO Electric on the issue of whether the AUC erred in failing to provide ATCO Electric with a reasonable opportunity to recover and earn a fair return on its prudent costs of capital for its required Grid Modernization Program during the PBR3 term, contrary to the regulatory compact and the statutory obligation of the AUC as per the *Electric Utilities Act*. The appeal was heard on January 15, 2026 and a decision is expected within 2026.

Second Generation PBR (PBR2) Re-openers

In June 2023, the AUC initiated a proceeding for Electricity Distribution and Natural Gas Distribution as the re-opener clause was triggered by both utilities' earnings in 2022, the final year of PBR2. The PBR2 re-opener thresholds were triggered as a result of both utilities' earnings being either +/- 500 basis points from the approved ROE in one year or +/- 300 basis points from the approved ROE in two consecutive years.

On May 22, 2024, the AUC issued a decision to re-open the PBR2 plan and advanced to the second phase of the proceeding (Phase I Decision). The AUC claimed that the distribution businesses failed to quantify or attribute all efficiency gains under PBR2 to specific programs or initiatives. An appeal with the Alberta Court of Appeal was filed on the Phase I Decision of the proceeding.

On May 28, 2025, the AUC issued its Phase II Decision related to the PBR2 re-opener proceeding to refund $35 million to the customers of Electricity Distribution and $36 million to the customers of Natural Gas Distribution over a six-month period, from September 1, 2025 to February 28, 2026. In regard to the Phase II Decision, a Review and Variance (R&V) and a PTA were filed with the AUC and the Alberta Court of Appeal, respectively, on June 27, 2025. On September 22, 2025, the PTA of the Phase II Decision was granted by the Alberta Court of Appeal. The Phase I and Phase II appeals have been combined into a single proceeding before the Alberta Court of Appeal, which is scheduled to be heard in April 2026. On October 6, 2025, the AUC denied the application to R&V the Phase II Decision.

Electricity Distribution and Natural Gas Distribution were the only utilities in Alberta to lower rates in 2023 due to efficiencies being passed onto customers. The after-the-fact requirement to track cost efficiencies at a granular level is inconsistent with PBR regulatory principles and past AUC positions. As Electricity Distribution and Natural Gas Distribution are appealing both the Phase I and Phase II Decisions of the PBR2 re-opener proceeding with the Alberta Court of Appeal, and the Company believes it will more likely than not succeed on appeal, no impact to Adjusted Earnings has been recognized in 2025 related to the PBR2 re-opener decisions.

Natural Gas Transmission

2026-2028 General Rate Application (GRA)

On September 22, 2025, ATCO Pipelines filed its GRA with the AUC to establish its revenue requirement for the 2026–2028 Test Period. The application seeks approval for revenue requirements of $381 million, $489 million and $680 million for the years 2026, 2027 and 2028, respectively. Increases over the test period are largely related to the Yellowhead Pipeline Project. ATCO Pipelines is requesting a deferral account to manage uncertainties for Yellowhead and measures to provide credit relief during the construction. The temporary credit relief includes three options to be considered: a temporary ROE adder of 1 per cent for 2026 and 2027, a temporary deemed equity thickness adder of 2 per cent for 2026 and 2027, and Construction Work in Progress to be included in rate base.

In January 2026, ATCO Pipelines and interveners reached a comprehensive settlement in principle, except for IT O&M costs and matters excluded from negotiations by the AUC, including requested deferral accounts for growth and Yellowhead, temporary credit relief during construction of the Yellowhead project, and a depreciation expense placeholder. These excluded items will be adjudicated separately by the AUC.

Electricity Transmission

2026-2027 General Tariff Application (GTA)

On November 21, 2025, Electricity Transmission filed its GTA with the AUC. This application seeks approval for revenue requirements of $687 million for 2026 and $701 million for 2027, which includes the impact of capital investments made in

2023 and 2024 that are not yet in rate base. This GTA reflects Electricity Transmission being mindful of affordability – the modest proposed tariff increases are less than 3 per cent in 2026 and 2 per cent in 2027.

Along with the GTA, Electricity Transmission filed its 2022-2024 Deferral Application, which establishes the prudence of actual expenditures and investments incurred in deferral accounts in 2022-2024. The largest of these are direct assigned capital investments put into service during that period.

POLICY AND REGULATORY UPDATES

We constructively work with all levels of government to advocate for enabling policy and regulation, and to identify barriers that impede cost-effective, economy-wide solutions. We participate in a wide number of discussions, and the following are examples of where we focus our efforts on policies or regulations most relevant to our existing or planned projects.

CANADA

CANADA'S NEW PRIME MINISTER, MARK CARNEY

On April 28, 2025, the Liberal Party secured victory in the federal election, bringing Mark Carney to office. His campaign emphasized making Canada the "world's leading superpower in both clean and conventional energy," guided by three core objectives: energy security, trade diversification, and long-term competitiveness. Following the election, the Prime Minister committed to addressing economic challenges, housing, defence, energy, trade, and affordability, particularly in response to escalating external tariff pressures and economic threats from Canada's largest trading partner, the US. Early policy direction also highlights the federal government's intention to accelerate the removal of interprovincial trade barriers, a reform expected to strengthen economic resilience and enhance national competitiveness.

ENVIRONMENTAL CLAIMS - THE COMPETITION ACT AND FEDERAL BILL C-15

During the fiscal period, regulatory developments occurred relating to environmental claims under the *Competition Act (Canada)*, affecting compliance expectations, legal-risk management, environmental disclosure practices, and strategic planning for sustainability-related communications.

On June 5, 2025, the Competition Bureau released final guidelines to help address the anti-greenwashing provisions that came into force on June 20, 2024. These guidelines clarified the Bureau's approach to assessing environmental claims, outlined six compliance principles, and reaffirmed that due diligence may serve as a defence against deceptive-marketing allegations.

On November 18, 2025, the federal government introduced Bill C-15 as part of its broader Climate Competitiveness Strategy under Budget 2025. Budget 2025 acknowledged that the greenwashing rules introduced in 2024–2025 created investment uncertainty and, in some cases, impeded environmental initiatives. Bill C-15 proposes amendments to remove the "internationally recognized methodology" requirement and reduces exposure to private enforcement.

These amendments could reduce regulatory uncertainty and mitigate litigation risk associated with business-activity environmental claims, while maintaining the Bureau's oversight of environmental representations.

MAJOR PROJECTS OFFICE

On August 29, 2025, the federal government launched the Major Projects Office (MPO) under the *Building Canada Act*, which came into force on June 26, 2025. The MPO is intended to accelerate and streamline the approval of nationally significant infrastructure projects, targeting a two-year regulatory timeline, while coordinating financing from private capital and federal initiatives such as the Canada Infrastructure Bank, the Canada Growth Fund, and the Indigenous Loan Guarantee Program.

On September 11, 2025, the MPO announced its first tranche of five nation-building projects, which will be fast-tracked through the regulatory process. A second tranche was subsequently announced on November 13, 2025. These projects include major clean energy, liquified natural gas, transmission, and critical minerals developments, supporting federal objectives to enhance energy security, diversify trade corridors, and expand Canada's critical mineral and strategic infrastructure base.

FEDERAL BUDGET 2025

On November 4, 2025, the federal government released Budget 2025, marking a shift toward an investment-focused fiscal strategy centered on large-scale national infrastructure, clean-energy development, and long-term economic competitiveness. The budget introduced a five-year, $280 billion capital plan, including $115 billion for federal infrastructure, with priority placed on expanding interprovincial transmission, modernizing the grid, and accelerating clean-energy and trade-enabling projects. To support these goals, Budget 2025 established two structural policy mechanisms—the *One Canadian Economy Act* and the Buy Canadian Policy—to strengthen domestic supply chains, harmonize procurement, and reduce internal trade barriers. The budget also provided the legislative foundation for the *Building Canada Act* and the creation of the MPO, reinforcing the federal push to accelerate project delivery amid heightened trade uncertainty and rising national infrastructure demand.

US TARIFFS ON CANADA

Throughout 2025, trade tensions between Canada and the US escalated sharply, resulting in multiple rounds of tariff measures that materially increased uncertainty for Canadian exporters. Beginning in March 2025, the US imposed significant tariffs on a wide range of Canadian goods, including 25 per cent duties on most imports and targeted surcharges on steel and aluminum. Subsequent actions expanded these measures to cover automobiles and, later in the year, a broad 35 per cent tariff on nearly all Canadian imports, subject to limited exemptions for goods compliant with the Canada-U.S.–Mexico Agreement (CUSMA).

For Canada, these developments created heightened risks for key sectors such as manufacturing, metals, automobiles, and agriculture, and introduced volatility in cross-border supply chains. The Government of Canada continues to negotiate with its US counterparts, and has indicated that some level of tariffs may need to be accepted as part of a broader trade resolution. The situation remains fluid and represents a continued external risk factor for 2026. Beyond potential inflationary impacts, CU Inc. is largely shielded from the impacts as the company does not rely on exports.

ALBERTA

BILL 52 & BILL 8 – MODERNIZING ALBERTA'S ELECTRICITY AND UTILITIES FRAMEWORK

In 2025, Alberta advanced two major legislative initiatives—Bill 52: *Energy and Utilities Statutes Amendment Act, 2025* and Bill 8: *Utilities Statutes Amendment Act, 2025*—together representing one of the most significant restructurings of the province's electricity and utility industries in decades.

Bill 52 – Energy and Utilities Statutes Amendment Act, 2025

On April 10, 2025, Alberta introduced Bill 52, a key legislative step enabling the province's transition to the REM and the new OTP framework. The legislation introduces a dual-market design with both a day-ahead and real-time market, expands administrative and locational pricing tools, and enhances AESO's authority to manage transmission constraints and implement new ISO rules. Provincial implementation is targeted for 2027. The bill also permits hydrogen blending in natural-gas distribution under defined conditions.

Bill 8 – Utilities Statutes Amendment Act, 2025

Bill 8 builds on Bill 52 to address surging demand from Artificial Intelligence (AI)-driven, energy-intensive data centres. The bill enables "bring-your-own-power" models, prioritizes grid access for self-supplied projects, and requires developers—not ratepayers—to fund transmission upgrades. Additional regulatory powers allow tailored rules for large-load integration as Alberta prepares for REM deployment.

TECHNOLOGY INNOVATION AND EMISSIONS REDUCTION (TIER) – INDUSTRIAL CARBON PRICING

On May 12, 2025, the Government of Alberta announced it would freeze the TIER Fund price at $95/tonne CO_2e, halting the scheduled annual increases that were previously intended to reach $170/tonne by 2030 under the federal program. This freeze provides short-term cost relief for regulated facilities but introduces longer-term uncertainty regarding carbon-price signals for emissions-reduction investments.

On September 16, 2025, the Government of Alberta introduced further proposed adjustments to TIER, some of the highlights include:

- allowing certain facilities which voluntarily opted in to opt back out, following the federal elimination of the fuel charge; and
- establishing a direct investment compliance pathway, permitting regulated entities to meet a portion of their obligations through eligible on-site emissions-reduction projects rather than solely through fund payments or credit instruments.

On December 3, 2025, the Government of Alberta implemented amendments to TIER introducing investment credits and credit reactivation, formally establishing the direct investment pathway as an additional compliance mechanism. While these changes expand compliance options, the overall implications for long-term costs, investment decisions, and emissions-reduction strategies remain uncertain as program details and standards continue to evolve.

AESO LARGE LOAD INTEGRATION

In June 2025, the AESO launched a two-phase Large Load Integration program in response to unprecedented large load connection requests (including data centres), with reported requests exceeding 16-GW in the connection process. As an interim reliability measure, the AESO established a 1,200-MW interim connection limit for near-term large load connections (2027/2028 horizon), including qualification requirements such as municipal support and financial security.

In November 2025, the AESO reported Phase 1 completion, with the interim 1,200-MW limit fully allocated and confirmed that remaining large-load requests will progress under the forthcoming Phase 2 long-term framework. Phase 2 pre-engagement began in late 2025, incorporating early stakeholder input and establishing a working group to guide development. A draft proposal is planned for consultation in early 2026, with Phase 2 work continuing through the year to define long-term connection pathways and refine large-load integration processes.

TRANSMISSION INTERTIES – PROVINCIAL DIRECTION

On October 14, 2025, the Government of Alberta issued direction to the AESO underscoring the need to restore and expand provincial intertie capability, including the Montana–Alberta Tie Line (MATL) and other key interconnections. The province instructed the AESO to take all reasonable steps to restore MATL's available transfer capability by 2029, provide regular public reporting on intertie performance, and support full import capability during normal operating conditions. The provincial government also directed the AESO to engage with all intertie owners in Alberta's neighbouring jurisdictions to explore value-creation opportunities for each interconnection, with the desired outcome of developing appropriate agreements with each jurisdiction. These measures are intended to enhance system reliability, improve import flexibility, and align Alberta's transmission planning with evolving market and policy requirements.

CANADA–ALBERTA MEMORANDUM OF UNDERSTANDING (MOU) – ENERGY COLLABORATION

On November 27, 2025, Canada and Alberta signed an energy MOU establishing a collaborative framework to advance major infrastructure—pipelines, transmission systems, ports, and trade corridors—while improving regulatory alignment and expanding Indigenous economic participation. The agreement is intended to enhance long-term competitiveness by accelerating market access, modernizing energy systems, and supporting investment in low-carbon and strategically important infrastructure.

A key feature of the MOU is the suspension of the federal Clean Electricity Regulations (CER) in Alberta, enabling work toward a province-specific equivalency pathway for electricity-sector emissions. With CER paused, carbon pricing becomes the primary compliance tool, increasing reliance on Alberta's TIER program to guide emissions-reduction decisions and support low-carbon investment. The MOU also links regulatory cooperation to major project advancement, including large-scale carbon capture utilization and storage (CCUS) initiatives and potential new export pipelines tied to successful carbon-capture deployment. Alongside commitments to streamline approvals and shorten permitting timelines, the agreement aims to reduce regulatory uncertainty and support investment in transmission, generation capacity, and emissions-reduction infrastructure.

Alberta must still demonstrate that its carbon-pricing-based approach can deliver emissions-reduction outcomes equivalent to federal expectations. This includes showing an effective carbon price consistent with federal benchmark stringency, meeting methane-reduction equivalency obligations—such as the federal–Alberta commitment to a 2035 target date and a 75 per cent reduction relative to 2014 levels—and continuing progress on CCUS and cooperative federal–provincial processes, including impact assessment frameworks. Continued progress will depend on stable federal–provincial cooperation, investor confidence in CCUS development, and predictable long-term carbon-price signals—all critical to advancing major infrastructure and sustaining Alberta's decarbonization trajectory.

SUSTAINABILITY

Within the ATCO Group of companies (including CU Inc.), our guiding principle is to deliver long-term value to our customers, share owners, and other stakeholders through sustainable growth. This requires more than strong financial performance – it requires integrating financial and environmental, social and governance (ESG) considerations into our strategy and anticipating the evolving needs and expectations of society and our customers.

For decades, our commitment to these principles has guided investments in critical energy infrastructure, created ambitious and transformative partnerships with Indigenous communities, and supported the growth and prosperity of the hundreds of communities we are privileged to serve. We continue to pursue growth by investing in regulated utilities. Our priority is scalable projects that deliver measurable impacts today while laying the groundwork for long-term transformation.

When we disclosed our 2050 net-zero ambition in our 2021 Sustainability Report, we recognized it would require unprecedented, coordinated action across industries, policy, and markets. However, recent shifts—including regulatory and policy changes, legal liability concerns, and macroeconomic pressures—have introduced uncertainty regarding the feasibility, timing, and pathways for achieving net-zero by the middle of this century. While our commitment to enabling the energy transition remains strong, we continue to review our 2050 net-zero ambition and the key dependencies influencing the pace of transition. Our 2025 Sustainability Report will be published in May of 2026.

The 2024 Sustainability Report, ESG Datasheet, materiality assessment, 2024 highlights, and other disclosures are available on our website at www.canadianutilities.com.

OTHER EXPENSES AND INCOME

A financial summary of other consolidated expenses and income items for the fourth quarter and full year of 2025 and 2024 is given below. These amounts are presented in accordance with IFRS accounting standards. They have not been adjusted for the timing of revenues and expenses associated with rate-regulated activities and other items that are not in the normal course of business.

	Three Months Ended December 31			Year Ended December 31		
($ millions)	**2025**	**2024**	**Change**	**2025**	**2024**	**Change**
Operating costs	**392**	404	(12)	**1,472**	1,488	(16)
Depreciation, amortization and impairments	**211**	148	63	**665**	586	79
Net finance costs	**95**	102	(7)	**371**	396	(25)
Income tax expense	**24**	33	(9)	**123**	126	(3)

OPERATING COSTS

Operating costs, which are total costs and expenses less depreciation, amortization and impairments, decreased by $12 million and $16 million in the fourth quarter and full year of 2025 compared to the same periods in 2024. Decreased operating costs were mainly due to the restructuring costs incurred in 2024 and realized cost efficiencies. Decreased operating costs were partially offset by higher flow-through expense in Natural Gas Distribution for third party franchise and transmission fees, and the recognition of transition costs related to activities to shift the managed IT services from a single-vendor service provider to a hybrid model of multiple new vendors and internal teams.

DEPRECIATION, AMORTIZATION AND IMPAIRMENTS

Depreciation, amortization and impairments increased by $63 million and $79 million in the fourth quarter and full year of 2025 compared to the same periods in 2024 mainly due to asset impairments and write-offs recognized in the fourth quarter of 2025. These asset impairments and write-offs include certain hydrogen assets in Natural Gas Distribution impacted by regulatory uncertainty, electricity generation assets in Electricity Transmission that are no longer in service, and inventories in Natural Gas Transmission. Ongoing capital investment also contributed to increased expenses in the fourth quarter and full year of 2025.

NET FINANCE COSTS

Net finance costs decreased by $7 million and $25 million in the fourth quarter and full year of 2025 compared to the same periods in 2024 mainly due to increased capitalization of interest on construction activities and decreased interest rates.

INCOME TAX EXPENSE

Income taxes decreased by $9 million and $3 million in the fourth quarter and full year of 2025 compared to the same periods in 2024 mainly due to lower IFRS earnings before income taxes during the fourth quarter of 2025, and investment tax credits.

LIQUIDITY AND CAPITAL RESOURCES

Our business strategies, funding of operations, and planned future growth are supported by maintaining strong investment grade credit ratings and access to capital markets at competitive rates. Primary sources of capital are cash flows from operations and capital markets. Liquidity is generated by cash flows from operations and is supported by appropriate levels of cash and available committed credit facilities.

CREDIT RATINGS

The following table shows the credit ratings assigned to CU Inc. at December 31, 2025.

	DBRS	Fitch
CU Inc.		
Issuer	A (high)	A-
Senior unsecured debt	A (high)	A
Commercial paper	R-1 (low)	F2
Preferred shares	PFD-2 (high)	BBB+

On July 23, 2025, DBRS Limited affirmed its 'A (high)' long-term corporate credit rating and stable outlook on CU Inc.

On October 27, 2025, Fitch Ratings affirmed its 'A-' issuer rating with a stable outlook on CU Inc.

LINES OF CREDIT

At December 31, 2025, CU Inc. and its subsidiaries had the following lines of credit.

($ millions)	Total	Used	Available
Long-term committed	**900**	125	775
Uncommitted	**100**	56	44
Total	**1,000**	181	819

Of the $1 billion in total lines of credit, $100 million was in the form of uncommitted credit facilities with no set maturity date. The other $900 million in credit lines was committed, with maturities between 2027 and 2028, and may be extended at the option of the lenders. The majority of the credit lines are provided by Canadian banks.

CONSOLIDATED CASH FLOWS

At December 31, 2025, the Company's cash position was $23 million. This represents an increase of $186 million compared to the cash position at December 31, 2024. Cash movements for the fourth quarter and full year of 2025 and 2024 are outlined in the following table:

	Three Months Ended December 31			Year Ended December 31		
($ millions)	**2025**	**2024**	**Change**	**2025**	**2024**	**Change**
Cash position, beginning of period	**15**	(28)	43	**(163)**	(71)	(92)
Cash from (used in):						
Operating activities	**424**	414	10	**1,722**	1,596	126
Investing activities	**(403)**	(438)	35	**(1,400)**	(1,327)	(73)
Financing activities	**(13)**	(111)	98	**(136)**	(361)	225
Cash position, end of the period	**23**	(163)	186	**23**	(163)	186

The opening cash position of $15 million in the fourth quarter of 2025 was $43 million higher compared to the opening cash position for the fourth quarter of 2024 mainly due to 2025 debt issuances and repayments.

The opening cash position of $(163) million in the full year of 2025 was $92 million lower compared to the opening cash position for the full year of 2024 mainly due to repayment of long-term debt, and funding of capital projects.

Operating Activities

Cash flows from operating activities of $424 million and $1,722 million in the fourth quarter and full year of 2025 were $10 million and $126 million higher than the same periods in 2024 mainly due to the timing of settlement of accounts payable and the collection of trade receivables from customers, and increased customer contributions in Electricity Transmission and Natural Gas Transmission. Increases were partially offset by higher income tax payments.

Investing Activities

Cash flows used in investing activities of $403 million in the fourth quarter of 2025 were $35 million lower than the same period in 2024 mainly due to the timing of capital projects related to system reliability and safety, as well as climate adaptation and resilience, partially offset by higher capital expenditures in Natural Gas Transmission on growth projects for new customers, such as Yellowhead.

Cash flows used in investing activities of $1,400 million in the full year of 2025 were $73 million higher than the same period in 2024 mainly due to timing of settlement of accounts payable for capital projects. Higher capital expenditures in Natural Gas Transmission were mainly due to increased spend related to growth projects for new customers, such as Yellowhead, offset by decreased project spending in Electricity Distribution and Transmission related to system reliability and safety, as well as climate adaptation and resilience.

Cash Used for Capital Expenditures

Capital expenditures for the fourth quarter and full year of 2025 and 2024 are shown in the table below.

	Three Months Ended December 31			Year Ended December 31		
($ millions)	**2025**	**2024**	**Change**	**2025**	**2024**	**Change**
Electricity Distribution	**102**	136	(34)	**393**	455	(62)
Electricity Transmission	**55**	133	(78)	**271**	306	(35)
Natural Gas Distribution	**132**	111	21	**443**	407	36
Natural Gas Transmission	**69**	91	(22)	**292**	231	61
Total (1) (2)	**358**	471	(113)	**1,399**	1,399	—

(1) Includes additions to property, plant and equipment, intangibles, and $10 million and $31 million (2024 - $4 million and $14 million) of capitalized interest during construction for the fourth quarter and full year of 2025.

(2) Includes $38 million and $128 million for the fourth quarter and full year of 2025 (2024 - $23 million and $100 million) of capital expenditures that were funded with the assistance of customer contributions.

Cash used for capital expenditures was $358 million in the fourth quarter of 2025, $113 million lower compared to the same period in 2024 mainly due to lower ongoing capital maintenance and infrastructure upgrades in Electricity Distribution and Electricity Transmission due to the timing of capital project spend.

Cash used for capital expenditures was $1,399 million in the full year of 2025, which was comparable to the same period in 2024. Increased capital expenditures in Natural Gas Transmission on growth projects for new customers, such as Yellowhead, was offset by lower capital maintenance and infrastructure upgrades in Electricity Distribution.

Financing Activities

Cash flows used in financing activities were $13 million in the fourth quarter of 2025, $98 million lower than the same period in 2024 mainly due to the increased debt issuances to fund growth projects for new customers, partially offset by higher dividends paid to the Class A and B share owner.

Cash flows used in financing activities were $136 million in the full year of 2025, $225 million lower than the same period in 2024 mainly due to increased debt issuances related to growth projects for new customers, including Yellowhead in Natural Gas Transmission and CETO in Electricity Transmission, partially offset by higher repayments of long term debt in 2025 and higher dividends paid to the Class A and Class B share owner.

Debenture Issuances

In 2025, CU Inc. borrowed $65 million from its $155 million non-revolving unsecured amortizing credit facility to support the construction of CETO within the Electricity Transmission business. The fixed interest rate is at a below-market rate of interest of 2.17 per cent. The difference between the market rate for an equivalent loan and the rate granted is accounted for as a government grant and will be amortized over the useful life of the asset. Quarterly repayments, which will commence once the project reaches commercial operations, are expected to continue until June 30, 2056. Additional draws from the facility are expected in 2026 as construction progresses.

In September 2025, CU Inc. issued $370 million of 4.787 per cent debentures maturing on September 16, 2055. The proceeds from the issuance were used to finance capital expenditures, repay existing indebtedness, and for other general corporate purposes.

Cash Requirements

Contractual financial obligations and other commitments for the next five years and thereafter are shown below:

($ millions)	2026	2027	2028	2029	2030	2031 and thereafter
Financial Liabilities (1)						
Accounts payable and accrued liabilities	463	—	—	—	—	—
Accounts payable to parent and affiliate companies	28	—	—	—	—	—
Long-term debt:						
Principal	—	132	125	—	—	9,365
Interest payments	411	404	408	399	399	6,627
	902	536	533	399	399	15,992
Commitments (1)						
Purchase obligations:						
Operating and maintenance agreements (2)	491	417	428	332	95	86
Capital expenditures	629	5	—	—	—	—
Other	6	6	6	6	6	51
	1,126	428	434	338	101	137
Total	**2,028**	**964**	**967**	**737**	**500**	**16,129**

(1) Additional detail is discussed in Note 19 ("Risk Management") and Note 25 ("Commitments") of the 2025 Consolidated Financial Statements.

(2) The Company's operating and maintenance agreements include undiscounted Information Technology (IT) service costs. In 2025, IT service transitioned from a single-vendor service provider to a hybrid model of multiple third-party vendors and internal teams.

SHARE CAPITAL

CU Inc.'s equity securities consist of Class A shares and Class B shares.

At February 24, 2026, the Company had outstanding 3,570,322 Class A shares and 2,188,262 Class B shares.

QUARTERLY INFORMATION

The following table shows financial information for the eight quarters ended March 31, 2024 through December 31, 2025.

($ millions)	Q1 2025	Q2 2025	Q3 2025	Q4 2025
Revenues	920	701	656	**803**
Earnings for the period	212	89	67	**81**
Adjusted earnings (loss) (1)				
Electricity (2)	86	81	83	**80**
Natural Gas (2)	130	20	1	**101**
Financing & Other (2) and Intersegment Eliminations	(1)	—	—	**—**
Total adjusted earnings (1)	215	101	84	**181**

($ millions)	Q1 2024	Q2 2024	Q3 2024	Q4 2024
Revenues	880	696	645	822
Earnings for the period	200	49	63	135
Adjusted earnings (loss) (1)				
Electricity (2)	88	76	83	93
Natural Gas (2)	121	23	(4)	97
Financing & Other (2) and Intersegment Eliminations	(4)	(5)	(6)	(5)
Total adjusted earnings (1)	205	94	73	185

(1) *Total of segments measure (as defined in NI 52-112). See "Other Financial and Non-GAAP Measures" and "Reconciliation of Adjusted Earnings to Earnings for the Period" in this MD&A.*

(2) *Non-GAAP financial measures (as defined in NI 52-112). See "Other Financial and Non-GAAP Measures" and "Reconciliation of Adjusted Earnings to Earnings for the Period" in this MD&A.*

Our financial results for the previous eight quarters reflect the timing of utility regulatory decisions, and the seasonal nature of demand for natural gas and electricity.

ADJUSTED EARNINGS

In the first three quarters of 2025, adjusted earnings were higher in each quarter compared to the same periods in 2024 mainly due to growth in rate base and cost efficiencies. Higher earnings were partially offset by a decrease in 2025 ROE which is set at 8.97 per cent compared to the 2024 rate of 9.28 per cent, and the completion of ECM funding of up to 0.5 per cent additional ROE in 2024 for Electricity Distribution and Natural Gas Distribution.

In the fourth quarter of 2025, adjusted earnings were lower than the same period in 2024 mainly due to a decrease in 2025 ROE which was set at 8.97 per cent compared to the 2024 rate of 9.28 per cent, and the completion of ECM funding of up to 0.5 per cent additional ROE in 2024 for Electricity Distribution and Natural Gas Distribution, partially offset by growth in rate base and cost efficiencies. Additionally, lower earnings were partially due to tax adjustments recorded in the fourth quarter of 2024 in Electricity Distribution.

EARNINGS FOR THE PERIOD

Earnings for the period include timing adjustments related to rate-regulated activities. They also include one-time gains and losses, impairments, dividends on equity preferred shares, and other items that are not in the normal course of business or a result of day-to-day operations recorded at various times over the past eight quarters. These items are excluded from adjusted earnings and are highlighted below:

- In the second and fourth quarters of 2024, the Company recorded restructuring costs of $32 million (after-tax) and $5 million (after-tax), respectively, mainly related to staff reductions and associated severance costs.
- In the second quarter of 2024, the Company recorded an $8 million (after-tax) reduction to earnings related to an AUC enforcement decision on two historical matters the Electric Transmission business had self-reported to AUC Enforcement staff.
- In the first quarter of 2025, the Company recorded restructuring costs of $10 million (after-tax) mainly related to staff reductions and associated severance costs. Restructuring costs incurred in 2025 were a continuation of restructuring activities commenced in 2024.
- In each of the four quarters of 2025, the Company recognized IT transition costs of $7 million (after-tax), $4 million (after-tax), $2 million (after-tax), and $4 million (after-tax), respectively. The transition activities commenced on January 1, 2025 and concluded in the fourth quarter of 2025. The transition costs were primarily related to activities to shift the managed IT services from a single-vendor service provider to a hybrid model of multiple new vendors and internal teams.
- In the fourth quarter of 2025, the Company recognized asset impairments and write-offs of $42 million (after-tax). These asset impairments and write-offs include certain hydrogen assets in Natural Gas Distribution impacted by regulatory uncertainty, electricity generation assets in Electricity Transmission that are no longer in service, and inventories in Natural Gas Transmission.

BUSINESS RISKS AND RISK MANAGEMENT

The Board is responsible for understanding the principal risks of the businesses in which the Company is engaged. The Board strives for a prudent balance between risks incurred and the potential return to the share owner and confirms appropriate controls are in place that effectively monitor and manage those risks for the Company's long-term viability.

The Board has an Audit Committee, which reviews significant risks associated with future performance and growth. This committee is responsible for confirming that management has procedures in place to appropriately manage identified risks.

We have an established enterprise risk management process that allows us to identify and evaluate our risks by both severity of impact and probability of occurrence. Materiality thresholds are reviewed annually by the Audit Committee. Non-financial risks that may have an impact on the safety of our employees, customers or the general public and reputation risks are also evaluated. Details regarding business risks, both financial and operational, and our risk management approach are discussed below.

FINANCIAL RISKS

Project Execution / Capital Investment

DESCRIPTION AND CONTEXT

The Company's strategy includes multiple capital projects. The Company is subject to normal risks associated with major capital projects, including cancellations, delays, cost increases, and execution risk.

RISK MANAGEMENT APPROACH

The Company strives to reduce the risks of project delays and cost increases through careful project feasibility, development and management processes, reliable procurement practices and entering into fixed price contracts when possible.

Planned capital expenditures for the Regulated Utilities are based on a number of significant assumptions, including: projects identified by the AESO will proceed as currently scheduled; the remaining planned capital investments are required to maintain safe and reliable service and meet planned growth in the Regulated Utilities’ service areas; regulatory approval for capital projects can be obtained in a timely manner; and access to capital market financings can be maintained.

Financing

DESCRIPTION AND CONTEXT

The Company's financing risk relates to price volatility and availability of external financing to fund the Company's capital expenditure program and refinance existing debt maturities. Financing risk is directly influenced by market factors. As financial market conditions change, these risk factors can affect the availability of capital and the relevant financing costs.

RISK MANAGEMENT APPROACH

To address this risk, the Company manages its capital structure to maintain strong investment grade credit ratings that allow continued ease of access to the capital markets. The Company also considers it prudent to maintain sufficient liquidity to fund approximately one full year of cash requirements to preserve strong financial flexibility. This liquidity is generated by cash flows from operations and supported by appropriate levels of cash and available committed credit facilities and provides flexibility in the timing of and amount of external financing.

Liquidity

DESCRIPTION AND CONTEXT

Liquidity risk is the risk that the Company will not be able to meet its financial obligations.

RISK MANAGEMENT APPROACH

Liquidity risk includes contractual financial obligations, which the Company plans to meet with cash flows from operations, existing cash balances and external financing, if necessary. See the "Liquidity and Capital Resources" section of this MD&A for the Company's contractual financial obligations for the next five years and thereafter.

Credit

DESCRIPTION AND CONTEXT

For cash and cash equivalents and accounts receivable and contract assets, credit risk represents the carrying amount on the consolidated balance sheet. Derivative assets and finance lease receivable credit risk arises from the possibility that a counterparty to a contract fails to perform according to the terms and conditions of that contract. The maximum exposure to credit risk is the carrying value of loans and receivables and derivative financial instrument assets.

RISK MANAGEMENT APPROACH

The Company reduces cash and cash equivalents credit risk by investing in instruments issued by credit-worthy financial institutions and in federal government-issued short-term instruments.

The Company minimizes other credit risks by dealing with credit-worthy counterparties, following established credit approval policies, and requiring credit security, such as letters of credit.

The Regulated Utilities are able to recover an estimate for doubtful accounts through approved customer rates and to request recovery through customer rates for any material losses from the retailers beyond the retailer security mandated by provincial regulations.

Foreign Exchange

DESCRIPTION AND CONTEXT

The Company is exposed to transactional foreign exchange risk through transactions denominated in a foreign currency.

RISK MANAGEMENT APPROACH

In conducting its business, the Company may use forward contracts to manage the risks arising from known fluctuations in exchange rates. Such instruments are used only to manage risk and not for trading purposes. The foreign exchange impact is partially offset by hedging activities.

Interest Rate

DESCRIPTION AND CONTEXT

The interest rate risk faced by the Company is largely a result of its long-term debt at variable rates as well as cash and cash equivalents. The Company also has exposure to interest rate movements that occur beyond the term of maturity of the fixed-rate investments.

RISK MANAGEMENT APPROACH

In conducting its business, the Company may use swap agreements to manage the risks arising from fluctuations in interest rates. All such instruments are used only to manage risk and not for trading purposes. The Company has converted certain variable rate long-term debt to fixed rate debt through interest rate swap agreements. At December 31, 2025, the Company had fixed interest rates, either directly or through interest rate swap agreements, on 96 per cent (2024 - 96 per cent) of total long-term debt. Consequently, the Company’s exposure to fluctuations in future cash flows, with respect to debt, from changes in market interest rates is limited. The Company’s cash and cash equivalents include fixed rate instruments with maturities of generally 90 days or less that are reinvested as they mature. The Company maintains strong investment grade ratings, which helps mitigate the risk of higher interest costs, and the vast majority of the Company’s outstanding debt carries fixed rate interest, which helps to alleviate the impact of increasing short-term interest rates.

Inflation Risk

DESCRIPTION AND CONTEXT

Inflation has the potential to impact the economies and business environments in which the Company operates. Increased inflation and any economic conditions resulting from governmental monetary policy intended to reduce inflation may negatively impact demand for products and services and/or adversely affect profitability.

RISK MANAGEMENT APPROACH

The Company monitors the impacts of inflation on the procurement of goods and services and seeks to minimize its effects in future periods through pricing strategies, productivity improvements, and cost reductions. The majority of the impact on costs resulting from inflation is mitigated through the regulatory construct, long-term contractual terms, and pricing of short-term contractual sales.

Income Tax Risk

DESCRIPTION AND CONTEXT

The Company is subject to income taxes in Canada. Due to economic and political conditions, tax rates, tax laws and interpretation of those laws may be subject to significant change that cannot be predicted. Such changes can materially impact current tax obligations and the valuation of deferred tax assets and liabilities, resulting in material change to the Company's effective tax rate. Although income taxes at our Regulated Utilities are generally recovered in customer rates, regulatory lag can defer recovery for certain periods.

The Company is also subject to the audit of our tax returns and other tax matters by Canada Revenue Agency. We regularly and prudently assess the possibility of adverse outcomes resulting from these audits in providing for income taxes in the financial statements. However, there can be no assurance as to the outcome of these audits. Our financial statements could be materially impacted should the outcome of such an audit result in an excess of taxes owing than was previously accrued.

RISK MANAGEMENT APPROACH

The Company manages tax risk by staying informed about changes in tax legislation through ongoing communication with advisors and via membership in tax-focused lobby groups. When necessary, the Company obtains third-party opinions on significant transactions and reviews plans to ensure compliance with current laws and guidelines.

OPERATIONAL RISKS

Health and Safety

DESCRIPTION AND CONTEXT

The operation of the Company's businesses inherently involves risk to the health and safety of both employees and the public. Such hazards include but are not limited to: the uncontrolled release of substances from our natural gas transmission and distribution systems resulting in blowouts, fires, explosions, or gaseous leaks; and exposure to an unintended release of electrical energy from our transmission and distribution wires system, including contact with an energized circuit, electrical component, or equipment.

The failure to identify or inadequately identify worksite and/or work environment hazards or implement adequate controls may cause loss of life or personal injury.

RISK MANAGEMENT APPROACH

Safety is one of the Company's core values and is the first consideration in everything we do. The Company has controls in place to mitigate these risks through pipeline and facility integrity programs, inspection programs, operator training, emergency response full mobilization and tabletop exercises, mutual aid agreements (with others in industry and municipalities), external awareness and education training through its damage prevention department.

The Company has a number of safety programs, specialized training, detailed work methods and processes to ensure the safety of our employees and contractors as they perform their work duties to help mitigate these risks. From a public safety perspective, the Company participates in a number of public communication campaigns and joint utility working groups and various other public safety activities and campaigns at the regional level.

Cybersecurity

DESCRIPTION AND CONTEXT

The Company's reliance on technology, which supports its information and industrial control systems, is subject to potential cyber-attacks, which may include but are not limited to: unauthorized access of confidential information, outage of critical infrastructure and/or ransomware attacks.

RISK MANAGEMENT APPROACH

The Company has an enterprise-wide cybersecurity program covering all technology assets. The cybersecurity program includes employee awareness, layered access controls, continuous monitoring, network threat detection, and coordinated incident response through a centralized security operations centre. The Company's cybersecurity management is consolidated under a common, centralized organization structure to increase effectiveness and compliance across the entire enterprise.

Regulatory

DESCRIPTION AND CONTEXT

The Regulated Utilities are subject to risks associated with the regulator's approval of customer rates that permit a reasonable opportunity to recover service costs on a timely basis, including a fair return on rate base. The Regulated Utilities are also subject to the potential risk of the regulator disallowing costs incurred. Electricity Distribution and Natural Gas Distribution operate under PBR. Under PBR, revenues are formula driven, which raises the uncertainty of cost recovery.

RISK MANAGEMENT APPROACH

Electricity Transmission and Natural Gas Transmission file forecasts in the rate-setting process to recover the costs of providing services and earn a fair rate of return. The determination of a fair rate of return on the common equity component of rate base is determined in a GCOC proceeding in Alberta. The Regulated Utilities continuously monitor various regulatory decisions and cases to assess how they might impact the Company's regulatory applications for the recovery of costs. The Regulated Utilities are proactive in demonstrating prudence and continuously look for ways to lower operating costs while maintaining service levels.

Climate Change - Transition Risk

While climate-related risks and opportunities are integrated into our enterprise risk management process, we also recognize unique attributes, such as longer time horizons and interconnectivity, could change the profile of this risk over time. In some cases, there could be overlap between the climate-related risks noted below, and business risks noted elsewhere in this document. However, we understand that specifically disclosing climate-related information is useful for the investment community.

DESCRIPTION AND CONTEXT

Climate-related transition risk includes policy and regulatory risks related to potential shifts in government decarbonization policies, at times with limited transitional periods. The potential of aggressive shifts increases investment uncertainty for future projects in addition to increasing risk to the energy transition being implemented in an effective, reliable and affordable manner.

The Company has operations which generate carbon offsets, emission performance credits, and renewable energy certificates through projects that have voluntarily reduced or avoided GHG emissions. Changes in carbon pricing and policies, fluctuations in commodity pricing, and uncertainties in carbon markets could impact revenue streams and operational costs.

Changing customer, public and stakeholder perceptions of climate-related risks and opportunities could impact the Company's businesses from a reputational perspective. In addition, changing customer sentiment and behaviour could cause changes to traditional energy systems and energy flows which introduce both risk and opportunity for the Company.

RISK MANAGEMENT APPROACH

The Company is actively and constructively working with different levels of government, communities, and Indigenous partners to advance the opportunities, policy needs, market access, and funding requirements for projects that help support customers' and partners' goals for the pace and scale of energy transition while maintaining essential infrastructure and services.

The Company's exposure to climate-related transition risk is mitigated to some extent for the Regulated Utilities because GHG emission charges are generally recovered in rates. In addition, future requirements, such as upgrading equipment to further reduce methane emissions in the natural gas utilities, are expected to be included in rate base on a go-forward basis.

The Company undertakes engagement and collaboration with municipalities, customers, and partners to better understand their needs for the future, and to guide the development of strategic partnerships and common advocacy efforts. Where possible, we share our expertise and innovation in our operating communities to inform discussions regarding the pace of energy transition taking into consideration safety, reliability, resiliency and affordability.

The Company reports annually on its sustainability activities, emissions reduction efforts and initiatives, as well as continued business and portfolio diversification.

Climate Change - Physical Risks

Climate-related risks and opportunities are integrated into our risk management processes and are identified, assessed and managed similar to other risks. In some cases, there could be overlap between the climate-related risks noted below, and business risks noted elsewhere in this document. However, we understand that specifically disclosing climate-related information is useful for the investment community.

DESCRIPTION AND CONTEXT

Physical risks associated with climate change include those arising from an increase in frequency and severity of extreme weather events such as wildfires, floods, extreme winds, and ice storms. While a number of assets within our businesses are exposed to extreme weather events, our above ground linear infrastructure has been identified as having the highest exposure.

In addition to these acute physical risks, chronic physical risks include those arising from longer-term shifts in weather patterns such as changes in seasonal temperatures or precipitation levels.

RISK MANAGEMENT APPROACH

The Company continues to carefully manage physical risks, including preparing for extreme weather events through activities such as proactive route and site selection, asset hardening, regular maintenance, and insurance. The Company follows regulated engineering codes, continues to evaluate ways to create greater system reliability and resiliency and, where appropriate, submits regulatory applications for capital expenditures aimed at creating greater system reliability and resiliency.

For example, for electricity transmission and distribution operations, the Company continues to invest in wildfire mitigation and obtains approval of its costs from the Alberta regulator. The Company benefits from agreements to limit exposure to wildfire suppression costs as well as liability and damages protections contained within legislation in Alberta. Risk to linear infrastructure is typically not insured and, as such, any restoration costs are generally recovered through regulatory processes subject to prudency review.

Prevention and adaptation activities include vegetation management for electricity transmission and distribution operations, as well as burying power lines in select areas. The majority of the Company's natural gas pipeline network is in the ground, making it less susceptible to extreme weather events.

The Company maintains in-depth emergency response measures for extreme weather events, including Wildfire Management Plans. When planning for capital investments and acquisitions, site specific climate and weather factors, such as flood plain mapping and extreme weather history, are considered.

Pipeline Integrity

DESCRIPTION AND CONTEXT

Natural Gas Transmission and Natural Gas Distribution have significant pipeline infrastructure. Although the probability of a pipeline failure is very low, the consequences of a failure could be severe.

RISK MANAGEMENT APPROACH

Programs are in place to monitor the integrity of the pipeline infrastructure and remediate or replace pipelines or pipeline infrastructure as required to address safety, reliability, and future growth. These programs include Natural Gas Transmission and Distribution integrity management programs, as well as Natural Gas Distribution's Mains Replacement program. The Company also carries property and liability insurance. The Company actively engages in damage prevention initiatives including proactive direct engagement with the building, excavation and homeowner communities, promoting ground disturbance and excavation safety.

Political

DESCRIPTION AND CONTEXT

The Company's operations are exposed to risks arising from changes in relevant political and legislative environments in which we operate, including regulations, policy shifts and compliance requirements. In addition, adjustments to international trade policies, such as US tariffs and supporting domestic suppliers, may influence supply chain costs and market dynamics. Collectively, these changes could negatively impact the financial performance of operations, including earnings, ROE, asset values, and credit metrics.

RISK MANAGEMENT APPROACH

Participation in policy consultations with governments and engagement of stakeholder groups ensure ongoing communication and that the impacts and costs from changes and proposed policies are identified and understood. Where appropriate, the Company collaborates with peers and industry associations to develop common positions and strategies. Additionally, geographic diversification of assets by region and by country helps reduce the impact of political and legislative changes.

Supply Chain Risk

DESCRIPTION AND CONTEXT

The Company faces increasing supply chain risk driven by global volatility, inflationary pressures, labour constraints, and geopolitical uncertainty. As supply chains grow more interconnected and vulnerable to disruption — from severe weather, trade disputes, labour conditions and ethical sourcing risks, cybersecurity incidents, and international conflicts to shipping constraints and material shortages — the Company may experience delays, increased costs, or constrained access to critical equipment, materials, and services essential to operations and capital projects. These pressures could impede timely project execution, elevate operational and development expenditures, and create challenges in maintaining reliable service to customers. In addition, sustainability considerations and responsible sourcing expectations, evolving regulatory requirements, and potential shifts in tariff or trade policy introduce further uncertainty that may affect procurement strategies and supplier resilience.

RISK MANAGEMENT APPROACH

The Company mitigates these risks by maintaining robust supplier due diligence and onboarding processes, diversified relationships, securing multiple procurement channels, monitoring critical inventories, placing orders earlier to offset extended lead times, and embedding sustainability considerations and responsible sourcing expectations into supplier engagement.

Collectively, these measures aim to strengthen long-term supply chain reliability and reduce our exposure to external disruption.

US Tariffs and Canadian Retaliatory Measures

DESCRIPTION AND CONTEXT

Recent changes in trade policies between Canada and the US could have an adverse effect on our business, financial condition and results of our operations. As new tariffs are introduced or existing tariffs are increased, implications for our operations could include higher procurement costs, supply chain disruptions with potential delays in project timelines, regulatory uncertainty and market capital volatility which could negatively impact overall profitability. Additionally, the Canadian government may implement retaliatory tariffs or other countermeasures in response to US trade actions. Certain goods used by the Company in its operations are procured from the US. Any escalation in trade disputes between Canada and the US, such as additional tariff hikes or expanded retaliatory measures, could intensify these risks, undermine investor confidence and create volatility in capital markets, potentially affecting both current operations and future investment plans.

RISK MANAGEMENT APPROACH

We continue to monitor trade developments closely and assess mitigation strategies, taking appropriate actions as needed to reduce potential risks. However, the scope, duration and impact of any US tariffs or Canadian retaliatory measures remain uncertain at this time, and as such, we cannot predict the scope, duration, or impact of potential tariffs and trade restrictions on our business.

Reputation

DESCRIPTION AND CONTEXT

The Company’s operations and growth prospects require strong relationships with key stakeholders, including regulators, governments and agencies, Indigenous communities, landowners, and environmental organizations. Inadequately managing expectations and issues important to stakeholders, including those arising during construction of major capital projects and operation of critical energy infrastructure, could affect the Company's reputation as well as have a significant impact on both current and future operations and infrastructure development.

There is risk of non-compliance with the Company's internal policies, including its Code of Ethics, or anti-bribery and anti-corruption laws by the Company’s employees, affiliates, independent contractors and/or agents, which may potentially lead to reputational damage, in addition to fines, penalties, or litigation.

Any accusation of poor operational, leadership, or governance actions and/or practices that may be levelled against the Company could create reputational risk for the Company, even with respect to issues or events that are largely outside of our control, including but not limited to: protests, activist activity, sabotage, terrorism, failure of supply, weather, catastrophic events and natural disasters, fires, floods, explosions, earthquakes and other similar events, government policy, economic and/or social circumstances, and/or actions of third parties, which may affect safety or quality of life of citizens.

Rising costs and uncertainty regarding the changing landscape of energy due to the ongoing energy transition, can contribute to customer dissatisfaction, frustration or confusion, leading to potential reputational and/or financial impacts on the Company.

RISK MANAGEMENT APPROACH

To address these risks, the Company has robust frameworks, practices, and training programs for employees in place with respect to operations and maintenance, safety, whistleblower complaints, governance, and community engagement. The Company will continue to ensure a rapid and effective operational response is in place when responding to operational issues such as fires, line strikes, extreme weather events or similar events that may affect our services. The Company prepares informational materials for customers and other stakeholders as rate changes are approved by the regulator and ready to be applied to the customers' bills. These communications address the specific reasons and drivers for changes in rates.

The Company's Marketing & Communications team is engaged at the outset on all customer-facing initiatives and issues ensuring information is accurate, clear and concise. The Company also allocates resources and personnel to support public consultation around capital work, educational safety campaigns and business development efforts.

The Company has a strong focus on community investment and communications efforts ensuring the Company's commitment and actions that support being a positive contributor to the communities we operate in are demonstrable to the public and our customers.

Other Operational Risks

DESCRIPTION AND CONTEXT

The Company's operations are subject to the risks normally associated with the operating and development of power systems and facilities, and transportation of natural gas. These can include, without limitation; mechanical failure, transportation problems, physical degradation, operator error, manufacturer defects, constraints on natural resource development, delay of or restrictions on projects due to climate change policies and initiatives, protests, activist activity, sabotage, terrorism, failure of supply, weather, catastrophic events and natural disasters, fires, floods, explosions, earthquakes, and other similar events. These types of events could result in injuries to personnel, third parties, including the public, damage to property and the environment, as well as unplanned outages or prolonged downtime for maintenance and repair. Among other things, these events can increase operational and maintenance expenses and reduce revenues. The occurrence or continuation of any of these events could result in significant losses for which insurance may not be sufficient or available. Environmental damage could also result in increased costs to operate and insure the Company's assets and have a negative impact on the Company's reputation and its ability to work collaboratively with stakeholders.

RISK MANAGEMENT APPROACH

To mitigate these risks, the Company has policies and an associated system of standards, processes and procedures to identify, assess and mitigate safety, operational and environmental risks across our operations. In addition, the Company maintains a comprehensive insurance program with respect to our assets and operations. The occurrence of an event that is not fully covered by our insurance program could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Third Party Risk

DESCRIPTION AND CONTEXT

Certain of the Company's assets are jointly owned or are governed by partnership, joint venture, shareholder agreements, or other contracts entered into with third parties. As a result, certain decisions relating to such contracts, relationships, or assets require the approval of a simple or special majority of the partners, owners, or counterparties, while others require unanimous approval. In addition, certain assets are owned, constructed, maintained, and/or operated by unrelated third-party entities. The success of such assets is, to some extent, dependent on the effectiveness of the business relationship and decision-making among the Company and the other partner(s), owner(s) or counterparties, and the expertise and ability of any third-party contract counterparties, constructors, material suppliers, consultants or operators with respect to the ownership, operation, or maintenance of the assets. The Company may encounter disputes with contract counterparties, partners, or owners, or assets operated by third parties may not perform as expected. Such events could impact operations or cash flows related to contracts, joint ventures, partnerships, or assets, or cause them to not operate as the Company expects, which could, in turn, have a negative impact on the Company's business operations and financial performance.

RISK MANAGEMENT APPROACH

The Company believes that it has prudent governance and other contractual rights in place, along with robust third-party selection due diligence to help mitigate third party risk, reduce the likelihood of disputes and ensure assets operated by third parties perform as expected.

Technological Transformation and Disruption

DESCRIPTION AND CONTEXT

The introduction and rapid, widespread adoption of transformative technology could lead to disruption of the Company's existing business models and introduce new competitive market dynamics. Failure to effectively identify and manage disruptive technology and/or changing consumer attitudes and preferences may result in disruptions to the business and an inability to achieve strategic and financial objectives.

RISK MANAGEMENT APPROACH

The strategic plans of each business unit incorporate transformative technology into the evolution of their business and ensure that the best available technology is deployed to support current state operational efficiency and reliability. The business seeks opportunities to minimize costs by monitoring trends occurring in other jurisdictions that may be ahead of the technological curve.

Artificial Intelligence (AI)

DESCRIPTION AND CONTEXT

The Company leverages advanced technologies, including generative AI, across all business units to deliver services in innovative, efficient, and cost effective ways. When deployed securely, generative AI enhances productivity, communication, and user experience.

While AI offers significant opportunities to improve efficiency and performance, it also introduces operational and compliance risks. A primary risk associated with generative AI is content integrity. Errors or biases within AI models, or insufficient user diligence, may result in inaccurate outputs or data reliability concerns. In addition, because AI systems depend on large volumes of data, they may be exposed to cybersecurity threats, data breaches, and privacy risks. Finally, the Company's reliance on third-party vendors for AI-enabled solutions may create additional exposure to service disruptions, regulatory non-compliance, or other operational risks arising from those vendors' use of AI.

RISK MANAGEMENT APPROACH

To manage AI-related opportunities and risks, the Company has established an AI strategy to ensure that AI is adopted responsibly and in a manner that mitigates operational, financial, cybersecurity, and privacy risks.

This program includes an AI Acceptable Use Policy, a user attestation process, controls to prevent AI development or deployment without internal IT/Cybersecurity oversight and approval, testing of AI in a controlled internal IT environment, blocking of all AI except for the Company-approved AI tools (Co-Pilot and Google), and the use of approved AI tools focused on augmenting employee productivity.

The Company permits the use of approved generative AI tools only and does not allow the use of agentic AI. Accordingly, the Company's AI systems do not operate, control, or independently interact with other company assets or operations. All permitted AI activities are accompanied by human oversight, data protection measures, and transparency in usage. Collectively, these measures are intended to reduce AI-associated risks and prevent unauthorized data exposure or loss.

Indigenous Land Claims and Consultation

DESCRIPTION AND CONTEXT

Indigenous peoples assert and claim, or have established, Aboriginal and/or Treaty rights and/or Aboriginal title in relation to a substantial portion of the lands and waters in Canada, where the Company operates.

There is a risk of project delays and relationship challenges caused by changes to consultation and engagement policies and expectations and formal challenges at the community, provincial and federal levels. In addition, the United Nations *Declaration* *on the Rights of Indigenous Peoples (UNDRIP)* is in place and being incorporated into Canadian law with the adoption of *The United Nations Declaration on the Rights of Indigenous Peoples Act*. The *UNDRIP Act* provides a roadmap for the Government of Canada and Indigenous peoples to work together to implement the rights of Indigenous peoples based on lasting reconciliation, healing, and cooperative relations.

The ongoing implementation of the *UNDRIP Act* and the associated Action Plan, released on June 21, 2023, is intended to provide direction to the Government of Canada's continued efforts to break down barriers, combat systemic racism and discrimination, close socio-economic gaps, and promote greater equality and prosperity for Indigenous peoples. The impact of the *UNDRIP Act* and the Action Plan and how they will be implemented and interpreted as part of Canadian law are still in the process of being defined, often via the court, and therefore the Company is currently not fully able to assess the effect that any land claims, cumulative impact claims, consultation requirements with Indigenous peoples, or the *UNDRIP Act* and the Action Plan may have on the Company's business. However, the potential impact could have a material adverse effect on the Company's operations.

ATCO, CU Inc.'s ultimate parent company, has a long history of successful partnerships with Indigenous communities with over 40 current partnerships, however, ongoing efforts need to be undertaken to truly engage and include Indigenous communities into the economy. Indigenous communities throughout the areas of Canada where the Company operates have indicated their desire for this inclusion and participation in the economy with a focus being shown towards energy infrastructure ownership.

RISK MANAGEMENT APPROACH

It is evident to the Company that the desire for Indigenous energy autonomy and ownership is increasing, so it is imperative that the Company continues to evaluate options, educates key parties on the regulatory, financial and operational risks, and determine our stance and goals for these engagements. The Company views a proactive approach as our best strategy to continue to be leaders in the Indigenous equity space.

Workforce Retention

DESCRIPTION AND CONTEXT

Should the Company face significant employee departures, and therefore a low level of retention in its workforce, especially within critical roles, this could result in a shortage of personnel that may hamper Company operations and negatively impact the ability of the Company to meet its business objectives and be costly for the organization to build back the organizational knowledge and critical skills of the departed employees.

RISK MANAGEMENT APPROACH

The Company's investment in our people provides an attractive environment that fosters retention. The Company continuously reviews and enhances its people resourcing and retention strategy. This includes enhancing ATCO employee value proposition branding and highlighting our Company values, building strong partnerships with educational institutions to attract new graduates and co-operative education students, aligning total rewards (including compensation, benefits, pension and employee share purchase programs) with market practice, and delivering orientation and onboarding for cultural and strategy awareness. We promote and support the development of our people, complete succession and development planning annually with a significant focus on critical roles and skills, and provide leadership training for leaders and individual development programs for all employees. The annual performance management program facilitates discussions on annual goals, development plans and career planning.

To promote a culture of inclusiveness we have an established and active Diversity, Equity and Inclusion (DE&I) Council and wellness programs. We continue to build an environment where people feel safe (physically and psychologically), have equal opportunity, and feel included. To understand more deeply the risks to retention, exit interviews and employee engagement surveys are conducted. Results are reviewed with leaders to inform areas of risk, and action plans are developed accordingly to address risks. As a result, the Company's retention rates continue to be at or higher than global benchmarks in a majority of the industries in which we operate.

Labour Relations

DESCRIPTION AND CONTEXT

Most of the Company's business units employ members of associations or labour unions under collective bargaining agreements. Risks exist in existing unionized environments for potential labour disruption, loss of favourable management rights (e.g., contracting out ability), strong push for job determinations (and therefore losing flexibility), and we may face union drive attempts in our non-union environments. In addition, should any developments result in a strained relationship with any of our associations or labour unions, it could create operational and financial risk for our businesses through increased grievances, arbitrations, and/or collective bargaining, which may impede our ability to make progress on our business agenda.

RISK MANAGEMENT APPROACH

The Company has dedicated labour relations resources which focus on advancing mutually respectful relationships to resolve issues, grievances and arbitrations. The Company ensures all human resources business partners and business leaders who manage large in-scope employee populations attend labour relations training to provide practical day-to-day knowledge of our collective agreements and to develop capability in the areas of performance management and investigations. The Company is committed to early and open dialogue with our associations and labour unions regarding business changes and employee impacts in order to maintain a mutually beneficial relationship. Two of our larger associations, Canadian Energy Workers Association (CEWA) and Natural Gas Employees' Association (NGEA), have collective bargaining agreements that do not provide bargaining unit employees with the right to strike and that prohibit lock-outs by management. In non-unionized environments, we are committed to quickly resolving employee concerns through transparent communication and strong leadership.

Litigation and Claims

DESCRIPTION AND CONTEXT

In the ordinary course of business, the Company or entities in which it has an interest may be subject to demands, disputes, proceedings, arbitrations and/or litigation (Claims) arising out of or related to our operations and other contractual relationships, and any such Claims may be material. Due to the nature of our operations, various types of Claims may be raised, including, but not limited to, failure to comply with applicable laws and regulations including health and safety, environmental damage, climate change and the impacts thereof, breach of contract, negligence, product liability, antitrust, bribery and other forms of corruption, tax, disclosure, securities class actions, derivative actions, patent infringement, privacy, employment matters or labour relations, personal injury, and in relation to a cyber attack, breach or unauthorized access to the Company's information technology and infrastructure. Litigation is subject to uncertainty, and it is possible that Claims could result in unfavourable judgments, decisions, fines, sanctions, monetary damages, temporary or permanent suspensions of operations, or the inability to engage in certain transactions. In addition, unfavourable outcomes or settlements of Claims could encourage further Claims. The Company may also be subject to adverse publicity and reputational impacts associated with such matters, regardless of whether the Company is ultimately found liable. There is a risk that the outcome of any such Claims may be materially adverse to the Company and/or that the Company may be required to incur significant expenses or devote significant resources in defence of such Claims, the success of which cannot be guaranteed.

RISK MANAGEMENT APPROACH

The Company reviews all Claims it receives, including the nature of each Claim, the amount in dispute or claimed and the availability of insurance coverage, and allocates internal or external resources in defence of such Claims, as it deems appropriate.

Pandemic Risk

DESCRIPTION AND CONTEXT

An outbreak of infectious disease, a pandemic or a similar public health threat, such as the COVID-19 pandemic, or a fear of any of the foregoing, could adversely impact the Company by causing operating, supply chain and project development delays and/or disruptions, inflation risk, labour shortages and/or shutdowns as a result of government regulation and prevention measures. These impacts could increase strain on employees and compromise levels of customer service, either of which could have a negative impact on the Company's operations.

Any deterioration in general economic and market conditions resulting from a public health threat could negatively affect demand for electricity and natural gas, revenue, operating costs, timing and extent of capital expenditures, results of financing efforts, or credit risk and counterparty risk, any of which could have a negative impact on the Company's business.

RISK MANAGEMENT APPROACH

The Company's investments in essential services are largely focused on our Regulated Utilities, creating a resilient investment portfolio. CU Inc. has a comprehensive pandemic plan that is activated when a pandemic is declared. The plan includes travel restrictions, limited access to facilities, a direction to work from home whenever possible, physical distancing measures and other protocols (including the use of personal protective equipment while at a work premise). Additionally, the Company follows recommendations by local, provincial and national public health authorities in Canada to adjust operational requirements as needed to ensure a coordinated approach across the Company.

OTHER FINANCIAL AND NON-GAAP MEASURES

This MD&A should be read with the Company's 2025 Consolidated Financial Statements. The 2025 Consolidated Financial Statements are prepared according to IFRS as issued by the International Accounting Standards Board (IFRS Accounting Standards).

This MD&A contains various "total of segments measures", "non-GAAP financial measures", and "non-GAAP ratios" (as such terms are defined in NI 52-112), which are described in further detail below.

TOTAL OF SEGMENTS MEASURE

NI 52-112 defines a "total of segments measure" as a financial measure disclosed by an issuer that (a) is a subtotal or total of two or more reportable segments of an entity, (b) is not a component of a line item disclosed in the primary financial statements of the entity, (c) is disclosed in the notes to the financial statements of the entity, and (d) is not disclosed in the primary financial statements of the entity.

Consolidated adjusted earnings (loss) is a total of segments measure, as defined in NI 52-112.

The consolidated adjusted earnings (loss) total of segments measure is most directly comparable to total earnings (loss) for the period. A comparable total of segments measure for the same periods in 2024 has been calculated using the same composition and has been disclosed alongside the current total of segments measure in this MD&A. A reconciliation of the total of segments measure with total earnings (loss) for the period is presented in this MD&A.

NON-GAAP FINANCIAL MEASURES

NI 52-112 defines a "non-GAAP financial measure" as a financial measure disclosed by an issuer that (a) depicts the historical or expected future financial performance, financial position or cash flows of an entity, (b) with respect to its composition, excludes an amount that is included in, or includes an amount that is excluded from, the composition of the most directly comparable financial measure disclosed in the primary financial statements of the entity, (c) is not disclosed in the financial statements of the entity, and (d) is not a ratio, fraction, percentage or similar representation.

Adjusted earnings (loss) for each of Electricity Distribution, Electricity Transmission, Total Electricity, Natural Gas Distribution, Natural Gas Transmission and Total Natural Gas, and mid-year rate base are non-GAAP financial measures, as defined in NI 52-112.

Adjusted Earnings

Adjusted earnings (loss) are defined as earnings (loss) for the period after adjusting for the timing of revenues and expenses associated with rate-regulated activities and dividends on equity preferred shares of the Company. Adjusted earnings (loss) also exclude one-time gains and losses, impairments, and items that are not in the normal course of business or a result of day-to-day operations.

Adjusted earnings (loss) present earnings from rate-regulated activities on the same basis as was considered prior to adopting IFRS Accounting Standards - that basis being the US accounting principles taking into account a more likely than not recognition threshold for rate regulated activities. Management's view is that adjusted earnings (loss) allow for a more effective analysis of operating performance and trends. Adjusted earnings (loss) are presented in Note 3 of the 2025 Consolidated Financial Statements.

Adjusted earnings (loss) is most directly comparable to earnings (loss) for the period but is not a standardized financial measure under the reporting framework used to prepare our financial statements. Adjusted earnings (loss) may not be comparable to similar financial measures disclosed by other issuers. For investors, adjusted earnings (loss) may provide value as it excludes items that are not in the normal course of business and, as such, provides insight as to earnings (loss) resulting from the issuer's usual course of business. A reconciliation of adjusted earnings (loss) to earnings (loss) for the period of the Company is presented in this MD&A.

Mid-Year Rate Base

Mid-year rate base is a non-GAAP financial measure. Mid-year rate base for a given year is calculated as the average of the opening rate base and the closing rate base. Growth in mid-year rate base is a leading indicator of a utility's earnings trend, depending on changes in the equity ratio of the mid-year rate base and the rate of return on common equity. Mid-year rate base is not a standardized financial measure under the reporting framework used to prepare our financial statements and may not be comparable to similar financial measures disclosed by other issuers. Management views mid-year rate base as a key metric for determining the Company's profitability. The most directly comparable measures to mid-year rate base reported in accordance with IFRS are property, plant and equipment and intangible assets. For further information, a "Reconciliation of Rate Base and Mid-Year Rate Base to Property, Plant and Equipment, and Intangible Assets" is presented in this MD&A.

NON-GAAP RATIO

NI 52-112 defines a "non-GAAP ratio" as a financial measure disclosed by an issuer that (a) is in the form of a ratio, fraction, percentage or similar representation, (b) has a non-GAAP financial measure as one or more of its components, and (c) is not disclosed in the financial statements of the entity. Mid-year rate base CAGR is a non-GAAP ratio, as defined in NI 52-112.

RECONCILIATION OF ADJUSTED EARNINGS TO EARNINGS FOR THE PERIOD

Adjusted earnings (loss) are earnings (loss) for the period after adjusting for the timing of revenues and expenses associated with rate-regulated activities and dividends on equity preferred shares of the Company. Adjusted earnings (loss) also exclude one-time gains and losses, impairments, and items that are not in the normal course of business or a result of day-to-day operations.

Adjusted earnings (loss) are a key measure of segment earnings that management uses to assess segment performance and allocate resources. It is management's view that adjusted earnings (loss) allow a better assessment of the economics of rate regulation in Canada than IFRS earnings. Additional information regarding this measure is provided in the "Other Financial and Non-GAAP Measures" section of this MD&A.

The following tables reconcile adjusted earnings (loss) to the directly measurable financial measure, earnings (loss) for the period.

($ millions)

2025 2024	Electricity	Natural Gas	Financing & Other	Intersegment Eliminations	Consolidated
					Three Months Ended December 31
Revenues	**351**	**457**	**—**	**(5)**	**803**
	354	469	—	(1)	822
Adjusted earnings (loss)	**80**	**101**	**—**	**—**	**181**
	93	97	(5)	—	185
Impairments	**(12)**	**(30)**	**—**	**—**	**(42)**
	—	—	—	—	—
Transition of managed IT services	**(2)**	**(2)**	**—**	**—**	**(4)**
	—	—	—	—	—
Restructuring	**—**	**—**	**—**	**—**	**—**
	(3)	(2)	—	—	(5)
Rate-regulated activities	**(35)**	**(19)**	**—**	**—**	**(54)**
	(40)	(1)	—	—	(41)
IT Common Matters decision	**(1)**	**(1)**	**—**	**—**	**(2)**
	(3)	(3)	—	—	(6)
Dividends on equity preferred shares of the Company	**1**	**1**	**—**	**—**	**2**
	1	1	—	—	2
Earnings (loss) for the period	**31**	**50**	**—**	**—**	**81**
	48	92	(5)	—	135

($ millions)

2025 2024	Electricity	Natural Gas	Financing & Other	Intersegment Eliminations	Consolidated
					Year Ended December 31
Revenues	**1,420**	**1,673**	**—**	**(13)**	**3,080**
	1,395	1,655	—	(7)	3,043
Adjusted earnings (loss)	**330**	**252**	**(1)**	**—**	**581**
	340	237	(20)	—	557
Impairments	**(12)**	**(30)**	**—**	**—**	**(42)**
	—	—	—	—	—
Transition of managed IT services	**(7)**	**(10)**	**—**	**—**	**(17)**
	—	—	—	—	—
Restructuring	**(6)**	**(4)**	**—**	**—**	**(10)**
	(16)	(21)	—	—	(37)
Rate-regulated activities	**(64)**	**(2)**	**—**	**—**	**(66)**
	(76)	26	—	—	(50)
IT Common Matters decision	**(3)**	**(1)**	**—**	**—**	**(4)**
	(12)	(10)	—	—	(22)
ATCO Electric settlement	—	—	—	—	—
	(8)	—	—	—	(8)
Dividends on equity preferred shares of the Company	**4**	**3**	**—**	**—**	**7**
	4	3	—	—	7
Earnings (loss) for the year	**242**	**208**	**(1)**	**—**	**449**
	232	235	(20)	—	447

IMPAIRMENTS

In 2025, impairments and asset write-offs of $42 million (after-tax) were recorded for assets that, as of December 31, 2025, do not represent value to the Company. Of these impairments, $26 million (after-tax) related to certain hydrogen assets in Natural Gas Distribution which were impaired due to the uncertainty of utility hydrogen regulations being considered by the Government of Alberta, and $8 million (after-tax) related to certain electricity generation assets in Electricity Transmission which are no longer in service. In addition, an impairment of $3 million (after-tax) was recognized related to emissions credits and allowances inventories in Natural Gas Transmission due to continued uncertainty associated with proposed government reforms. The remaining amount of $5 million (after-tax) relates to individually insignificant impairments for assets that no longer have value to the Company.

TRANSITION OF MANAGED IT SERVICES

The Company recognized IT transition costs of $4 million and $17 million (after-tax) in the fourth quarter and year ended December 31, 2025. The transition costs were primarily related to activities to shift from a single-vendor service provider to a hybrid model of multiple new vendors and internal teams. The transition activities commenced on January 1, 2025 and were substantially completed in the fourth quarter of 2025. As these costs are not in the normal course of business, they have been excluded from adjusted earnings.

RESTRUCTURING

The Company recorded restructuring costs of nil and $10 million (after-tax) (2024 - $5 million and $37 million (after-tax)) in the fourth quarter and full year of 2025. These costs are mainly related to staff reductions and associated severance costs. This restructuring is a continuation of the restructuring activities commenced in 2024. As these costs are not in the normal course of business, they have been excluded from adjusted earnings.

RATE-REGULATED ACTIVITIES

ATCO Electric Transmission, ATCO Electric Distribution, ATCO Electric Yukon, Naka Power Utilities (NWT) Ltd. (Naka), ATCO Gas and ATCO Pipelines are collectively referred to as the Regulated Utilities or the Utilities.

There is currently no specific guidance under IFRS Accounting Standards for rate-regulated entities that the Company is eligible to adopt. In the absence of this guidance, the Utilities do not recognize assets and liabilities from rate-regulated activities as may be directed by regulatory decisions. Instead, the Utilities recognize revenues in earnings when amounts are billed to customers, consistent with the regulator-approved rate design. Operating costs and expenses are recorded when incurred. Costs incurred in constructing an asset that meet the asset recognition criteria are included in the related property, plant and equipment or intangible asset.

The Company considers standards issued by the Financial Accounting Standards Board (FASB) in the United States as another source of generally accepted accounting principles taking into account a more likely than not recognition threshold in accounting for rate-regulated activities in its internal reporting provided to the Senior Management Team, which believes that earnings presented in this manner are a better representation of the operating results of the Company's rate-regulated activities. Therefore, the Company presents adjusted earnings as part of its segmented disclosures on this basis. Rate-regulated accounting (RRA) standards impact the timing of how certain revenues and expenses are recognized when compared to non-rate regulated activities, to appropriately reflect the economic impact of a regulator's decisions on revenues.

Rate-regulated accounting differs from IFRS Accounting Standards in the following ways:

Timing Adjustment	Items	RRA Treatment	IFRS Treatment
Additional revenues billed in current period	Future removal and site restoration costs, and impact of colder temperatures.	The Company defers the recognition of cash received in advance of future expenditures.	The Company recognizes revenues when amounts are billed to customers and costs when they are incurred.
Revenues to be billed in future periods	Deferred income taxes and impact of warmer temperatures.	The Company recognizes revenues associated with recoverable costs in advance of future billings to customers.	The Company recognizes costs when they are incurred, but does not recognize their recovery until customer rates are changed and amounts are collected through future billings.

Timing Adjustment	Items	RRA Treatment	IFRS Treatment
Regulatory decisions received	Regulatory decisions received which relate to current and prior periods.	The Company recognizes the earnings from a regulatory decision pertaining to current and prior periods when the decision is received.	The Company does not recognize earnings from a regulatory decision when it is received as regulatory assets and liabilities are not recorded under IFRS Accounting Standards.
Settlement of regulatory decisions and other items	Settlement of amounts receivable or payable to customers and other items.	The Company recognizes the amount receivable or payable to customers as a reduction in its regulatory assets and liabilities when collected or refunded through future billings.	The Company recognizes earnings when customer rates are changed and amounts are recovered or refunded to customers through future billings.

For the fourth quarter and full year of 2025 and 2024, the significant timing adjustments as a result of the differences between rate-regulated accounting and IFRS Accounting Standards are as follows:

	Three Months Ended December 31			Year Ended December 31		
($ millions)	2025	2024	Change	2025	2024	Change
Additional revenues billed in current period						
Future removal and site restoration costs (1)	**35**	29	6	**135**	123	12
Revenues to be billed in future periods						
Deferred income taxes (2)	**(50)**	(50)	—	**(156)**	(143)	(13)
Impact of warmer temperatures (3)	**3**	(8)	11	**(10)**	(9)	(1)
Settlement of regulatory decisions and other items						
PBR2 re-opener proceeding refund to customers (4)	**(29)**	—	(29)	**(36)**	—	(36)
Other (5)	**(13)**	(12)	(1)	**1**	(21)	22
	(54)	(41)	(13)	**(66)**	(50)	(16)

(1) Removal and site restoration costs are billed to customers over the estimated useful life of the related assets based on forecast costs to be incurred in future periods.

(2) Income taxes are billed to customers when paid by the Company.

(3) Natural Gas Distribution's customer rates are based on a forecast of normal temperatures. Fluctuations in temperatures may result in more or less revenue being recovered from customers than forecast. Revenues above or below normal temperatures in the current period are refunded to or recovered from customers in future periods.

(4) In connection with the PBR2 re-opener proceeding (Phase II Decision), Electricity Distribution and Natural Gas Distribution refunded $18 million (after-tax) and $18 million (after-tax), respectively, to customers for the year ended December 31, 2025.

(5) In 2024, Natural Gas Distribution recorded a decrease in earnings of $6 million (after-tax) related to payments of gas pipeline system load balancing costs, and Electricity Distribution recorded a decrease in earnings of $4 million (after-tax) related to deferral of generation expenses and $4 million (after-tax) related to final rate decisions.

IT COMMON MATTERS DECISION

Consistent with the treatment of the gain on sale in 2014 from the IT services business by CU Inc.'s parent, Canadian Utilities, financial impacts associated with the IT Common Matters decision are excluded from adjusted earnings. The amount excluded from adjusted earnings in the fourth quarter and full year of 2025 was $2 million and $4 million (after-tax) (2024 - $6 million and $22 million (after-tax)).

ATCO ELECTRIC SETTLEMENT

On June 24, 2024, AUC Enforcement filed a joint submission with ATCO Electric seeking the AUC's approval of a settlement agreement involving two historical matters ATCO Electric had previously identified and self-reported to AUC Enforcement staff. The settlement agreement included an administrative penalty of $3 million, and a refund to customers through a billing adjustment to the AESO of $4 million. For the year ended December 31, 2024, the Company recognized costs of $8 million (after tax) related to the proceeding. As this was not in the normal course of business, it was excluded from adjusted earnings.

SEGMENTED RECONCILIATION OF ADJUSTED EARNINGS TO EARNINGS FOR THE PERIOD

The following tables reconcile adjusted earnings (loss) for Utilities to the directly comparable financial measure, earnings (loss) for the period.

($ millions) — Three Months Ended December 31

2025 / 2024	CU Inc.						
	Electricity			Natural Gas			Consolidated
	Electricity Distribution	Electricity Transmission	Consolidated Electricity	Natural Gas Distribution	Natural Gas Transmission	Consolidated Natural Gas	
Adjusted earnings	**36**	**44**	**80**	**73**	**28**	**101**	**181**
	46	47	93	69	28	97	190
Impairments	**(1)**	**(11)**	**(12)**	**(27)**	**(3)**	**(30)**	**(42)**
	—	—	—	—	—	—	—
Transition of managed IT services	**(1)**	**(1)**	**(2)**	**(2)**	**—**	**(2)**	**(4)**
	—	—	—	—	—	—	—
Restructuring	**—**	**—**	**—**	**—**	**—**	**—**	**—**
	(2)	(1)	(3)	(1)	(1)	(2)	(5)
Rate-regulated activities	**(27)**	**(8)**	**(35)**	**(8)**	**(11)**	**(19)**	**(54)**
	(19)	(21)	(40)	6	(7)	(1)	(41)
IT Common Matters decision	**(1)**	**—**	**(1)**	**(1)**	**—**	**(1)**	**(2)**
	(2)	(1)	(3)	(3)	—	(3)	(6)
Dividends on equity preferred shares of the Company	**1**	**—**	**1**	**1**	**—**	**1**	**2**
	1	—	1	1	—	1	2
Earnings for the period	**7**	**24**	**31**	**36**	**14**	**50**	**81**
	24	24	48	72	20	92	140

($ millions)							Year Ended December 31
2025 / 2024	CU Inc.						
	Electricity			Natural Gas			Consolidated
	Electricity Distribution	Electricity Transmission	Consolidated Electricity	Natural Gas Distribution	Natural Gas Transmission	Consolidated Natural Gas	
Adjusted earnings	**153**	**177**	**330**	**143**	**109**	**252**	**582**
	150	190	340	142	95	237	577
Impairments	**(1)**	**(11)**	**(12)**	**(27)**	**(3)**	**(30)**	**(42)**
	—	—	—	—	—	—	—
Transition of managed IT services	**(6)**	**(1)**	**(7)**	**(10)**	**—**	**(10)**	**(17)**
	—	—	—	—	—	—	—
Restructuring	**(4)**	**(2)**	**(6)**	**(2)**	**(2)**	**(4)**	**(10)**
	(10)	(6)	(16)	(17)	(4)	(21)	(37)
Rate-regulated activities	**(42)**	**(22)**	**(64)**	**17**	**(19)**	**(2)**	**(66)**
	(42)	(34)	(76)	40	(14)	26	(50)
IT Common Matters decision	**(2)**	**(1)**	**(3)**	**(1)**	**—**	**(1)**	**(4)**
	(7)	(5)	(12)	(9)	(1)	(10)	(22)
ATCO Electric settlement	**—**	**—**	**—**	**—**	**—**	**—**	**—**
	—	(8)	(8)	—	—	—	(8)
Dividends on equity preferred shares of the Company	**2**	**2**	**4**	**2**	**1**	**3**	**7**
	2	2	4	2	1	3	7
Earnings for the year	**100**	**142**	**242**	**122**	**86**	**208**	**450**
	93	139	232	158	77	235	467

RECONCILIATION OF RATE BASE AND MID-YEAR RATE BASE TO PROPERTY, PLANT AND EQUIPMENT, AND INTANGIBLE ASSETS

The Company refers to rate base and mid-year rate base throughout the MD&A. Growth in mid-year rate base is a leading indicator of a utility's earnings trend. Rate base is a measure specific to rate-regulated utilities and is used by the regulatory authorities in the jurisdictions in which a company operates, which in Alberta, is the AUC.

The Regulated Utilities finance infrastructure investments, referred to as rate base, through a combination of equity and debt. Regulatory proceedings establish the approved rate of ROE and the equity ratio – the proportion of utility investments financed with equity, with the remainder financed by debt.

Both the ROE and the equity ratio are determined based on the concept of "fair return," which includes three main components: (i) comparability, (ii) financial integrity, and (iii) financial attractiveness. The costs of equity and debt are included in the amounts collected as revenues.

Mid-year rate base for a given year is calculated as the average of the opening rate base and the closing rate base. The Company determines its customer rates by multiplying its rate base by the approved equity ratio and the approved rate of ROE, as well as recovering forecast costs and return of capital. As such, the Company's earnings will trend based on changes in the approved ROE, the approved equity ratio, and the mid-year rate base.

SEGMENTED RECONCILIATION OF RATE BASE AND MID-YEAR RATE BASE TO PROPERTY, PLANT AND EQUIPMENT, AND INTANGIBLE ASSETS

The most comparable financial measures under IFRS with respect to rate base are property, plant and equipment and intangible assets. Additional information regarding this non-GAAP measure is provided in the "Other Financial and Non-GAAP Measures" section of this MD&A.

The following table reconciles rate base and mid-year rate base to property, plant and equipment and intangible assets for 2025, 2024 and 2023.

		Year Ended December 31	
($ billions)	**2025**	**2024**	**2023**
Property, plant and equipment [(1)]	**18.4**	17.8	17.0
Intangible assets [(2)]	**0.9**	0.9	0.8
	19.3	18.7	17.8
Adjustments:			
Customer contributions [(3)]	**(2.1)**	(2.0)	(2.0)
Removal costs collected through customer rates	**(1.7)**	(1.6)	(1.5)
Other	**(0.1)**	(0.3)	(0.2)
Rate Base [(4)]	**15.4**	14.8	14.1
Mid-Year Rate Base [(4)]	**15.1**	14.5	14.0

(1) Please refer to Note 10 - Property, Plant and Equipment section of the Company's 2025 Consolidated Financial Statements (2024 - Note 9).

(2) Please refer to Note 11 - Intangibles section of the Company's 2025 Consolidated Financial Statements (2024 - Note 10).

(3) Please refer to Note 8 - Customer Contributions section of the Company's 2025 Consolidated Financial Statements (2024 - Note 13).

(4) Non-GAAP financial measure.

OTHER FINANCIAL INFORMATION

OFF BALANCE SHEET ARRANGEMENTS

CU Inc. does not have any off-balance sheet arrangements that have, or are reasonably likely to have, a current or future effect on the financial performance or financial condition of the Company, including, without limitation, the Company's liquidity and capital resources.

CONTINGENCIES

The Company is party to a number of claims, disputes, lawsuits and other legal matters. The Company believes the ultimate liability arising from these matters will have no material impact on its 2025 Consolidated Financial Statements.

MATERIAL ACCOUNTING JUDGMENTS, ESTIMATES AND ASSUMPTIONS

The Company’s material accounting judgments, estimates and assumptions are described in Note 21 of the 2025 Consolidated Financial Statements, which are prepared in accordance with IFRS. Management makes judgments and estimates that could materially affect how policies are applied, amounts in the consolidated financial statements are reported, and contingent assets and liabilities are disclosed. Most often these judgments and estimates concern matters that are inherently complex and uncertain. Judgments and estimates are reviewed on an ongoing basis; changes to accounting estimates are recognized prospectively.

FINANCIAL INSTRUMENTS

Financial instruments are measured at amortized cost or fair value. The valuation methods used to measure financial instruments are described in Note 18 of the 2025 Consolidated Financial Statements, which are prepared in accordance with IFRS.

RELATED PARTY TRANSACTIONS

Transactions with related parties in the normal course of business are measured at the exchange amount. Transfers of assets between entities under common control are measured at the carrying amount. For further information, please refer to Note 26 of the 2025 Consolidated Financial Statements.

NEW OR AMENDED IFRS ACCOUNTING STANDARDS ADOPTED

No new or amended standards were adopted during the current year that have a material effect on the 2025 Consolidated Financial Statements.

IFRS ACCOUNTING STANDARDS NOT YET ADOPTED

Certain new or amended IFRS Accounting Standards were recently issued by the International Accounting Standards Board (IASB). The following outlines the IFRS Accounting Standards that are applicable to, or may have a future material effect on, the Company's consolidated financial statements or note disclosures.

Settlement by electronic payments

In May 2024, the IASB issued amendments to IFRS 9, *Financial Instruments,* to clarify the date of recognition and derecognition of financial assets and liabilities, with a new exception for financial liabilities settled using electronic forms of payment. The amendments are effective for annual periods beginning on or after January 1, 2026. The Company has completed its assessment of the amendments and they are not expected to have a significant impact on its consolidated financial statements when adopted on January 1, 2026.

Presentation and disclosure in financial statements

In April 2024, the IASB issued IFRS 18, *Presentation and Disclosure in Financial Statements,* which will replace IAS 1, *Presentation of Financial Statements.* IFRS 18 sets out the requirements for presentation and disclosures in financial statements with focus on the income statement and reporting of management-defined performance measures (often referred to as non-GAAP measures). The new standard is effective for annual periods beginning on or after January 1, 2027, with earlier application permitted.

To facilitate the transition to IFRS 18, the Company has established a project team to evaluate the impact on financial reporting systems and accounting processes required for adoption, and continues to assess the impact of the standard on its consolidated financial statements.

Disclosures about uncertainties in the financial statements

In November 2025, the IASB issued illustrative examples as part of its project, *Disclosures about Uncertainties in the Financial Statements*, which show how an entity discloses uncertainties in its financial statements. The examples do not change requirements in the IFRS accounting standards but give an illustration of how the requirements should be applied in practice. The Company continues to assess the impact of this guidance on its consolidated financial statements.

DISCLOSURE CONTROLS AND PROCEDURES

As of December 31, 2025, management evaluated the effectiveness of the Company’s disclosure controls and procedures as required by the Canadian Securities Administrators. This evaluation was performed under the supervision of, and with the participation of, the CEO and the Chief Financial Officer (CFO).

Disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed by the Company in documents filed by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in the securities legislation. The disclosure controls and procedures also seek to assure that information required to be disclosed by the Company is accumulated and communicated to management, including the CEO and the CFO, as appropriate, to allow timely decisions on required disclosure.

Management, including the CEO and the CFO, does not expect the Company's disclosure controls and procedures will prevent or detect all errors. The inherent limitations in all control systems are that they can provide only reasonable, not absolute, assurance that all control issues and instances of error, if any, within the Company have been detected.

Based on this evaluation, the CEO and the CFO have concluded that the Company’s disclosure controls and procedures were effective at December 31, 2025.

INTERNAL CONTROL OVER FINANCIAL REPORTING

The certification of annual filings for the year ended December 31, 2025, requires that the Company disclose in the annual MD&A any changes in the Company's internal controls over financial reporting (ICFR) that occurred during the period that have materially affected, or are reasonably likely to materially affect, the Company's ICFR. The Company confirms that no such changes were identified in the Company's ICFR during the period beginning on January 1, 2025 and ending on December 31, 2025.

The Company's ICFR is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. Internal control over financial reporting, no matter how well designed, has inherent limitations. Therefore, ICFR can provide only reasonable assurance regarding the reliability of financial statement preparation and may not prevent or detect all misstatements.

As of December 31, 2025, management evaluated the effectiveness of the Company's ICFR as required by the Canadian Securities Administrators. This evaluation was performed under the supervision of, and with the participation of, the CEO and the CFO.

Based on this evaluation, the CEO and the CFO have concluded that the Company's ICFR was effective at December 31, 2025.

FORWARD-LOOKING INFORMATION

Certain statements contained in this MD&A constitute forward-looking information. Forward-looking information is often, but not always, identified by the use of words such as "anticipate", "plan", "estimate", "expect", "may", "will", "intend", "should", "goals", "targets", "strategy", "future", and similar expressions. In particular, forward-looking information in this MD&A includes, but is not limited to, references to: strategic and growth plans and opportunities; the Company's 2050 net-zero ambition; expected growth, expansion and diversification opportunities; the expected timing of commencement, completion or commercial operations of activities, contracts and projects; the expected term or expiry of contracts; the impact or benefits of contracts, including economic and other benefits for the Company and its partners and counterparties; the size, storage, generation or transmission capacity expected from assets and projects; the Company's $11.5 billion five-year (2026-2030) regulated utility capital expenditure plan; expectations regarding the Utilities' mid-year rate base CAGR; expectations regarding the PBR2 and PBR3 appeals, including timing expectations, scope of the proceedings, and anticipated outcomes; expectations regarding ATCO Pipeline's 2026-2028 GRA; the anticipated size, specifications and incremental natural gas delivery capacity of Yellowhead, the anticipated capital spend on Yellowhead and expected accuracy of the estimate, and the number of regulatory applications and expected timing for commencement of construction and bringing Yellowhead on-stream; expectations regarding Yellowhead's funding structure, including sources of equity and debt funding for the project and potential Indigenous equity participation on the project; expectations regarding Electricity Transmission's 2026-2027 GTA; expectations regarding CETO, including the anticipated size, capacity and benefits of the project, the anticipated timing for energization of the project, and the anticipated total investment in the project; expectations regarding the use of proceeds resulting from CU Inc.'s recent debenture issuance; the expected impact of new legislation; the expected timing and impact of policy and regulatory decisions and announcements, including the new federal MPO, and governmental frameworks; and the Company's liquidity, capital resources, contractual financial obligations and other commitments.

Although the Company believes that the expectations reflected in the forward-looking information are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and no assurance can be given that these expectations will prove to be correct. Forward-looking information should not be unduly relied upon. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties, and other factors, which may cause actual results, levels of activity, and achievements to differ materially from those anticipated in such forward-looking information. The forward-looking information reflects the Company's beliefs and assumptions with respect to, among other things: the Yellowhead and CETO projects underpinning the Company's $11.5 billion five-year (2026-2030) regulated utility capital expenditure plan; other utility capital spending during the five-year forecast period being associated with customer growth, system reliability and safety, climate and technology, energy transition initiatives, and program and system investments; planned capital investments for the regulated utilities being based on a number of significant assumptions, including projects identified by the AESO will proceed as currently scheduled, the remaining planned capital investments being required to maintain safe and reliable service and meet planned growth in the Utilities' service areas, regulatory approval for capital projects being obtained in a timely manner, and access to capital market financings being maintained; the approval of capital expenditures; regulatory approvals to allow for the recovery of prudently incurred capital expenditures and to earn a fair return on investment; certain other regulatory applications being made and approved; the applicability and stability of legal and regulatory requirements in the jurisdictions in which we invest and/or operate; the payment of fees owing pursuant to applicable contracts; the growth of energy demand; inflation; the development and performance of technology and technological innovations and the ability to otherwise access and implement all technology necessary to achieve business objectives; continuing collaboration with certain business partners and engagement with new business partners, and regulatory and environmental groups; the performance of assets and equipment; demand levels for oil, natural gas, gasoline, diesel and other energy sources; certain levels of future energy use; future production rates; future revenue and earnings; the ability to meet current project schedules, and complete proposed development projects at currently estimated budgets; the availability of financing sources on acceptable terms; expected future borrowing costs and interest rates; and other assumptions inherent in management's expectations in respect of the forward-looking information identified herein.

The Company's actual results could differ materially from those anticipated in this forward-looking information as a result of, among other things: risks inherent in the performance of assets; capital efficiencies and cost savings; applicable laws and regulations and the interpretation and manner of enforcement of such laws and regulations; changes to government policies; regulatory decisions; competitive factors in the industries in which the Company operates; evolving market or economic conditions; credit risk; interest rate fluctuations; the availability and cost of labour, materials, services, infrastructure, and future demand for resources; the development and execution of projects, including development projects not proceeding on schedule or at all, or at currently estimated budgets; the availability of financing sources for development projects on acceptable terms; prices of electricity, natural gas, natural gas liquids, and renewable energy; the development and performance of technology and new energy efficient products, services, and programs including but not limited to the use of zero-emission and renewable fuels, carbon capture, and storage, electrification of equipment powered by zero-emission energy sources and utilization and availability of carbon offsets; potential cancellation, termination, default, non-compliance, or breach of contract by contract counterparties; the risk that payments owed may not be collected or received in a timely manner, or at all; risks associated with potential litigation proceedings; potential damage to our brand and/or reputation that may result from a failure to perform, or from factors outside of our control, or negative publicity related to significant projects, investments, operations or activities; the risk of operational disruptions, outages, or force majeure events; the occurrence of unexpected events such as fires, extreme weather conditions, explosions, blow-outs, equipment failures, transportation incidents, and other accidents or similar events; global pandemics; the imposition of or changes to existing customs duties, tariffs or other trade restrictions; geopolitical tensions and wars; and other risk factors, many of which are beyond the control of the Company. Due to the interdependencies and correlation of these factors, the impact of any one material assumption or risk on a forward-looking statement cannot be determined with certainty. Readers are cautioned that the foregoing lists are not exhaustive. For additional information about the principal risks that the Company faces, see the “Business Risks and Risk Management” section in this MD&A.

This MD&A may contain information that constitutes future-oriented financial information or financial outlook information, all of which are subject to the same assumptions, risk factors, limitations and qualifications set forth above. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise or inaccurate and, as such, undue reliance should not be placed on such future-oriented financial information or financial outlook information. The Company's actual results, performance and achievements could differ materially from those expressed in, or implied by, such future-oriented financial information or financial outlook information. The Company has included such information in order to provide readers with a more complete perspective on its future operations and its current expectations relating to its future performance. Such information may not be appropriate for other purposes and readers are cautioned that such information should not be used for purposes other than those for which it has been disclosed herein. Future-oriented financial information or financial outlook information contained herein was made as of the date of this MD&A.

Any forward-looking information contained in this MD&A represents the Company's expectations as of the date hereof, and is subject to change after such date. The Company disclaims any intention or obligation to update or revise any forward-looking information whether as a result of new information, future events or otherwise, except as required by applicable securities legislation.

ADDITIONAL INFORMATION

Additional information relating to the Company, including the Company's 2025 Consolidated Financial Statements and most recent Annual Information Form dated March 31, 2025, can be found on SEDAR+ at www.sedarplus.ca.

Copies of these documents may also be obtained upon request from Investor Relations at 3rd Floor, West Building, 5302 Forand Street S.W., Calgary, Alberta, T3E 8B4, telephone 403-292-7500, or email investorrelations@atco.com. Corporate information is also available on the Company's website at www.canadianutilities.com.

GLOSSARY

AESO means Alberta Electric System Operator.

AUC means the Alberta Utilities Commission.

CAGR means compound annual growth rate.

Class A shares means Class A non-voting common shares of the Company.

Class B shares means Class B common shares of the Company.

Company means CU Inc. and, unless the context otherwise requires, includes its subsidiaries.

Consumer price index (CPI) measures the average change in prices over time that consumers pay for a basket of goods and services.

COS means Cost of Service.

Customer contributions are non-refundable cash contributions made by customers for certain additions to property, plant and equipment. These contributions are made when the estimated revenue is less than the cost of providing service.

ECM means efficiency carry-over mechanism.

ESG means Environmental, Social and Governance.

FWI means Fixed Weighted Index of average hourly earnings for all employees, by industry, monthly.

GAAP means Canadian generally accepted accounting principles.

GHG means greenhouse gas.

Gigawatt hour (GWh) is a measure of electricity consumption equal to the use of 1 billion watts of power over a one-hour period.

GRA means general rate application.

GTA means general tariff application.

IFRS means International Financial Reporting Standards.

I-X means the Inflation Adjuster (I Factor) minus Productivity Adjuster (X Factor).

K Bar means the AUC allowance for capital additions under Performance Based Regulation.

Megawatt (MW) is a measure of electric power equal to 1,000,000 watts.

O&M means operating and maintenance.

PBR means Performance Based Regulation.

ROE means return on equity.

The Utilities or Regulated Utilities means Electricity Distribution, Electricity Transmission, Natural Gas Distribution and Natural Gas Transmission, and their related subsidiaries.

APPENDIX 1:
FOURTH QUARTER FINANCIAL INFORMATION

Financial information for the three months ended December 31, 2025 and 2024 is shown below.

CONSOLIDATED STATEMENTS OF EARNINGS

	Three Months Ended December 31	
(millions of Canadian Dollars)	**2025**	**2024**
Revenues	**803**	822
Costs and expenses		
Salaries, wages and benefits	**(71)**	(77)
Energy transmission and transportation	**(85)**	(78)
Plant and equipment maintenance	**(48)**	(55)
Fuel costs	**(5)**	(5)
Purchased power	**(23)**	(20)
Depreciation, amortization and impairments	**(211)**	(148)
Franchise fees	**(80)**	(79)
Property and other taxes	**(18)**	(17)
Other	**(62)**	(73)
	(603)	(552)
Operating profit	**200**	270
Interest income	**6**	2
Interest expense	**(101)**	(104)
Net finance costs	**(95)**	(102)
Earnings before income taxes	**105**	168
Income taxes	**(24)**	(33)
Earnings for the period	**81**	135

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended December 31	
(millions of Canadian Dollars)	**2025**	**2024**
Operating activities		
Earnings for the period	**81**	135
Adjustments to reconcile earnings to cash flows from operating activities	**354**	318
Changes in non-cash working capital	**(11)**	(39)
Cash flows from operating activities	**424**	414
Investing activities		
Additions to property, plant and equipment	**(311)**	(440)
Additions to intangibles	**(37)**	(27)
Changes in non-cash working capital	**(45)**	22
Other	**(10)**	7
Cash flows used in investing activities	**(403)**	(438)
Financing activities		
Issue of long-term debt	**155**	—
Repayment of long-term debt	**(35)**	—
Repayment of lease liabilities	**(1)**	(1)
Dividends paid on equity preferred shares	**(2)**	(2)
Dividends paid to Class A and Class B share owner	**(35)**	(9)
Interest paid	**(95)**	(98)
Other	**—**	(1)
Cash flows used in financing activities	**(13)**	(111)
Increase (decrease) in cash position	**8**	(135)
Beginning of period	**15**	(28)
End of period	**23**	(163)

APPENDIX 2: SUPPLEMENTAL NON-AUDITED FINANCIAL INFORMATION

Management uses numerous metrics and financial measures to evaluate our success and better identify possible challenges while capitalizing on emerging opportunities and continuing to deliver high-performing results. These measures support our ability to assess segment performance and allocate resources and allow for a more effective analysis of operating performance and trends.

From time to time, management may choose to provide supplemental non-audited financial information to help readers further understand key operational and financial events that may influence the results during a quarter.

CAPITAL EXPENDITURES BY CATEGORY

Management has chosen to provide supplemental non-audited financial information to help readers further understand the five-year (2026-2030) capital expenditure plan in the Utilities. The approximately $11.5 billion of anticipated capital spend will support the evolving needs of our customers throughout our regulated jurisdictions. These capital projects are expected to be primarily aligned with customer growth, system reliability and safety, climate adaptation and resilience, new technologies and energy transition initiatives supporting decarbonization. Additionally, the Yellowhead Pipeline project supports the expansion of natural gas transmission in Alberta, relieving capacity constraints and supporting economic growth within Canada. In the latter years of the forecast period, we anticipate customer growth, system reliability and safety, and climate adaptation and resilience to continue to be strong investment themes.

($ billions)	2026	2027	2028	2029	2030	Cumulative
Utilities						
Yellowhead Pipeline	1.1	1.4	0.2	0.1	—	2.8
Customer Growth	0.5	0.6	0.6	0.7	1.1	3.5
System Reliability and Safety	0.7	0.7	0.7	0.8	0.8	3.7
Climate and Technology	0.3	0.3	0.3	0.3	0.3	1.5
Total Capital Expenditures	**2.6**	**3.0**	**1.8**	**1.9**	**2.2**	**11.5**