News Release

TransAlta Reports Fourth Quarter and Year End 2025 Results, Announces Data Centre Agreement, Declares Dividend Increase and Provides 2026 Outlook

CALGARY, Alberta (February 27, 2026)

TransAlta Corporation (TransAlta or the Company) (TSX: TA) (NYSE: TAC) today reported its financial results for the fourth quarter and year ended Dec. 31, 2025.

“TransAlta delivered strong performance in 2025, demonstrating its ability to generate solid free cash flow notwithstanding softer Alberta power prices, subdued market volatility, and lower merchant production. Our hedging strategy and contracted portfolio supported our strong ongoing performance and helped offset a challenging price environment" said John Kousinioris, President and Chief Executive Officer of TransAlta. "I'm pleased to share that free cash flow came in above the midpoint of our 2025 Outlook."

"We are pleased to announce that our Board of Directors has approved an eight per cent increase to our common share dividend, now equivalent to $0.28 per share on an annualized basis. This represents our seventh consecutive annual dividend increase, affirming our confidence in the Company’s future and commitment to returning value to shareholders,” concluded Mr. Kousinioris.

"Over the past few months, we focused on executing our strategic priorities. During the fourth quarter, we secured a definitive tolling agreement to convert Centralia Unit 2 to natural-gas-fired generation under a long-term contract and today, we announced the signing of a memorandum of understanding for our Alberta data centre strategy with Canada Pension Plan Investments and Brookfield," said Joel Hunter, Executive Vice President, Finance and Chief Financial Officer. "We also recently closed the acquisition of Far North which enhances our position in Ontario," added Mr. Hunter.

"We are entering 2026 with a growing and diversified fleet that is underpinned by long-term contracts and strong hedging positions. Our guidance incorporates a balanced view of our fleet's expected generation as well as Alberta power market fundamentals, which we expect to markedly improve as expected data centre load growth comes online in the coming years. We look forward to sharing more with you on our long-term outlook and strategy at our upcoming Investor Day scheduled for March 23, 2026," concluded Mr. Hunter.

Fourth Quarter 2025 Highlights

- Achieved strong operational availability of 90.1 per cent in 2025, compared to 87.8 per cent in 2024
- Adjusted EBITDA[(1)] of $247 million, compared to $282 million for the same period in 2024
- Free cash flow (FCF)[(1)] of $93 million, or $0.31 per share, compared to $46 million, or $0.15 per share, for the same period in 2024
- Adjusted earnings before income taxes[(1)] of $14 million, compared to $38 million, for the same period in 2024
- Cash flow from operating activities of $231 million, or $0.78 per share, compared to $215 million, or $0.72 per share, for the same period in 2024
- Net loss attributable to common shareholders[(1)] of $62 million, or $0.21 per share, compared to $65 million, or $0.22 per share, for the same period in 2024

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Full Year 2025 Highlights

- Achieved strong operational availability of 92.3 per cent in 2025, compared to 91.2 per cent in 2024
- Adjusted EBITDA[(1)] of $1,104 million, compared to $1,255 million for the same period in 2024
- Free cash flow (FCF)[(1)] of $514 million, or $1.73 per share, compared to $575 million, or $1.90 per share, for the same period in 2024
- Adjusted earnings before income taxes[(1)] of $181 million, compared to $396 million, for the same period in 2024
- Cash flow from operating activities of $646 million, or $2.18 per share, compared to $796 million, or $2.64 per share, for the same period in 2024
- Net loss attributable to common shareholders[(1)] of $190 million, or $0.64 per share, compared to net earnings attributable to common shareholders of $177 million, or $0.59 per share, for the same period in 2024
- Announced an annual dividend increase of eight per cent, now equivalent to $0.28 per share on an annualized basis, which represents the seventh year of consecutive dividend growth
- Provided 2026 Outlook including adjusted EBITDA of $950 million to $1,050 million and FCF of $350 million to $450 million, or $1.18 to $1.51 per share
- Reduced scope 1 and 2 GHG emissions intensity in 2025 to 0.31 tCO2e/MWh from 2024 levels of 0.35 tCO2e/MWh
- Reduced scope 1 and 2 annual GHG emissions by 30.7 million tonnes of CO_2e or 76 per cent since 2015, achieving our goal of a 75 per cent reduction by 2026
- 2025 Total Recordable Injury Frequency of 0.12 compared to 0.56 in 2024

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Fourth Quarter and Year Ended 2025 Operational and Financial Highlights

$ millions, unless otherwise stated	Three Months Ended Dec. 31, 2025	Three Months Ended Dec. 31, 2024	Year Ended Dec. 31, 2025	Year Ended Dec. 31, 2024
Operational information[2]				
Availability (%)	**90.1**	87.8	**92.3**	91.2
Production (GWh)	**6,725**	6,199	**24,521**	22,811
Select financial information[2]				
Revenues	**599**	678	**2,405**	2,845
Adjusted EBITDA[1]	**247**	282	**1,104**	1,255
Adjusted earnings before income taxes[1]	**14**	38	**181**	396
(Loss) earnings before income taxes	**(42)**	(51)	**(141)**	319
Adjusted net (loss) earnings attributable to common shareholders[1]	**(19)**	3	**57**	236
Net (loss) earnings attributable to common shareholders	**(62)**	(65)	**(190)**	177
Cash flows[2]				
Cash flow from operating activities	**231**	215	**646**	796
Funds from operations[1]	**162**	135	**749**	816
Free cash flow[1]	**93**	46	**514**	575
Per share[2]				
Adjusted net (loss) earnings attributable to common shareholders per share[1][3]	**(0.06)**	0.01	**0.19**	0.78
Net (loss) earnings per share attributable to common shareholders, basic and diluted	**(0.21)**	(0.22)	**(0.64)**	0.59
Cash flow from operating activities per share[4]	**0.78**	0.72	**2.18**	2.64
Funds from operations per share[1][3]	**0.55**	0.45	**2.52**	2.70
Free cash flow per share[1][3]	**0.31**	0.15	**1.73**	1.90
Dividends declared per common share	**0.13**	0.13	**0.26**	0.24
Weighted average number of common shares outstanding	**297**	298	**297**	302

Segmented Financial Performance

$ millions	Three Months Ended Dec. 31, 2025	Dec. 31, 2024	Year Ended Dec. 31, 2025	Dec. 31, 2024
Hydro	**39**	57	**285**	316
Wind and Solar	**102**	95	**338**	316
Gas	**96**	116	**438**	524
Energy Transition	**16**	26	**100**	89
Energy Marketing	**21**	26	**85**	146
Corporate	**(27)**	(38)	**(142)**	(136)
Total adjusted EBITDA[1][5]	**247**	282	**1,104**	1,255
Adjusted earnings before income taxes[1]	**14**	38	**181**	396
(Loss) earnings before income taxes	**(42)**	(51)	**(141)**	319
Adjusted net (loss) earnings attributable to common shareholders[1]	**(19)**	3	**57**	236
Net (loss) earnings attributable to common shareholders	**(62)**	(65)	**(190)**	177

1. These are non-IFRS measures and ratios, which are not defined and have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the "Segmented Financial Performance and Operating Results" section of this news release for further discussion of these items. Also, refer to the "Non-IFRS and Supplementary Financial Measures" section of this news release for more information regarding these non-IFRS measures and ratios, including, where applicable, reconciliations to measures calculated in accordance with IFRS.

2. On Dec. 4, 2024, the Company completed the acquisition of Heartland Generation, which added 1,747 MW to gross installed capacity, excluding the Poplar Hill and Rainbow Lake facilities (collectively, the Required Divestitures). Refer to the "Significant and Subsequent Events" section of this MD&A. IFRS financial statements include the results attributable to the Required Divestitures up until the date of disposal, in accordance with a consent agreement entered into with the Commissioner of Competition for Canada. Our non-IFRS measures and operational Key Performance Indicators exclude the results of the Required Divestitures.

3. Adjusted net (loss) earnings attributable to common shareholders per share, funds from operations (FFO) per share and free cash flow (FCF) per share are calculated using the weighted average number of common shares outstanding during the period. Refer to the "Non-IFRS and Supplementary Financial Measures" section of this news release for more information regarding these non-IFRS measures and ratios.

4. Represents a supplementary financial measure and is calculated as Cash flow from operating activities for the period divided by the weighted average number of common shares outstanding during the period.

5. During the first quarter of 2025, our Adjusted EBITDA composition was amended to exclude the impact of realized gain (loss) on closed exchange positions and Australian interest income. Therefore, the Company has applied this composition to all previously reported periods. Refer to the "Non-IFRS and Supplementary Financial Measures" section of this news release.

Key Business Developments

Memorandum of Understanding for Data Centre Development at Keephills Site Signed

On Feb. 26, 2026, the Company entered into a Memorandum of Understanding (MOU) with Canada Pension Plan Investments and Brookfield to advance data centre development in Alberta, for which TransAlta is the exclusive site and power provider. The MOU establishes a framework for phased development at the Company's Keephills site in Parkland County, including an initial long-term power purchase agreement for approximately 230 MW and the evaluation of additional development aggregating up to 1 Gigawatt of load. Development is subject to regulatory approvals and the parties reaching definitive agreements.

Declared Increase in Common Share Dividend

The Company's Board has approved a $0.02 annualized (eight per cent) increase to the common share dividend and declared a dividend of $0.07 per common share on Feb. 25, 2026 to be payable on July 1, 2026 to shareholders of record at the close of business on June 1, 2026. The quarterly dividend of $0.07 per common share represents an annualized dividend of $0.28 per common share.

Acquisition of Far North

On Feb. 2, 2026, the Company closed the acquisition of Far North Power Corporation (Far North) for a purchase price of $95 million from an affiliate of Hut 8 Corporation, subject to working capital and other adjustments. The net cash payment for the transaction was funded through a combination of cash on hand and borrowings under TransAlta's credit facilities.

The transaction adds 310 MW of capacity from four natural gas-fired facilities in our core market of Ontario, increasing the Company's total installed capacity in the province to 1,384 MW.

US$400 million Senior Notes Offering and Early Redemption of the 7.8% Senior Notes

On Dec. 22, 2025, the Company issued US$400 million senior notes with a fixed annual coupon rate of 5.9 per cent, maturing on Feb. 1, 2034. The notes are unsecured and rank equally in right of payment with all existing and future senior indebtedness and senior in right of payment to all future subordinated indebtedness. The notes were issued at 99.39 per cent of par value, resulting in net proceeds of $541 million (US$393 million), and are callable in three years. Interest payments on the notes are made semi-annually, on Feb. 1 and Aug. 1, with the first payment scheduled for Aug. 1, 2026.

The proceeds from the offering were used to redeem all of the Company's outstanding 7.8 per cent US$400 million senior notes for the total redemption price of $573 million (US$416 million) in advance of the scheduled maturity date of Nov. 15, 2029.

Mothballing of Sheerness Unit 1

On Dec. 18, 2025, the Company provided notice to the Alberta Electric System Operator (AESO) that Sheerness Unit 1 will be mothballed effective April 1, 2026, for a period of up to two years. The Company maintains the flexibility to return the mothballed unit to service when market fundamentals improve or contracting opportunities are secured. The unit will remain available and fully operational through the first quarter of 2026 and Sheerness Unit 2 will remain fully in service.

Centralia Unit 2 Mandated to Remain Available

On Dec. 16, 2025, the Company received an order from the United States Department of Energy (the Order) requiring that our 700 MW Centralia Unit 2 facility remain available if called upon to operate for a period of 90 days, until March 16, 2026. The Company is currently compliant with the Order and continues to work with the state and federal governments in relation thereto.

Centralia Tolling Agreement Signed

On Dec. 9, 2025, the Company announced it had entered into a long-term tolling agreement (Tolling Agreement) with Puget Sound Energy to convert our 700 MW Centralia Unit 2 facility from coal to natural gas. The conversion extends the operating life of facility and will leverage existing turbines, transmission and infrastructure, while also lowering emissions.

The Tolling Agreement provides a fixed-price capacity payment through 2044 for the facility. The coal-to-gas conversion project is expected to require approximately US$600 million in capital and, once in service, will generate contracted cash flow over the life of the Tolling Agreement. The Company expects to declare a final investment decision for the project in early 2027, after receiving required regulatory approvals. Permitting work will continue through 2026, followed by construction in 2027–2028, with converted natural gas-fired operations expected to begin in late 2028.

Chief Executive Officer Succession

On Nov. 6, 2025, the Company announced that John Kousinioris, President and Chief Executive Officer and a Director of TransAlta, plans to retire effective April 30, 2026. Concurrent with this announcement, the Board of Directors appointed Joel Hunter, TransAlta's Executive Vice President, Finance and Chief Financial Officer, to succeed Mr. Kousinioris as President and Chief Executive Officer and be nominated to join the Board effective April 30, 2026. Mr. Kousinioris has agreed to serve as a strategic advisor to Mr. Hunter and the Board for a period of six months following his retirement. The Company's Chief Financial Officer successor will be announced in the coming months.

Demand Transmission Service Contract

On Oct. 3, 2025, the Company entered into a 230 MW Demand Transmission Service Contract with the AESO, representing the full allocation awarded to the Company through Phase I of the AESO's Data Centre Large Load Integration Program.

2026 Outlook

For 2026, the Company expects Adjusted EBITDA to be in the range of $950 million to $1,050 million and FCF to be in the range of $350 million to $450 million, based on the following expectations:

- Lower contribution from the Energy Transition segment due to the Centralia facility ceasing dispatchable coal-fired generation at the end of 2025;
- Lower contribution from the Alberta merchant gas portfolio as a result of lower average hedge prices and higher fuel costs, partially offset by lower carbon compliance costs due to a higher utilization of internally generated low-cost environmental credits;
- Lower contributions from Sarnia, reflecting a step down in contracted pricing and the expiry of the contract and decommissioning of the Ada Cogeneration facility;
- Higher contributions within the Hydro, Gas and Wind and Solar segments due to the expected realization of carbon credits against in-year, in addition to 2025, carbon compliance costs in Alberta;
- Higher contributions from the Gas segment due to the acquisition of the Far North Ontario gas facilities;
- Higher contributions from the Wind and Solar segment as a result of higher expected production;
- Higher income tax expense; and
- Lower Net Interest Expense as a result of lower interest rates on refinanced debt and lower interest on non-recourse debt as a result of amortizing repayments.

The following table outlines our expectations on key financial targets and related assumptions for 2026 and should be read in conjunction with the narrative discussion that follows and the "Risk Management" section of TransAlta's MD&A for the Fourth Quarter and Year Ended Dec. 31, 2025:

Measure	2026 Target[2]	2025 Target	2025 Actual[3]
Adjusted EBITDA[1]	$950 million to $1,050 million	$1,150 million to $1,250 million	$1,104 million
FCF[1]	$350 million to $450 million	$450 million to $550 million	$514 million
FCF per share[1]	$1.18 to $1.51	$1.51 to $1.85	$1.73
Dividend per share	$0.28 annualized	$0.26 annualized	$0.26 annualized

1. *These are non-IFRS measures and ratios, which are not defined and have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. We believe that presenting these items from period to period provides*

management and investors with the ability to evaluate (loss) earnings and cash flow trends more readily in comparison with prior periods' results. Please refer to the Non-IFRS and supplementary financial measures section of this news release for further discussion of these items.

2. *Represents forward-looking information.See "Cautionary Statement Regarding Forward-Looking Information" herein.*
3. *The actual 2025 amounts for the most directly comparable IFRS measures for Adjusted EBITDA and FCF were as follows: Loss before income taxes of $141 million and Cash flow from operating activities of $646 million. The most directly comparable IFRS ratio to FCF per share is cash flow from operating activities per share of $2.18, which is calculated as cash flow from operating activities for the period divided by the weighted average number of common shares outstanding during the period. Refer to the "Non-IFRS and Supplementary Financial Measures" section of this news release for further discussion of these items.*

The Company's outlook for 2026 may be impacted by a number of factors as detailed further below:

Market	2026 Assumptions	2025 Assumptions	2025 Actual
Alberta spot ($/MWh)	$40 to $60	$40 to $60	$44
AECO gas price ($/GJ)	$2.65 to $3.15	$1.60 to $2.10	$1.61

Alberta spot price sensitivity: a +/- $1 per MWh change in spot price is expected to have a +/- $2 million impact on Adjusted EBITDA for 2026.

Measure	2026 Expectations	2025 Expectations	2025 Actual
Energy Marketing Adjusted Revenues[1]	$110 million to $130 million	$110 million to $130 million	$122 million
Sustaining capital expenditures[2]	$140 million to $160 million	$145 million to $165 million	$162 million
Current income tax expense	$70 million to $100 million	$95 million to $130 million	$49 million
Net Interest Expense[1]	$240 million to $260 million	$255 million to $275 million	$264 million

1. *Energy Marketing Adjusted Revenues and Net Interest Expense are non-IFRS measures, are not defined, have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. The most directly comparable IFRS measure to Energy Marketing Adjusted Revenues is revenues of $130 million for the year ended Dec. 31, 2025 and to Net Interest Expense — interest expense of $347 million for the year ended Dec. 31, 2025*

Range of hedging assumptions	Q1 2026	Q2 2026	Q3 2026	Q4 2026	2027
Hedged production (GWh)	2,302	1,990	2,172	2,027	3,967
Hedge price ($/MWh)	$65	$65	$65	$65	$71
Hedged gas amounts (GJ)	12 million	7 million	8 million	7 million	19 million
Hedge gas prices ($/GJ)	$3.21	$3.33	$3.29	$3.39	$3.04

Conference call and webcast

TransAlta will host a conference call and webcast at 9:00 a.m. MST (11:00 a.m. EST) today, Feb. 27, 2026, to discuss our fourth quarter and full year 2025 results along with the Company's 2026 annual guidance. The call will begin with comments from John Kousinioris, President and Chief Executive Officer, and Joel Hunter, EVP Finance and Chief Financial Officer, followed by a question-and-answer period.

Fourth Quarter and Full Year 2025 Results Conference Call

Webcast link: https://edge.media-server.com/mmc/p/whytyzbs

To access the conference call via telephone, please register ahead of time using the call link here: https://register-conf.media-server.com/register/BIaa8023bbcae44cde8d2a046c730467b3. Once registered, participants will have the option of 1) dialing into the call from their phone (via a personalized PIN); or 2) clicking the "Call Me" option to receive an automated call directly to their phone.

If you are unable to participate in the call, the replay will be accessible at https://edge.media-server.com/mmc/p/whytyzbs. A transcript of the broadcast will be posted on TransAlta's website once it becomes available.

TransAlta is in the process of filing its Annual Information Form, audited Consolidated Financial Statements and accompanying notes, as well as the associated Management's Discussion & Analysis (MD&A). These documents will be available today on the Investors section of TransAlta's website at www.transalta.com or through SEDAR+ at www.sedarplus.ca and with the U.S. Securities and Exchange Commission on EDGAR at www.sec.gov.

About TransAlta Corporation:

TransAlta is one of Canada's largest publicly traded power generators, delivering reliable electricity across Canada, the United States and Western Australia. For more than 100 years, our people have safely operated and evolved essential energy infrastructure that powers customers and communities. Our technology-diverse portfolio and disciplined execution allow us to deliver dependable power across evolving energy systems. We take a practical, responsible approach to meeting today's energy needs while building for what comes next.

For more information about TransAlta, visit our web site at transalta.com.

Cautionary Statement Regarding Forward-Looking Information

This news release includes "forward-looking information," within the meaning of applicable Canadian securities laws, and "forward-looking statements," within the meaning of applicable United States securities laws, including the Private Securities Litigation Reform Act of 1995 (collectively referred to herein as "forward-looking statements"). Forward-looking statements are not facts, but only predictions and generally can be identified by the use of statements that include phrases such as "may", "will", "believe", "expect", "estimate", "anticipate", "intend", "plan", "forecast", "continue" or other similar words. In particular, this news release contains forward-looking statements about the following, among other things: our 2026 Outlook; the potential arising out of the MOU for data centre development for additional phases of development to aggregate to 1GW of load at the Company's Keephills site; the costs and permitting, regulatory approvals, construction and operational timelines for the Centralia Unit 2 coal to natural gas conversion project; and the timing of the announcement of the Company's Chief Financial Officer successor.

Forward-looking statements and future-oriented financial information in this news release are intended to provide the reader information about management's current expectations and plans and readers are cautioned that such information may not be appropriate for other purposes. Forward-looking statements are subject to important risks and uncertainties and are based on certain key assumptions. All forward-looking statements reflect TransAlta's beliefs and assumptions based on information available at the time the statements were made and as such are not guarantees of future performance. As actual results could vary significantly from the forward-looking statements, you should not put undue reliance on forward-looking statements and should not use future-oriented information or financial outlooks for anything other than their intended purpose. We do not update our forward-looking statements due to new information or future events, unless we are required to by law. For additional information on the assumptions made, and the risks and uncertainties which could cause actual results to differ from the anticipated results, refer to our most recent MD&A, which forms part of this news release, and the 2025 Integrated Report, including the section titled "*Governance and Risk Management*" in our MD&A for the year ended December 31, 2025, filed under TransAlta's profile on SEDAR+ at www.sedarplus.ca and with the U.S. Securities and Exchange Commission at www.sec.gov.

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Non-IFRS and Supplementary Financial Measures

This news release contains references to the following Non-IFRS measures: Adjusted EBITDA; Free Cash Flow (FCF) (including per share); Adjusted earnings (loss) before income taxes; Adjusted net earnings (loss) attributable to common shareholders (including per share); Funds from operations (FFO) (including per share); Energy Marketing adjusted revenues and net interest expense. Non-IFRS measures do not have standardized meanings under IFRS and are unlikely to be comparable to similar measures presented by other companies and should not be viewed in isolation from, as an alternative to, or more meaningful than, our IFRS results. We use these measures to evaluate our performance and the performance of our business segments and believe that these measures, read together with our IFRS measures, provide readers with a better understanding of how management assesses results. Presenting these measures from period to period provides management and investors with the ability to evaluate earnings (loss) trends more readily in comparison to prior periods' results. These measures are calculated by adjusting certain IFRS measures for certain items we believe are not reflective of our ongoing operations in a period and are calculated on a consistent basis from period to period and are adjusted for specific items in each period, unless stated otherwise. Refer to the Non-IFRS and Supplementary Measures section of our most recent MD&A, which forms part of this news release, for more information about these measures including, where applicable, reconciliations to measures calculated in accordance with IFRS.

Note: All financial figures are in Canadian dollars unless otherwise indicated.

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TRANSALTA CORPORATION Management's Discussion and Analysis

This Management's Discussion and Analysis (MD&A) contains forward-looking statements. These statements are based on certain estimates and assumptions and involve risks and uncertainties. Actual results may differ materially. Refer to the "Forward-Looking Statements" section of this MD&A for additional information.

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*This MD&A should be read in conjunction with our 2025 audited annual consolidated financial statements (the consolidated financial statements) and our 2025 Annual Information Form (AIF), each for the fiscal year ended Dec. 31, 2025. In this MD&A, unless the context otherwise requires, "we", "our", "us", the "Company" and "TransAlta" refer to TransAlta Corporation and its subsidiaries. The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (IFRS) for Canadian publicly accountable enterprises as issued by the International Accounting Standards Board (IASB) and in effect at Dec. 31, 2025. All tabular amounts in the following discussion are in millions of Canadian dollars unless otherwise noted, except amounts per share, which are in whole dollars to the nearest two decimals. This MD&A is dated Feb. 26, 2026. Additional information respecting TransAlta, including our AIF for the year ended Dec. 31, 2025, is available on SEDAR+ at **www.sedarplus.ca**, on EDGAR at **www.sec.gov** and on our website at **www.transalta.com**. Information on or connected to our website is not incorporated by reference herein.*

Forward-Looking Statements

This MD&A includes "forward-looking information" within the meaning of applicable Canadian securities laws and "forward-looking statements" within the meaning of applicable U.S. securities laws, including the *Private Securities Litigation Reform Act of 1995* (collectively referred to herein as "forward-looking statements").

Forward-looking statements are not facts, but only predictions and generally can be identified by the use of statements that include phrases such as "may", "will", "can", "could", "would", "shall", "believe", "expect", "estimate", "anticipate", "intend", "plan", "forecast", "foresee", "potential", "enable", "continue" or other comparable terminology.

In particular, this MD&A contains forward-looking statements about the following, among other things:

- The strategic objectives of the Company and that the execution of the Company's strategy will realize value for shareholders;
- Our capital allocation and financing strategy;
- Our 2026 Outlook;
- Our financial and operational performance, including our hedge position;
- The optimization and diversification of our existing assets;
- The increasingly contracted nature of our fleet;
- Expectations about strategies for growth and expansion;
- Execution of a data centre memorandum of understanding and its framework for phased development of the Keephills site, including the execution of definitive binding agreements with our counterparties for phase 1, the evaluation of opportunities for additional phases of development and the potential for such additional phases of development to aggregate to 1GW of load;
- Expected costs and schedules for planned projects, including the Centralia coal-to-gas conversion project;
- Expected regulatory processes and outcomes, including in respect of the U.S. Department of Energy Order regarding Centralia Unit 2;
- The power generation industry and the supply of, and demand for, electricity;
- Our CEO and CFO succession plans;
- The cyclicality of our business;
- Expected outcomes with respect to legal proceedings;
- The expected impact of future tax and accounting changes; and
- Expected industry, market and economic conditions.

The forward-looking statements contained in this MD&A are based on many assumptions including, but not limited to, the following:

- No significant changes to applicable laws and regulations, including carbon pricing, renewable energy incentives, royalty rates and climate-related regulations;
- No unexpected delays in obtaining required regulatory and other third-party approvals;
- No material adverse impacts to investment and credit markets;
- No significant changes to power price and hedging assumptions;
- No significant changes to gas commodity price assumptions and transport costs;
- No significant changes to interest or foreign exchange rates;
- No significant changes to the demand for, and growth of, electricity generation;
- No significant changes to the integrity and reliability of our facilities;
- No significant changes to the Company's debt and credit ratings;
- No unforeseen changes to economic and market conditions;
- No significant event occurring outside the ordinary course of business;
- No significant changes to the Company's ability to develop, access or implement, on a timely basis and on reasonable terms, the technology necessary to efficiently and effectively operate the Company's assets and achieve expected future results;
- No significant supply chain disruptions or shortages of raw materials or skilled labour;
- No significant changes to the Company's ability to access the capital markets on reasonable terms; and
- No material changes to international trade laws, regulations, agreements, treaties, taxes, tariffs, duties or policies of Canada, the United States or other countries.

These assumptions are based on information currently available to TransAlta, including information obtained from third-party sources. Actual results may differ materially from those predicted by such assumptions.

Factors that may adversely impact what is expressed or implied by forward-looking statements contained in this MD&A include, but are not limited to:

- Fluctuations in power prices;
- Changes in supply and demand for electricity;
- Our ability to contract our electricity generation for prices that will provide expected returns;
- Our ability to replace contracts as they expire;
- Risks associated with development projects and acquisitions;
- Our ability to develop, access or implement, on a timely basis and on reasonable terms, the technology necessary to efficiently and effectively operate our assets and achieve expected future results;

- Any difficulty raising needed capital in the future on reasonable terms;
- Long-term commitments on gas transportation capacity that may not be fully utilized over time;
- Changes to legislative, regulatory and political environments, including changes to carbon pricing, renewable energy policies and emissions regulations in Canada, the United States and Australia;
- Environmental requirements and changes in, or liabilities under, these requirements;
- Operational risks involving our facilities, including unplanned outages and equipment failure;
- Disruptions in the transmission and distribution of electricity;
- Grid reliability;
- Reductions in production;
- Impairments and/or writedowns of assets;
- Adverse impacts on our information technology systems and our internal control systems, including increased cybersecurity threats;
- Commodity risk management and energy-trading risks;
- Reduced labour availability, ability to continue to staff our operations and facilities and other labour relations matters;
- Disruptions to our supply chains;
- Weather conditions and their impact on electricity generation and demand;
- Climate change-related risks, including the increased frequency and severity of extreme weather events;
- Reductions to our generating units' relative efficiency or capacity factors;
- General economic risks, including deterioration of equity markets, increasing interest rates, changes to foreign exchange rates or rising inflation;
- General domestic and international economic and political developments, including potential trade tariffs;
- Industry risk and competition, including from emerging technologies affecting the demand, generation, distribution or storage of electricity;
- Counterparty credit risks;
- Inadequacy or unavailability of insurance coverage;
- Increases in the Company's income taxes and any risk of reassessments;
- Legal, regulatory and contractual disputes and proceedings involving the Company;
- Reputational and stakeholder-related risks; and
- Reliance on key personnel.

The foregoing risk factors, among others, are described in further detail in the "Risk Management" section of this MD&A.

Readers are urged to consider these factors carefully when evaluating the forward-looking statements, which reflect the Company's expectations only as of the date of this MD&A and are cautioned not to place undue reliance on them. The forward-looking statements included in this document are made only as of the date of its release and we do not undertake to publicly update these forward-looking statements to reflect new information, future events or otherwise, except as required by applicable laws. The purpose of the financial outlooks contained in this document is to give the reader information about management's current expectations and plans and readers are cautioned that such information may not be appropriate for other purposes. In light of these risks, uncertainties and assumptions, the forward-looking statements might occur to a different extent or at a different time than we have described, or might not occur at all. We cannot assure that projected results or events will be achieved.

Description of the Business

TransAlta Corporation is one of Canada's largest publicly traded power generators, owning and operating a diverse fleet across Canada, the United States (U.S.) and Western Australia. Our portfolio includes hydro, wind, solar, battery storage and thermal generation, complemented by our asset optimization and energy marketing capabilities. As one of Canada's largest producers of wind and thermal generation and Alberta's largest producer of hydroelectric power, TransAlta remains committed to a diverse generation mix. With strong cash flows underpinned by a high-quality portfolio, TransAlta strives to deliver sustainable long-term shareholder value in an evolving energy landscape.

Portfolio of Assets

Our asset portfolio is geographically diversified with operations across our core markets.

Our Hydro, Wind and Solar, Gas and Energy Transition segments are responsible for operating and maintaining our generation facilities. Our Energy Marketing segment is responsible for marketing and scheduling our merchant asset fleet in North America (excluding Alberta) along with the procurement, transport and storage of natural gas, providing knowledge to support our growth team, and generating a stand-alone gross margin separate from our asset business through a leading North American energy marketing and trading platform.

Our diversified portfolio consists of both high-quality contracted assets and merchant assets. Our contracted assets provide stable long-term cash flow and earnings, balancing our merchant fleet. Our merchant assets include our unique hydro merchant portfolio and our merchant legacy thermal portfolio and wind assets. Our merchant exposure is primarily in Alberta, where 58 per cent of our capacity is located and 77 per cent of our Alberta capacity is available to participate in the merchant market.

In Alberta, the Company manages its merchant exposure by executing hedging strategies that include a significant base of commercial and industrial customers, supplemented with financial hedges. A significant portion of our thermal and hydro generation capacity in Alberta may be hedged to provide greater cash flow certainty while also being available to capture upside through the optimization of our merchant generation portfolio. Refer to the "2026 Outlook" section and the "Optimization of the Alberta Portfolio" section of this MD&A for further details.

The following table provides our consolidated ownership by segment of our facilities across the regions in which we operate as at Dec. 31, 2025:

As at Dec. 31, 2025		Hydro	Wind & Solar	Gas	Energy Transition[2]	Total
Alberta	Gross installed capacity (MW)[1]	834	764	3,650	—	5,248
	Number of facilities	17	14	15	—	46
	Weighted average contract life (years)	—	16	8	—	10
	Contracted capacity (MW)	—	336	887	—	1,223
	Contracted capacity as a % of total capacity (%)	—	44	24	—	23
Canada, excluding Alberta	Gross installed capacity (MW)[1]	88	751	705	—	1,544
	Number of facilities	7	9	4	—	20
	Weighted average contract life (years)	14	8	6	—	7
	Contracted capacity (MW)	88	751	705	—	1,544
	Contracted capacity as a % of total capacity (%)	100	100	100	—	100
U.S.	Gross installed capacity (MW)[1]	—	1,024	29	671	1,724
	Number of facilities	—	10	1	2	13
	Weighted average contract life (years)	—	12	—	—	9
	Contracted capacity (MW)	—	1,024	29	301	1,354
	Contracted capacity as a % of total capacity (%)	—	100	100	45	79
Western Australia	Gross installed capacity (MW)[1]	—	48	450	—	498
	Number of facilities	—	3	6	—	9
	Weighted average contract life (years)	—	13	13	—	13
	Contracted capacity (MW)	—	48	450	—	498
	Contracted capacity as a % of total capacity (%)	—	100	100	—	100
Total	Gross installed capacity (MW)[1]	**922**	**2,587**	**4,834**	**671**	**9,014**
	Number of facilities	**24**	**36**	**26**	**2**	**88**
	Weighted average contract life (years)	**14**	**11**	**8**	**—**	**9**
	Contracted capacity (MW)	**88**	**2,159**	**2,071**	**301**	**4,619**
	Contracted capacity as a % of total capacity (%)[3]	**10**	**83**	**43**	**45**	**51**

(1) Gross installed capacity for consolidated reporting is based on a proportionate interest held in a facility. Refer to the "Plant Summary" section of the 2025 Annual Report for details.

(2) Includes the Centralia coal facility and the Skookumchuck hydro facility.

(3) Approximately 51 per cent of our total installed capacity is contracted with creditworthy counterparties.

Highlights

The Company demonstrated strong operational performance for the year ended Dec. 31, 2025. Lower power pricing in Alberta, subdued market volatility and lower wind resource impacted the Company's results year-over-year, with Adjusted EBITDA coming in below the lower end of the range of management's expectations. Free cash flow, while lower year-over-year, came in slightly above the midpoint of the Company's 2025 Outlook, primarily due to lower current tax expense and lower distributions paid to non-controlling interests. The Company partially mitigated the impact of lower power pricing in Alberta by settling a higher volume of hedges at prices that were significantly above the spot market and also benefited from the integration of Heartland assets, acquired at the end of 2024.

	3 months ended Dec. 31,		Year ended Dec. 31	
(in millions of Canadian dollars except where noted)	**2025**	**2024**	**2025**	**2024**
Operational information[1]				
Availability (%)	**90.1**	87.8	**92.3**	91.2
Production (GWh)	**6,725**	6,199	**24,521**	22,811
Select financial information[1]				
Revenues	**599**	678	**2,405**	2,845
Adjusted EBITDA[2]	**247**	282	**1,104**	1,255
Adjusted Earnings before income taxes[2]	**14**	38	**181**	396
(Loss) earnings before income taxes	**(42)**	(51)	**(141)**	319
Adjusted Net (Loss) Earnings Attributable to Common Shareholders[2]	**(19)**	3	**57**	236
Net (loss) earnings attributable to common shareholders	**(62)**	(65)	**(190)**	177
Cash flows[1]				
Cash flow from operating activities	**231**	215	**646**	796
Funds from operations[2]	**162**	135	**749**	816
Free cash flow[2]	**93**	46	**514**	575
Per share[1]				
Weighted average number of common shares outstanding	**297**	298	**297**	302
Adjusted Net (Loss) Earnings Attributable to Common Shareholders per share[2][3]	**(0.06)**	0.01	**0.19**	0.78
Net (loss) earnings per share attributable to common shareholders, basic and diluted	**(0.21)**	(0.22)	**(0.64)**	0.59
Dividends declared per common share	**0.13**	0.13	**0.26**	0.24
Dividends declared per preferred share	**0.68**	0.69	**1.36**	1.36
Cash flow from operating activities per share[4]	**0.78**	0.72	**2.18**	2.64
Funds from operations per share[2][3]	**0.55**	0.45	**2.52**	2.70
Free cash flow per share[2][3]	**0.31**	0.15	**1.73**	1.90

(1) On Dec. 4, 2024, the Company completed the acquisition of Heartland Generation, which added 1,747 MW to gross installed capacity, excluding the Poplar Hill and Rainbow Lake facilities (collectively, the Required Divestitures). Refer to the "Significant and Subsequent Events" section of this MD&A. IFRS financial statements include the results attributable to the Required Divestitures up until the date of disposal, in accordance with a consent agreement entered into with the Commissioner of Competition for Canada. Our non-IFRS measures and operational Key Performance Indicators exclude the results of the Required Divestitures.

(2) These are non-IFRS measures and ratios, which are not defined and have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the "Segmented Financial Performance and Operating Results" section of this MD&A for further discussion of these items. Also, refer to the "Non-IFRS and Supplementary Financial Measures" section of this MD&A for more information regarding these non-IFRS measures and ratios, including, where applicable, reconciliations to measures calculated in accordance with IFRS.

(3) Adjusted Net (Loss) Earnings Attributable to Common Shareholders per share, funds from operations (FFO) per share and free cash flow (FCF) per share are calculated using the weighted average number of common shares outstanding during the period. Refer to the "Non-IFRS and Supplementary Financial Measures" section of this MD&A for more information regarding these non-IFRS measures and ratios.

(4) Represents a supplementary financial measure and is calculated as cash flow from operating activities for the period divided by the weighted average number of common shares outstanding during the period.

(in millions of Canadian dollars except where noted)

As at Dec. 31	2025	2024
Liquidity and capital resources		
Available liquidity[1]	**1,500**	1,616
Adjusted Net Debt to Adjusted EBITDA (times)[2][3]	**4.0**	3.6
Total Consolidated Net Debt[2][4]	**3,725**	3,798
Assets and liabilities		
Total assets	**8,661**	9,499
Total long-term liabilities[5]	**5,366**	5,087
Total liabilities	**7,196**	7,656

(1) Available liquidity is a supplementary financial measure and is calculated as the sum of total available capacity under the committed credit and term facilities and cash and cash equivalents less bank overdraft and the amounts drawn under the non-committed demand facilities.

(2) These are non-IFRS measures and ratios, which are not defined and have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the "Segmented Financial Performance and Operating Results" section of this MD&A for further discussion of these items. Also, refer to the "Non-IFRS and Supplementary Financial Measures" section of this MD&A for more information regarding these non-IFRS measures and ratios, including, where applicable, reconciliations to measures calculated in accordance with IFRS.

(3) The most directly comparable IFRS ratio to Adjusted Net Debt to Adjusted EBITDA (times) is calculated as credit facilities, long-term debt and lease liabilities of $3,593 million (Dec. 31, 2024 — $3,808 million) divided by loss before income taxes for the last four quarters of $141 million (Dec. 31, 2024 — earnings before income taxes $319 million) and is equal to (25) times (Dec. 31, 2024 — 12 times). Refer to the "Key Non-IFRS Financial Ratios" section of this MD&A for details of the calculation.

(4) The most directly comparable IFRS measure to Total Consolidated Net Debt is total credit facilities, long-term debt and lease liabilities, which is equal to $3,593 million (Dec. 31, 2024 — $3,808 million). Refer to the table in the "Financial Condition" section of this MD&A for more details on the composition of Total Consolidated Net Debt.

(5) Total long-term liabilities are equal to total non-current liabilities in the consolidated statements of financial position under IFRS.

Significant and Subsequent Events

Memorandum of Understanding for Data Centre Development at Keephills Site Signed

On Feb. 26, 2026, the Company entered into a Memorandum of Understanding (MOU) with Canada Pension Plan Investments and Brookfield to advance data centre development in Alberta, for which TransAlta is the exclusive site and power provider. The MOU establishes a framework for phased development at the Company's Keephills site in Parkland County, including an initial long-term power purchase agreement for approximately 230 MW and the evaluation of additional development aggregating up to 1 Gigawatt of load. Development is subject to regulatory approvals and the parties reaching definitive agreements.

Declared Increase in Common Share Dividend

The Company’s Board has approved a $0.02 annualized (eight per cent) increase to the common share dividend and declared a dividend of $0.07 per common share on Feb. 25, 2026 to be payable on July 1, 2026 to shareholders of record at the close of business on June 1, 2026. The quarterly dividend of $0.07 per common share represents an annualized dividend of $0.28 per common share.

Acquisition of Far North

On Feb. 2, 2026, the Company closed the acquisition of Far North Power Corporation (Far North) for a purchase price of $95 million from an affiliate of Hut 8 Corporation, subject to working capital and other adjustments. The net cash payment for the transaction was funded through a combination of cash on hand and borrowings under TransAlta's credit facilities.

The transaction adds 310 MW of capacity from four natural gas-fired facilities in our core market of Ontario, increasing the Company's total installed capacity in the province to 1,384 MW.

US$400 Million Senior Notes Offering and Early Redemption of the 7.8% Senior Notes

On Dec. 22, 2025, the Company issued US$400 million senior notes with a fixed annual coupon rate of 5.9 per cent, maturing on Feb. 1, 2034. The notes are unsecured and rank equally in right of payment with all existing and future senior indebtedness and senior in right of payment to all future subordinated indebtedness. The notes were issued at 99.4 per cent of par value, resulting in net proceeds of $541 million (US$393 million), and are callable in three years. Interest payments on the notes are made semi-annually, on Feb. 1 and Aug. 1, with the first payment scheduled for Aug. 1, 2026.

The proceeds from the offering were used to redeem all of the Company's outstanding 7.8 per cent US$400 million senior notes for the total redemption price of $573 million (US$416 million) in advance of the scheduled maturity date of Nov. 15, 2029.

Mothballing of Sheerness Unit 1

On Dec. 18, 2025, the Company provided notice to the Alberta Electric System Operator (AESO) that Sheerness Unit 1 will be mothballed effective April 1, 2026, for a period of up to two years. The Company maintains the flexibility to return the mothballed unit to service when market fundamentals improve or contracting opportunities are secured. The unit will remain available and fully operational through the first quarter of 2026 and Sheerness Unit 2 will remain fully in service.

Centralia Unit 2 Mandated to Remain Available

On Dec. 16, 2025, the Company received an order from the United States Department of Energy (the Order) requiring that our 700 MW Centralia Unit 2 facility remain available if called upon to operate for a period of 90 days, until March 16, 2026. The Company is currently compliant with the Order and continues to work with the state and federal governments in relation thereto.

Centralia Tolling Agreement Signed

On Dec. 9, 2025, the Company announced it had entered into a long-term tolling agreement (Tolling Agreement) with Puget Sound Energy to convert our 700 MW Centralia Unit 2 facility from coal to natural gas. The conversion extends the operating life of facility and will leverage existing turbines, transmission and infrastructure, while also lowering emissions.

The Tolling Agreement provides a fixed-price capacity payment through 2044 for the facility. The coal-to-gas conversion project is expected to require approximately US$600 million in capital and, once in service, will generate contracted cash flow over the life of the Tolling Agreement. The Company expects to declare a final investment decision for the project in early 2027, after receiving required regulatory approvals. Permitting work will continue through 2026, followed by construction in 2027–2028, with converted natural gas-fired operations expected to begin in late 2028.

Chief Executive Officer Succession

On Nov. 6, 2025, the Company announced that John Kousinioris, President and Chief Executive Officer and a Director of TransAlta, plans to retire effective April 30, 2026. Concurrent with this announcement, the Board of Directors appointed Joel Hunter, TransAlta's Executive Vice President, Finance and Chief Financial Officer, to succeed Mr. Kousinioris as President and Chief Executive Officer and be nominated to join the Board effective April 30, 2026. Mr. Kousinioris has agreed to serve as a strategic advisor to Mr. Hunter and the Board for a period of six months following his retirement. The Company's Chief Financial Officer successor will be announced in the coming months.

Demand Transmission Service Contract

On Oct. 3, 2025, the Company entered into a 230 MW Demand Transmission Service Contract with the AESO, representing the full allocation awarded to the Company through Phase I of the AESO's Data Centre Large Load Integration Program.

Completion of Required Divestitures

On Aug. 1, 2025, the Company completed the sale of its 100 per cent interest in the 48 MW Poplar Hill facility, followed by the completion of the sale of its 50 per cent interest in the 97 MW Rainbow Lake facility on Oct. 2, 2025. Both divestitures were required by the consent agreement entered into with the federal Competition Bureau as part of its regulatory approval for the Company's acquisition of Heartland Generation. Energy Capital Partners received the proceeds from the sale of both facilities, net of certain adjustments.

Credit Facility Extension

On July 16, 2025, the Company strengthened its liquidity profile by executing agreements with its lending syndicate to extend its committed credit facilities totalling $2.1 billion by one year. The revised agreements reduced the syndicated facility size from $1.95 billion to $1.90 billion, and extended its maturity to June 30, 2029. The bilateral credit facilities of $240 million were extended by one year to June 30, 2027. The amended agreements enhance financial flexibility, which is a strategic priority.

Recontracting of Ontario Wind Facilities

During the second quarter of 2025, the Company successfully recontracted its Melancthon 1, Melancthon 2 and Wolfe Island wind facilities through the Ontario Independent Electricity System Operator Five-Year Medium-Term 2 Energy Contract (MT2e). MT2e will replace current energy contracts for the three wind facilities when they expire, extending the contract dates until April 30, 2031, for Melancthon 1 and April 30, 2034, for Melancthon 2 and Wolfe Island.

Senior Notes Offering

On March 24, 2025, the Company issued $450 million of senior notes with a fixed annual coupon of 5.625 per cent, maturing on March 24, 2032. The notes are unsecured and rank equally in right of payment with all existing and future senior indebtedness and are senior in right of payment to all future subordinated indebtedness. Interest payments on the notes are made semi-annually, on March 24 and Sept. 24, with the first payment made on Sept. 24, 2025.

On March 25, 2025, the Company repaid its $400 million variable rate term loan facility in advance of the scheduled maturity date of Sept. 7, 2025, with the proceeds received from the senior notes offering.

Nova Clean Energy, LLC

During the first quarter of 2025, the Company made a strategic investment in Nova Clean Energy, LLC (Nova), a developer of renewable energy projects. The investment includes a US$75 million term loan and US$100 million revolving facility. As at Dec. 31, 2025, US$106 million was drawn by Nova under the credit facilities. The outstanding principal under the term loan and the revolving facility bear interest at seven per cent per year with interest due quarterly. The terms of the term loan and the revolving facility are six and five years, respectively, unless accelerated. The term loan is convertible to a minority equity interest at any time, prior to maturity, at the option of the Company and any remaining unused term loan commitments at the time of conversion would be terminated. This investment provides the Company with the exclusive right to purchase Nova's late-stage development projects in the western U.S.

Normal Course Issuer Bid (NCIB)

On May 27, 2025, the Company announced that it had received approval from the Toronto Stock Exchange to repurchase up to a maximum of 14 million common shares during the 12-month period that commenced May 31, 2025 and will terminate on May 30, 2026.

For the year ended Dec. 31, 2025, the Company purchased and cancelled a total of 1,932,800 common shares, at an average price of $12.42 per common share, for a total cost of $24 million, including taxes.

Mothballing of Sundance 6

On April 1, 2025, the Company mothballed the Sundance Unit 6 facility for a period of up to two years depending on market conditions. TransAlta maintains the flexibility to return the mothballed unit to service when market fundamentals improve or opportunities to contract are secured.

Operating and Financial Performance

Operating Performance

Availability

The following table provides availability (%) by segment:

	3 months ended Dec. 31,		Year ended Dec. 31	
	2025	**2024**	**2025**	**2024**
Hydro	**94.4**	85.8	**92.0**	90.7
Wind and Solar	**94.6**	92.2	**94.4**	93.4
Gas	**85.9**	84.1	**91.8**	92.2
Energy Transition	**92.5**	91.7	**88.5**	80.0
Availability (%)	**90.1**	87.8	**92.3**	91.2

Availability is an important measure for the Company as it represents the percentage of time a facility is available to produce electricity, and is an indicator of the overall performance of the fleet.

Availability is impacted by planned and unplanned outages, and derates. The Company schedules planned outages to maintain, repair or make improvements to the facilities at times chosen to minimize operational impacts. In high price environments, outage schedules may be adjusted to accelerate the unit's return to service.

Three months ended Dec. 31, 2025

Availability for the three months ended Dec. 31, 2025, was 90.1 per cent compared to 87.8 per cent for the same period in 2024, primarily due to:

- Lower planned maintenance outages in the Hydro, Gas and Energy Transition segments; and
- Lower unplanned maintenance outages in the Wind and Solar segment.

Year ended Dec. 31, 2025

Availability for the year ended Dec. 31, 2025, was 92.3 per cent compared to 91.2 per cent in 2024. Higher availability compared to the prior year was primarily due to:

- Lower planned and unplanned outages at the Centralia facility in the Energy Transition segment;
- The impact from the White Rock and Horizon Hill wind facilities which achieved commercial operation in the first half of 2024 and operated at higher availability in 2025; and
- Lower planned and unplanned maintenance outages in the Hydro segment; partially offset by
- Higher unplanned outages and derates in the Gas segment.

Production and Long-Term Average Generation

The following table provides the production and long-term average generation (LTA generation) on a consolidated basis for each of our segments:

	2025			2024		
3 months ended Dec. 31	**Actual production (GWh)**	**LTA generation (GWh)**	**Production as a % of LTA**	**Actual production (GWh)**	**LTA generation (GWh)**	**Production as a % of LTA**
Hydro	**336**	**447**	**75%**	452	447	101%
Wind and Solar	**2,008**	**2,175**	**92%**	1,831	2,175	84%
Gas	**3,499**			2,875		
Energy Transition	**882**			1,041		
Total	**6,725**			6,199		

	2025			2024		
Year ended Dec. 31	**Actual production (GWh)**	**LTA generation (GWh)**	**Production as a % of LTA**	**Actual production (GWh)**	**LTA generation (GWh)**	**Production as a % of LTA**
Hydro	**1,914**	**2,015**	**95%**	1,723	2,015	86%
Wind and Solar[(1)]	**6,454**	**7,457**	**87%**	5,949	6,876	87%
Gas	**13,003**			12,317		
Energy Transition	**3,150**			2,822		
Total	**24,521**			22,811		

(1) LTA generation for Wind and Solar increased as a result of new wind facilities, including the White Rock and the Horizon Hill wind facilities commissioned in the first half of 2024.

In addition to availability, the Company uses LTA generation as another indicator of performance for its renewable facilities, whereby actual production levels are compared against expected long-term average production levels. In the short term, for each of the Hydro and Wind and Solar segments, the conditions will vary from one period to the next. Over longer durations, facilities are expected to produce in-line with their long-term averages, which is broadly considered a reliable indicator of performance.

LTA generation is calculated on an annualized basis from the average annual energy yield predicted from our simulation model based on historical resource data performed over a period of typically greater than 25 years.

The LTA generation for Gas and Energy Transition is not applicable as these facilities are dispatchable and their production largely depends on market conditions and merchant demand.

Three months ended Dec. 31, 2025

Total production for the three months ended Dec. 31, 2025, increased by 526 GWh, or eight per cent, compared to the same period in 2024, primarily due to:

- Addition of production from the Heartland gas facilities acquired in December 2024;
- Higher production at the Sarnia gas facility due to higher availability compared to the same period in 2024, when the facility experienced a planned outage during a portion of the quarter; and
- Higher availability and wind resource across Canada and the U.S. partially offset by
- Higher dispatch optimization in Alberta in the Gas segment due to lower market prices;
- Lower production in the Hydro segment due to lower market prices and water conservation; and
- Lower production at Centralia due to lower Mid-Columbia prices.

Year ended Dec. 31, 2025

Total production for 2025 increased by 1,710 GWh, or seven per cent, compared to 2024, primarily due to:

- Addition of production from the Heartland gas facilities acquired in December 2024;
- Production impact from the White Rock and Horizon Hill wind facilities which achieved commercial operation in the first half of 2024;
- Higher production at the Sarnia gas facility due to higher availability compared to 2024, when the facility experienced a planned outage during a portion of the fourth quarter;
- Improved availability at Centralia;
- Higher production in the Hydro segment due to higher water reserves and optimization of water supply; and
- Higher wind resource in Eastern Canada; partially offset by
- Higher dispatch optimization in Alberta in the Gas segment due to lower market prices.

Market Pricing

	3 months ended Dec. 31,		Year ended Dec. 31	
	2025	**2024**	**2025**	**2024**
Alberta spot power price ($/MWh)	**43**	52	**44**	63
Mid-Columbia spot power price (US$/MWh)	**38**	41	**42**	56
Ontario spot power price[1] ($/MWh)	**78**	34	**60**	32
Natural gas price (AECO) per GJ ($)	**2.15**	1.42	**1.61**	1.29

(1) Ontario spot power prices through to the end of April 2025 were based on the hourly Ontario energy price (HOEP). Starting May 1, 2025 prices are based on the settled day ahead hourly Ontario zonal energy prices.

For the three months and year ended Dec. 31, 2025, spot power prices in Alberta were 17 and 30 per cent lower, respectively, compared to the same periods in 2024, driven by generally milder weather and increased supply from new renewable and gas-fired facilities.

For the three months and year ended Dec. 31, 2025, Mid-Columbia spot power prices in the Pacific Northwest were seven and 25 per cent lower, respectively, compared to the same periods in 2024, due to the impact of milder weather.

Ontario spot power prices were higher on average compared to the three months and year ended Dec. 31, 2024, due to nuclear refurbishments occurring in 2025 and higher natural gas prices.

For the three months and year ended Dec. 31, 2025, AECO natural gas prices were 51 and 25 per cent higher, respectively, compared to the same periods in 2024, mainly due to lower gas production and lower storage levels in Alberta and throughout North America, as well as stronger demand.

Financial Performance Review of Consolidated Information

	3 months ended Dec. 31,		Year ended Dec. 31	
	2025	**2024**	**2025**	**2024**
Revenues	**599**	678	**2,405**	2,845
Fuel and purchased power	**(258)**	(249)	**(935)**	(939)
Carbon compliance costs	**(40)**	(39)	**(50)**	(112)
Operations, maintenance and administration	**(186)**	(234)	**(711)**	(655)
Depreciation and amortization	**(148)**	(143)	**(579)**	(531)
Asset impairment reversals (charges)	**68**	(20)	**13**	(46)
Interest expense	**(81)**	(92)	**(347)**	(324)
(Loss) earnings before income taxes	**(42)**	(51)	**(141)**	319
Income tax recovery (expense)	**2**	8	**(17)**	(80)
Net (loss) earnings attributable to common shareholders	**(62)**	(65)	**(190)**	177
Net (loss) earnings attributable to non-controlling interests	**(4)**	(4)	**(20)**	10

Three months ended Dec. 31, 2025

Revenues for the three months ended Dec. 31, 2025 decreased by $79 million, or 12 per cent, compared to the same period in 2024, primarily due to:

- Lower spot power prices in the Alberta market;
- Higher dispatch optimization in the Gas segment driven by lower power prices in Alberta;
- Higher unrealized mark-to-market losses on the long-term wind energy sales related to the Oklahoma facilities in the Wind and Solar segment;
- Lower revenues in the Energy Transition segment due to lower Mid-Columbia prices, reduced production and a lower volume of favourable hedge positions settled;
- Lower realized mark-to-market gains on settled trades in the Gas segment; partially offset by
- The addition of the Heartland facilities in the Gas segment;
- Lower unrealized mark-to-market losses in the Gas segment due to favourable changes in forward prices;
- Higher revenue from the Sarnia gas facility in the current period as the facility experienced a planned outage during a portion of the quarter in 2024;
- Lower unrealized mark-to-market losses in the Energy Marketing segment due to more favourable forward positions across North American power and natural gas markets; and
- Higher revenues in the Wind and Solar segment due to higher wind resource in Alberta and the U.S..

Fuel and purchased power costs for the three months ended Dec. 31, 2025 increased by $9 million, or four per cent, compared to the same period in 2024, primarily due to:

- The full quarter impact from the addition of the Heartland facilities in the fourth quarter of 2024;
- Higher natural gas prices; and
- Higher production at the Sarnia gas facility as the facility experienced a planned outage during a portion of the quarter in 2024; partially offset by
- Lower purchased power costs driven by lower Mid-Columbia prices on repurchases of power and lower production in the Energy Transition segment.

Carbon compliance costs for the three months ended Dec. 31, 2025 were comparable to the same period of 2024 primarily due to:

- The full quarter impact from the addition of the Heartland facilities in the fourth quarter of 2024;
- Higher production at the Sarnia gas facility in the current period as the facility experienced a planned outage during a portion of the quarter in 2024; and
- An increase in the carbon price from $80 to $95 per tonne; partially offset by
- Favourable impact on carbon compliance cost from higher production at lower-carbon-emitting cogeneration facilities.

OM&A expenses for the three months ended Dec. 31, 2025 decreased by $48 million, or 21 per cent, compared to the same period in 2024, primarily due to:

- No penalties recognized in the current period compared to the same period in 2024, when the Company recognized the penalties assessed by the Alberta Market Surveillance Administrator for self-reported contraventions pertaining to Brazeau hydro ancillary services provided during 2021 and 2022;
- Lower acquisition-related transaction and restructuring costs;

- Lower spending related to the planning, design and implementation of an upgrade to our Enterprise Resource Planning (ERP) system; and
- Lower incentive costs; partially offset by
- The full quarter impact from the addition of the Heartland facilities in the fourth quarter of 2024 and associated corporate costs.

Depreciation and amortization for the three months ended Dec. 31, 2025 increased by $5 million, or three per cent, compared to the same period in 2024, primarily due to full quarter impact from the addition of Heartland facilities in the fourth quarter of 2024.

Asset impairment reversals for the three months ended Dec. 31, 2025 increased by $88 million, from asset impairment charges for the same period in 2024, primarily due to:

- A change in the decommissioning and restoration provisions driven by the revisions in estimated cash flows, timing of cash flows and discount rates in the Energy Transition segment; and
- Lower impairment charges related to development projects that are no longer proceeding.

Interest expense for the three months ended Dec. 31, 2025 decreased by $11 million, or 12 per cent, compared to 2024, primarily due to:

- Lower interest on exchangeable debentures due to the financing costs amortization completion in 2024; and
- Net gain on early redemption of the US$400 million senior notes; partially offset by
- Higher interest on debt driven by the addition of the Heartland term facility.

Loss before income taxes for the three months ended Dec. 31, 2025 totalling $42 million, decreased by $9 million, or 18 per cent, compared to the same period in 2024, due to:

- The items noted above; partially offset by
- Realized foreign exchange loss on early redemption of the US$400 million senior notes; and
- Lower unrealized foreign exchange gains due to unfavourable changes in foreign exchange rates.

Income tax recovery for the three months ended Dec. 31, 2025 decreased by $6 million, or 75 per cent, compared to the same period in 2024 due to a decrease in loss before income taxes.

Net loss attributable to common shareholders for the three months ended Dec. 31, 2025 increased by $3 million, or 5 per cent, compared to the same period of 2024 due to the above noted items.

Year ended Dec. 31, 2025

Revenues totalled $2,405 million, a decrease of $440 million, or 15 per cent, compared to 2024, primarily due to:

- Lower Alberta and Mid-Columbia power prices;
- Higher dispatch optimization in the Gas segment driven by lower power prices in Alberta;
- Higher unrealized mark-to-market losses in the Wind and Solar, Gas and Energy Transition segments primarily related to unfavourable changes in forward prices; and
- Lower realized mark-to-market gains on settled trades in the Energy Marketing, Gas and Energy Transition segments; partially offset by
- The full year impact from the addition of the Heartland facilities in the fourth quarter of 2024;
- Higher revenues from the Sarnia gas facility in the current period as the facility experienced a planned outage during a portion of the fourth quarter in 2024; and
- The impact from the White Rock and Horizon Hill wind facilities which achieved commercial operation in the first half of 2024.

Fuel and purchased power costs totalled $935 million, which is comparable to 2024, primarily due to:

- Lower purchased power costs driven by higher availability in the Energy Transition segment; partially offset by
- The full year impact from the addition of the Heartland facilities in the fourth quarter of 2024;
- Higher natural gas prices;
- Higher production in the Energy Transition segment due to higher availability; and
- Higher production at the Sarnia gas facility in the fourth quarter of 2025 compared to the same period in 2024, when the facility experienced a planned outage during a portion of the fourth quarter in 2024.

Carbon compliance costs totalled $50 million, a decrease of $62 million, or 55 per cent, compared to 2024, primarily due to:

- Higher utilization of internally generated and externally purchased emission credits in the current period compared to the same period in 2024 to settle a portion of our GHG obligation and a portion of the 2024 GHG obligation assumed with the Heartland acquisition; and
- The favourable impact on carbon compliance costs due to increased production from lower-carbon-emitting cogeneration facilities; partially offset by
- The addition of carbon compliance costs from the Heartland facilities acquired in the fourth quarter of 2024; and

- An increase in the carbon price from $80 per tonne in 2024 to $95 per tonne in 2025.

OM&A expenses totalled $711 million, an increase of $56 million, or nine per cent, compared to 2024, primarily due to:

- The full year impact from the addition of the Heartland facilities in the fourth quarter of 2024 and associated corporate costs;
- Higher spending to support strategic and growth initiatives;
- Higher spending related to the planning, design and implementation of an upgrade to our ERP system; and
- The full year impact from the White Rock and Horizon Hill wind facilities which achieved commercial operation in the first half of 2024; partially offset by
- No penalties recognized in 2025 compared to 2024, when the Company recognized the penalties assessed by the Alberta Market Surveillance Administrator for Brazeau self-reported contraventions pertaining to hydro ancillary services provided during 2021 and 2022; and
- Lower acquisition-related transaction and restructuring costs.

Depreciation and amortization totalled $579 million, an increase of $48 million, or nine per cent, compared to 2024, primarily due to:

- The full year impact from the addition of the Heartland facilities in the fourth quarter of 2024; and
- The full year impact from the White Rock and Horizon Hill wind facilities which achieved commercial operation in the first half of 2024; partially offset by
- Revisions to the useful lives of certain gas facilities in the fourth quarter of 2024.

Asset impairment reversals totalled $13 million, an increase of $59 million compared to asset impairment charges in the same period in 2024, primarily due to:

- A change in decommissioning and restoration provisions driven by the revisions in estimated cash flows, timing of cash flows and discount rates, and higher impairment reversals related to generation equipment in the Energy Transition segment; partially offset by
- An impairment charge on Required Divestiture assets previously classified as Assets Held for Sale; and
- An impairment charge, net of impairment reversals, related to certain Wind and Solar facilities due to changes in expected production volumes and price assumptions.

Interest expense totalled $347 million, an increase of $23 million, or seven per cent, compared to 2024, primarily due to:

- Higher interest on debt driven by the addition of the Heartland term facility;
- No capitalized interest during 2025 due to lower construction activity compared to the same period in 2024; partially offset by
- Lower interest on debt due to the refinancing of senior notes at lower interest rates during 2025;
- Lower interest on exchangeable debentures due to the financing costs amortization completion in 2024; and
- Net gain on early redemption of the US$400 million senior notes.

Loss before income taxes totalled $141 million, an increase of $460 million, or 144 per cent from earnings before income taxes of $319 million for the same period in 2024, primarily due to:

- The items noted above;
- Realized foreign exchange loss on early redemption of the US$400 million senior notes; and
- Higher unrealized foreign exchange losses due to unfavourable changes in foreign currency rates.

Income tax expense totalled $17 million, a decrease of $63 million, or 79 per cent, compared to 2024, due to the increase in loss before income taxes, partially offset by a higher valuation allowance on U.S. operations.

Net loss attributable to non-controlling interests totalled $20 million an increase of $30 million from net earnings of $10 million for the same period in 2024, primarily due to lower net earnings for TA Cogen resulting from lower merchant pricing in the Alberta market.

Refer to the "Segment Financial Performance and Operating Results" section for additional information.

Adjusted EBITDA

For the three months ended Dec. 31, 2025, the Company's Adjusted EBITDA was $247 million compared to $282 million for the same period in 2024, a decrease of $35 million, or 12 per cent.

The major factors impacting Adjusted EBITDA for the three months ended Dec. 31, 2025 are summarized in the following table:

	3 months ended Dec. 31
Adjusted EBITDA[1] for the three months ended Dec. 31, 2024[2]	282
Hydro: Lower due to lower spot and ancillary services power prices in the Alberta market and lower merchant volumes in Alberta driven by lower market prices and water conservation.	(18)
Wind and Solar: Higher due to higher wind resource and availability across Canada and the U.S. and higher environmental and tax attributes revenues driven by an increase in sales of emission credits to third parties.	7
Gas: Lower primarily due to higher dispatch optimization driven by lower market prices, lower spot power prices in the Alberta market, lower hedge power prices compared to the same period in 2024 and an increase in the carbon price, partially offset by the positive contribution from the addition of the Heartland facilities, higher production at the Sarnia gas facility due to higher availability compared to the same period in 2024, when the facility experienced a planned outage during a portion of the quarter, and favourable hedge positions settled, which generated positive contributions over settled spot prices in Alberta.	(20)
Energy Transition: Lower primarily due to lower Mid-Columbia power prices, partially offset by lower purchased power costs due to fewer repurchases to fulfil contractual obligations during outages and favourable hedge positions settled, which generated positive contributions over settled spot prices.	(10)
Energy Marketing: Lower primarily due to comparatively subdued market volatility across North American natural gas and power markets and lower realized gains.	(5)
Corporate: Higher primarily due to lower incentive costs, partially offset by the addition of corporate costs related to Heartland.	11
Adjusted EBITDA[1] for the three months ended Dec. 31, 2025	**247**

(1) Adjusted EBITDA is a non-IFRS measure. Refer to the "Non-IFRS and Supplementary Financial Measures" section of this MD&A. The most directly comparable IFRS measure is loss before income taxes of $42 million for the three months ended Dec. 31, 2025 ($51 million for the three months ended Dec. 31, 2024). Refer to the "Reconciliation of Non-IFRS Measures on a Consolidated Basis by Segments" section of this MD&A.

(2) During the first quarter of 2025, our Adjusted EBITDA composition was amended to exclude the impact of realized gain (loss) on closed exchange positions and Australian interest income. The Company has therefore applied this composition to all previously reported periods. Refer to the "Non-IFRS and Supplementary Financial Measures" section of this MD&A for more details.

For the year ended Dec. 31, 2025, the Company's Adjusted EBITDA was $1,104 million compared to $1,255 million in 2024, a decrease of $151 million, or 12 per cent.

The major factors impacting Adjusted EBITDA for the year ended Dec. 31, 2025 are summarized in the following table:

	Year ended Dec. 31
Adjusted EBITDA[(1)] for the year ended Dec. 31, 2024[(2)]	1,255
Hydro: Lower primarily due to lower spot and ancillary services power prices in the Alberta market, partially offset by higher merchant and contract volumes, higher volume of favourable hedge positions settled (which generated positive contributions over settled spot prices in Alberta), higher regulated transmission revenues related to the reimbursement of costs incurred in prior periods and higher environmental and tax attributes revenue due to increased intercompany sales of emission credits to the Gas segment to fulfil our 2024 GHG obligation.	(31)
Wind and Solar: Higher primarily due to the positive contribution from the impact of the White Rock and Horizon Hill wind facilities, which achieved commercial operation in the first half of 2024; higher environmental and tax attributes revenue due to increased sales of emission credits to third parties and intercompany sales to the Gas segment; and higher production volumes due to higher availability across the fleet and higher wind resource in Eastern Canada and the U.S.; partially offset by lower Alberta spot power prices, lower wind resource in Alberta and lower liquidated damages recognized at various wind facilities.	22
Gas: Lower primarily due to higher dispatch optimization driven by lower market prices, lower spot power prices in the Alberta market, lower hedge power prices compared to the same period in 2024, higher natural gas prices and an increase in the carbon price, partially offset by the positive contributions from the addition of the Heartland facilities, favourable hedge positions settled (which generated positive contributions over settled spot prices in Alberta and the reduction of carbon compliance costs driven by using internally generated and externally purchased emission credits to settle a portion of our GHG obligation and a portion of the 2024 GHG obligation assumed in the Heartland acquisition) and an increase of production from lower carbon-emitting cogeneration facilities.	(86)
Energy Transition: Higher primarily due to lower purchased power costs driven by higher availability and favourable hedge positions settled, which generated positive contributions over settled spot prices, partially offset by lower revenue due to lower Mid-Columbia prices and higher OM&A related to community fund spending.	11
Energy Marketing: Lower primarily due to comparatively subdued market volatility across North American natural gas and power markets and lower realized gains in 2025 compared to 2024.	(61)
Corporate: Lower primarily due to increased spending to support strategic and growth initiatives and the addition of corporate costs related to Heartland, partially offset by cost saving initiatives.	(6)
Adjusted EBITDA[(1)] for the year ended Dec. 31, 2025	**1,104**

(1) Adjusted EBITDA is a non-IFRS measure. Refer to the "Non-IFRS and Supplementary Financial Measures" section of this MD&A. The most directly comparable IFRS measure is loss before income taxes of $141 million for the year ended Dec. 31, 2025 (earnings before income taxes were $319 million for the year ended Dec. 31, 2024). Refer to "Reconciliation of Non-IFRS Measures on a Consolidated Basis by Segments" section of this MD&A.

(2) During the first quarter of 2025, our Adjusted EBITDA composition was amended to exclude the impact of realized gain (loss) on closed exchange positions and Australian interest income. The Company has therefore applied this composition to all previously reported periods. Refer to the "Non-IFRS and Supplementary Financial Measures" section of this MD&A for more details.

Free Cash Flow

For the three months ended Dec. 31, 2025, the Company's free cash flow (FCF) increased by $47 million, or 102 per cent, compared to the same period in 2024.

The major factors impacting FCF for the three months ended Dec. 31, 2025 are summarized in the following table:

	3 months ended Dec. 31
FCF[1] for the three months ended Dec. 31, 2024.	46
Lower Adjusted EBITDA[2] due to the items noted above.	(35)
Higher current income tax recovery due to the higher loss before income taxes in 2025.	28
Lower sustaining capital expenditures[3] due to lower major maintenance for our Canadian gas facilities and lower major maintenance at our Hydro facilities in Alberta due to timing of spend.	22
Higher provisions settled, resulting in lower FCF.	(8)
Lower realized foreign exchange losses from operating activities.	20
Other[4]	6
Other non-cash items[5]	14
FCF[1] for the three months ended Dec. 31, 2025	**93**

(1) FCF is a non-IFRS measure, is not defined and has no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the "Non-IFRS and Supplementary Financial Measures" section of this MD&A for more information regarding this measure. The most directly comparable IFRS measure is cash flow from operating activities, which was $231 million and $215 million for the three months ended Dec. 31, 2025 and 2024, respectively. Refer to the "Cash Flows" section of this MD&A.

(2) During the first quarter of 2025, our Adjusted EBITDA composition was amended to exclude the impact of realized gain (loss) on closed exchange positions and Australian interest income. The Company has therefore applied this composition to all previously reported periods. Refer to the "Non-IFRS and Supplementary Financial Measures" section of this MD&A.

(3) Sustaining capital expenditures is a supplementary financial measure. Refer to "Capital Expenditures" section of this MD&A for more information regarding this measure.

(4) Other consists primarily of lower decommissioning and restoration costs settled, lower Net Interest Expense, and lower dividends paid on preferred shares, partially offset by higher loan advances and higher distributions paid to subsidiaries' non-controlling interests relating to TA Cogen.

(5) Other non-cash items primarily consist of changes in deferred payments, contract assets and liabilities, onerous contracts and long-term incentive accruals.

For the year ended Dec. 31, 2025, the Company's FCF decreased by $61 million, or 11 per cent, compared to 2024, but was within the range of our expected full-year financial guidance.

The major factors impacting FCF for the year ended Dec. 31, 2025 are summarized in the following table:

	Year ended Dec. 31
FCF[1] for the year ended Dec. 31, 2024	575
Lower Adjusted EBITDA[2] due to the items noted above.	(151)
Lower current income tax expense due to loss before income taxes in 2025 compared to earnings before income taxes in the same period in 2024.	94
Higher Net Interest Expense[3] due to higher interest on debt primarily driven by the addition of the Heartland term facility and lower capitalized interest resulting from lower construction activity compared to the same period in 2024.	(33)
Lower distributions paid to subsidiaries' non-controlling interests relating to lower TA Cogen net earnings resulting from lower merchant pricing in the Alberta market.	29
Higher provisions settled in the current year compared to the prior year, resulting in lower FCF.	(14)
Higher sustaining capital expenditures due to higher major maintenance at our Canadian gas facilities due to timing of spend and the addition of maintenance for the gas facilities acquired from Heartland, and higher major maintenance in the Wind and Solar segment, partially offset by no major maintenance occurring in the Energy Transition segment in the current period and lower major maintenance at our Hydro facilities in Alberta due to timing of spend. In addition, the first quarter of 2024 was impacted by the receipt of a lease incentive related to the Company's head office.	(20)
Lower realized foreign exchange losses from operating activities.	27
Other non-cash items[4]	8
Other[5]	(1)
FCF[1] for the year ended Dec. 31, 2025	**514**

(1) FCF is a non-IFRS measure, is not defined and has no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the "Non-IFRS and Supplementary Financial Measures" section of this MD&A for more information regarding this measure. The most directly comparable IFRS measure is cash flow from operating activities, which was $646 million and $796 million for the years ended Dec. 31, 2025 and 2024, respectively. Refer to the "Cash Flows" section of this MD&A.

(2) During the first quarter of 2025, our Adjusted EBITDA composition was amended to exclude the impact of realized gain (loss) on closed exchange positions and Australian interest income. The Company has therefore applied this composition to all previously reported periods. Refer to the "Non-IFRS and Supplementary Financial Measures" section of this MD&A.

(3) Net Interest Expense is a non-IFRS measure, is not defined and has no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to "Non-IFRS and Supplementary Financial Measures" section of this MD&A for more information regarding this measure. The most directly comparable IFRS measure is interest expense of $347 million for the year ended Dec. 31, 2025 (Dec. 31, 2024 — $324 million).

(4) Other non-cash items primarily consist of changes in deferred payments, contract assets and liabilities, onerous contracts and long-term incentive accruals.

(5) Other primarily consists of lower decommissioning and restoration costs settled and lower principal payments on lease liabilities, partially offset by higher loan advances.

2026 Outlook

For 2026, the Company expects Adjusted EBITDA to be in the range of $950 million to $1,050 million and FCF to be in the range of $350 million to $450 million, based on the following expectations:

- Lower contribution from the Energy Transition segment due to the Centralia facility ceasing dispatchable coal-fired generation at the end of 2025;
- Lower contribution from the Alberta merchant gas portfolio as a result of lower average hedge prices and higher fuel costs, partially offset by lower carbon compliance costs due to a higher utilization of internally generated low-cost environmental credits;
- Lower contributions from Sarnia, reflecting a step down in contracted pricing and the expiry of the contract and decommissioning of the Ada Cogeneration facility;
- Higher contributions within the Hydro, Gas and Wind and Solar segments due to the expected realization of carbon credits against in-year, in addition to 2025, carbon compliance costs in Alberta;
- Higher contributions from the Gas segment due to the acquisition of the Far North Ontario gas facilities;
- Higher contributions from the Wind and Solar segment as a result of higher expected production;
- Higher income tax expense; and
- Lower Net Interest Expense as a result of lower interest rates on refinanced debt and lower interest on non-recourse debt as a result of amortizing repayments.

The following table outlines our expectations on key financial targets and related assumptions for 2026 and should be read in conjunction with the narrative discussion that follows and the "Risk Management" section of this MD&A:

Measure	2026 Target(2)	2025 Target	2025 Actual(3)
Adjusted EBITDA(1)	$950 million to $1,050 million	$1,150 million to $1,250 million	$1,104 million
FCF(1)	$350 million to $450 million	$450 million to $550 million	$514 million
FCF per share(1)	$1.18 to $1.51	$1.51 to $1.85	$1.73
Dividend per share	$0.28 annualized	$0.26 annualized	$0.26 annualized

(1) These are non-IFRS measures, which are not defined and have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the "Reconciliation of Non-IFRS Measures" section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS. See also the "Non-IFRS and Supplementary Financial Measures" section of this MD&A.

(2) Represents forward-looking information.

(3) The actual 2025 amounts for the most directly comparable IFRS measures for Adjusted EBITDA and FCF were as follows: Loss before income taxes of $141 million and Cash flow from operating activities of $646 million. The most directly comparable IFRS ratio to FCF per share is cash flow from operating activities per share of $2.18, which is calculated as cash flow from operating activities for the period divided by the weighted average number of common shares outstanding during the period. Refer to the "Non-IFRS and Supplementary Financial Measures" section of the MD&A for additional information.

The Company's outlook for 2026 may be impacted by a number of factors as detailed further below.

Range of key 2026 power and gas price assumptions

Market	2026 Assumptions	2025 Assumptions	2025 Actual
Alberta spot ($/MWh)	$40 to $60	$40 to $60	$44
AECO gas price ($/GJ)	$2.65 to $3.15	$1.60 to $2.10	$1.61

Alberta spot price sensitivity: a +/- $1 per MWh change in spot price is expected to have a +/- $2 million impact on Adjusted EBITDA for 2026.

Other assumptions relevant to the 2026 outlook

Measure	2026 Expectations	2025 Expectations	2025 Actual
Energy Marketing Adjusted Revenues(1)	$110 million to $130 million	$110 million to $130 million	$122 million
Sustaining capital expenditures(2)	$140 million to $160 million	$145 million to $165 million	$162 million
Current income tax expense	$70 million to $100 million	$95 million to $130 million	$49 million
Net Interest Expense(1)	$240 million to $260 million	$255 million to $275 million	$264 million

(1) Energy Marketing Adjusted Revenues and Net Interest Expense are non-IFRS measures, are not defined, have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. The most directly comparable IFRS measure to Energy Marketing Adjusted Revenues is revenues of $130 million for the year ended Dec. 31, 2025 and to Net Interest Expense — interest expense of $347 million for the year ended Dec. 31, 2025.

(2) Sustaining capital expenditures is a supplementary financial measure. Refer to "Capital Expenditures" section of this MD&A for more information regarding this measure.

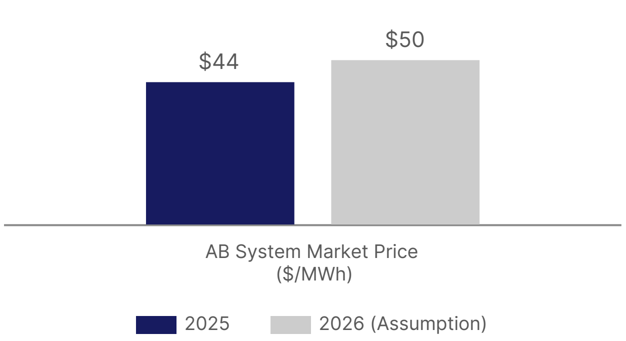
Alberta Hedging

Range of hedging assumptions	Q1 2026	Q2 2026	Q3 2026	Q4 2026	2027
Hedged production (GWh)	2,302	1,990	2,172	2,027	3,967
Hedge price ($/MWh)	$65	$65	$65	$65	$71
Hedged gas amounts (GJ)	12 million	7 million	8 million	7 million	19 million
Hedge gas prices ($/GJ)	$3.21	$3.33	$3.29	$3.39	$3.04

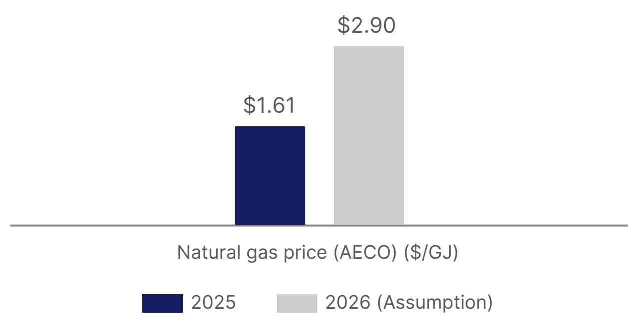
Market Pricing

The following graphs include 2026 pricing assumptions and are subject to change:

Annual Average Spot Electricity Prices



Annual Average Gas (AECO) Prices



For 2026, spot electricity prices in Alberta are expected to be higher compared to 2025, driven by ongoing load growth and slowing additions of new supply in the province. Where power prices settle in relationship to 2025 prices, will ultimately depend on actual weather conditions.

AECO natural gas prices are expected to be higher than in 2025.

The objective of our portfolio management strategy in Alberta is to balance opportunity and risk and to deliver optimization strategies that contribute to our total investment, which includes a return on invested capital. We can be more or less hedged in a given period, and we expect to realize our annual targets through a combination of forward hedging and selling generation into the spot market. The assets within the Alberta electricity portfolio are managed as a portfolio to maximize the overall value of generation and capacity from our hydro, wind, energy storage and thermal facilities. Hedging is a key component of cash flow certainty and the hedges are primarily tied to our portfolio of gas facilities and also allocated to our portfolio of hydro facilities rather than a single facility.

Sustaining Capital Expenditures

Our estimate for total sustaining capital is as follows:

	Expected spend in 2026	Spent in 2025
Total sustaining capital	$140 million to $160 million	$162 million

The Company expects sustaining capital to be in the range of $140 million to $160 million in 2026. The Gas segment is expected to incur higher sustaining capital related to planned major maintenance, offset by lower spend in the Hydro segment.

Liquidity and Capital Resources

We maintain adequate available liquidity under our committed credit facilities. As at Dec. 31, 2025, we had access to $1.5 billion in liquidity, including $205 million in cash, which exceeds the funds required for committed growth, sustaining capital and productivity projects.

Segmented Financial Performance and Operating Results

Segmented information is prepared on the same basis that the Company manages its business, evaluates financial results and makes key operating decisions. The following table reflects the summary financial information on a consolidated basis for the three months and year ended Dec. 31:

	3 months ended Dec. 31,		Year ended Dec. 31	
	2025	2024	2025	2024
Hydro	39	57	285	316
Wind and Solar	102	95	338	316
Gas	96	116	438	524
Energy Transition	16	26	100	89
Energy Marketing	21	26	85	146
Corporate	(27)	(38)	(142)	(136)
Total Adjusted EBITDA(1)(2)	247	282	1,104	1,255
Adjusted Earnings before income taxes(1)	14	38	181	396
(Loss) earnings before income taxes	(42)	(51)	(141)	319
Adjusted Net (Loss) Earnings Attributable to Common Shareholders(1)	(19)	3	57	236
Net (loss) earnings attributable to common shareholders	(62)	(65)	(190)	177

(1) These are non-IFRS measures, which are not defined, have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the "Non-IFRS and Supplementary Financial Measures" section of this MD&A for more information regarding these measures. The most directly comparable IFRS measure to Adjusted EBITDA and Adjusted Earnings before income taxes is (loss) earnings before income taxes. The most directly comparable IFRS measure to Adjusted Net (Loss) Earnings Attributable to Common Shareholders is Net (loss) earnings attributable to common shareholders. Refer to "Reconciliation of Non-IFRS Measures on a Consolidated Basis by Segments" section of this MD&A.

(2) During the first quarter of 2025, our Adjusted EBITDA composition was amended to exclude the impact of realized gain (loss) on closed exchange positions and Australian interest income. Therefore, the Company has applied this composition to all previously reported periods. Refer to the "Non-IFRS and Supplementary Financial Measures" section of this MD&A.

Three months ended Dec. 31, 2025

Adjusted Earnings before income taxes for the three months ended Dec. 31, 2025 decreased by $24 million, or 63 per cent, from Adjusted Earnings before income taxes for the same period in 2024, primarily due to:

- The factors causing lower Adjusted EBITDA described in the "Adjusted EBITDA" section of this MD&A; and
- Higher depreciation due to the addition of the Heartland gas facilities in December 2024; partially offset by
- Lower interest expense as explained in the Corporate segment of the "Segmented Financial Performance and Operating Results" section of this MD&A.

Adjusted Net Loss attributable to common shareholders for the three months ended Dec. 31, 2025 increased by $22 million from Adjusted Earnings Attributable to Common Shareholders for the same period in 2024, primarily due to:

- The factors causing higher Adjusted Earnings before Income Taxes described above; and
- Lower calculated tax expense on adjustments and reclassifications compared to the same period in 2024; partially offset by
- Lower income tax recovery compared to the same period in 2024 due to a decrease in loss before income taxes.

Loss before income taxes for the three months ended Dec. 31, 2025, decreased by $9 million, or 18 per cent, compared to the same period in 2024. Net loss attributable to common shareholders for the three months ended Dec. 31, 2025, decreased by $3 million compared to the same period in 2024. For an explanation of the variance and reconciliation to the most directly comparable IFRS measure refer to the "Financial Performance Review of Consolidated Information" and "Non-IFRS and Supplementary IFRS Measures" sections of this MD&A, respectively.

Year ended Dec. 31, 2025

Adjusted Earnings before income taxes for the year ended Dec. 31, 2025 decreased by $215 million, or 54 per cent, compared to the same period in 2024, primarily due to:

- The factors causing lower Adjusted EBITDA described in the "Adjusted EBITDA" section of this MD&A;
- Higher depreciation and amortization due to the addition of the Heartland gas facilities in December 2024 and the full-year impact from the White Rock and Horizon Hill wind facilities which achieved commercial operation in the first half of 2024; and
- Higher interest expense as explained in the "Financial Performance Review of Consolidated Information" and Corporate segment of the "Segmented Financial Performance and Operating Results" section of this MD&A.

Adjusted Net Earnings Attributable to Common Shareholders for the year ended Dec. 31, 2025 decreased by $179 millions, or 76 per cent, compared to the same period in 2024, primarily due to:

- The factors causing lower Adjusted Earnings before Income Taxes described above; partially offset by
- Lower income tax expense due to a higher loss before income taxes compared to earnings before income taxes in the same period in 2024, partially offset by higher valuation allowance on U.S. operations; and
- Higher net loss attributable to non-controlling interests compared to net earnings in the same period of 2024.

Loss before income taxes for the year ended Dec. 31, 2025, increased by $460 million, or 144 per cent, from earnings before income taxes in 2024. Net loss attributable to common shareholders for the year ended Dec. 31, 2025, increased by $367 million compared to net earnings attributable to common shareholders in 2024. For an explanation of the variance and reconciliation to the most directly comparable IFRS measure refer to the "Financial Performance Review of Consolidated Information and Non-IFRS" and "Supplementary IFRS Measures" sections of this MD&A, respectively.

Hydro

	3 months ended Dec. 31				Year ended Dec. 31			
	2025	2024	Change		2025	2024	Change	
Gross installed capacity (MW)	922	922	—	— %	922	922	—	— %
LTA generation (GWh)	447	447	—	— %	2,015	2,015	—	— %
Availability (%)	94.4	85.8	8.6	10 %	92.0	90.7	1.3	1 %
Production								
Contract production (GWh)	70	85	(15)	(18)%	346	281	65	23 %
Merchant production (GWh)	266	367	(101)	(28)%	1,568	1,442	126	9 %
Total energy production (GWh)	336	452	(116)	(26)%	1,914	1,723	191	11 %
Ancillary service volumes (GWh)[(1)]	761	713	48	7 %	2,934	2,951	(17)	(1)%
Alberta Hydro Assets ancillary services revenues[(1)]	27	28	(1)	(4)%	112	136	(24)	(18)%
Alberta Hydro Assets revenues[(2)]	22	33	(11)	(33)%	125	144	(19)	(13)%
Other Hydro Assets revenues and other Hydro revenues[(3)]	11	16	(5)	(31)%	57	49	8	16 %
Environmental and tax attributes revenues	—	—	—	— %	70	61	9	15 %
Adjusted Revenues[(4)]	60	77	(17)	(22)%	364	390	(26)	(7)%
Fuel and purchased power	(4)	(3)	(1)	33 %	(20)	(16)	(4)	25 %
Adjusted Gross Margin[(4)]	56	74	(18)	(24)%	344	374	(30)	(8)%
Adjusted OM&A[(4)]	(16)	(16)	—	— %	(56)	(55)	(1)	2 %
Taxes, other than income taxes	(1)	(1)	—	— %	(3)	(3)	—	— %
Adjusted EBITDA[(4)]	39	57	(18)	(32)%	285	316	(31)	(10)%
Depreciation and amortization	(12)	(18)	6	(33)%	(38)	(41)	3	(7)%
Adjusted Earnings before Income Taxes[(4)]	27	39	(12)	(31)%	247	275	(28)	(10)%
Earnings before income taxes	25	24	1	4 %	251	263	(12)	(5)%
Supplementary Information: Gross revenues per MWh								
Alberta Hydro Assets revenues ($/MWh)[(2)]	83	90	(7)	(8)%	79	100	(21)	(21)%
Alberta Hydro Assets ancillary services revenues ($/MWh)[(1)]	35	39	(4)	(10)%	38	46	(8)	(17)%

(1) Alberta Hydro Assets ancillary services revenues is a supplementary financial measure. Alberta Hydro Assets ancillary services revenues are revenues earned from providing services required to ensure that the interconnected electric system is operated in a manner that provides a satisfactory level of service with acceptable levels of voltage and frequency as described in the AESO Consolidated Authoritative Document Glossary. Revenues per MWh are calculated by dividing Alberta Hydro Assets ancillary services revenues by ancillary service volumes in MWh.

(2) Alberta Hydro Assets revenues is a supplementary financial measure and is comprised of revenues from 13 hydro facilities on the Bow and North Saskatchewan river systems, as well as revenues from swaps and forward hedges. Revenues per MWh are calculated by dividing Alberta Hydro Assets revenues by merchant production in MWh.

(3) Other Hydro Assets revenues is a supplementary financial measure and consists of revenues from our hydro facilities in British Columbia, Ontario and Alberta (other than the Alberta Hydro Assets). Other Hydro revenues is a supplementary financial measure and includes revenues from our transmission business and other contractual arrangements, including the flood mitigation agreement with the Government of Alberta and black start services.

(4) Adjusted Revenues, Adjusted Gross Margin, Adjusted OM&A, Adjusted EBITDA and Adjusted Earnings before Income Taxes are non-IFRS measures, are not defined and have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the "Non-IFRS and Supplementary Financial Measures" section of this MD&A for more information regarding these measures. The most directly comparable IFRS measure to Adjusted Revenues is revenues of $58 million and $368 million for the three months and year ended Dec. 31, 2025, respectively (Dec. 31, 2024 — $93 million and $409 million), to Adjusted Gross Margin — gross margin of $54 million and $348 million for the three months and year ended Dec. 31, 2025, respectively (Dec. 31, 2024 — $90 million and $393 million), to Adjusted OM&A - OM&A of $16 million and $56 million the three months and year ended Dec. 31, 2025, respectively (Dec. 31, 2024 — $47 million and $86 million), to Adjusted EBITDA and Adjusted Earnings before Income Taxes — earnings before income taxes of $25 million and $251 million for the three months and year ended Dec. 31, 2025, respectively (Dec. 31, 2024 — $24 million and $263 million).

Three months ended Dec. 31, 2025

Adjusted Revenues for the three months ended Dec. 31, 2025 decreased compared to the same period in 2024, primarily due to:

- Lower spot and ancillary services power prices in the Alberta market; and
- Lower merchant volumes in Alberta due to lower market prices and water conservation.

Adjusted EBITDA and Adjusted Earnings before income taxes for the three months ended Dec. 31, 2025, decreased compared to the same period in 2024, primarily due to lower Adjusted Revenues as explained by the factors above.

Earnings before income taxes for the three months ended Dec. 31, 2025 were consistent compared to the same period in 2024 primarily due to:

- No penalties recognized in the current period compared to the same period in 2024, when the Company recognized the penalties assessed by the Alberta Market Surveillance Administrator for self-reported contraventions pertaining to Brazeau hydro ancillary services provided during 2021 and 2022; partially offset by
- Lower Adjusted Earnings before income taxes.

Year ended Dec. 31, 2025

Adjusted Revenues for the year ended Dec. 31, 2025, decreased compared to 2024, primarily due to:

- Lower spot and ancillary services power prices in the Alberta market; partially offset by
- Higher merchant and contract volumes;
- Higher volume of favourable hedge positions settled, which generated positive contributions over settled spot prices in Alberta;
- Higher regulated transmission revenues related to the reimbursement of costs incurred in prior periods; and
- Higher environmental and tax attributes revenues due to increased intercompany sales of emission credits to the Gas segment to fulfil our GHG obligation.

Adjusted EBITDA and Adjusted Earnings before income taxes for the year ended Dec. 31, 2025 decreased compared to 2024, primarily due to lower Adjusted Revenues as explained by the factors above.

Earnings before income taxes for the year ended Dec. 31, 2025 decreased compared to 2024 primarily due to:

- Lower Adjusted Earnings before income taxes; partially offset by
- No penalties recognized in 2025 compared to 2024, when the Company recognized the penalties assessed by the Alberta Market Surveillance Administrator for self-reported contraventions pertaining to Brazeau hydro ancillary services provided during 2021 and 2022.

For further discussion on Alberta market conditions and pricing, refer to the "Optimization of Alberta Portfolio" section of this MD&A.

Wind and Solar

	3 months ended Dec. 31				Year ended Dec. 31			
	2025	2024	Change		2025	2024	Change	
Gross installed capacity (MW)	2,587	2,587	—	— %	2,587	2,587	—	— %
LTA generation (GWh)	2,175	2,175	—	— %	7,457	6,876	581	8 %
Availability (%)	94.6	92.2	2.4	3 %	94.4	93.4	1.0	1 %
Production								
Contract production (GWh)	1,651	1,469	182	12 %	5,450	4,720	730	15 %
Merchant production (GWh)	357	362	(5)	(1)%	1,004	1,229	(225)	(18)%
Total production (GWh)	2,008	1,831	177	10 %	6,454	5,949	505	8 %
Adjusted Revenues(1)	120	114	6	5 %	394	372	22	6 %
Environmental and tax attributes revenues(1)	23	16	7	44 %	106	77	29	38 %
Adjusted Revenues(2)(3)	143	130	13	10 %	500	449	51	11 %
Fuel and purchased power	(7)	(8)	1	(13)%	(31)	(30)	(1)	3 %
Carbon compliance costs	(1)	—	(1)	— %	(3)	—	(3)	— %
Adjusted Gross Margin(2)(3)	135	122	13	11 %	466	419	47	11 %
OM&A	(24)	(27)	3	(11)%	(106)	(97)	(9)	9 %
Taxes, other than income taxes	(8)	(3)	(5)	167 %	(23)	(16)	(7)	44 %
Adjusted Net Other Operating (Expense) Income (3)	(1)	3	(4)	(133)%	1	10	(9)	(90)%
Adjusted EBITDA(2)(3)	102	95	7	7 %	338	316	22	7 %
Depreciation and amortization	(52)	(55)	3	(5)%	(209)	(198)	(11)	6 %
Adjusted Earnings before Income Taxes(2)(3)	50	40	10	25 %	129	118	11	9 %
(Loss) earnings before income taxes(4)	(38)	12	(50)	(417)%	(165)	19	(184)	(968)%

(1) Production Tax Credits related to the U.S. wind facilities that are subject to tax equity financing arrangements are excluded from the Environmental and tax attributes revenues line and are included under Adjusted Revenues line.

(2) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.

(3) Adjusted Revenues, Adjusted Gross Margin, Adjusted Net Other Operating Income, Adjusted EBITDA and Adjusted Earnings before Income Taxes are non-IFRS measures, are not defined and have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the "Non-IFRS and Supplementary Financial Measures" section of this MD&A for more information regarding these measures. The most directly comparable IFRS measure to Adjusted Revenues is revenues of $51 million and $206 million for the three months and year ended Dec. 31, 2025, respectively (Dec. 31, 2024 — $97 million and $336 million), to Adjusted Gross Margin — gross margin of $43 million and $172 million for the three months and year ended Dec. 31, 2025, respectively (Dec. 31, 2024— $89 million and $306 million), to Adjusted Net Other Operating (Expense) Income — net other operating expense of $1 million and income of $3 million for the three months and year ended Dec. 31, 2025, respectively (Dec. 31, 2024 — net other operating income of $3 million and $10 million), to Adjusted EBITDA and Adjusted Earnings before Income Taxes — loss before income taxes of $38 million and $165 million for the three months and year ended Dec. 31, 2025, respectively (Dec. 31, 2024 — earnings before income taxes of $12 million and $19 million).

(4) (Loss) earnings before income taxes exclude the contribution from Skookumchuck wind facility.

Three months ended Dec. 31, 2025

Adjusted Revenues for the three months ended Dec. 31, 2025 increased compared to the same period in 2024, primarily due to:

- Higher wind resource and availability across Canada and the U.S.; and
- Higher environmental and tax attributes revenue driven by an increase in sales of emission credits to third parties.

Adjusted EBITDA and Adjusted Earnings before income taxes for the three months ended Dec. 31, 2025 increased compared to the same period in 2024, primarily due to higher Adjusted Revenues as explained by the factors above.

Loss before income taxes for the three months ended Dec. 31, 2025 increased from earnings before income taxes for the same period in 2024 primarily due to:

- Higher unrealized mark-to-market losses on the long-term wind energy sales related to the Oklahoma facilities; partially offset by
- Higher Adjusted Earnings before income taxes;

Year ended Dec. 31, 2025

Adjusted Revenues for the year ended Dec. 31, 2025, increased compared to 2024, primarily due to:

- The impact from the White Rock and Horizon Hill wind facilities which achieved commercial operation in the first half of 2024;
- Higher environmental and tax attributes revenues due to the increased sales of emission credits to third parties and intercompany sales to the Gas segment; and
- Higher production volumes due to higher availability across the fleet and higher wind resource in Eastern Canada and the U.S.; partially offset by
- Lower Alberta spot power prices; and
- Lower production volumes in Alberta due to lower wind resource.

Adjusted EBITDA for the year ended Dec. 31, 2025 increased compared to 2024, primarily due to:

- Higher Adjusted Revenues as explained by the factors above; partially offset by
- Higher OM&A and taxes, other than income taxes, due to the addition of new wind facilities in the first half of 2024; and
- Lower liquidated damages recognized at various wind facilities.

Adjusted Earnings before income taxes for the year ended Dec. 31, 2025 increased compared to 2024, primarily due to:

- Higher Adjusted EBITDA; partially offset by
- Higher depreciation and amortization due to the addition of new wind facilities in the first half of 2024.

Loss before income taxes for the year ended Dec. 31, 2025 increased from earnings before income taxes in 2024 due to:

- Higher unrealized mark-to-market losses on the long-term wind energy sales related to the Garden Plain and Oklahoma facilities, partially offset by unrealized mark-to-market gains related to the Big Level facility; and
- Higher impairment charges, net of reversals, recognized for certain facilities due to changes in expected production volumes and lower power price assumptions; partially offset by
- Higher Adjusted Earnings before income taxes as explained above.

Gas

	3 months ended Dec. 31,				Year ended Dec. 31			
	2025	2024	Change		2025	2024	Change	
Gross installed capacity (MW)	4,834	4,834	—	— %	4,834	4,834	—	— %
Availability (%)	85.9	84.1	1.8	2 %	91.8	92.2	(0.4)	— %
Production								
Contract sales volume (GWh)	2,455	1,932	523	27 %	9,539	6,874	2,665	39 %
Merchant sales volume (GWh)	1,292	1,387	(95)	(7)%	4,566	6,576	(2,010)	(31)%
Purchased power (GWh)(1)	(248)	(444)	196	(44)%	(1,102)	(1,133)	31	(3)%
Total production (GWh)	3,499	2,875	624	22 %	13,003	12,317	686	6 %
Adjusted Revenues(2)	359	351	8	2 %	1,328	1,314	14	1 %
Adjusted Fuel and Purchased Power(2)	(161)	(135)	(26)	19 %	(547)	(474)	(73)	15 %
Carbon compliance costs	(39)	(39)	—	— %	(115)	(145)	30	(21)%
Adjusted Gross Margin(2)	159	177	(18)	(10)%	666	695	(29)	(4)%
Adjusted OM&A(2)	(68)	(67)	(1)	1 %	(251)	(198)	(53)	27 %
Taxes, other than income taxes	(6)	(4)	(2)	50 %	(21)	(13)	(8)	62 %
Net other operating income	11	10	1	10 %	44	40	4	10 %
Adjusted EBITDA(2)(3)	96	116	(20)	(17)%	438	524	(86)	(16)%
Depreciation and amortization	(69)	(49)	(20)	41 %	(266)	(212)	(54)	25 %
Adjusted Earnings before Income Taxes(2)	27	67	(40)	(60)%	172	312	(140)	(45)%
Earnings before income taxes	15	37	(22)	(59)%	120	355	(235)	(66)%

(1) Power required to fulfil contractual obligations is included in purchased power.

(2) Adjusted Revenues, Adjusted Fuel and Purchased Power, Adjusted Gross Margin, Adjusted OM&A, Adjusted EBITDA and Adjusted Earnings before Income Taxes are non-IFRS measures, are not defined and have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. The most directly comparable IFRS measure to Adjusted Revenues is revenues of $347 million and $1,267 million for the three months and year ended Dec. 31, 2025, respectively (Dec. 31, 2024 — 319 million and $1,350 million), to Adjusted Fuel and Purchased Power — fuel and purchased power of $161 million and $549 million for the three months and year ended Dec. 31, 2025, respectively (Dec. 31, 2024 — $134 million and $475 million), to Adjusted Gross Margin — gross margin of $147 million and $603 million for the three months and year ended Dec. 31, 2025, respectively (Dec. 31, 2024 — $146 million and $730 million), to Adjusted OM&A — OM&A of $69 million and $257 million for the three months and year ended Dec. 31, 2025, respectively (Dec. 31, 2024 — $67 million and $198 million), to Adjusted EBITDA and Adjusted Earnings before Income Taxes — loss before income taxes of $15 million and earnings before income taxes of $120 million for the three months and year ended Dec. 31, 2025, respectively (Dec. 31, 2024 — earnings before income taxes of $37 million and $355 million).

(3) During the first quarter of 2025, our Adjusted EBITDA composition was amended to exclude the impact of realized gain (loss) on closed exchange positions and Australian interest income. Therefore, the Company has applied this composition to all previously reported periods. Refer to the "Non-IFRS and Supplementary Financial Measures" section of this MD&A.

Three months ended Dec. 31, 2025

Adjusted Revenues for the three months ended Dec. 31, 2025 are comparable to the same period in 2024, primarily due to:

- The addition of the Heartland facilities;
- Higher production at the Sarnia gas facility due to higher availability compared to the same period in 2024, when the facility experienced a planned outage during a portion of the quarter; and
- Favourable hedge positions settled, which generated positive contributions over settled spot prices in Alberta; partially offset by
- Higher dispatch optimization due to lower market prices driven by milder weather and new gas generation in Alberta; and
- Lower spot power prices in the Alberta market and lower hedge power prices compared to the same period in 2024.

Adjusted EBITDA for the three months ended Dec. 31, 2025 decreased compared to the same period in 2024, primarily due to:

- Higher fuel costs, carbon compliance cost and OM&A related to the addition of the Heartland facilities;

- Higher fuel costs due to higher production at the Sarnia gas facility as the facility experienced a planned outage during a portion of the quarter in 2024; and
- An increase in the carbon price from $80 to $95 per tonne, impacting gross margin from our Canadian gas facilities; partially offset by
- Favourable impact on carbon compliance cost due to an increase of production from lower-carbon-emitting cogeneration facilities.

Adjusted Earnings before income taxes for the three months ended Dec. 31, 2025 decreased compared to the same period in 2024 due to:

- Lower Adjusted EBITDA as explained above; and
- Higher depreciation due to the full quarter impact from the addition of the Heartland facilities.

Earnings before income taxes for the three months ended Dec. 31, 2025 decreased compared the same period in 2024, primarily due to:

- Lower Adjusted Earnings before income taxes compared to the same period in 2024; partially offset by
- Higher unrealized mark-to-market gains due to favourable hedges.

Year ended Dec. 31, 2025

Adjusted Revenues for the year ended Dec. 31, 2025 increased compared to 2024, primarily due to:

- Addition of gas facilities from Heartland;
- Higher production at the Sarnia gas facility due to higher availability in the fourth quarter of 2025 compared to the same period in 2024, when the facility had a planned outage during a portion of the fourth quarter in 2024; and
- Favourable hedge positions settled, which generated positive contributions over settled spot prices in Alberta; partially offset by
- Higher dispatch optimization due to lower market prices driven by new gas generation in Alberta; and
- Lower spot power prices in the Alberta market and lower hedge power prices compared to the same period in 2024.

Adjusted EBITDA for the year ended Dec. 31, 2025 decreased compared to 2024, primarily due to:

- Higher fuel costs, carbon compliance cost and OM&A related to the addition of the Heartland facilities;
- Higher natural gas prices;
- Higher fuel costs at the Sarnia gas facility due to higher production; and
- An increase in the carbon price from $80 to $95 per tonne, impacting gross margin from our Canadian gas facilities; partially offset by
- A reduction to carbon compliance costs by using internally generated and externally purchased emission credits in the current period compared to the same period in the prior year to settle a portion of our GHG obligation and a portion of the 2024 GHG obligation assumed in the Heartland acquisition; and
- Higher Adjusted Revenues as explained by the factors above; and
- Favourable impact on carbon compliance cost due to an increase of production from lower-carbon-emitting cogeneration facilities.

Adjusted Earnings before income taxes for the year ended Dec. 31, 2025 decreased compared to 2024 due to:

- Lower Adjusted EBITDA as explained above; and
- Higher depreciation due to the addition of the Heartland facilities; partially offset by
- Revisions to the useful lives of certain gas facilities in the fourth quarter of 2024.

Earnings before income taxes for the year ended Dec. 31, 2025 decreased compared to 2024 due to:

- Higher unrealized mark-to-market losses due to less favourable hedges;
- Lower Adjusted Earnings before income taxes compared to the same period in 2024; partially offset by
- Higher lease income due to the addition of finance leases from the Heartland acquisition.

Energy Transition

	3 months ended Dec. 31,				Year ended Dec. 31			
	2025	2024	Change		2025	2024	Change	
Gross installed capacity (MW)	671	671	—	— %	671	671	—	— %
Availability (%)	92.5	91.7	0.8	1 %	88.5	80.0	8.5	11 %
Production								
Contract sales volume (GWh)	663	839	(176)	(21)%	2,628	3,338	(710)	(21)%
Merchant sales volume (GWh)	951	1,137	(186)	(16)%	3,467	3,201	266	8 %
Purchased power (GWh)(1)	(732)	(935)	203	(22)%	(2,945)	(3,717)	772	(21)%
Total production (GWh)	882	1,041	(159)	(15)%	3,150	2,822	328	12 %
Adjusted Revenues(2)	115	147	(32)	(22)%	504	580	(76)	(13)%
Fuel and purchased power	(81)	(102)	21	(21)%	(328)	(418)	90	(22)%
Carbon compliance costs	—	—	—	— %	—	(1)	1	(100)%
Adjusted Gross Margin(2)	34	45	(11)	(24)%	176	161	15	9 %
Adjusted OM&A(2)	(18)	(19)	1	(5)%	(73)	(69)	(4)	6 %
Taxes, other than income taxes	—	—	—	— %	(3)	(3)	—	— %
Adjusted EBITDA(2)	16	26	(10)	(38)%	100	89	11	12 %
Depreciation and amortization	(10)	(18)	8	(44)%	(49)	(66)	17	(26)%
Adjusted Earnings before Income Taxes(2)	6	8	(2)	(25)%	51	23	28	122 %
Earnings before income taxes	64	15	49	327 %	114	46	68	148 %
Supplementary information:								
Highvale mine reclamation spend(3)	4	3	1	33 %	12	11	1	9 %
Centralia mine reclamation spend(3)	3	4	(1)	(25)%	15	16	(1)	(6)%

(1) All of the power produced by Centralia is sold by the Energy Marketing segment for physical market delivery, which is shown as merchant sales volumes. Power required to fulfil contractual obligations is included in purchased power. Total production from the facility includes the net result of merchant sales volumes and purchased power.

(2) Adjusted Revenues, Adjusted Gross Margin, Adjusted OM&A, Adjusted EBITDA and Adjusted Earnings before Income Taxes are non-IFRS measures, are not defined and have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. The most directly comparable IFRS measure to Adjusted Revenues is revenues of $110 million and $495 million for the three months and year ended Dec. 31, 2025, respectively (Dec. 31, 2024 — $155 million and $616 million), to Adjusted Gross Margin — gross margin of $29 million and $167 million for the three months and year ended Dec. 31, 2025, respectively (Dec. 31, 2024 — $53 million and $197 million), to Adjusted OM&A — OM&A of $20 million and $75 million for the three months and year ended Dec. 31, 2025, respectively (Dec. 31, 2024 — $19 million and $69 million), to Adjusted EBITDA and Adjusted Earnings before Income Taxes — earnings before income taxes of $64 million and $114 million for the three months and year ended Dec. 31, 2025, respectively (Dec. 31, 2024 — $15 million and $46 million).

(3) Highvale and Centralia mine reclamation spend, which represent the costs necessary to bring the sites to their original condition, are supplementary financial measures and are included in the Decommissioning and restoration liabilities settled during the period in the consolidated statements of financial position under IFRS.

Three months ended Dec. 31, 2025

Adjusted Revenues for the three months ended Dec. 31, 2025 decreased compared to the same period in 2024, primarily due to:

- Lower Mid-Columbia prices; partially offset by
- Favourable hedge positions settled, which generated positive contributions over settled spot prices.

Adjusted EBITDA for the three months ended Dec. 31, 2025 decreased compared to the same period in 2024, primarily due to:

- Lower Adjusted Revenues as explained above; partially offset by
- Lower purchased power costs due to fewer repurchases to fulfil contractual obligations during outages.

Adjusted Earnings before Income Taxes for the three months ended Dec. 31, 2025 decreased compared to the same period in 2024, primarily due to:

- Lower Adjusted EBITDA as explained above; partially offset by
- Lower depreciation due to Centralia approaching its end of life as a coal-fired facility.

Earnings before income taxes for the three months ended Dec. 31, 2025 increased compared to the same period in 2024 due to:

- A change in decommissioning and restoration provisions driven by the revisions in estimated cash flows, timing of cash flows and discount rates; partially offset by
- Higher unrealized mark-to-market losses due to less favourable hedges;
- Lower net other operating income in the current period due to Sundance A decommissioning cost reimbursement in the same period of 2024; and
- Lower Adjusted Earnings before income taxes as explained above.

Year ended Dec. 31, 2025

Adjusted Revenues for year ended Dec. 31, 2025 decreased compared to 2024, primarily due to:

- Lower Mid-Columbia prices; partially offset by
- Favourable hedge positions settled, which generated positive contributions over settled spot prices; and
- Higher production.

Adjusted EBITDA for the year ended Dec. 31, 2025 increased compared to 2024 due to:

- Lower purchased power costs driven by higher availability; partially offset by
- Lower Adjusted Revenues as explained above; and
- Higher OM&A related to community fund spending.

Adjusted Earnings before income taxes for the year ended Dec. 31, 2025 increased compared to 2024 due to:

- Lower depreciation due to Centralia approaching its end of life as a coal-fired facility.; and
- Higher Adjusted EBITDA as explained above.

Earnings before income taxes for the year ended Dec. 31, 2025 increased compared to 2024 due to:

- Impairment reversal related to generation equipment;
- A change in decommissioning and restoration provisions driven by the revisions in estimated cash flows, timing of cash flows and discount rates; and
- Higher Adjusted Earnings before Income Taxes as explained above; partially offset by
- Higher unrealized mark-to-market losses due to less favourable hedges; and
- Lower net other operating income in the current period due to Sundance A decommissioning cost reimbursement in the same period of 2024.

Mine reclamation spending for the three months and the year ended Dec. 31, 2025, was consistent with 2024.

Energy Marketing

	3 months ended Dec. 31				Year ended Dec. 31			
	2025	2024	Change		2025	2024	Change	
Adjusted Revenues[1]	30	33	(3)	(9)%	122	182	(60)	(33)%
OM&A	(9)	(7)	(2)	29 %	(37)	(36)	(1)	3 %
Adjusted EBITDA[1]	21	26	(5)	(19)%	85	146	(61)	(42)%
Depreciation and amortization	—	—	—	— %	(2)	(2)	—	— %
Adjusted Earnings before Income Taxes[1][2]	21	26	(5)	(19)%	83	144	(61)	(42)%
Earnings before income taxes	19	7	12	171 %	91	130	(39)	(30)%

(1) Adjusted Revenues, Adjusted EBITDA and Adjusted Earnings before Income Taxes are non-IFRS measures, are not defined and have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. The most directly comparable IFRS measure to Adjusted Revenues for the three months and year ended Dec. 31, 2025 is revenues of $28 million and $130 million, respectively (Dec. 31, 2024 — $14 million and $168 million), to Adjusted EBITDA and Adjusted Earnings before Income Taxes — earnings before income taxes of $19 million and $91 million, respectively (Dec. 31, 2024 — $7 million and $130 million).

(2) During the first quarter of 2025, our Adjusted EBITDA composition was amended to exclude the impact of realized gain (loss) on closed exchange positions. Therefore, the Company has applied this composition to all previously reported periods. Refer to the "Non-IFRS and Supplementary Financial Measures" section of this MD&A.

Three months and year ended Dec. 31, 2025

Adjusted Revenues and Adjusted EBITDA for the three months and the year ended Dec. 31, 2025 decreased compared to the same periods in 2024, primarily due to:

- Comparatively subdued market volatility across North American natural gas and power markets; and
- Lower realized gains in 2025 compared to the same period in the prior year.

Adjusted Earnings before Income Taxes for the three months and year ended Dec. 31, 2025 decreased compared to the same periods in 2024 mainly due to lower Adjusted Revenues as explained above.

Earnings before income taxes for the three months ended Dec. 31, 2025 increased compared to the same period in 2024 due to:

- Lower unrealized mark-to-market losses due to more favourable positions; partially offset by
- Lower Adjusted Earnings before Income Taxes as explained above.

Earnings before income taxes for the year ended Dec. 31, 2025 decreased compared to 2024 due to:

- Lower Adjusted Earnings before Income Taxes; partially offset by
- Higher unrealized mark-to-market gains due to more favourable positions.

Corporate

	3 months ended Dec. 31,				Year ended Dec. 31			
	2025	**2024**	**Change**		**2025**	**2024**	**Change**	
Adjusted OM&A[1]	**(28)**	**(38)**	*10*	*(26)%*	**(141)**	**(135)**	*(6)*	*4%*
Taxes, other than income taxes	**1**	**—**	*1*	*—%*	**(1)**	**(1)**	*—*	*—%*
Adjusted EBITDA[1]	**(27)**	**(38)**	*11*	*(29)%*	**(142)**	**(136)**	*(6)*	*4%*
Depreciation and amortization	**(6)**	**(4)**	*(2)*	*50%*	**(21)**	**(18)**	*(3)*	*17%*
Equity income (loss)	**—**	**(3)**	*3*	*(100)%*	**(2)**	**(4)**	*2*	*(50)%*
Interest income	**9**	**11**	*(2)*	*(18)%*	**30**	**32**	*(2)*	*(6)%*
Interest expense	**(80)**	**(93)**	*13*	*(14)%*	**(350)**	**(328)**	*(22)*	*7%*
Realized foreign exchange loss[2]	**(13)**	**(15)**	*2*	*(13)%*	**(16)**	**(22)**	*6*	*(27)%*
Adjusted Loss before Income Taxes[1]	**(117)**	**(142)**	*25*	*(18)%*	**(501)**	**(476)**	*(25)*	*5%*
Loss before income taxes	**(127)**	**(146)**	*19*	*(13)%*	**(552)**	**(494)**	*(58)*	*12%*

(1) Adjusted OM&A, Adjusted EBITDA and Adjusted Loss before Income Taxes are non-IFRS measures, are not defined and have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. The most directly comparable IFRS measure to Adjusted OM&A for the three months and year ended Dec. 31, 2025 is OM&A of $50 million and $185 million, respectively (Dec. 31, 2024 — $68 million and $173 million). The most directly comparable IFRS measure to Adjusted EBITDA and Adjusted Loss before Income Taxes is loss before income taxes of $127 million and $552 million for the three months and year ended Dec. 31, 2025, respectively (Dec. 31, 2024 — $146 million and $494 million).

(2) Realized foreign exchange (loss) gain is a supplementary financial measure consisting of foreign exchange gains and losses related to the actual payment transactions. Refer to the "Non-IFRS and Supplementary Financial Measures" section of this MD&A for more details.

Three months ended Dec. 31, 2025

Adjusted EBITDA for the three months ended Dec. 31, 2025 increased compared to the same period in 2024, primarily due to lower Adjusted OM&A driven by lower incentive costs, partially offset by the addition of corporate costs related to Heartland.

Adjusted Loss before Income Taxes for the three months ended Dec. 31, 2025 decreased compared to the same period in 2024, primarily due to:

- Lower interest expense driven by lower interest on debt, and net gain on early redemption of the US$400 million senior notes, partially offset by full quarter interest on the Heartland term facility; and
- Higher Adjusted EBITDA as explained above.

Loss before income taxes for the three months ended Dec. 31, 2025 decreased compared to the same period in 2024 due to:

- Lower Adjusted Loss before Income Taxes as explained above;
- Lower acquisition-related transaction and restructuring costs compared to the same period of 2024; and
- Lower spending related to the planning, design and implementation of an upgrade to our ERP system; partially offset by
- Higher termination and restructuring costs associated with cost saving initiatives, mainly comprising termination and severance payments;
- Lower unrealized foreign exchange gains driven by unfavourable changes in foreign currency rates; and
- Lower impairment charges related to development projects that are no longer proceeding.

Year ended Dec. 31, 2025

Adjusted EBITDA for the year ended Dec. 31, 2025, decreased compared to 2024, primarily due to:

- Increased spending to support strategic and growth initiatives; and
- The full year impact from the addition of the Heartland facilities acquired in the fourth quarter of 2024 and associated corporate costs; partially offset by
- Cost saving initiatives.

Adjusted Loss before Income Taxes for the year ended Dec. 31, 2025 increased compared to 2024 due to:

- Lower Adjusted EBITDA as explained above; and
- Higher interest expense due to higher interest on debt driven by the addition of the Heartland term facility, and lower capitalized interest resulting from lower construction activity during 2025 compared to 2024, partially offset by lower interest on senior notes due to the refinancing at lower interest rates during 2025 and a net gain on the early redemption of the US$400 million senior notes.

Loss before income taxes for the year ended Dec. 31, 2025 increased compared to 2024 due to:

- Higher Adjusted Loss before income taxes as explained above;
- Higher spending related to the planning, design and implementation of an upgrade to our ERP system; and
- Higher unrealized foreign exchange losses due to unfavourable changes in foreign currency rates; partially offset by
- Lower Heartland acquisition-related transaction and restructuring costs, mainly comprising severance, legal and consulting fees; and
- Lower impairment charges related to development projects that are no longer proceeding.

Performance by Segment with Supplementary Geographical Information

The following table provides Adjusted EBITDA by segment across the regions we operate in:

3 months ended Dec. 31, 2025	Hydro	Wind & Solar(3)	Gas	Energy Transition	Energy Marketing	Corporate	Total
Alberta	36	12	39	(4)	21	(27)	77
Canada, excluding Alberta	3	41	31	—	—	—	75
U.S.	—	47	3	20	—	—	70
Western Australia	—	2	23	—	—	—	25
Adjusted EBITDA(1)	**39**	**102**	**96**	**16**	**21**	**(27)**	**247**
Adjusted Earnings (Loss) before Income Taxes(1)	**27**	**50**	**27**	**6**	**21**	**(117)**	**14**
Earnings (loss) before income taxes	**25**	**(38)**	**15**	**64**	**19**	**(127)**	**(42)**

3 months ended Dec. 31, 2024	Hydro	Wind & Solar(3)	Gas	Energy Transition	Energy Marketing	Corporate	Total
Alberta	54	8	74	(3)	26	(38)	121
Canada, excluding Alberta	3	42	19	—	—	—	64
U.S.	—	43	3	29	—	—	75
Western Australia	—	2	20	—	—	—	22
Adjusted EBITDA(1)(2)	57	95	116	26	26	(38)	282
Adjusted Earnings (Loss) before Income Taxes(1)	39	40	67	8	26	(142)	38
Earnings (loss) before income taxes	24	12	37	15	7	(146)	(51)

(1) Adjusted EBITDA and Adjusted Earnings (Loss) before Income Taxes are non-IFRS measures, are not defined, have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers.

(2) During the first quarter of 2025, our Adjusted EBITDA composition was amended to exclude the impact of realized gain (loss) on closed exchange positions and Australian interest income. Therefore, the Company has applied this composition to all previously reported periods. Refer to the "Non-IFRS and Supplementary Financial Measures" section of this MD&A.

(3) (Loss) earnings before income taxes for the Wind and Solar segment exclude the contribution from Skookumchuck wind facility.

Year ended Dec. 31, 2025	Hydro	Wind & Solar(3)	Gas	Energy Transition	Energy Marketing	Corporate	Total
Alberta	271	43	220	(11)	85	(142)	466
Canada, excluding Alberta	14	136	112	—	—	—	262
U.S.	—	151	12	111	—	—	274
Western Australia	—	8	94	—	—	—	102
Adjusted EBITDA(1)	**285**	**338**	**438**	**100**	**85**	**(142)**	**1,104**
Adjusted Earnings (Loss) before Income Taxes(1)	**247**	**129**	**172**	**51**	**83**	**(501)**	**181**
Earnings (loss) before income taxes	**251**	**(165)**	**120**	**114**	**91**	**(552)**	**(141)**

Year ended Dec. 31, 2024	Hydro	Wind & Solar(3)	Gas	Energy Transition	Energy Marketing	Corporate	Total
Alberta	307	51	333	(10)	146	(136)	691
Canada, excluding Alberta	9	122	91	—	—	—	222
U.S.	—	135	12	99	—	—	246
Western Australia	—	8	88	—	—	—	96
Adjusted EBITDA(1)(2)	316	316	524	89	146	(136)	1,255
Adjusted Earnings (Loss) before Income Taxes(1)	275	118	312	23	144	(476)	396
Earnings (loss) before income taxes	263	19	355	46	130	(494)	319

(1) Adjusted EBITDA and Adjusted Earnings (Loss) before Income Taxes are non-IFRS measures, are not defined, have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers.

(2) During the first quarter of 2025, our Adjusted EBITDA composition was amended to exclude the impact of realized gain (loss) on closed exchange positions and Australian interest income. Therefore, the Company has applied this composition to all previously reported periods. Refer to the "Non-IFRS and Supplementary Financial Measures" section of this MD&A.

(3) (Loss) earnings before income taxes for the Wind and Solar segment exclude the contribution from Skookumchuck wind facility.

Optimization of the Alberta Portfolio

The Alberta electricity portfolio metrics disclosed below are supplementary financial measures used to present the detailed performance by segment for the Alberta market.

Our merchant exposure is primarily in Alberta, where 58 per cent of our capacity is located, 77 per cent of which is available to participate in the merchant market. Our portfolio of assets consists of hydro, wind, battery storage and natural gas generation facilities.

The acquisition of Heartland on Dec 4. 2024, enhanced and further diversified TransAlta's competitive portfolio in the highly dynamic and shifting electricity landscape in Alberta, by adding 376 MW of contracted cogeneration capacity, 361 MW of contracted and merchant peaking generation capacity, 950 MW of merchant natural gas-fired thermal generation capacity and transmission capacity. We believe that the fast-ramping nature of certain Heartland facilities are well positioned to respond to price volatility and deliver peaking capacity during periods of higher demand in the Alberta market.

Generating capacity in Alberta is subject to market forces. Power from commercial generation is cleared through a wholesale electricity market. Power is dispatched in accordance with an economic merit order administered by the AESO, based upon offers by generators to sell power in the real-time energy-only market. Our merchant Alberta fleet operates under this framework and we internally manage our offers to sell power.

Optimization of portfolio performance in the Alberta merchant market is driven by the diversity of fuel types, which enables portfolio management. It also provides us with capacity that can be monetized as either energy production or ancillary services. A significant portion of the installed generation capacity in the portfolio has been hedged to provide greater cash flow certainty. The Company's hedging strategy includes maintaining a significant base of commercial and industrial customers and is supplemented with financial hedges.

During periods of low market prices, the Company may choose not to generate power from the thermal fleet and instead monetize its hedged or contract positions. This results in a change in revenue that does not correlate with a change in production. During the year, there were periods of low market prices, and the Company opted not to generate production from its thermal fleet, which resulted in thermal generation sold through contracts with commercial and industrial customers, and financial hedges exceeding the actual merchant production generated.

The Alberta hydro and gas fleets provide ancillary services. The hydro fleet also provides grid reliability products such as black start services in the event of a system-wide blackout. Hydro assets also support drought mitigation by systematically regulating river flows.

Our Alberta wind and hydro fleets provide a steady stream of environmental credits that the Company sells to third parties and to the Gas segment.

The following table provides information for the Company's Alberta electricity portfolio for the three months ended Dec. 31:

	2025					2024				
3 months ended Dec. 31	**Hydro**	**Wind & Solar**	**Gas**	**Energy Transition**	**Total**	**Hydro**	**Wind & Solar**	**Gas**	**Energy Transition**	**Total**
Gross installed capacity (MW)	**834**	**764**	**3,650**	**—**	**5,248**	834	764	3,650	—	5,248
Total production[1] (GWh)	**266**	**640**	**2,183**	**—**	**3,089**	367	619	2,164	—	3,150
Contract production (GWh)	**—**	**284**	**1,382**	**—**	**1,666**	—	257	837	—	1,094
Merchant production (GWh)	**266**	**356**	**801**	**—**	**1,423**	367	362	1,327	—	2,056
Ancillary services volumes (GWh)	**761**	**21**	**199**	**—**	**981**	713	12	201	—	926
Hedged volumes (GWh)	**210**	**47**	**1,803**	**—**	**2,060**	205	44	2,388	—	2,637
Production contracted or hedged (%)	**79%**	**52%**	**146%**	**—%**	**121%**	56%	49%	149%	—%	118%
Hedged volumes as a percentage of gross installed capacity (%)	**12%**	**3%**	**23%**	**—%**	**18%**	11%	3%	30%	—%	23%
Adjusted Revenues[2][3] ($)	**53**	**27**	**218**	**2**	**300**	72	24	236	1	333
Fuel ($)	**(1)**	**(4)**	**(99)**	**(1)**	**(105)**	(1)	(3)	(86)	(1)	(91)
Purchased power ($)	**(2)**	**—**	**(11)**	**—**	**(13)**	(1)	(1)	(14)	—	(16)
Carbon compliance costs[3] ($)	**—**	**(1)**	**(30)**	**(1)**	**(32)**	—	—	(34)	—	(34)
Adjusted Gross Margin[2] ($)	**50**	**22**	**78**	**—**	**150**	70	20	102	—	192

(1) Total production includes contract and merchant production and excludes ancillary services volumes.

(2) Revenues have been adjusted to exclude the impact of unrealized mark-to-market gains or losses. During the first quarter of 2025, our Adjusted Revenues and Adjusted Gross Margin composition was amended to exclude the impact of realized gain (loss) on closed exchange positions. Therefore, the Company has applied this composition to all previously reported periods.

(3) The intercompany sales of emission credits from the Hydro and Wind and Solar segments to the Gas segment are eliminated on consolidation in the Corporate segment. Refer to the "Non-IFRS and Supplementary Financial Measures" section of this MD&A.

Three months ended Dec. 31, 2025

Total production for the Alberta portfolio for the three months ended Dec. 31, 2025, was 3,089 GWh, compared to 3,150 GWh for the same period in 2024. The decrease of 61 GWh, or two per cent, was primarily due to:

- Lower merchant production in the Gas segment due to dispatch optimization driven by lower market prices; and
- Lower production from the Hydro segment due to lower market prices and water conservation; partially offset by
- Higher contract production in the Gas segment due to the addition of the Heartland gas facilities in the fourth quarter of 2024; and
- Higher production volumes in the Wind and Solar segment due to higher wind resource in Alberta.

Ancillary services volumes for the three months ended Dec. 31, 2025 were 981 GWh compared to 926 GWh in the same period of 2024. The increase of 55 GWh, or six per cent, was primarily due to an increase in Hydro ancillary services volumes in the course of optimizing our portfolio and water reserves in the quarter.

Hedged volumes for the Alberta portfolio for the three months ended Dec. 31, 2025, decreased compared to the same period in 2024 due to planned outages in the Gas segment. Realized gains and losses on financial hedges are included in Adjusted Revenues in the table above.

Adjusted Gross Margin for the Alberta portfolio for the three months ended Dec. 31, 2025, was $150 million, compared to $192 million in 2024. The decrease of $42 million, or 22 per cent, was primarily due to:

- The impact of lower Alberta spot and hedge power prices;
- Higher dispatch optimization in the Gas segment;
- Lower favourable contributions from the hedge positions settled;
- Lower revenues in the Hydro segment due to lower market prices and optimization of water reserves;
- Higher fuel costs in the Gas segment due to higher natural gas prices; and
- An increase in the carbon price per tonne from $80 in 2024 to $95 in 2025; partially offset by
- Positive contribution from the addition of the Heartland facilities in the Gas segment; and
- Favourable impact on carbon compliance cost due to an increase of production from lower-carbon-emitting cogeneration facilities.

The following table provides information for the Company's Alberta electricity portfolio for the year ended Dec. 31:

	2025					2024				
Year ended Dec. 31	**Hydro**	**Wind & Solar**	**Gas**	**Energy Transition**	**Total**	**Hydro**	**Wind & Solar**	**Gas**	**Energy Transition**	**Total**
Gross installed capacity (MW)	834	764	3,650	—	5,248	834	764	3,650	—	5,248
Total production[(1)] (GWh)	1,568	1,883	8,506	—	11,957	1,443	1,981	8,385	—	11,809
Contract production (GWh)	—	879	5,244	—	6,123	—	928	2,566	—	3,494
Merchant production (GWh)	1,568	1,004	3,262	—	5,834	1,443	1,053	5,819	—	8,315
Ancillary services volumes (GWh)	2,934	71	852	—	3,857	2,951	36	550	—	3,537
Hedged volumes (GWh)	1,206	134	7,313	—	8,653	558	136	8,386	—	9,080
Production contracted or hedged (%)	77%	54%	148%	—%	124%	39%	54%	131%	—%	106%
Hedged volumes as a percentage of gross installed capacity (%)	17%	2%	23%	—%	19%	8%	2%	26%	—%	20%
Adjusted Revenues[(2)(3)] ($)	338	106	812	6	1,262	370	105	880	5	1,360
Fuel ($)	(6)	(13)	(330)	(1)	(350)	(6)	(11)	(297)	(1)	(315)
Purchased power ($)	(10)	(2)	(50)	—	(62)	(7)	(3)	(60)	—	(70)
Carbon compliance costs[(3)] ($)	—	(3)	(81)	(1)	(85)	—	—	(125)	(1)	(126)
Adjusted Gross Margin[(2)] ($)	322	88	351	4	765	357	91	398	3	849

(1) Total production includes contract and merchant production and excludes ancillary services volumes.

(2) Revenues have been adjusted to exclude the impact of unrealized mark-to-market gains or losses. During the first quarter of 2025, our Adjusted Revenues and Adjusted Gross Margin composition was amended to exclude the impact of realized gain (loss) on closed exchange positions. Therefore, the Company has applied this composition to all previously reported periods.

(3) The intercompany sales of emission credits from the Hydro and Wind and Solar segments to the Gas segment are eliminated on consolidation in the Corporate segment. Refer to the "Non-IFRS and Supplementary Financial Measures" section of this MD&A.

Year ended Dec. 31, 2025

Total production for the Alberta portfolio for the year ended Dec. 31, 2025 was 11,957 GWh, compared to 11,809 GWh in 2024. The increase of 148 GWh, or one per cent, was primarily due to:

- Higher contract production in the Gas segment due to the addition of the Heartland gas facilities in the fourth quarter of 2024; and
- Higher production from the Hydro segment due to higher water resource and the optimization of water supply to facilitate generation during higher demand periods; partially offset by
- Lower merchant production in the Gas segment due to higher dispatch optimization driven by lower market prices; and
- Lower production volumes in the Wind and Solar segment due to lower wind resource compared to the same period in 2024.

Ancillary services volumes for the year ended Dec. 31, 2025 were 3,857 GWh compared to 3,537 GWh in 2024. The increase of 320 GWh, or nine per cent, was primarily due to an increase in volumes in the Gas segment due to the addition of the Heartland facilities.

Hedged volumes for the year ended Dec. 31, 2025, decreased by five per cent compared to 2024, whereas merchant production decreased by 30 per cent. The Company deployed a defensive strategy to enter into financial hedges for the merchant portfolio at attractive margins in anticipation of the risk of lower prices in 2025. Realized gains and losses on financial hedges are included in Adjusted Revenues in the table above.

Adjusted Gross Margin for the Alberta portfolio for the year ended Dec. 31, 2025, was $765 million, compared to $849 million in 2024. The decrease of $84 million, or 10 per cent, was primarily due to:

- The impact of lower Alberta spot and ancillary services prices, and lower hedge prices;
- Lower merchant production in the Gas segment due to higher dispatch optimization driven by lower market prices; and
- An increase in the carbon price from $80 per tonne in 2024 to $95 per tonne in 2025;
- Higher fuel costs in the Gas segment due to higher natural gas prices; and
- Lower favourable contributions from the hedge positions settled in the year; partially offset by
- Positive contribution from the addition of the Heartland facilities in the Gas segment;
- Lower carbon compliance costs due to the use of internally generated and externally purchased emission credits to settle a portion of our GHG obligation in 2025 as well as a portion of the 2024 GHG obligation assumed in the Heartland acquisition and the favourable impact of increased production from lower-carbon-emitting cogeneration facilities; and
- Higher environmental and tax attributes revenue due to increased sales of emission credits to third parties and intercompany sales from the Hydro and Wind and Solar segments to the Gas segment.

The following table provides information for the Company's Alberta electricity portfolio:

	3 months ended Dec. 31		Year ended Dec. 31	
	2025	**2024**	**2025**	**2024**
Alberta Market				
Spot power price average per MWh	**43**	52	**44**	63
Natural gas price (AECO) per GJ	**2.15**	1.42	**1.61**	1.29
Carbon compliance price per tonne	**95**	80	**95**	80
Alberta Portfolio Results				
Realized merchant power price per MWh(1)	**105**	110	**107**	109
Hydro energy spot power price per MWh	**53**	78	**58**	91
Hydro ancillary services price per MWh	**35**	39	**38**	46
Wind energy spot power price per MWh	**26**	26	**24**	35
Gas spot power price per MWh	**65**	75	**66**	86
Hedged power price average per MWh(2)	**73**	80	**70**	84
Hedged volume (GWh)	**2,060**	2,637	**8,653**	9,080
Fuel cost per MWh(3)	**48**	42	**41**	38
Carbon compliance cost per MWh(4)	**15**	16	**10**	15

(1) Realized merchant power price per MWh for the Alberta electricity portfolio is a supplementary financial measure and represents the average price realized as a result of the Company's merchant power sales and portfolio optimization activities. It is calculated as merchant revenues (excluding assets under long-term contract and ancillary revenues, but including the impact of gains and losses from derivatives and trading activities) for the reporting period divided by total merchant GWh produced during the reporting period.

(2) Hedged power price average per MWh is a supplementary financial measure and is calculated as the average sales price for all hedges and direct customer sales during the reporting period.

(3) Fuel cost per MWh is a supplementary financial measure and is calculated as total fuel costs for the facilities in Alberta divided by production from carbon-emitting generation in the Gas and Energy Transition segments.

(4) Carbon compliance per MWh is a supplementary financial measure and is calculated as total carbon compliance costs for the Gas and Energy Transition segments in Alberta divided by production from carbon-emitting generation in the Gas and Energy Transition segments.

The average spot power price per MWh in Alberta for the three months and year ended Dec. 31, 2025 decreased by $9 and $19 per MWh, respectively, compared to the same periods in 2024, primarily due to the addition of increased supply from renewables and combined-cycle gas facilities into the market and the impact of milder weather during the year.

The realized merchant power price per MWh of production for Alberta for the three months and year ended Dec. 31, 2025, decreased by $5 and $2 per MWh, respectively, compared to the same periods in 2024, primarily due to:

- Lower average spot power prices as explained above and lower hedge power prices compared to the same period in 2024; partially offset by
- Favourable hedge positions settling and production optimization, which generated positive contributions over settled spot prices in Alberta.

Fuel cost per MWh for the three months and year ended Dec. 31, 2025, increased by $6 and $3 per MWh, respectively, compared to the same periods in 2024, primarily due to higher natural gas prices.

Carbon compliance cost per MWh of production for the Alberta portfolio for the three months and year ended Dec. 31, 2025, decreased by $1 and $5 per MWh, respectively, compared to the same periods in 2024, primarily due to:

- A favourable impact on carbon compliance cost per MWh due to increased production from lower-carbon-emitting cogeneration facilities; partially offset by
- An increase in the carbon compliance price per tonne from $80 per tonne in 2024 to $95 per tonne in 2025.

Carbon compliance cost for the year ended Dec. 31, 2025 was further impacted by the use of a higher quantity of internally generated and externally purchased emission credits in the current period compared to the prior year to settle a portion of our GHG obligation and a portion of the 2024 GHG obligation assumed in the Heartland acquisition.

Selected Quarterly Information

Our results are seasonal due to the nature of the electricity market and related fuel costs. Higher maintenance costs are often incurred in the spring and fall when electricity prices are expected to be lower, and electricity prices generally increase in the peak winter and summer months in our main markets due to increased heating and cooling loads. Margins are also typically impacted in the second quarter due to the volume of hydro production resulting from spring runoff and rainfall in the Pacific Northwest, which impacts production at Centralia. Typically, hydroelectric facilities generate most of their electricity and revenues during the spring months when melting snow starts feeding watersheds and rivers. Inversely, wind speeds are historically greater during the cold winter months and lower in the warm summer months.

	Q1 2025	Q2 2025	Q3 2025	Q4 2025
Revenues	758	433	615	**599**
Gross margin	432	334	353	**301**
OM&A	173	173	179	**186**
Depreciation and amortization	146	150	135	**148**
Earnings (loss) before income taxes	49	(95)	(53)	**(42)**
Net earnings (loss) attributable to common shareholders	46	(112)	(62)	**(62)**
Net earnings (loss) per share attributable to common shareholders, basic and diluted(1)	0.15	(0.38)	(0.20)	**(0.21)**

	Q1 2024	Q2 2024	Q3 2024	Q4 2024
Revenues	947	582	638	678
Gross margin	584	436	384	390
OM&A	134	144	143	234
Depreciation and amortization	124	131	133	143
Earnings (loss) before income taxes	267	94	9	(51)
Net earnings (loss) attributable to common shareholders	222	56	(36)	(65)
Net earnings (loss) per share attributable to common shareholders, basic and diluted(1)	0.72	0.18	(0.12)	(0.22)

(1) Basic and diluted earnings (loss) per share attributable to common shareholders is calculated in each period using the basic and diluted weighted average common shares outstanding during the period, respectively. As a result, the sum of the earnings (loss) per share for the four quarters making up the calendar year may sometimes differ from the annual earnings (loss) per share.

Operating results have been impacted by the following events:

- The acquisition of Heartland on Dec. 4, 2024; and
- The Mount Keith 132kV expansion in the first quarter of 2024 and the impact from the White Rock and Horizon Hill wind facilities which achieved commercial operation in the first half of 2024.

In addition to the items described above, revenues have been impacted by:

- Additional production from the Heartland facilities, which was more than offset by lower production from the Company's existing Gas facilities;
- Lower Alberta spot and hedged power prices in all quarters of 2025;
- Lower Mid-Columbia power prices in three quarters of 2025 and higher prices in the second quarter 2025;
- Higher Ontario spot power prices in all four quarters of 2025;
- The effects of unrealized mark-to-market gains and losses from hedging and derivative positions due to favourable and unfavourable changes in forward rates; and
- The effects of realized mark-to-market gains and losses on settled trades.

Gross Margin has been impacted by:

- Factors impacting revenues as described above;
- Lower purchased power costs driven by higher availability in the Energy Transition segment in the first, third and fourth quarters of 2025; partially offset by
- The impact from the addition of the Heartland facilities in all four quarters of 2025;
- Higher natural gas prices in the first, second and fourth quarters of 2025 and lower natural gas prices in the third quarter of 2025; and
- Higher costs of carbon per tonne, which increased from $80 in 2024 to $95 in 2025. In the second quarter of 2025, carbon compliance costs were reduced by $103 million due to using internally generated and externally purchased emission credits to settle a portion of our 2024 GHG obligation and a portion of the GHG obligation assumed in the Heartland acquisition. In the second quarter of 2024, carbon compliance costs were reduced by $42 million due to using internally generated and externally purchased emission credits to settle a portion of our 2023 GHG obligation.

OM&A has been impacted by:

- Higher spending to support strategic and growth initiatives in the first and second quarters of 2025 and in the third and fourth quarters of 2024, compared to same periods in the prior year;
- The impact from the Horizon Hill and White Rock wind facilities which achieved commercial operation in the first half of 2024;
- The addition of the Heartland facilities and associated corporate costs in all quarters of 2025 and part of the fourth quarter of 2024;
- Higher costs stemming from the planning, design and implementation of an upgrade to our ERP system in the first three quarters of 2025 and the fourth quarter of 2024; and
- In the fourth quarter of 2024, penalties assessed by the Alberta Market Surveillance Administrator for self-reported contraventions pertaining to Brazeau hydro ancillary services provided during 2021 and 2022.

Depreciation has been higher in all quarters of 2025 due to:

- An increase in depreciation due to the impact from the White Rock and Horizon wind facilities which achieved commercial operation in the first half of 2024; and
- The acquisition of Heartland in the fourth quarter of 2024; partially offset by
- Revision to the useful lives of certain facilities in the third quarter of 2024.

(Loss) earnings before income taxes have been impacted by the factors explained above and by asset impairment charges and reversals due to:

- A change in the decommissioning provisions for retired assets driven by changes in estimated cash flows and discount rates in the third and fourth quarters of 2024 and the third and fourth quarters of 2025;
- A change in the decommissioning provision for Centralia driven by a change in the timing of cash flow estimates in the fourth quarter of 2025; and
- Impairment, net of reversals, related to certain Wind and Solar facilities due to changes in expected production volumes and lower power price assumptions in the third quarter of 2025.

Net (loss) earnings attributable to common shareholders have been impacted by:

- Lower earnings in the first quarter of 2025 and higher losses in the second, third and fourth quarters of 2025 as explained above; and
- Lower net earnings and higher net losses attributable to non-controlling interests in all four quarters of 2025 primarily due to lower net earnings for TA Cogen resulting from lower merchant pricing in the Alberta market.

Financial Condition

Balance Sheet Analysis

The following table highlights significant changes in the Consolidated Statements of Financial Position from Dec. 31, 2024 to Dec. 31, 2025.

As at	Dec. 31, 2025	Dec. 31, 2024	Increase/ (decrease)
Total current assets	**1,336**	1,773	(437)
Total non-current assets	**7,325**	7,726	(401)
Total assets	**8,661**	9,499	(838)
Total current liabilities	**1,830**	2,569	(739)
Total non-current liabilities	**5,366**	5,087	279
Total liabilities	**7,196**	7,656	(460)

Working Capital

The deficit of current assets over current liabilities, including the current portion of long-term debt and lease liabilities, was $494 million as at Dec. 31, 2025 (Dec. 31, 2024 – deficit of current assets over current liabilities of $796 million).

The deficit of current assets relative to current liabilities is primarily caused by the classification of exchangeable securities totaling $750 million as current liabilities because of Brookfield's conversion option that can be exercised at any time after Dec. 31, 2024, although there is no obligation to deliver cash equivalent resources and Brookfield cannot call for repayment. Refer to Note 26 of the consolidated financial statements for details.

The deficit as at Dec. 31, 2025 decreased from Dec. 31, 2024 primarily as a result of a decrease in the current portion of credit facilities, long-term debt and lease liabilities. On March 25, 2025, the Company repaid its $400 million variable rate term loan facility in advance of the scheduled maturity date of Sept. 7, 2025, with the proceeds received from the $450 million senior notes offering completed in the first quarter of 2025. For the working capital management discussion, refer to the "Financial Capital" section below.

Non-Current Assets

Non-current assets as at Dec. 31, 2025, were $7,325 million, a decrease of $401 million from $7,726 million as at Dec. 31, 2024, primarily due to:

- Lower property, plant and equipment (PP&E) resulting from depreciation of $547 million for the year ended Dec. 31, 2025, and higher foreign exchange losses on translation of the balances denominated in foreign currency to the presentation currency, partially offset by capital additions of $249 million (refer to the "Capital Expenditures" section of this MD&A for more information); and
- Lower risk management assets due to changes in market pricing across multiple markets and changes in price forecasts; partially offset by
- Higher long-term financial assets due a term loan and a revolving facility made available to Nova, a developer of renewable energy projects.

Non-Current Liabilities

Non-current liabilities as at Dec. 31, 2025 were $5,366 million, an increase of $279 million from $5,087 million as at Dec. 31, 2024, mainly due to:

- Higher risk management liabilities due to forward price changes and volatility in market pricing across multiple markets; and
- An increase in credit facilities, long-term debt and lease liabilities due to the $450 million senior notes offering on March 24, 2025; partially offset by
- A decrease in decommissioning and other provisions due to liabilities settled, revisions in discount rates and estimated decommissioning costs; and
- A decrease in long-term debt due to scheduled principal repayments related to our bonds, senior notes and tax equity financing, as well as repayments, net of cash drawings under the syndicated credit facility.

On Dec. 22, 2025 the Company issued US$400 million of senior notes with a fixed annual coupon rate of 5.9 per cent, maturing on Feb. 1, 2034. The proceeds were used to redeem all of the outstanding 7.8 per cent US$400 million senior notes in advance of the scheduled maturity date of Nov. 15, 2029. Refer to "Financial Capital" and "Significant and Subsequent Events" sections of this MD&A.

Contractual Obligations

Refer to Note 36 Commitments and Contingencies in the consolidated financial statements for details. Material contractual obligations as at Dec. 31, 2025 are as follows:

	2026	2027	2028	2029	2030	2031 and thereafter	Total
Natural gas and transportation contracts[1]	83	67	67	63	62	350	692
Transmission[1]	29	31	22	20	21	114	237
Long-term service agreements[1]	55	44	21	14	15	105	254
Operating leases[1,2]	5	2	2	2	2	59	72
Long-term debt[3]	170	331	163	343	281	2,199	3,487
Exchangeable securities[4]	—	—	—	—	—	750	750
Principal payments on lease liabilities	5	5	5	5	5	121	146
Interest on long-term debt and lease liabilities[1][5]	179	184	167	156	138	705	1,529
Interest on exchangeable securities[1][4]	53	53	53	52	53	457	721
Growth[1]	7	—	11	—	—	—	18
Total	**586**	**717**	**511**	**655**	**577**	**4,860**	**7,906**

(1) Not recognized as a financial liability on the Consolidated Statements of Financial Position and excludes the impact of interest rate hedges.

(2) Includes leases that have not been recognized as a lease liability and leases that have not yet commenced.

(3) Excludes impact of hedge accounting and derivatives.

(4) The exchangeable debentures are due May 1, 2039 and the exchangeable preferred shares are perpetual. However, a cash payment could occur after Dec. 31, 2028, at the Company's option, if the exchangeable securities are not exchanged by Brookfield Renewable Partners or its affiliates (collectively Brookfield). At Brookfield's option, the exchangeable securities are currently exchangeable into an equity ownership interest in TransAlta's Alberta Hydro Assets between Dec. 31, 2024 and Dec. 31, 2028.

(5) Interest on long-term debt is based on debt currently in place with no assumption as to refinancing on maturity.

Financial Capital

The Company is focused on maintaining a strong balance sheet and financial position to ensure access to sufficient financial capital. The Company expects the cash flow from operating activities to be sufficient to meet its obligations, support sustaining capital expenditures and fund dividends over both the short- and long-term. Given its financing track record in recent years, the Company has robust access to capital markets for future funding needs. The Company has a total of $2.2 billion committed capacity under its credit facilities as at Dec. 31, 2025, of which $1.3 billion remains available for short-term borrowings. Refer to the "Credit Facilities" section below for further details.

The Company manages working capital deficits through ongoing cash generation from operating activities, available credit facilities and access to capital markets.

Management continues to monitor liquidity and considers current leverage appropriate given the characteristics of the Company's contracted and merchant assets.

Credit ratings provide information relating to the Company's financing costs, liquidity and operations, and affect the Company's ability to obtain short and long-term financing and/or the cost of such financing. Maintaining a strong balance sheet also allows the Company to enter into contracts with a variety of counterparties on terms and prices that are favourable to the Company's financial results and provide TransAlta with better access to capital markets through commodity and credit cycles.

In 2025, Moody's reaffirmed the Company's long-term rating of Ba1 with a stable outlook. Morningstar DBRS reaffirmed the Company's issuer rating and unsecured debt/medium-term notes rating of BBB (low) and the Company's preferred shares rating of Pfd-3 (low), all with a stable outlook. In addition, S&P Global Ratings reaffirmed the Company's senior unsecured debt rating and issuer credit rating of BB+ with a stable outlook. Risks associated with our credit ratings are discussed in the "Risk Management" section of this MD&A.

Capital Structure

Our capital structure consists of the following components as shown below:

	2025		2024	
	$	% of total	$	% of total
Senior unsecured debt	**1,734**	**31**	1,789	29
Non-recourse debt	**1,471**	**26**	1,575	27
Recourse debt - OCP Bond	**166**	**3**	192	3
Tax equity financing	**76**	**1**	101	1
Lease liabilities	**146**	**3**	151	2
Credit facilities, long-term debt and lease liabilities[1]	**3,593**	**64**	3,808	62
Add: Exchangeable debentures	**350**	**6**	350	6
Add: Bank overdraft	**—**	**—**	1	—
Less: Cash and cash equivalents	**(205)**	**(3)**	(337)	(6)
Less: TransAlta OCP LP restricted cash[2]	**(17)**	**—**	(17)	—
Less: Fair value of foreign exchange forward contracts on foreign-currency denominated debt	**4**	**—**	(7)	—
Total Consolidated Net Debt[3][4][5]	**3,725**	**67**	3,798	62
Exchangeable preferred securities[5]	**400**	**7**	400	7
Total equity	**1,465**	**26**	1,843	31
Total capital	**5,590**	**100**	6,041	100

(1) Credit facilities, long-term debt and lease liabilities consist of current and non-current portions in the Consolidated Statements of Financial Position. For detailed breakdown refer to Note 25 of the Consolidated Statements of Financial Position.

(2) Principal portion of the TransAlta OCP LP restricted cash related to the TransAlta OCP LP bonds, as this cash is restricted specifically to repay the bonds.

(3) Total Consolidated Net Debt is a non-IFRS measure, which is not defined and has no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. The most directly comparable IFRS measure is total credit facilities, long-term debt and lease liabilities. Refer to the "Non-IFRS and Supplementary Financial Measures" section of this MD&A for further discussion.

(4) Tax equity financing for the Skookumchuck wind facility, an equity-accounted joint venture, is not represented in these amounts.

(5) Total Consolidated Net Debt excludes the exchangeable preferred shares as they are considered equity with dividend payments for credit purposes.

We have enhanced liquidity and shareholder value through the following:

2025

- On Dec. 22, 2025, the Company issued US$400 million of senior notes with a fixed annual coupon rate of 5.9 per cent, maturing on Feb. 1, 2034. The notes are unsecured and rank equally in right of payment with all existing and future senior indebtedness and senior in right of payment to all future subordinated indebtedness. The notes were issued at 99.4 per cent of par value, resulting in proceeds of $541 million (US$393 million) and are callable in three years. Interest payments on the notes are made semi-annually, on Feb. 1 and Aug. 1, with the first payment commencing Aug. 1, 2026.
- On Dec. 22, 2025 the Company redeemed all of its outstanding 7.8 per cent US$400 million senior notes in advance of the scheduled maturity date of Nov. 15, 2029.
- During the year ended Dec. 31, 2025, the size of the syndicated credit facility was reduced from $1.95 to $1.90 billion, and the maturity was extended by one year to June 30, 2029.
- During the year ended Dec. 31, 2025, the maturity of the bilateral credit facilities in the aggregate amount of $240 million were also extended by one year to June 30, 2027.
- On March 24, 2025, the Company issued $450 million of senior notes with a fixed annual coupon of 5.6 per cent, maturing on March 24, 2032. The notes are unsecured and rank equally in right of payment with all existing and future senior indebtedness and senior in right of payment to all future subordinated indebtedness. Interest payments on the notes are made semi-annually, on March 24 and Sept. 24.
- On March 25, 2025, the Company repaid its $400 million variable rate term loan facility in advance of the scheduled maturity date of Sept. 7, 2025, with the proceeds received from the $450 million senior notes offering.

- During the year ended Dec. 31, 2025, the Company purchased and cancelled 1,932,800 common shares at an average price of $12.42 per share through our NCIB program, for a total cost of $24 million.

2024

- During the year ended Dec. 31, 2024, the Company purchased and cancelled 13,467,400 common shares at an average price of $10.59 per share through our NCIB program, for a total cost of $143 million; and
- The Company assumed new credit facilities and letter of credit facilities as part of the Heartland acquisition.

Credit Facilities

The Company's credit facilities are summarized in Note 25 of the Consolidated Financial Statements.

The Company maintains a strong financial position, with $1.5 billion in liquidity as at Dec. 31, 2025. Credit facilities are the primary source of short-term liquidity after internally generated cash flow.

As at Dec. 31, 2025, the Company had total committed capacity of $2.2 billion, against which $606 million of letters of credit were issued and $98 million was drawn in cash. Under the $400 million non-committed capacity, the Company issued $223 million of fully backstopped letters of credit, which reduced the available capacity on the committed credit facilities. The Company is in compliance with all covenants under its credit facilities and all undrawn amounts are fully available.

In addition to the net $1.3 billion of remaining committed capacity, the Company held $205 million in cash and cash equivalents, resulting in total available liquidity of $1.5 billion as at Dec. 31, 2025.

TransAlta's debt has terms and conditions, including financial covenants, that are considered ordinary and customary. As at Dec. 31, 2025, the Company was in compliance with all of its debt covenants.

Non-Recourse Debt and Other

All non-recourse debt, the TransAlta OCP LP bond, and the Heartland credit facilities are subject to customary financing conditions and covenants that may restrict the Company's ability to access funds generated by the facilities' operations. Upon meeting certain distribution tests, typically performed once per quarter, the funds can be distributed by the subsidiary entities to their respective parent entity. These conditions include meeting a debt-service coverage ratio prior to distribution, which was met by these entities in the fourth quarter of 2025, with the exception of Windrise Wind LP. The funds in Windrise that have accumulated since the fourth quarter test will remain there until the next debt-service coverage ratio is calculated in the first quarter of 2026. At Dec. 31, 2025, $101 million (Dec. 31, 2024 – $117 million) of cash was subject to these financial restrictions.

At Dec. 31, 2025, $8 million (AU$9 million) of funds held by TEC Hedland Pty Ltd. are not accessible by other corporate entities as the funds must be solely used by the project entities to pay major maintenance costs.

Additionally, certain non-recourse bonds require that reserve accounts be established and funded through cash held on deposit and/or by providing letters of credit.

Between 2026 and 2028, the Company has a total of $664 million of scheduled debt and tax equity repayments. The $750 million of exchangeable securities are exchangeable into an equity ownership interest in TransAlta's Alberta Hydro Assets between Dec. 31, 2024 and Dec. 31, 2028.

Guarantee Contracts

We have obligations to issue letters of credit and cash collateral to secure potential liabilities to certain parties, including those related to potential environmental obligations, commodity risk management and hedging activities, pension plan obligations, construction projects and purchase obligations. At Dec. 31, 2025, we provided letters of credit totalling $829 million (2024 – $865 million) and cash collateral of $92 million (2024 – $124 million).

These letters of credit and cash collateral secure certain amounts included on our Consolidated Statements of Financial Position under risk management liabilities, defined benefit obligations and other long-term liabilities and decommissioning and other provisions. A decrease in the value of letters of credit outstanding as at Dec. 31, 2025 primarily relates to the changes in the contractual requirements under a third-party contract and a decrease in the letters of credit issued under the Heartland credit facilities.

U.S. Tax Equity Financing and Production Tax Credits

The Company owns equity interests in wind facilities that qualify for tax incentives available for renewable energy facilities in the U.S. Current U.S. tax law allows qualified wind energy projects to receive production tax credits (PTCs) that are earned for each MWh of generation during the first 10 years of the project's operation. To monetize tax incentives, the Company has partnered with Tax Equity Investors (TEIs) who invest in these facilities in exchange for a share of the tax incentives and cash. TransAlta accounts for the TEIs' interest as long-term debt, where cash distributions and allocations of tax incentives to the TEIs primarily reduce the long-term debt balance. Upon the TEIs achieving an agreed-upon after-tax investment return, the project flip point occurs (Flip Point). Prior to achieving the Flip Point, the TEIs are allocated substantially all of the taxable attributes, including PTCs produced and a proportion of cash. After the Flip Point has been reached, the Company retains substantially all of the cash and the taxable income (losses) generated by the facility.

The following table outlines information regarding the Company's tax equity financing arrangements with PTC eligibility:

Facility	Commercial operation date	Expected Flip Point	Initial TEI investment ($US)	Expected annual PTC ($US)	Expected annual Pay-go Contribution ($)	TEI allocation of cash distributions (pre-Flip Point) Undiscounted(1) ($US)	TEI allocation of taxable income and PTCs (pre-Flip Point)
Lakeswind	2014	2030	45	—	—	11	99%
Big Level and Antrim	2019	2029	126	11	2	33	99%
Skookumchuck(2)	2020	2030	121	11	—	14	99%
North Carolina Solar	2021	2030	64	—	—	3	— %

(1) Cumulative expected cash distributions from Dec. 31, 2025 to the expected Flip Point.

(2) The Company has a 49 per cent interest in the Skookumchuck wind facility, which is treated as an equity investment under IFRS and our proportionate share of the net earnings is reflected as equity income on the statement of earnings under IFRS.

Returns to Providers of Capital

Interest Income and Interest Expense

The components of interest expense are disclosed in Note 10 of the Consolidated Financial Statements. Net Interest Expense in the reconciliation of our Adjusted EBITDA to our FFO and FCF is calculated as follows:

	3 months ended Dec. 31,		Year ended Dec. 31	
	2025	**2024**	**2025**	**2024**
Interest expense	**81**	92	**347**	324
Less: Interest Income	**(10)**	(11)	**(28)**	(30)
Less: non-cash items(1)	**(11)**	(17)	**(55)**	(63)
Net Interest Expense(2)	**60**	64	**264**	231

(1) Non-cash items include accretion of provisions, financing cost amortization, interest paid in kind and other non-cash items.

(2) Net Interest Expense is a non-IFRS measure, is not defined and has no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the table above for detailed calculation.

Interest income for the three months and year ended Dec. 31, 2025 was comparable to the same period in 2024.

Interest expense for the three months ended Dec. 31, 2025 was lower compared to the same period in 2024, primarily due to lower interest on senior notes following their refinancing at lower interest rates during 2025 and the net gain on the early redemption of the US$400 million senior notes, partially offset by higher interest on debt with the addition of the Heartland term facility.

Interest expense for the year ended Dec. 31, 2025 was higher compared to the same period in 2024, primarily due to higher interest on debt driven by the addition of the Heartland term facility, and lower capitalized interest resulting from lower construction activity during 2025 compared to 2024, partially offset by lower interest on senior notes due to the refinancing at lower interest rates during 2025 and a net gain on the early redemption of the US$400 million senior notes.

Share Capital

For details on Common and preferred shares issued and outstanding refer to Notes 28 and 29 of the Consolidated Financial Statements.

As at Feb.26, 2026 the outstanding number of common shares was 296.8 million. The outstanding number of preferred shares was as follows: Series A 9.6 million, Series B 2.4 million, Series C 10.0 million, Series D 1.0 million, Series E 9.0 million, Series G 6.6 million.

Cash Flows

The following table highlights significant changes in the Consolidated Statements of Cash Flows for the year ended Dec. 31, 2025 and Dec. 31, 2024:

Year ended Dec. 31	2025	2024	Increase/ (decrease)
Cash and cash equivalents, beginning of year	**337**	348	(11)
Provided by (used in):			
Operating activities	**646**	796	(150)
Investing activities	**(418)**	(520)	102
Financing activities	**(362)**	(291)	(71)
Effect of translation on foreign currency cash	**2**	4	(2)
Cash and cash equivalents, end of year	**205**	337	(132)

Cash Flow from Operating Activities

Cash from operating activities for the year ended Dec. 31, 2025, decreased compared to 2024, primarily due to the following:

	Year ended Dec. 31
Cash flow from operating activities for the year ended Dec. 31, 2024	796
Lower gross margin due to lower revenues, partially offset by lower carbon compliance and lower fuel and purchased power costs.	(87)
Higher OM&A due to the addition of the Heartland facilities and associated corporate costs; spending on strategic and growth initiatives, higher spending related to the planning, design and implementation of an ERP system upgrade and the impact from the White Rock and Horizon Hill wind facilities which achieved commercial operation in the first half of 2024, partially offset by lower Heartland acquisition-related transaction and restructuring costs, mainly comprising severance, legal and consulting fees.	(56)
Lower current income tax expense due to a higher loss before income taxes in 2025 compared to earnings before income taxes in the same period in 2024.	94
Higher interest expense primarily due to higher interest on debt driven by the addition of the Heartland term facility, and lower capitalized interest resulting from lower construction activity in 2025.	(23)
Unfavourable change in non-cash operating working capital balances due to lower accounts payable and accrued liabilities and lower income taxes payable, partially offset by lower accounts receivable and lower collateral provided.	(35)
Settlement of Brazeau penalties related to 2024 assessment by the Alberta Market Surveillance Administrator for self-reported contraventions pertaining to hydro ancillary services provided during 2021 and 2022.	(33)
Other non-cash items	(10)
Cash flow from operating activities for the year ended Dec. 31, 2025	**646**

Cash Flow Used in Investing Activities

Cash used in investing activities for the year ended Dec. 31, 2025, decreased compared to 2024, primarily due to the following:

	Year ended Dec. 31
Cash flow used in investing activities for the year ended Dec. 31, 2024	(520)
Increase in long-term financial assets during 2025 related to the Company's investment in Nova.	(145)
Lower additions to PP&E due to larger construction program in the year ended Dec. 31, 2024 compared to the current year.	62
Acquisition of Heartland in 2024.	217
Unfavourable change in non-cash investing working capital balances due to lower capital accruals.	(3)
Other[1]	(29)
Cash flow used in investing activities for the year ended Dec. 31, 2025	**(418)**

(1) Mainly includes finance lease payments, and proceeds on the sale of property plant and equipment offset by an increase in the restricted cash balance and other investing items.

Cash Flow Used in Financing Activities

Cash used in financing activities for the year ended Dec. 31, 2025, increased compared to 2024, primarily due to the following:

	Year ended Dec. 31
Cash flow used in financing activities for the year ended Dec. 31, 2024	(291)
Repayment of US$400 million 7.8 per cent senior notes during the fourth quarter of 2025.	(573)
Repayment of the $400 million variable rate term facility during the first quarter of 2025.	(400)
Higher amount of long-term debt repayments during 2025 compared to prior year.	(175)
Issuance of US$400 million 5.9 per cent senior notes during the fourth quarter of 2025.	541
Issuance of $450 million 5.6 per cent senior notes during the first quarter of 2025.	450
Lower repurchases of common shares under the NCIB in 2025 compared to prior year.	119
Repayments, net of cash drawings under the syndicated credit facility.	(48)
Lower distributions paid to non-controlling interests due to lower net earnings.	29
Higher financing fees related to the issuance of new debt.	(7)
Other[1]	(7)
Cash flow used in financing activities for the year ended Dec. 31, 2025	**(362)**

(1) Consists of higher dividends paid on common shares, lower proceeds on issuance of common shares and lower realized gains on financial instruments, partially offset by a favourable change in non-cash financing working capital balances and lower payments under finance lease obligations.

Capital Expenditures

Sustaining capital and growth and development capital expenditures represent supplementary financial measures used to present our spending related to the safe and reliable operation of our existing facilities and the construction of projects, respectively. The sum of sustaining capital and growth and development capital expenditures, adjusted for non-cash items and transfers, is equal to the additions to property, plant and equipment and intangible assets, and development capital expenditures during the period in the consolidated statement of cash flows.

Sustaining Capital Expenditures

We are in a long-cycle business that requires significant capital expenditures. Our goal is to undertake sustaining capital expenditures that ensure our facilities operate reliably and safely. Sustaining capital are capital expenditures incurred for major maintenance to sustain the existing capacity or production of the existing asset to the end of its useful life.

The Company's sustaining capital expenditures by segment are summarized in the table below:

	3 months ended Dec. 31		Year ended Dec. 31	
	2025	**2024**	**2025**	**2024**
Hydro	**14**	22	**46**	56
Wind and Solar	**6**	8	**24**	20
Gas	**22**	32	**78**	52
Energy Transition	**—**	—	**—**	12
Corporate	**3**	5	**14**	2
Sustaining capital expenditures	**45**	67	**162**	142

Total sustaining capital expenditures for the three months ended Dec. 31, 2025 were $22 million lower compared to the same period in 2024, primarily due to:

- Lower major maintenance for our Canadian gas facilities due to timing of spend; and
- Lower major maintenance at our Hydro facilities in Alberta due to timing of spend.

Total sustaining capital expenditures in 2025 were $20 million higher compared to 2024, primarily due to:

- Higher major maintenance for our Canadian gas facilities due to timing of spend and the addition of maintenance for the gas facilities acquired from Heartland;
- Higher major maintenance in the Wind and Solar segment; partially offset by
- No major maintenance occurring in the Energy Transition segment in the current period; and
- Lower major maintenance at our Hydro facilities in Alberta due to timing of spend.

Total sustaining capital expenditures for the year ended Dec. 31, 2024 were also impacted by the receipt of a lease incentive related to the Company's head office during the first quarter of 2024, included in the Corporate segment.

Growth and Development Capital Expenditures

Growth and development expenditures are impacted by the timing and construction of projects within the development pipeline. Growth capital represents capital expenditures incurred that will add megawatts to the Company or will generate new incremental revenues and consists of engineering, design, contracting, permitting, payroll and overhead expenditures that meet capitalization criteria.

The following table provides our growth and development spending by segment:

	3 months ended Dec. 31		Year ended Dec. 31	
	2025	**2024**	**2025**	**2024**
Hydro	**1**	3	**3**	9
Wind and Solar	**34**	10	**33**	64
Gas	**13**	21	**56**	59
Energy Transition	**4**	—	**8**	—
Growth and development expenditures	**52**	34	**100**	132

Growth and development expenditures for the three months ended Dec. 31, 2025 were higher compared to the same period in 2024, primarily due to:

- Higher spend in the Wind and Solar segment driven by the final completion payments for the Oklahoma wind facilities and the Garden Plain wind facility payment to a third-party contractor for a dispute arising during the construction phase; partially offset by
- Lower spend in the Gas segment primarily due to a completion of the capital maintenance at Sarnia caused by the plant outage during a portion of the fourth quarter in 2024.

Growth and development expenditures for the year ended Dec. 31, 2025 were lower compared to 2024, primarily due to:

- Lower spend for Wind and Solar as the majority of the growth projects achieved commercial operation in the first half of 2024; partially offset by
- Higher spend in the Energy Transition segment related to the Centralia conversion from coal to natural gas, which extends the operating life of the existing plant.

Refer to the "Strategic Priorities" section of this MD&A for more details.

Strategic Priorities

The Company remains focused on investing in electricity solutions that meet the evolving needs of customers and communities. Our strategy focuses on maximizing the value of our base business, including the effective operation of our diverse fleet, enhancing value with our unique marketing and trading capabilities, continuously optimizing our Alberta fleet and expanding our generating portfolio by adding strategic assets through M&A, redevelopment at our legacy generation sites and from our development pipeline. With a disciplined approach to capital allocation, we are well-positioned to create long-term shareholder value through opportunities in our core operating markets of Canada, the U.S. and Western Australia.

The Company continues to make strong progress on key strategic priorities, ensuring the business remains resilient, growth-focused and aligned with the evolving energy landscape.

Operate with Excellence to Maximize Value of Our Base Business

Safe, Reliable Operations

Safety is our core value, and safe production is the only production. The Company's safety driven operational strategy is built on our extensive operating history and the expertise of our team, enabling us to deliver our current and future operational commitments. We are also committed to continuous improvement and identifying additional ways to maximize operational efficiencies and reduce costs, which ultimately benefit our customers and increase shareholder value.

Optimize Alberta Fleet

In Alberta, the Company continues to proactively deploy hedging strategies and optimization activities to mitigate the impact of lower merchant power prices. The acquisition of Heartland Generation has significantly strengthened our Alberta portfolio, and our fleet is continuously optimized to address increasing volatility in supply and intermittency in Alberta. The Company is maximizing the value of its hydro fleet by enhancing its operational capabilities and flexibility.

The Company is also advancing initiatives to maximize the value of our existing thermal assets and meet the growing demand for data centre load as well as affordable and reliable power.

Enhance Financial Flexibility

The Company maintains a strong financial position, with $1.5 billion in liquidity as of Dec. 31, 2025, and a disciplined approach to capital allocation and cost control. The Company balances investments in growth, debt repayments and returns to shareholders through share repurchases and dividend payments. Reflecting confidence in the business, the annual common share dividend was increased by eight per cent to $0.28 per share, our seventh consecutive dividend increase, effective July 1, 2026.

Grow with Discipline to Maximize Value for Our Shareholders

Advance Legacy Site Projects

The Company is seeing considerable opportunities to support the build-out of the energy transition, inclusive of data centres, with innovative, reliable and affordable power solutions in our core operating jurisdictions of Alberta and Washington State, where we are actively pursuing accretive opportunities with existing and prospective customers. We believe that our current sites hold significant value and provide unique advantages to customers that can be realized through brownfield development.

Specifically, we are pleased to have announced a tolling agreement to progress a coal-to-gas conversion at Centralia, along with a memorandum of understanding to advance a data centre development in Alberta.

Pursue Accretive M&A

The Company will continue to pursue M&A opportunities, with a focus within our core jurisdictions that are accretive and complementary to our asset portfolio or can be enhanced through our energy marketing and trading business.

Develop Greenfield Projects

Development of greenfield projects is focused in our core jurisdictions and is diversified across fuel types and technologies. The Company's development pipeline provides optionality for attractive long-term growth that will increase shareholder value beyond opportunities that are present at our legacy sites.

Growth

Over the course of 2024 and 2025, we refined our development pipeline to align with evolving regulatory and interconnection dynamics, while progressing opportunities at our legacy assets. The pipeline now includes 860 MW of mid-stage projects and 2,590 MW of early-stage projects. We remain focused on the redevelopment of existing thermal sites and pursuing greenfield and M&A opportunities in our core markets.

Early-Stage Development

Project feasibility is evaluated through initial assessments including market, technical, land and permitting evaluations. Milestones include securing key landowner control, establishment of interconnection access, transmission capacity, on-site resource measurement and initial stakeholder consultations. Projects are advanced to mid-stage development if a viable economic development path is identified.

The following table shows the pipeline of future growth projects currently under early-stage development:

Early-Stage Projects (MW)	Thermal Generation	Wind	Solar	Storage	Total
Various	1,590	465	190	345	2,590

Mid-Stage Development

Project scope and commercial structure are matured at mid-stage development. Key milestones include finalizing core technologies and location, securing full land control, progressing through the interconnection process, initiating offtake negotiations, advancing environmental and regulatory applications, and preparing a Class 4 capital cost estimate. Successful completion of mid-stage development means a project is ready for detailed definition to support a final investment decision.

The following table shows the pipeline of future growth projects currently under mid-stage development:

Mid-Stage Projects (MW)	Thermal Generation	Wind	Solar	Storage	Total
Canada	—	100	—	20	120
U.S.	700	—	—	—	700
Western Australia	—	—	40	—	40
Total	700	100	40	20	860

Projects under Construction

Current projects under construction are financed through existing liquidity in the near term and we continue to explore permanent financing solutions on an asset-by asset basis.

The following projects have been approved by the Board of Directors, have executed Power Purchase Agreements (PPA) and are currently under construction or in the process of being commissioned:

				Total project ($ millions)				
Project	Type	Region	MW	Estimated spend	Spent to date	Target completion date	PPA Term (years)	Status
Western Australia								
Mount Keith West network upgrade	Transmission	WA	—	AU$40 — AU$42	AU$37	Q1 2026	13	• All major equipment delivered and installed • On-track to be completed in Q1 2026
Total[(1)]			—	$34 — $36	$36			

(1) Total estimated spend was converted using a Canadian dollar forward exchange rate for 2025. Spent to date was converted using the period-end closing rate.

Other Consolidated Analysis

Related-Party Transactions

In the normal course of operations, we enter into transactions on market terms with related parties, including consolidated and equity accounted entities, which have been measured at exchange value and are recognized in the consolidated financial statements, including, but not limited to power purchase and derivative contracts. Refer to Note 35, Related-Party Transactions in the consolidated financial statements for further details.

Commitments

Refer to Note 36 Commitments and Contingencies in the consolidated financial statements for further details.

Contingencies

TransAlta is occasionally named as a party in various claims and legal and regulatory proceedings that arise during the normal course of its business. TransAlta reviews each of these claims, including the nature of the claim, the amount in dispute or claimed and the availability of insurance coverage. There can be no assurance that any particular claim will be resolved in the Company's favour or that such claims may not have a material adverse effect on TransAlta. Inquiries from regulatory bodies may also arise in the normal course of business, to which the Company responds as required.

The Company conducts internal reviews of its offers and offer behaviour in both the energy and ancillary services markets in Alberta on an ongoing basis and will self-report suspected contraventions or respond to inquiries from regulatory agencies as required. There currently is no certainty that any particular matter will be resolved in the Company's favour or that such matters may not have a material adverse effect on TransAlta.

Refer to Note 36 Commitments and Contingencies in the consolidated financial statements for further details.

Selected Annual Information

Year ended and as at Dec. 31	2025	2024	2023
Revenues	**2,405**	2,845	3,355
(Loss) earnings before income taxes	**(141)**	319	880
Net (loss) earnings attributable to common shareholders	**(190)**	177	644
Net (loss) earnings per share attributable to common shareholders, basic and diluted	**(0.64)**	0.59	2.33
Total assets	**8,661**	9,499	8,659
Total non-current liabilities	**5,366**	5,087	5,253
Dividends declared per common share	**0.26**	0.24	0.22
Dividends declared per preferred share:	**1.36**	1.36	1.33
Series A	**0.72**	0.72	0.72
Series B	**1.16**	1.60	1.72
Series C	**1.46**	1.46	1.46
Series D	**1.42**	1.87	1.99
Series E	**1.72**	1.72	1.72
Series G	**1.69**	1.47	1.25
Series I(1)	**70.00**	70.00	70.00

(1) The Series I Preferred Shares are accounted for as long-term debt. Refer to Note 26 for further details.

Refer to "Financial Performance Review of Consolidated Information" and "Selected Quarterly Information" sections of this MD&A for the factors impacting the years ended Dec. 31, 2025 and 2024.

Revenues totalled $2,845 million for the year ended Dec. 31, 2024, a decrease of $510 million, or 15 per cent, compared to 2023, primarily due to:

- Lower merchant spot and hedged power prices across markets; partially offset by
- Commercial operation of the White Rock and Horizon Hill wind facilities, the Northern Goldfields solar facilities, the Mount Keith 132kV expansion and return to service of the Kent Hills wind facilities; and
- Higher revenue due to the acquisition of Heartland in the fourth quarter of 2024.

Earnings before income taxes for the year ended Dec. 31, 2024 decreased by $561 million, or 64 per cent, compared to 2023, primarily due to:

- The factors causing lower revenues above;
- Higher asset impairment charges related to an increase in the decommissioning provision on retired assets, driven by a decrease in discount rates and revisions in estimated decommissioning costs, and higher impairment charges related to development projects that are no longer proceeding;
- Higher OM&A due to Heartland acquisition-related transaction and restructuring costs, spending relating to planning and design work on a planned upgrade to our ERP system and penalties assessed by the Alberta Market Surveillance Administrator for self-reported contraventions pertaining to Hydro ancillary services provided during 2021 and 2022;
- Higher interest expense primarily due to lower capitalized interest resulting from lower construction activity in 2024 compared to 2023; partially offset by
- Lower fuel and purchased power costs due to lower Mid-Columbia prices on repurchases of power, lower fuel consumption due to higher dispatch optimization in the Gas segment in Alberta, higher economic dispatch in the Energy Transition segment and lower natural gas prices; and
- Lower depreciation expense due to revisions to useful lives of certain facilities in prior and current periods, partially offset by commercial operation of the White Rock and Horizon Hill wind facilities and return to service of the Kent Hills wind facilities.

Net earnings attributable to common shareholders for the year ended Dec. 31, 2024, decreased by $467 million, or 73 per cent, compared to 2023, primarily due to:

- The factors causing lower earnings before income taxes as explained above; partially offset by
- Lower net earnings attributable to non-controlling interests primarily due to lower net earnings for TA Cogen, resulting from lower merchant pricing in the Alberta market.

Total assets as at Dec. 31, 2024 increased by $840 million compared to Dec. 31, 2023 primarily due to the Heartland acquisition.

Total non-current liabilities as at Dec. 31, 2024 decreased by $166 million compared to Dec. 31, 2023 primarily due to:

- The exchangeable securities being classified as current liabilities; partially offset by
- An increase in non-current liabilities due to the acquisition of Heartland.

Non-IFRS and Supplementary Financial Measures

We use a number of financial measures to evaluate our performance and the performance of our business segments, including measures and ratios that are presented on a non-IFRS basis, as described below. Unless otherwise indicated, all amounts are in Canadian dollars and have been derived from our consolidated financial statements prepared in accordance with IFRS. We believe that these non-IFRS amounts, measures and ratios, read together with our IFRS amounts, provide readers with a better understanding of how management assesses results.

Non-IFRS amounts, measures and ratios do not have standardized meanings under IFRS. They are unlikely to be comparable to similar measures presented by other companies and should not be viewed in isolation from, as an alternative to, or more meaningful than our IFRS results.

We calculate adjusted measures by adjusting certain IFRS measures for certain items that we do not believe reflect our ongoing operations in the period. Except as otherwise described, these adjusted measures are calculated on a consistent basis from period to period and are adjusted for specific items in each period, unless stated otherwise.

Non-IFRS Financial Measures

Adjusted EBITDA, Adjusted Revenues, Adjusted Fuel and Purchased Power, Adjusted Gross Margin, Adjusted OM&A, Adjusted Net Other Operating Income, Adjusted (Loss) Earnings before Income Taxes, Adjusted Net (Loss) Earnings after Income Taxes Attributable to Common Shareholders, FFO, FCF, Total Consolidated Net Debt, Adjusted Net Debt and Net Interest Expense are non-IFRS measures that are presented in this MD&A. This section provides additional information on these non-IFRS measures, including their reconciliation to the most comparable IFRS measure.

Adjusted EBITDA

Each business segment assumes responsibility for its operating results measured by Adjusted EBITDA. Adjusted EBITDA is an important metric for management that represents our core operational results.

During the first quarter of 2025, our Adjusted EBITDA composition was amended to remove the impact of realized gain (loss) on closed exchange positions, which was included in Adjusted EBITDA composition until the fourth quarter of 2024. The adjustment was intended to explain a timing difference between our internally and externally reported results and was useful at a time when markets were more volatile. The impact of realized gain (loss) on closed exchange positions was removed to simplify our reporting. Accordingly, the Company has applied this composition to all previously reported periods.

During the first quarter of 2025, our Adjusted EBITDA composition was amended to remove the impact of Australian interest income, which was included in Adjusted EBITDA composition until the fourth quarter of 2024. Initially, on the commissioning of the South Hedland facility in July 2017, we prepaid approximately $74 million of electricity transmission and distribution costs. Interest income, which was recorded on the prepaid funds, was reclassified as a reduction in the transmission and distribution costs expensed each period to reflect the net cost to the business. The impact of Australian interest income was removed to simplify our reporting since the amounts were not material. Accordingly, the Company has applied this composition to all previously reported periods.

Interest, taxes, depreciation and amortization are not included, as differences in accounting treatment may distort our core business results. In addition, certain reclassifications and adjustments are made to better assess results, excluding those items that may not be reflective of ongoing business performance. This presentation may facilitate the readers' analysis of trends. The most directly comparable IFRS measure is earnings before income taxes.

The following are descriptions of the adjustments made to arrive at the non-IFRS measures:

Adjusted Revenue

Adjusted Revenues are revenues (the most directly comparable IFRS measure) adjusted to exclude:

- The impact of unrealized mark-to-market gains or losses and unrealized foreign exchange gains or losses on commodity transactions.
- Certain assets that we own in Canada and Western Australia are fully contracted and recorded as finance leases under IFRS. We believe that it is more appropriate to reflect the payments we receive under the contracts as a capacity payment in our revenues instead of as finance lease income and a decrease in finance lease receivables.
- Revenues from the Required Divestitures as they do not reflect ongoing business performance.
- The Brazeau penalties in 2024, which were issued by the Alberta Market Surveillance Administrator for self-reported contraventions pertaining to Hydro ancillary services provided during 2021 and 2022. The penalties have been excluded from the Adjusted Revenues for the year ended Dec. 31, 2024 as they do not represent ongoing performance. In 2022 a provision of $20 million was initially recognized in revenue reflecting a potential disgorgement of revenue and $2 million for potential penalties and fines. The final assessment contained no disgorgement of revenue and penalties of $33 million. This resulted in a reversal of the original disgorgement provision in revenue in the year ended Dec. 31, 2024 and recognition of the full amount of the penalties assessed in OM&A.

Adjusted Fuel and Purchased Power

Adjusted Fuel and Purchased Power is fuel and purchased power (the most directly comparable IFRS measure) adjusted to exclude fuel and purchased power from the Required Divestitures as it does not reflect ongoing business performance.

Adjusted OM&A

Adjusted OM&A is OM&A (the most directly comparable IFRS measure) adjusted to exclude:

- Termination, restructuring and facility shutdown costs mainly for costs incurred as part of strategic decisions and facility shutdowns, and that do not represent ongoing business performance and are not reflective of the Company's ability to generate cash flows in the future. Termination, restructuring and facility shutdown costs mainly include termination, severance, inventory write downs and related costs.
- Acquisition-related transaction and restructuring costs, mainly comprising severance, legal and consultant fees as these do not reflect ongoing business performance.
- ERP integration costs representing planning, design and implementation costs of upgrades to the existing ERP system as they represent project costs that do not occur on a regular basis, and therefore do not reflect ongoing performance.
- OM&A from the Required Divestitures as it does not reflect ongoing business performance.

- The Brazeau penalties in 2024, which were issued by the Alberta Market Surveillance Administrator for self-reported contraventions pertaining to Hydro ancillary services provided during 2021 and 2022. The penalties have been excluded from OM&A for the year ended Dec. 31, 2024 as it does not represent ongoing performance. The provision was initially recognized in 2022 based on an estimate and revised in 2024 based on the actual resolution of the matter.

Adjusted Net Other Operating Income

Adjusted Net Other Operating Income is net other operating income (the most directly comparable IFRS measure) adjusted to exclude:

- Insurance recoveries related to the Kent Hills replacement costs of the tower collapse as these relate to investing activities and are not reflective of ongoing business performance.
- The Sundance A decommissioning cost reimbursement in 2024 is not included as it relates to a settlement of a contingency for a facility that is no longer in operation. Refer to Note 8 from our consolidated financial statements for further details.

Additional Adjustments

Adjustments to Earnings (Loss) in Addition to Interest, Taxes, Depreciation and Amortization

- Fair value change in contingent consideration payable is not included as it is not reflective of ongoing business performance.
- Asset impairment charges and reversals are not included as these are accounting adjustments that impact depreciation and amortization and do not reflect ongoing business performance.
- Any gains or losses on asset sales or foreign exchange gains or losses are not included as these are not part of operating income.

Adjustments for Equity-Accounted Investments

During the fourth quarter of 2020, we acquired a 49 per cent interest in the Skookumchuck wind facility, which is treated as an equity investment under IFRS and our proportionate share of the net earnings is reflected as equity income on the statement of earnings under IFRS. As this investment is part of our regular power-generating operations, we have included our proportionate share of Adjusted EBITDA for the Skookumchuck wind facility in our total Adjusted EBITDA. In addition, in the Wind and Solar adjusted results, we have included our proportionate share of revenues and expenses to reflect the full operational results of this investment. We have not included Adjusted EBITDA of other equity-accounted investments in our total Adjusted EBITDA as it does not represent our regular power-generating operations.

Adjusted (Loss) Earnings before Income Taxes

Adjusted (loss) Earnings before Income Taxes represents segmented (loss) earnings adjusted for certain items that we believe do not reflect ongoing business performance and is an important metric for evaluating performance trends in each segment.

For details of the adjustments made to (loss) earnings before income taxes (the most directly comparable IFRS measure) to calculate Adjusted (Loss) Earnings before Income Taxes, refer to the "Reconciliation of Non-IFRS Measures on a Consolidated Basis by Segment" section of this MD&A.

Adjusted Net (Loss) Earnings Attributable to Common Shareholders

Adjusted Net (Loss) Earnings Attributable to Common Shareholders represents net (loss) earnings attributable to common shareholders adjusted for specific reclassifications and adjustments and their tax impact, and is an important metric for evaluating performance. For details of the reclassifications and adjustments made to net (loss) earnings attributable to common shareholders (the most directly comparable IFRS measure), please refer to the reconciliation of net (loss) earnings to Adjusted Net (Loss) Earnings attributable to common shareholders in the "Reconciliation of Non-IFRS Measures on a Consolidated Basis by Segment" section of this MD&A.

Adjusted Net (Loss) Earnings per Common Share Attributable to Common Shareholders

Adjusted Net (Loss) Earnings per Common Share Attributable to Common Shareholders is calculated as Adjusted Net (Loss) Earnings attributable to Common Shareholders divided by a weighted average number of common shares outstanding during the period. The measure is useful in showing the earnings per common share for our core operational results as it excludes the impact of items that do not reflect an ongoing business performance. Adjusted Net (Loss) Earnings Attributable per Common Share is a non-IFRS ratio and the most directly comparable IFRS measure is net (loss) income per common share attributable to common shareholders. Refer to the reconciliation of (loss) earnings before income taxes to Adjusted Net (Loss) Earnings Attributable to Common Shareholders in the "Reconciliation of Non-IFRS Measures on a Consolidated Basis by Segment" section of this MD&A.

Funds From Operations (FFO)

FFO is an important metric as it provides a proxy for cash generated from operating activities before changes in working capital and provides the ability to evaluate cash flow trends in comparison with results from prior periods. FFO is a non-IFRS measure. For a description of the adjustments made to cash flow from operating activities (the most directly comparable IFRS measure) to calculate FFO, refer to the "Reconciliation of Cash Flow from Operations to FFO and FCF" section of this MD&A.

Adjustments to Cash Flow from Operations

- FFO related to the Skookumchuck wind facility, which is treated as an equity-accounted investment under IFRS and equity income, net of distributions from joint ventures, is included in cash flow from operations under IFRS. As this investment is part of our regular power-generating operations, we have included our proportionate share of FFO.
- Payments received on finance lease receivables are reclassified to reflect cash from operations.
- We adjust for costs associated with acquisition-related transaction and restructuring costs that are not reflective of ongoing operations.
- We adjust for the items included in the cash flow from operating activities related to the decision in 2020 to accelerate being off-coal and the shutdown of the Highvale mine in 2021 (Clean energy transition provisions and adjustments).
- Penalties totalling $33 million were issued by the Alberta Market Surveillance Administrator for self-reported contraventions pertaining to ancillary services provided during 2021 and 2022 at our Brazeau hydro facility. The penalties were recognized in OM&A during the fourth quarter of 2024 and paid during the first quarter of 2025, and have been excluded from FFO composition as they do not reflect ongoing business performance.
- Sundance A decommissioning cost reimbursement in 2024 is not included as it relates to a settlement of a contingency for a facility that is no longer in operation.
- Other adjustments include payments/receipts for production tax credits, which are reductions to tax equity debt and include distributions from equity-accounted joint ventures.

Free Cash Flow (FCF)

FCF is an important metric as it represents the amount of cash that is available to invest in growth initiatives, make scheduled principal debt repayments, repay maturing debt, pay common share dividends or repurchase common shares, and it provides the ability to compare cash flow trends with results from prior periods. Changes in working capital are excluded so that FFO and FCF are not distorted by changes that we consider temporary in nature, reflecting, among other things, the impact of seasonal factors and timing of receipts and payments. FCF is a non-IFRS measure. For a description of the adjustments made to cash flow from operating activities (the most directly comparable IFRS measure) to calculate FCF, refer to the "Reconciliation of Cash Flow from Operations to FFO and FCF" section of this MD&A.

Adjusted Net Debt

Adjusted Net Debt is calculated as a sum of current and non-current portions of credit facilities, long-term debt and lease liabilities, exchangeable debentures, 50 per cent of issued preferred shares and exchangeable preferred shares, less cash and cash equivalents, less the principal portion of TransAlta OCP restricted cash and fair value of hedging instruments on debt. Presenting this item from period to period provides management and investors with the ability to evaluate leverage trends more readily in comparison with prior periods' results. The most directly comparable IFRS measure is total credit facilities, long-term debt and lease liabilities.

Total Consolidated Net Debt

Total consolidated debt is calculated as a sum of current and non-current portions of credit facilities, long-term debt and lease liabilities, exchangeable debentures, less principal portion of TransAlta OCP restricted cash. Total Consolidated Net Debt excludes the exchangeable preferred shares as they are considered equity with dividend payments for credit purposes. Presenting this item from period to period provides management and investors with the ability to evaluate leverage trends more readily in comparison with prior periods' results. The most directly comparable IFRS measure is total credit facilities, long-term debt and lease liabilities; for reconciliation, refer to "Financial Capital" section of this MD&A.

Net Interest Expense

Net Interest Expense is calculated as total interest expense less total interest income and non-cash items. For detailed calculation refer to the table in the "Reconciliation of Adjusted EBITDA to FFO and FCF" section of this MD&A. Net Interest Expense is a proxy for the actual cash interest paid that approximates the cash outflow in the FFO and FCF calculation. The most directly comparable IFRS measure is total interest expense.

Adjusted Gross Margin

Adjusted Gross Margin is calculated as Adjusted Revenues less Adjusted Fuel and Purchased Power and carbon compliance costs, where adjustments to revenue or fuel and purchased power were applied as stated above. The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment. The most directly comparable IFRS measure is gross margin in the consolidated statement of earnings.

Non-IFRS Ratios

FFO per share, FCF per share and Adjusted Net Debt to Adjusted EBITDA are non-IFRS ratios that are presented in this MD&A. Refer to the "Reconciliation of Cash Flow from Operations to FFO and FCF" and "Key Non-IFRS Financial Ratios" sections of this MD&A for additional information.

FFO per Share and FCF per Share

FFO per share and FCF per share are calculated using the weighted average number of common shares outstanding during the period. FFO per share and FCF per share are non-IFRS ratios.

Supplementary Financial Measures

- Available liquidity
- Cash flow from operating activities per share
- Sustaining capital expenditures
- Growth and development expenditures
- Alberta Hydro Assets ancillary services revenues (total and revenues per MWh)
- Alberta Hydro Assets revenues (total and revenues per MWh)
- Other Hydro Assets revenues
- Other Hydro revenues
- Highvale mine reclamation spend
- Centralia mine reclamation spend
- Realized foreign exchange gain (loss)
- Unrealized foreign exchange gain (loss)
- The Alberta electricity portfolio metrics
- Realized merchant power price per MWh
- Hedged power price average per MWh
- Fuel cost per MWh
- Carbon compliance per MWh

Fourth Quarter Reconciliation of Non-IFRS Measures on a Consolidated Basis by Segment

The following table reflects Adjusted EBITDA by segment and provides reconciliation to loss before income taxes for the three months ended Dec. 31, 2025:

	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	58	58	347	110	28	5	606	(7)	—	599
Reclassifications and adjustments:										
Unrealized mark-to-market loss (gain)	2	83	(1)	5	1	—	90	—	(90)	—
Decrease in finance lease receivable	—	1	6	—	—	—	7	—	(7)	—
Finance lease income	—	1	5	—	—	—	6	—	(6)	—
Unrealized foreign exchange loss on commodity	—	—	2	—	1	—	3	—	(3)	—
Adjusted Revenue	60	143	359	115	30	5	712	(7)	(106)	599
Fuel and purchased power	(4)	(7)	(161)	(81)	—	(5)	(258)	—	—	(258)
Carbon compliance	—	(1)	(39)	—	—	—	(40)	—	—	(40)
Adjusted Gross Margin	56	135	159	34	30	—	414	(7)	(106)	301
OM&A	(16)	(24)	(69)	(20)	(9)	(50)	(188)	2	—	(186)
Reclassifications and adjustments:										
Termination, restructuring and facility shutdown costs	—	—	1	2	—	12	15	—	(15)	—
ERP integration costs	—	—	—	—	—	9	9	—	(9)	—
Acquisition-related transaction and restructuring costs	—	—	—	—	—	1	1	—	(1)	—
Adjusted OM&A	(16)	(24)	(68)	(18)	(9)	(28)	(163)	2	(25)	(186)
Taxes, other than income taxes	(1)	(8)	(6)	—	—	1	(14)	—	—	(14)
Net other operating (expense) income	—	(1)	11	—	—	—	10	—	—	10
Adjusted EBITDA[2]	39	102	96	16	21	(27)	247			
Depreciation and amortization	(12)	(52)	(69)	(10)	—	(6)	(149)	1	—	(148)
Equity income	—	—	—	—	—	—	—	—	4	4
Interest income	—	—	—	—	—	9	9	1	—	10
Interest expense	—	—	—	—	—	(80)	(80)	(1)	—	(81)
Realized foreign exchange loss[3]	—	—	—	—	—	(13)	(13)	—	—	(13)
Adjusted Earnings (Loss) before income taxes[2]	27	50	27	6	21	(117)	14			
Reclassifications and adjustments above	(2)	(85)	(13)	(7)	(2)	(22)	(131)			
Finance lease income	—	1	5	—	—	—	6	—	—	6
Skookumchuk earnings reclass to Equity income[1]	—	(4)	—	—	—	4	—	—	—	—
Asset impairment reversals	—	—	—	65	—	3	68	—	—	68
Loss on sale of assets and other	—	—	(4)	—	—	(5)	(9)	—	—	(9)
Unrealized foreign exchange gain[3]	—	—	—	—	—	10	10	—	—	10
Earnings (loss) before income taxes	25	(38)	15	64	19	(127)	(42)	—	—	(42)

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.

(2) Adjusted EBITDA, Adjusted Earnings (Loss) before income taxes are non-IFRS measures, are not defined and has no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the "Additional IFRS Measures and Non-IFRS Measures" section of this MD&A.

(3) Realized and unrealized foreign exchange (loss) gain are supplementary financial measures. Refer to the "Non-IFRS and Supplementary Financial Measures" section of this MD&A for more details.

The following table reflects Adjusted EBITDA by segment and provides reconciliation to loss before income taxes for the three months ended Dec. 31, 2024:

	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	93	104	319	155	14	—	685	(7)	—	678
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	4	23	26	(8)	19	—	64	—	(64)	—
Decrease in finance lease receivable	—	1	5	—	—	—	6	—	(6)	—
Finance lease income	—	2	3	—	—	—	5	—	(5)	—
Revenues from Required Divestitures	—	—	(1)	—	—	—	(1)	—	1	—
Brazeau penalties	(20)	—	—	—	—	—	(20)	—	20	—
Unrealized foreign exchange gain on commodity	—	—	(1)	—	—	—	(1)	—	1	—
Adjusted Revenues	77	130	351	147	33	—	738	(7)	(53)	678
Fuel and purchased power	(3)	(8)	(136)	(102)	—	—	(249)	—	—	(249)
Reclassifications and adjustments:										
Fuel and purchased power related to Required Divestitures	—	—	1	—	—	—	1	—	(1)	—
Adjusted Fuel and Purchased Power	(3)	(8)	(135)	(102)	—	—	(248)	—	(1)	(249)
Carbon compliance	—	—	(39)	—	—	—	(39)	—	—	(39)
Gross margin	74	122	177	45	33	—	451	(7)	(54)	390
OM&A	(47)	(27)	(67)	(19)	(7)	(68)	(235)	1	—	(234)
Reclassifications and adjustments:										
Brazeau penalties	31	—	—	—	—	—	31	—	(31)	—
ERP integration costs	—	—	—	—	—	14	14	—	(14)	—
Acquisition-related transaction and restructuring costs	—	—	—	—	—	16	16	—	(16)	—
Adjusted OM&A	(16)	(27)	(67)	(19)	(7)	(38)	(174)	1	(61)	(234)
Taxes, other than income taxes	(1)	(3)	(4)	—	—	—	(8)	(1)	—	(9)
Net other operating income	—	3	10	9	—	—	22	—	—	22
Reclassifications and adjustments:										
Sundance A decommissioning cost reimbursement	—	—	—	(9)	—	—	(9)	—	9	—
Adjusted Net Other Operating Income	—	3	10	—	—	—	13	—	9	22
Adjusted EBITDA[2][3]	57	95	116	26	26	(38)	282			
Depreciation and amortization	(18)	(55)	(49)	(18)	—	(4)	(144)	1	—	(143)
Equity income	—	—	—	—	—	(3)	(3)	—	5	2
Interest income	—	—	—	—	—	11	11	—	—	11
Interest expense	—	—	—	—	—	(93)	(93)	1	—	(92)
Realized foreign exchange loss[4]	—	—	—	—	—	(15)	(15)	—	—	(15)
Adjusted Earnings (Loss) before income taxes[2]	39	40	67	8	26	(142)	38			
Reclassifications and adjustments above	(15)	(26)	(33)	17	(19)	(30)	(106)	—	—	—
Finance lease income	—	2	3	—	—	—	5	—	—	5
Skookumchuk earnings reclass to equity income[1]	—	(5)	—	—	—	5	—	—	—	—
Asset impairment charges	—	1	—	(10)	—	(11)	(20)	—	—	(20)
Unrealized foreign exchange gain[4]	—	—	—	—	—	32	32	—	—	32
Earnings (loss) before income taxes	24	12	37	15	7	(146)	(51)	—	—	(51)

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.

(2) Adjusted EBITDA, Adjusted Earnings (Loss) before income taxes are non-IFRS measures, are not defined, have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the "Non-IFRS and Supplementary Financial Measures" section of this MD&A.

(3) During the first quarter of 2025, our Adjusted EBITDA composition was amended to exclude the impact of realized gain (loss) on closed exchange positions and Australian interest income. Therefore, the Company has applied this composition to all previously reported periods.

(4) Realized and unrealized foreign exchange (loss) gain are supplementary financial measures. Refer to the "Non-IFRS and Supplementary Financial Measures" section of this MD&A for more details.

Full-Year Reconciliation of Non-IFRS Measures on a Consolidated Basis by Segment

The following table reflects Adjusted EBITDA by segment and provides reconciliation to loss before income taxes for the year ended Dec. 31, 2025:

	Hydro	Wind & Solar[(1)]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments[(1)]	Reclass adjustments	IFRS financials
Revenues	368	227	1,267	495	130	(61)	2,426	(21)	—	2,405
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	(4)	265	26	9	(8)	—	288	—	(288)	—
Decrease in finance lease receivable	—	3	27	—	—	—	30	—	(30)	—
Finance lease income	—	5	18	—	—	—	23	—	(23)	—
Revenues from Required Divestitures	—	—	(11)	—	—	—	(11)	—	11	—
Unrealized foreign exchange loss on commodity	—	—	1	—	—	—	1	—	(1)	—
Adjusted Revenue	364	500	1,328	504	122	(61)	2,757	(21)	(331)	2,405
Fuel and purchased power	(20)	(31)	(549)	(328)	—	(7)	(935)	—	—	(935)
Reclassifications and adjustments:										
Fuel and purchased power related to Required Divestitures	—	—	2	—	—	—	2	—	(2)	—
Adjusted Fuel and Purchased Power	(20)	(31)	(547)	(328)	—	(7)	(933)	—	(2)	(935)
Carbon compliance (costs) recovery	—	(3)	(115)	—	—	68	(50)	—	—	(50)
Adjusted Gross Margin	344	466	666	176	122	—	1,774	(21)	(333)	1,420
OM&A	(56)	(106)	(257)	(75)	(37)	(185)	(716)	5	—	(711)
Reclassifications and adjustments:										
Termination, restructuring and facility shutdown costs	—	—	1	2	—	12	15	—	(15)	—
OM&A related to Required Divestitures	—	—	5	—	—	—	5	—	(5)	—
ERP integration costs	—	—	—	—	—	25	25	—	(25)	—
Acquisition-related transaction and restructuring costs	—	—	—	—	—	7	7		(7)	—
Adjusted OM&A	(56)	(106)	(251)	(73)	(37)	(141)	(664)	5	(52)	(711)
Taxes, other than income taxes	(3)	(23)	(21)	(3)	—	(1)	(51)	1	—	(50)
Net other operating income	—	3	44	—	—	—	47	—	—	47
Reclassifications and adjustments:										
Insurance recovery	—	(2)	—	—	—	—	(2)	—	2	—
Adjusted Net Other Operating Income	—	1	44	—	—	—	45	—	2	47
Adjusted EBITDA[(2)]	285	338	438	100	85	(142)	1,104			
Depreciation and amortization	(38)	(209)	(266)	(49)	(2)	(21)	(585)	6	—	(579)
Equity income	—	—	—	—	—	(2)	(2)	—	8	6
Interest income	—	—	—	—	—	30	30	(2)	—	28
Interest expense	—	—	—	—	—	(350)	(350)	3	—	(347)
Realized foreign exchange loss[(3)]	—	—	—	—	—	(16)	(16)	—	—	(16)
Adjusted Earnings (Loss) before income taxes[(2)]	247	129	172	51	83	(501)	181			
Reclassifications and adjustments above:	4	(271)	(69)	(11)	8	(44)	(383)			
Finance lease income	—	5	18	—	—	—	23	—	—	23
Skookumchuk earnings reclass to Equity income[(1)]	—	(8)	—	—	—	8	—	—	—	—
Fair value change in contingent consideration payable	—	—	37	—	—	—	37	—	—	37
Asset impairment (charges) reversals	—	(20)	(37)	74	—	(4)	13	—	—	13
Loss on sale of assets and other	—	—	(1)	—	—	(6)	(7)	—	—	(7)
Unrealized foreign exchange loss[(3)]	—	—	—	—	—	(5)	(5)	—	—	(5)
Earnings (loss) before income taxes	251	(165)	120	114	91	(552)	(141)	—	—	(141)

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.

(2) Adjusted EBITDA, Adjusted Earnings (loss) before income taxes are non-IFRS measures, are not defined, have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the "Non-IFRS and Supplementary Financial Measures" section of this MD&A.

(3) Realized and unrealized foreign exchange (loss) gain are supplementary financial measures. Refer to the "Non-IFRS and Supplementary Financial Measures" section of this MD&A for more details.

The following table reflects Adjusted EBITDA by segment and provides reconciliation to earnings before income taxes for the year ended Dec. 31, 2024:

	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	409	357	1,350	616	168	(34)	2,866	(21)	—	2,845
Reclassifications and adjustments:										
Unrealized mark-to-market loss (gain)	1	84	(60)	(36)	14	—	3	—	(3)	—
Decrease in finance lease receivable	—	2	19	—	—	—	21	—	(21)	—
Finance lease income	—	6	8	—	—	—	14		(14)	—
Revenues from Required Divestitures	—	—	(1)	—	—	—	(1)	—	1	—
Brazeau penalties	(20)	—	—	—	—	—	(20)	—	20	—
Unrealized foreign exchange gain on commodity	—	—	(2)	—	—	—	(2)	—	2	—
Adjusted Revenues	390	449	1,314	580	182	(34)	2,881	(21)	(15)	2,845
Fuel and purchased power	(16)	(30)	(475)	(418)	—	—	(939)	—	—	(939)
Reclassifications and adjustments:										
Fuel and purchased power related to Required Divestitures	—	—	1	—	—	—	1	—	(1)	—
Adjusted Fuel and Purchased Power	(16)	(30)	(474)	(418)	—	—	(938)	—	(1)	(939)
Carbon compliance (costs) recovery	—	—	(145)	(1)	—	34	(112)	—	—	(112)
Adjusted Gross Margin	374	419	695	161	182	—	1,831	(21)	(16)	1,794
OM&A	(86)	(97)	(198)	(69)	(36)	(173)	(659)	4	—	(655)
Reclassification and adjustments:										
Brazeau penalties	31	—	—	—	—	—	31	—	(31)	—
ERP integration costs	—	—	—	—	—	14	14	—	(14)	—
Acquisition-related transaction and restructuring costs	—	—	—	—	—	24	24	—	(24)	—
Adjusted OM&A	(55)	(97)	(198)	(69)	(36)	(135)	(590)	4	(69)	(655)
Taxes, other than income taxes	(3)	(16)	(13)	(3)	—	(1)	(36)	—	—	(36)
Net other operating income	—	10	40	9	—	—	59	—	—	59
Reclassifications and adjustments:										
Sundance A decommissioning cost reimbursement	—	—	—	(9)	—	—	(9)	—	9	—
Adjusted Net Other Operating Income	—	10	40	—	—	—	50	—	9	59
Adjusted EBITDA[2][3]	316	316	524	89	146	(136)	1,255			
Depreciation and amortization	(41)	(198)	(212)	(66)	(2)	(18)	(537)	6	—	(531)
Equity income	—	—	—	—	—	(4)	(4)	—	9	5
Interest income	—	—	—	—	—	32	32	(2)	—	30
Interest expense	—	—	—	—	—	(328)	(328)	4	—	(324)
Realized foreign exchange loss[4]	—	—	—	—	—	(22)	(22)	—	—	(22)
Adjusted earnings (loss) before income taxes[2]	275	118	312	23	144	(476)	396			
Reclassifications and adjustments above	(12)	(92)	35	45	(14)	(38)	(76)			
Finance lease income	—	6	8	—	—	—	14	—	—	14
Skookumchuk earnings reclass to equity income[1]	—	(9)	—	—	—	9	—	—	—	—
Asset impairment charges	—	(4)	—	(24)	—	(18)	(46)	—	—	(46)
Gain on sale of assets and other	—	—	—	2	—	2	4		—	4
Unrealized foreign exchange gain[4]	—	—	—	—	—	27	27	—	—	27
Earnings (loss) before income taxes	263	19	355	46	130	(494)	319	—	—	319

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.

(2) Adjusted EBITDA, Adjusted Earnings (Loss) before income taxes are non-IFRS measures, are not defined, have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the "Non-IFRS and Supplementary Financial Measures" section of this MD&A.

(3) During the first quarter of 2025, our Adjusted EBITDA composition was amended to exclude the impact of realized gain (loss) on closed exchange positions and Australian interest income. Therefore, the Company has applied this composition to all previously reported periods.

(4) Realized and unrealized foreign exchange (loss) gain are supplementary financial measures. Refer to the "Non-IFRS and Supplementary Financial Measures" section of this MD&A for more details.

Reconciliation of (Loss) Earnings before Income Taxes to Adjusted Net (Loss) Earnings Attributable to Common Shareholders

The following table reflects reconciliation of (loss) earnings before income taxes to Adjusted Net (Loss) Earnings Attributable to Common Shareholders for the three months and the year ended Dec. 31, 2025 and Dec. 31, 2024:

	3 months ended Dec. 31		Year ended Dec. 31	
(in millions of Canadian dollars except where noted)	**2025**	**2024**	**2025**	**2024**
(Loss) earnings before income taxes	**(42)**	(51)	**(141)**	319
Income tax expense (recovery)	**(2)**	(8)	**17**	80
Net (loss) earnings	**(40)**	**(43)**	**(158)**	**239**
Net loss (earnings) attributable to non-controlling interests	**4**	4	**20**	(10)
Preferred share dividends	**(26)**	(26)	**(52)**	(52)
Net (loss) earnings attributable to common shareholders	**(62)**	(65)	**(190)**	177
Adjustments and reclassifications (pre-tax):				
Adjustments and reclassifications to revenues	**106**	53	**331**	15
Adjustments and reclassifications to fuel and purchased power	**—**	(1)	**2**	1
Adjustments and reclassifications to OM&A	**25**	61	**52**	69
Adjustments and reclassifications to net other operating income	**—**	(9)	**(2)**	(9)
Fair value change in contingent consideration payable (gain)	**—**	—	**(37)**	—
Finance lease income	**(6)**	(5)	**(23)**	(14)
Asset impairment (reversals) charges	**(68)**	20	**(13)**	46
Loss (gain) on sale of assets and other	**9**	—	**7**	(4)
Unrealized foreign exchange (gain) loss(1)	**(10)**	(32)	**5**	(27)
Calculated tax expense on adjustments and reclassifications(2)	**(13)**	(20)	**(75)**	(18)
Adjusted Net (Loss) Earnings Attributable to Common Shareholders(3)	**(19)**	2	**57**	236
Weighted average number of common shares outstanding in the period	**297**	298	**297**	302
Net (loss) income per common share attributable to common shareholders	**(0.21)**	(0.22)	**(0.64)**	0.59
Adjustments and reclassifications (net of tax)	**0.15**	0.22	**0.83**	0.19
Adjusted Net (Loss) Earnings per Common Share Attributable to Common Shareholders(3)	**(0.06)**	—	**0.19**	0.78

(1) Unrealized foreign exchange (gain) loss is a supplementary financial measure. Refer to the "Non-IFRS and Supplementary Financial Measures" section of this MD&A for more details.

(2) Represents a theoretical tax calculated by applying the Company's consolidated effective tax rate of 23.3 per cent for the three months and year ended Dec. 31, 2025 (three months and year ended Dec. 31, 2024 — 23.3 per cent). The amount does not take into account the impact of different tax jurisdictions the Company's operations are domiciled and does not include the impact of deferred taxes.

(3) Adjusted Net (Loss) Earnings Attributable to Common Shareholders and Adjusted Net (Loss) Earnings per Common Share attributable to Common Shareholders are non-IFRS measures, are not defined, have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. The most directly comparable IFRS measures are net (loss) earnings attributable to common shareholders and net (loss) earnings per share attributable to common shareholders, basic and diluted. Refer to the "Non-IFRS and Supplementary Financial Measures" section of this MD&A for more details.

Reconciliation of Cash Flow from Operations to FFO and FCF

The table below reconciles our cash flow from operating activities to our FFO and FCF:

	3 months ended Dec. 31		Year ended Dec. 31	
	2025	**2024**	**2025**	**2024**
Cash flow from operating activities[1]	**231**	215	**646**	796
Change in non-cash operating working capital balances	**(97)**	(97)	**(3)**	(38)
Cash flow from operations before changes in working capital	**134**	118	**643**	758
Adjustments				
Share of adjusted FFO from joint venture[1]	**2**	4	**6**	8
Decrease in finance lease receivable	**7**	6	**30**	21
Brazeau penalties payment	**—**	—	**33**	—
Sundance A decommissioning cost reimbursement	**—**	(9)	**—**	(9)
Acquisition-related transaction and restructuring costs	**—**	11	**8**	19
Other[2]	**19**	5	**29**	19
FFO[3]	**162**	135	**749**	816
Deduct:				
Sustaining capital expenditures[1]	**(45)**	(67)	**(162)**	(142)
Productivity capital expenditures	**(1)**	(1)	**(1)**	(1)
Dividends paid on preferred shares	**(12)**	(13)	**(52)**	(52)
Distributions paid to subsidiaries' non-controlling interests	**(8)**	(6)	**(11)**	(40)
Principal payments on lease liabilities	**(3)**	(3)	**(4)**	(6)
Other	**—**	1	**(5)**	—
FCF[3]	**93**	46	**514**	575
Weighted average number of common shares outstanding in the period	**297**	298	**297**	302
Cash flow from operating activities per share	**0.78**	0.72	**2.18**	2.64
FFO per share[3]	**0.55**	0.45	**2.52**	2.70
FCF per share[3]	**0.31**	0.15	**1.73**	1.90

(1) Includes our share of amounts for the Skookumchuck wind facility, an equity-accounted joint venture. Supplementary financial measure. Refer to the "Non-IFRS and Supplementary Financial Measures" section of this MD&A for more details.

(2) Other consists of production tax credits, which is a reduction to tax equity debt, distributions from an equity-accounted joint venture and other adjustments to OM&A that are not reflective of ongoing operations.

(3) These items are non-IFRS measures, which are not defined and have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. During the first quarter of 2025, our Adjusted EBITDA composition was amended to exclude the impact of realized gain (loss) on closed exchange positions and Australian interest income. Consequently the change had an impact on FFO and FCF. Therefore, the Company has applied this composition to all previously reported periods. Refer to the "Non-IFRS and Supplementary Financial Measures" section of this MD&A.

The table below provides a reconciliation of our Adjusted EBITDA to our FFO and FCF:

	3 months ended Dec. 31		Year ended Dec. 31	
	2025	**2024**	**2025**	**2024**
Adjusted EBITDA(1)(2)	**247**	282	**1,104**	1,255
Provisions	**(6)**	2	**(4)**	10
Net Interest Expense(3)	**(60)**	(64)	**(264)**	(231)
Current income tax recovery (expense)	**8**	(20)	**(49)**	(143)
Realized foreign exchange loss(4)	**—**	(20)	**—**	(27)
Decommissioning and restoration costs settled	**(8)**	(12)	**(39)**	(41)
Other non-cash items(5)	**(19)**	(33)	**1**	(7)
FFO(2)(6)	**162**	135	**749**	816
Deduct:				
Sustaining capital(2)(4)	**(45)**	(67)	**(162)**	(142)
Productivity capital	**(1)**	(1)	**(1)**	(1)
Dividends paid on preferred shares	**(12)**	(13)	**(52)**	(52)
Distributions paid to subsidiaries' non-controlling interests	**(8)**	(6)	**(11)**	(40)
Principal payments on lease liabilities	**(3)**	(3)	**(4)**	(6)
Other(7)	**—**	1	**(5)**	—
FCF(2)(6)	**93**	46	**514**	575

(1) Adjusted EBITDA is defined in the "Non-IFRS and Supplementary Financial Measures" section of this MD&A and reconciled to (loss) earnings before income taxes above. During the first quarter of 2025, our Adjusted EBITDA composition was amended to exclude the impact of realized gain (loss) on closed exchange positions and Australian interest income. Therefore, the Company has applied this composition to all previously reported periods.

(2) Includes our share of amounts for the Skookumchuck wind facility, an equity-accounted joint venture.

(3) Net Interest Expense is a non-IFRS measure, not defined and has no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Net Interest Expense includes interest expense less interest income and excludes non-cash items like financing amortization and accretion. Net Interest Expense reconciliation is available in "Financial Capital" section of this MD&A

(4) Supplementary financial measure. Refer to the "Non-IFRS and Supplementary Financial Measures" section of this MD&A for more details.

(5) Other non-cash items primarily consist of changes in deferred payments, contract assets and liabilities, onerous contracts and long-term incentive accruals.

(6) These items are non-IFRS measures, are not defined and have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. FFO and FCF are defined in the "Non-IFRS and Supplementary Financial Measures" section of this MD&A and reconciled to cash flow from operating activities above.

(7) Other consists of unsecured loan advanced by the Company's subsidiary, Kent Hills Wind LP to its 17 per cent partner.

Key Non-IFRS Financial Ratios

The methodologies and ratios used by rating agencies to assess our credit rating are not publicly disclosed. We have developed our own definitions of ratios and targets to help evaluate the strength of our financial position.

These metrics and ratios are not defined and have no standardized meaning under IFRS and may not be comparable to those used by other entities or by rating agencies.

Adjusted Net Debt to Adjusted EBITDA

(in millions of Canadian dollars except where noted)

As at Dec. 31	2025	2024
Credit facilities, long-term debt and lease liabilities(1)	**3,593**	3,808
Exchangeable debentures	**350**	350
Less: Cash and cash equivalents	**(205)**	(337)
Add: Bank overdraft	**—**	1
Add: 50 per cent of issued preferred shares and exchangeable preferred shares(2)	**671**	671
Other(3)	**(13)**	(24)
Adjusted Net Debt(4)	**4,396**	4,469
Adjusted EBITDA(5)	**1,104**	1,255
Adjusted Net Debt to Adjusted EBITDA (times)	**4.0**	3.6

(1) Consists of current and non-current portions of long-term debt, which includes lease liabilities and tax equity financing.

(2) Exchangeable preferred shares are considered equity with dividend payments for credit-rating purposes. For accounting purposes, they are accounted for as debt with interest expense in the consolidated financial statements. For purposes of this ratio, we consider 50 per cent of issued preferred shares, including exchangeable preferred shares, as debt.

(3) Includes principal portion of TransAlta OCP restricted cash ($17 million as at Dec. 31, 2025 and Dec. 31, 2024) and fair value of hedging instruments on debt (included in risk management assets and/or liabilities on the Consolidated Statements of Financial Position).

(4) The tax equity financing for the Skookumchuck wind facility, an equity-accounted joint venture, is not represented in this amount. Adjusted Net Debt is a non-IFRS measure, is not defined and has no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Presenting this item from period to period provides management and investors with the ability to evaluate earnings trends more readily in comparison with prior periods' results. Refer to the "Non-IFRS and Supplementary Financial Measures" section of this MD&A.

(5) Last four quarters.

The Company's capital is managed using a net debt position. We use the Adjusted Net Debt to Adjusted EBITDA ratio as a measurement of financial leverage and to assess our ability to service debt. Our target for Adjusted Net Debt to Adjusted EBITDA is 3.0 to 4.0 times.

Our Adjusted Net Debt to Adjusted EBITDA ratio at Dec. 31, 2025 was higher compared to Dec. 31, 2024, due to lower Adjusted EBITDA for the year ended Dec. 31, 2025.

Material Accounting Policies, Accounting Changes and Critical Accounting Estimates

Material Accounting Policies and Accounting Changes

Our material accounting policies are described in Note 2 of the consolidated financial statements.

For a description of current and future accounting changes impacting our business, refer to Note 3 of the consolidated financial statements.

Critical Accounting Judgments and Estimates

The preparation of the Consolidated Financial Statements in accordance with IFRS requires management to apply judgment and to develop estimates and assumptions based on the conditions and information available as of the reporting date. These judgments, estimates, and assumptions influence the reported amounts of assets, liabilities, revenue, and expenses, and actual results may differ from those estimates.

Management reviews these judgments and estimates on a continuous basis. Any revisions are recognized in the period in which they are identified and in any subsequent periods impacted by the change. Refer to Note 2 of the consolidated financial statements for a description of our significant accounting judgments and key sources of estimation uncertainty. Additional detail regarding the estimates and judgments that have the most significant effect on the amounts recognized in the Consolidated Financial Statements is as follows:

Impairment of PP&E and Goodwill

An assessment is made at each reporting date as to whether there is any indication that an impairment loss may exist or that a previously recognized impairment loss may no longer exist or may have decreased. An impairment exists when the carrying amount of an asset exceeds its recoverable amount, which is the higher of its fair value less costs of disposal and its value in use. An impairment loss recognized in a prior period is reversed if there has been a change in the estimates used to determine the asset's recoverable amount.

During the year ended Dec. 31, 2025, internal valuations indicated that the carrying values of four wind facilities exceeded their fair value less costs of disposal primarily due to updated production profiles and lower power price assumptions, which unfavourably impacted estimated future cash flows and resulted in an impairment charge of $37 million. The recoverable amount of $363 million for these four facilities was estimated based on fair value less costs of disposal using a discounted cash flow model and was categorized as a Level III fair value measurement. The discount rates used in the fair value measurements were in the range of 5.53 to 7.24 per cent.

During the year ended Dec. 31, 2025, the Company recognized impairment reversals for one wind facility and one solar facility, which had been previously impaired. The impairment reversals of $17 million were primarily due to changes in power price assumptions that favourably impacted estimated future cash flows. The recoverable amount of $233 million for these two facilities was estimated based on fair value less costs of disposal using a discounted cash flow model and was categorized as a Level III fair value measurement. The discount rates used in the fair value measurements were in the range of 6.10 to 7.24 per cent.

We assess goodwill for impairment annually or when events indicate potential impairment. Key assumptions in determining recoverable amounts include:

- Discount rates,
- Forecasts of electricity production for each facility, taking into consideration contracts for the sale of electricity, historical production, regional supply-demand balances and capital maintenance and expansion plans, and
- Forecasted sales prices for each facility, based on contract prices for facilities subject to long- or short-term contracts, forward price curves for merchant plants and regional supply-demand balances. Where forward price curves are not available for the duration of the facility’s useful life, prices are determined by extrapolation techniques using historical industry and company-specific data.

For the purposes of the 2025 goodwill impairment review, the Company determined the recoverable amounts of Hydro, Wind and Solar, Gas and Energy Marketing segments by calculating the fair value less costs of disposal using discounted cash flow projections. The recoverable amounts are based on the Company's long-range forecasts for the periods extending to the last planned asset retirement in 2072. The resulting fair value measurements are categorized within Level III of the fair value hierarchy. No impairment of goodwill arose for any segment. Refer to Notes 2(Q)(II), 7 and 22 of the Company's 2025 audited annual consolidated financial statements for further details.

Fair Value of Level III Derivative Instruments

Some of the Company's derivative instruments fall under Level III fair value classification because they are not traded on an active exchange or have terms that extend beyond the time period for which exchange-based quotes are available and require the use of internal valuation techniques or models to determine fair value.

We also hold commodity contracts extending beyond liquid trading periods. For these, forward prices are estimated using a combination of external and internal models, including discounting, which results in Level III classification. Fair values can fluctuate significantly with market conditions and may be favourable or unfavourable.

The effect of using reasonably possible alternative assumptions as inputs to valuation techniques for contracts included in the Level III fair value measurements at Dec. 31, 2025 is an estimated total upside of $144 million (2024 – $200 million) and total downside of $132 million (2024 – $146 million) impact to the carrying value of the financial instruments. Fair values are stressed for unobservable inputs, which can include variable volumes, unobservable prices and wind discounts, among other inputs. The variable volumes are stressed up and down based on historically available production data. Prices are stressed for longer-term deals where there are no liquid market quotes using various internal and external forecasting sources to establish a high and a low price range. Wind discounts represent price to volume relationships and are stressed specific to each location.

The determination of the fair value of these contracts and derivative instruments can be complex and relies on judgments and estimates concerning future prices, volatility and liquidity, among other factors. These fair value estimates may not necessarily be indicative of the amounts that could be realized or settled and changes in these assumptions could affect the reported fair value of financial instruments. Fair values can fluctuate significantly and can be favourable or unfavourable depending on current market conditions. Judgment is also used to determine whether a highly probable forecasted transaction designated in a cash flow hedge is expected to occur based on the Company's estimates of pricing and production to allow the future transaction to be fulfilled.

Refer to Notes 2(Q)(V) and Note 14(B)(I)(c)) of the Company's 2025 audited annual consolidated financial statements for further details.

Financial Instruments

Financial instruments are used for proprietary trading purposes and to manage our exposure to interest rates, commodity prices and currency fluctuations, as well as other market risks. We may currently use physical and financial swaps, forward sale and purchase contracts, futures contracts, foreign exchange contracts, interest rate swaps and options to achieve our risk management objectives. Some of our physical commodity contracts have been entered into and are held for the purposes of meeting our expected purchase, sale or usage requirements and, as such, are not considered financial instruments, and are not recognized as a financial asset or financial liability. Other physical commodity contracts that are not held for normal purchase or sale requirements, and derivative financial instruments are recognized on the Consolidated Statements of Financial Position and are accounted for using the fair value method of accounting. The initial recognition of fair value and subsequent changes in fair value can affect reported earnings in the period when the change occurs if hedge accounting is not elected. Otherwise, changes in fair value will generally not affect earnings until the financial instrument is settled.

Some of our financial instruments and physical commodity contracts qualify for, and are recorded under, hedge accounting rules. The accounting for those contracts, for which we have elected to apply hedge accounting, depends on the type of hedge. Our financial instruments are mainly used for cash flow hedges or non-hedges. These categories and their associated accounting treatments are explained in further detail below.

For all types of hedges, we test for effectiveness at the end of each reporting period to determine if the instruments are performing as intended and hedge accounting can still be applied. The financial instruments we enter into are designed to ensure that future cash inflows and outflows are predictable. In a hedging relationship, the effective portion of the change in the fair value of the hedging derivative does not impact net earnings (loss), while any ineffective portion is recognized in net earnings (loss).

We have certain contracts in our portfolio that, at their inception, do not qualify for, or we have chosen not to elect to apply, hedge accounting. For these contracts, we recognize in net earnings (loss) mark-to-market gains and losses resulting from changes in forward prices compared to the price at which these contracts were transacted. These changes in price alter the timing of earnings recognition, but do not necessarily determine the final settlement amount received. The fair value of future contracts will continue to fluctuate as market prices change. The fair value of derivatives that are not traded on an active exchange, or extend beyond the time period for which exchange-based quotes are available, are determined using valuation techniques or models.

Cash Flow Hedges

Cash flow hedges are categorized as project, foreign exchange, interest rate or commodity hedges and are used to offset foreign exchange, interest rate and commodity price exposures resulting from market fluctuations.

Foreign currency forward contracts and cross-currency swaps may be used to hedge foreign exchange exposures resulting from anticipated contracts and firm commitments denominated in foreign currencies, primarily related to capital expenditures and currency exposures related to U.S. dollar denominated debt.

Physical and financial swaps, forward sale and purchase contracts, futures contracts and options may be used primarily to offset the variability in future cash flows caused by fluctuations in electricity and natural gas prices. Interest rate swaps may be used to convert the fixed interest cash flows related to interest expense on debt to floating rates and vice versa.

In a cash flow hedge, changes in the fair value of the hedging instrument (a forward contract or financial swap, for example) are recognized in risk management assets or liabilities and the related gains or losses are recognized in other comprehensive income or loss (OCI). These gains or losses are subsequently reclassified from OCI to net earnings (loss) in the same period as the hedged forecast cash flows impact net earnings (loss) and offset the losses or gains arising from the forecast transactions. For project hedges, the gains and losses reclassified from OCI are included in the carrying amount of the related PP&E.

Hedge accounting follows a principles-based approach for qualifying hedges that is aligned with an entity's approach to risk management. When we do not elect hedge accounting or when the hedge is no longer effective and does not qualify for hedge accounting, the gains or losses as a result of changes in prices, interest or exchange rates related to these financial instruments are recorded in net earnings (loss) in the period in which they arise.

Net Investment Hedges

Foreign-denominated long-term debt is used to hedge exposure to changes in the carrying values of our net investments in foreign operations that have a functional currency other than the Canadian dollar. Our net investment hedges using U.S. dollar denominated debt remain effective and in place. Gains or losses on these instruments are recognized and deferred in OCI and reclassified to net earnings (loss) on the disposal of the foreign operation. We also manage foreign exchange risk by matching foreign-denominated expenses with revenues, such as offsetting revenues from our U.S. operations with interest payments on our U.S. dollar denominated debt.

Non-Hedges

Financial instruments not designated as hedges are used for proprietary trading and to reduce commodity price, foreign exchange and interest rate risks. Changes in the fair value of financial instruments not designated as hedges are recognized in risk management assets or liabilities and the related gains or losses are recognized in net earnings (loss) in the period in which the change occurs.

Fair Values

The majority of fair values for our foreign exchange, interest rate, commodity hedges and non-hedge derivatives are calculated using adjusted quoted prices from an active market or inputs validated by broker quotes. We may enter into commodity transactions involving non-standard features for which market-observable data is not available. These transactions are defined under IFRS as Level III instruments. Level III instruments incorporate inputs that are not observable from the market and fair value is therefore determined using valuation techniques. Fair values are validated by using reasonably possible alternative assumptions as inputs to valuation techniques and any material differences are disclosed in the notes to the consolidated financial statements.

At Dec. 31, 2025, Level III instruments had a net liabilities carrying value of $312 million (2024 – net liabilities $234 million). The Level III liabilities increased in 2025 primarily due to unfavourable changes in market pricing across multiple markets driven by higher volatility, partially offset by an increase in long-term financial assets as a result of the Company making available a term loan and revolving facility to a developer of renewable energy projects and a decrease in the fair value of contingent consideration payable driven by updated expectations on the fair value less costs to sell on the Required Divestitures and derecognition of contingent consideration upon completion of the Required Divestitures. Our risk management profile and practices have not changed materially from Dec. 31, 2024.

Refer to the "Material Accounting Policies, Accounting Changes and Critical Accounting Estimates" section of this MD&A for further details regarding valuation techniques and Note 14 of the Company's 2025 audited annual consolidated financial statements for further details.

Risk Management

Our business activities expose us to a variety of risks and opportunities including, but not limited to, regulatory changes, rapidly changing market dynamics and increased volatility in our key commodity markets. Our goal is to manage these risks and opportunities so that we are in a position to develop our business and achieve our goals while remaining reasonably protected from an unacceptable level of risk or financial exposure. We use a multi-level risk management oversight structure to manage the risks and opportunities arising from our business activities, the markets in which we operate and the political environments and structures with which we interact.

Risk Controls

Our risk controls have several key components:

Enterprise Tone

We strive to foster beliefs and actions that are true to and respectful of our many stakeholders. We do this by investing in communities where we live and work, operating and growing sustainably, putting safety first and being responsible to the many groups and individuals with whom we work.

Policies

We maintain a comprehensive set of enterprise-wide policies. These policies establish delegated authorities and limits for business transactions, and they allow for an exception approval process. Periodic reviews and audits are performed to ensure compliance with these policies. All employees and directors are required to sign the Corporate Code of Conduct on an annual basis.

Reporting

On a regular basis, residual risk exposures are reported to key decision-makers including the Board, the Audit, Finance and Risk Committee (AFRC), senior management and/or the Commodity Risk & Compliance Committee, as applicable. Reporting to this latter committee includes analysis of new risks, monitoring of status to risk limits, reviewing events that can affect these risks, and discussing and reviewing the status of actions to minimize risks. This monthly reporting provides for effective and timely risk management and oversight.

Whistleblower System

We have a process in place where employees, contractors, shareholders or other stakeholders may confidentially or anonymously report any potential legal or ethical concerns, including concerns relating to accounting, internal control accounting, auditing or financial matters, or concerns relating to alleged violations of any laws or our Corporate Code of Conduct. These concerns can be submitted confidentially and anonymously, either directly to the AFRC or through TransAlta's toll-free telephone or online Ethics Helpline. The AFRC Chair is immediately notified of any material complaints and, otherwise, the AFRC receives a report at every quarterly committee meeting on all findings related to any material complaints or complaints relating to accounting or financial reporting or alleged breaches in internal controls over financial reporting.

Value at Risk and Trading Positions

Value at risk (VaR) is one of the primary measures used to manage our exposure to market risk resulting from commodity risk management activities. VaR is calculated and reported on a daily basis. This metric describes the potential change in the value of our trading portfolio over a three-day period within a 95 per cent confidence level, resulting from normal market fluctuations.

VaR is a commonly used metric that is employed by industry to track the risk in commodity risk management positions and portfolios. Two common methodologies for estimating VaR are the historical variance/covariance and scenario analysis approaches. We estimate VaR using the historical variance/covariance approach. An inherent limitation of historical variance/covariance VaR is that historical information used in the estimate may not be indicative of future market risk. Stress tests are performed periodically to measure the financial impact to the trading portfolio resulting from potential market events, including fluctuations in market prices, volatilities of those prices and the relationships between those prices. We also employ additional risk mitigation measures. VaR at Dec. 31, 2025, associated with our proprietary commodity risk management activities was $1 million (2024 – $3 million). Refer to the "Risk Factors – Commodity Price Risk" section of this MD&A below for further discussion.

Risk Factors

Risk is an inherent factor of doing business. The following section addresses some, but not all, risk factors that could affect our future plans, performance, results or outcomes and our activities in mitigating those risks. These risks do not occur in isolation, but must be considered in conjunction with each other.

A reference herein to a material adverse effect on the Company means such an effect on the Company or its business, operations, financial condition, results of operations and/or its cash flows, as the context requires.

For some risk factors, we show the after-tax effect on net earnings (loss) of changes in certain key variables. The analysis is based on business conditions and production volumes in 2025. Each item in the sensitivity analysis assumes all other potential variables are held constant. While these sensitivities are applicable to the period and the magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances or for a greater magnitude of changes. The changes in rates should also not be assumed to be proportionate to earnings in all instances.

Equipment failure and the operation and maintenance of our facilities involve risks that may materially and adversely affect our business.

There is a risk of equipment failure or underperformance to our operations due to wear and tear, latent defect, design error or operator error, among other things, which could have a material adverse effect on our business. Although our generation facilities have generally operated in accordance with expectations, there can be no assurance that they will continue to do so. Our facilities are exposed to operational risks that can lead to outages and increased production risk that could have a material adverse effect on our business. Further, some of our generation facilities were constructed many years ago and may require significant capital expenditures to maintain peak reliability or operations. Newer facilities also require various levels of capital expenditures to maintain peak reliability or operations. There can be no assurance that our maintenance program will be able to detect potential failures in our facilities before they occur or eliminate all adverse consequences in the event of failure.

As well, we are exposed to procurement risk for specialized parts that may have long lead times. If we are unable to procure these parts when they are needed for maintenance activities, we could face an extended period where our equipment is unavailable to produce electricity. Further, if a manufacturer is unable or unwilling to provide satisfactory maintenance or warranty support on reasonable terms, we may have to enter into alternative arrangements with other providers or perform the services ourselves. These arrangements could be more expensive than our current arrangements and if we are unable to enter into satisfactory alternative arrangements, our inability to access technical expertise or parts could have a material adverse effect. TransAlta manages this risk with our capital spares policy.

While we maintain an inventory of, or otherwise make arrangements to obtain, spare parts to replace critical equipment and maintain insurance for property damage and business interruption to protect against certain operating risks, these protections may not be adequate to cover lost revenues or increased expenses and penalties that could result if we were unable to operate our generation facilities at a level necessary to comply with our contracts. In addition, circumstances could arise whereby the Company may be obligated to produce power at a cost that exceeds the revenues generated from that production.

In addition, there can be no assurance that we will be able to restore equipment or assets that have reached the end of their useful lives.

Unexpected changes in the cost of maintenance or in the cost and durability of components for the Company's facilities may adversely affect the results of our operations.

Inflation or other increases in the Company's cost structure that are beyond the control of the Company could materially adversely impact our financial performance. Examples of such costs include, but are not limited to, unexpected increases in the cost of procuring materials and services required for maintenance activities, and unexpected replacement or repair costs associated with equipment underperformance or lower-than-anticipated durability.

Changes in the price of electricity may materially adversely affect our business.

A portion of our revenues are tied, either directly or indirectly, to the market price for electricity in the markets in which we operate, and in particular in the Alberta electricity market. Market electricity prices are impacted by a number of factors, including the strength of the economy, the available transmission capacity, the price of fuel that is used to generate electricity (and, accordingly, certain of the factors that affect the price of fuel described below), the management of generation, the amount of excess generating capacity relative to load in a particular market, the cost of controlling emissions and cost of carbon, the structure of the particular market, the availability of transmission (including from other jurisdictions), increased adoption of energy-efficiency and conservation initiatives, and weather conditions that impact electrical load. As a result, we cannot precisely predict future electricity prices and electricity price volatility (particularly lower Alberta electricity prices) that could have a material and adverse effect on us. Further, the Alberta market is the only fully deregulated electricity market in Canada and this market structure permits corporate offtakers to invest in new renewable generation in the province solely for environmental, social and governance reasons (i.e., to align with decarbonization goals) that may not align with supply and demand fundamentals. This could potentially result in an oversupply of intermittent electricity in the Alberta electricity market and could put downward pressure on electricity prices and contribute to significant price volatility in the near term.

Our facilities and construction projects have structured agreements in their contracts around force majeure events that are beyond our control, but positions the organization to industry standards for insurance or contract claw back in costs. Such events could result in material adverse effects.

Our facilities, construction projects and operations are exposed to potential interruption and damage, or partial or full loss resulting from environmental disasters (e.g., floods, high winds, fires, ice storms, earthquakes and public health crises, such as pandemics and epidemics), other seismic activity and equipment failures. Climate change can also increase the frequency and severity of these extreme weather events. There can be no assurance that in the event of an earthquake, flood, cyclone, hurricane, tornado, tsunami, terrorist attack, act of war or other natural, man-made or technical catastrophe, all or some parts of our generation facilities and infrastructure systems will not be disrupted. The occurrence of a significant event that disrupts the ability of our power generation assets to produce power for an extended period, including events that preclude existing customers under PPAs from purchasing electricity, could have a material negative impact on our business. Our facilities, construction projects and operations could be exposed to the effects of severe weather conditions, natural and man-made disasters and other potentially catastrophic events. The occurrence of such an event may not release us from performing our obligations pursuant to PPAs or other agreements with third parties. In addition, many of our generation facilities are located in remote areas, which can make repair of damage costly or difficult to access. Catastrophic events, including public health crises, could result in volatility and disruption to global supply chains, disruption to global financial markets, trade and market sentiment, risks to employee health and safety, a slowdown or temporary suspension of operations in impacted locations, postponements in the initiation and/or completion of the Company's development or construction projects, and delays in the completion of services, any of which may result in the Company incurring penalties under contracts, additional costs or the cancellation of contracts.

Risks relating to TransAlta's development and growth projects and acquisitions may materially and adversely affect us.

Development and growth projects and acquisitions that we undertake may be subject to execution and capital cost risks, including, but not limited to, risks relating to regulatory approvals, third-party opposition, cost escalations, securing land rights, construction delays, shortages of raw materials, supply chain constraints, or skilled labour and capital constraints. The occurrences of these risks could have a material and adverse impact on us, our financial condition, our ability to operate and our cash flows.

Expansion of our business through development projects and acquisitions may place increased demands on our management, operating systems, internal controls and financial and physical resources. In addition, the process of integrating acquired businesses or development projects may involve unforeseen difficulties. Failure to successfully manage or integrate any acquired businesses or development projects could have a material adverse impact on us, our financial condition, our ability to operate and our cash flows. Further, we cannot make assurances that we will be successful in integrating any acquisition or that the commercial opportunities or operational synergies of any acquisition will be realized as expected.

We may pursue acquisitions in new markets that are subject to regulation by various foreign governments and regulatory authorities and to the application of foreign laws. Such foreign laws or regulations may not provide for the same type of legal certainty and rights, in connection with our contractual relationships in such countries, as are afforded to us currently, which may adversely affect our ability to receive revenues or enforce our rights in connection with any such foreign operations. In addition, the laws and regulations of some countries may limit our ability to hold a majority interest in some of the projects that we may acquire, thus limiting our ability to control the operation of such projects. Any existing or new operations may also be subject to significant political, economic and financial risks, which vary by country, and may include: (a) changes in government policies or personnel; (b) changes in general economic conditions; (c) restrictions on currency transfer or convertibility; (d) changes in labour relations; (e) political instability and civil unrest; (f) regulatory or other changes in the local electricity market; and (g) breach or repudiation of important contractual undertakings by governmental entities and expropriation and confiscation of assets and facilities for less than fair market value.

With respect to acquisitions, we cannot make assurances that we will identify suitable transactions or that we will have access to sufficient resources, through our credit facilities, the capital markets or otherwise, to pursue and complete any identified acquisition opportunities on a timely basis and at a reasonable cost. Any acquisition that we propose or complete would be subject to regulatory approvals and other normal commercial risks that could result in the transaction not being completed on the terms anticipated, on time, or at all. In the event we are unable to close a transaction that we've entered into, we may be subject to termination fees that could become payable to the vendor. An unavoidable level of risk remains regarding potential undisclosed or unknown liabilities relating to any acquisition. The existence of such undisclosed liabilities may have a material adverse impact on our business, financial condition, results of operations and cash flows.

We could suffer lost revenues or increased expenses and penalties if we are unable to operate our generation facilities at a level necessary to comply with our PPAs.

The ability of our facilities to generate the maximum amount of power or steam that can be sold under PPAs is an important determinant of our revenues. Under certain PPAs, if the facility is not capable of generating electricity or steam for the required availability in a given contract year, we may be required to make penalty payments to the purchaser, and in some cases this could give rise to termination rights. The payment of any such penalties or the termination of such PPAs could adversely affect our revenues and profitability.

We rely on access to parts and equipment from certain key suppliers and we may be adversely affected if these relationships are not maintained.

Our ability to compete and expand depends on having access, at a reasonable cost, to equipment, parts and components that are technologically and economically competitive with those used by our competitors. Although we have individual framework agreements with various suppliers, there can be no assurance that these relationships with suppliers will be maintained or not adversely affected. If they are not maintained, or are adversely affected, our ability to compete may be impaired due to lack of access or significant delays to the supply of equipment, parts or components.

We depend on certain joint venture, strategic and other partners that may have interests or objectives that conflict with our objectives and such differences could have a negative impact on us.

We have entered into various arrangements with communities or joint venture, strategic or other partners in connection with the operation of our facilities and assets. Certain of these partners may have or develop interests or objectives that are different from, or in conflict with, our objectives. Any such differences could have a negative impact on the Company's ability to realize the anticipated benefits of, or the anticipated increase in the value of facilities or assets subject to, these arrangements. We are sometimes required through the permitting and approval processes to notify and consult with various stakeholder groups, including landowners, Indigenous groups and municipalities. Any unforeseen delays in this process may negatively impact our ability to complete any given facility on time or at all and could result in write-offs or give rise to reputational harm.

Dam and dyke failures may result in lost generating capacity, increased maintenance and repair costs and other liabilities.

A natural or man-made disaster, and certain other events, including natural or induced seismic activity, could potentially cause dam failures at our hydroelectric facilities and various dam sites. The occurrence of dam or dyke failures at any of our facilities could result in a loss of generating capacity, damage to the environment or damages and harm to third parties or the public, and such failures could require us to incur significant expenditures of capital and other resources or expose us to significant liabilities for damages. There can be no assurance that our dam safety program will be able to detect potential dam failures prior to their occurrence or eliminate all adverse consequences in the event of failure. Other safety regulations could change from time to time, potentially impacting our costs and operations. Reinforcing all dams or dykes to enable them to withstand more severe events could require us to incur significant expenditures of capital and other resources. The consequences of dam or dyke failures could have a material adverse effect on us. This includes any increased risk of dam failure due to induced seismic activity triggered by hydraulic fracturing near our hydroelectric facilities, which could increase the risk of dam failure or require the Company to incur potentially significant capital investments to mitigate such risk and that would not otherwise be required.

The power generation industry has certain inherent risks related to worker health and safety, and the environment, that could cause us to suffer unanticipated expenditures or to incur fines, penalties or other consequences material to our business and operations.

The ownership and operation of our power generation assets carry an inherent risk of liability and reputational harm related to worker health and safety, and the environment, including the risk of government-imposed orders to remedy unsafe conditions and/or to remediate or otherwise address environmental contamination, potential penalties for contravention of health, safety and environmental laws, licences, permits and other approvals, and potential civil liability. Compliance with (and any future changes to) health, safety and environmental laws and the requirements of licences, permits and other approvals are expected to remain material to our business. The occurrence of any of these events or any changes, additions to, or more rigorous enforcement of health, safety and environmental laws, licences, permits or other approvals could have a significant impact on our operations and/or result in additional material expenditures. As a consequence, no assurances can be given that additional environmental and workers' health and safety issues relating to presently known or unknown matters will not require unanticipated expenditures, or result in fines, penalties or other consequences (including changes to operations) material to our business and operations.

Climate change and other variations in weather can affect demand for electricity and our ability to generate electricity.

Due to the nature of our business, our earnings are sensitive to weather variations from period to period, as well as long-term changes due to climate change. Variations in winter weather affect the demand for electrical heating requirements. Variations in summer weather affect the demand for electrical cooling requirements. These variations in demand can translate into electricity market price volatility. Variations in precipitation also affect water supplies, which in turn affect our hydroelectric assets. Also, variations in sunlight and wind conditions can have an effect on energy production levels from our solar and wind facilities. Typically, when winters are warmer or summers are cooler, demand for energy is lower than expected, resulting in less electricity consumption than forecasted and often resulting in lower than expected market prices for electricity. Conversely, when winters are colder or summers are warmer, market prices for natural gas or electricity tend to be higher; however, in these circumstances, if we have entered into hedges and are unable to produce or consume the amount of natural gas or electricity that we have hedged we could be required to purchase additional volumes at higher prices to cover our hedge position.

Our generation facilities and their operations are exposed to potential damage and partial or complete loss resulting from environmental disasters (e.g., floods, strong winds, wildfires, earthquakes, tornados and cyclones), equipment failures and other events beyond our control, which could make it difficult for the Company to continue to generate electricity during such periods, and such circumstances could pose threats to the Company's equipment and personnel.

The accumulation of ice on wind turbine blades depends on a number of factors including temperature and ambient humidity, and can have a significant impact on energy yields and could result in the wind turbine experiencing more downtime. Extremely cold temperatures can also impact the ability of wind turbines to operate effectively, and this could result in more downtime and reduced production. Sudden temperature changes can increase the risk of ice crystal formation, which can pose a number of constraints on our hydro operations.

Climate change is expected to change the volume and timing of precipitation which may impact the ability of hydro facilities to maximize the generation from available water. These changes in flow may result in additional operational costs to manage water through the hydro plants. Variations in weather may be impacted by climate change resulting in sustained higher temperatures, rising sea levels and altered precipitation patterns that could have an impact on our generating assets. Furthermore, climate change could result in increased variability or sustained long-term changes to our water and wind resources impacting hydroelectric and wind electricity generation, which could adversely affect our revenues and profitability.

The sensitivity of volumes to our net earnings is shown below:

Factor	Increase or decrease (per cent)	Approximate impact on net earnings (millions)
Availability/production	1	**$17**

Variation in wind levels may negatively impact the amount of electricity generated at our wind facilities.

Given that wind is variable, the amount of electricity produced from our wind facilities is also variable. In addition, the strength and consistency of the wind resource at our wind facilities may vary from what we anticipate due to a number of factors, including the extent to which our site-specific historic wind data and wind forecasts accurately reflect actual long-term wind speeds, strength and consistency; the potential impact of climatic factors; the accuracy of our assumptions relating to, among other things, weather, icing, degradation, site access, wake and wind shear line losses and wind shear; and the potential impact of topographical variations and the potential for electricity losses to occur before delivery.

A reduced amount of wind at the location of one or more of our wind facilities over an extended period may reduce the production from such facilities, as well as any environmental attributes that accrue to us related to that production and reduce our revenues and profitability.

There can be no assurance that we will achieve or continue to meet our sustainability targets, and failure to do so may adversely affect our business.

The Company annually establishes sustainability targets to, among things, manage current and emerging material sustainability issues, which include targets relating to decarbonization. The Board of Directors has the discretion to determine the sustainability targets being adopted by the Company and may modify or cancel any previously established sustainability target at any time. The Board of Director's determination to establish, alter or cancel any sustainability target will depend on, among other things: the United Nations Sustainable Development Goals; results of operations; technological considerations; financial condition; market opportunities; legal, regulatory and contractual considerations; and other relevant factors. Further, there is no certainty that the Company will be successful in achieving any particular sustainability target within the stated time frame, or at all. If we are not able to achieve, or adhere to, our sustainability targets, we may not satisfy our stakeholders' current and future expectations, which could negatively impact our reputation and could result in certain investors being unable to hold our common shares.

Many of our activities and properties are subject to environmental regulations, and any liabilities arising under these requirements may materially adversely affect our business.

Our operations are subject to federal, provincial, state and local environmental laws, regulations and guidelines relating to the generation and transmission of electrical and thermal energy and surface mine reclamation (collectively, environmental regulations). These environmental regulations pertain to pollution and the protection of the environment, health and safety, and govern, among other things, air emissions, water usage and discharges, storage, treatment and disposal of waste and other materials, and remediation of sites and responsible land use. These laws and regulations can impose liability and obligations for costs to investigate and remediate contamination without regard to fault, and under certain circumstances liability may be joint and several, resulting in one responsible party being held responsible for the entire obligation. Environmental regulations can also impose, among other things, restrictions, liabilities and obligations in connection with the generation, handling, use, storage, transport, treatment and disposal of hazardous substances and waste, and can impose cleanup, disclosure or other responsibilities with respect to spills, releases and emissions of various substances to the environment. Environmental regulations can also require that facilities and other properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition, the relative stringency of environmental regulations can reduce or decline based on political direction, resulting in potentially unstable policy environments at national, state/provincial and regional levels in Canada, the U.S. and Western Australia, which may impose different compliance requirements or standards on our business. These various compliance standards may impact costs and/or our ability to operate our facilities.

Changes in standards, new or amended regulation, increased enforcement by regulatory authorities, more extensive permitting requirements, an increase in the number and types of assets operated by the Company subject to environmental regulation and the implementation or change to regional, provincial, state and national environmental regulations may impose varying obligations on us in the jurisdictions in which we operate, and could increase our expenditures. To the extent these expenditures cannot be passed through to our customers under our PPAs or otherwise, our costs could be material. In addition, compliance with environmental regulation may result in restrictions on some of our operations. It is anticipated that compliance costs are at risk of change due to increased political and public attention.

If we do not comply with environmental regulations, regulatory agencies could seek to impose statutory, administrative and/or criminal liabilities on us, curtail our operations, or require significant expenditures on compliance, new equipment or technology, reporting obligations and research and development.

With Bill C-59 we anticipate continued scrutiny by lawyers and other stakeholders relating to sustainability performance. We could face civil liability in the event that private parties seek to impose liability on us for property damage, personal injury or other costs and losses. We cannot guarantee that lawsuits or administrative or investigative actions will not be started against us and otherwise affect our operations and assets. If an action is filed against us or may otherwise affect our operations and assets, we could be required to make substantial expenditures to defend against, or provide evidence of our activities or to bring our Company, our operations and assets into compliance, which could have a material adverse effect on our business.

The estimated reclamation costs applicable to the Company's operations may be inaccurate and could require greater financial resources than currently anticipated. As an owner of mines that were previously in operation, we maintain permits from the applicable regulatory body providing for the authorization of certain mining operations that result in a disturbance of the surface. These requirements sought to limit the adverse impacts of coal mining with more restrictive requirements potentially being adopted from time to time. As an owner of mines that were previously in operation, we may also be required to submit a bond or otherwise secure payment of certain long-term obligations including mine closure or reclamation costs. Surety bond costs have increased in recent years and the market terms of such bonds have generally become more unfavourable. In addition, the number of companies willing to issue surety bonds has decreased. We could be required to self-fund these obligations should we be unable to renew or secure the required surety bonds for our mining operations or if it becomes more economical to do so.

The laws and regulations in the markets in which we operate are subject to change, which may materially adversely affect us.

Most of the markets in which we operate and intend to operate are subject to significant regulatory oversight and control. We are not able to predict whether there will be any further changes in the regulatory environment, including potential carbon and other environmental regulations, changes in market structure or market design, or changes in other laws and regulations. Existing market rules, regulations and reliability standards are often dynamic and may be revised or re-interpreted, and new laws and regulations may be adopted or become applicable to us or our facilities, which could have a material adverse effect on us. Many of our projects must also comply with reliability standards, including those established by the North American Electric Reliability Corporation and Alberta Reliability Standards. Failure to comply with these mandatory reliability standards could result in sanctions, including substantial monetary penalties. We manage these risks systematically through a regulatory and compliance program designed to reduce any potential negative impact on us. However, we cannot guarantee that we will be able to adapt our business in a timely manner in response to any changes in the regulatory regimes in which we operate, and such failure to adapt could have a material adverse effect on our business.

Regulatory authorities may also from time to time audit or investigate our activities in the markets in which we operate or pursue trading. Such audits or investigations may result in sanctions or penalties that may materially affect our future activities, reputation or financial status.

Our facilities are also subject to various licensing and permitting requirements in the jurisdictions in which we operate. Many of these licences and permits need to be renewed from time to time. If we are unsuccessful in obtaining or renewing such licences or permits, or the terms of such licences or permits are changed in a manner that is adverse to our business, we could be materially adversely affected.

Any changes in the rules and regulations of provincial or state public utility commissions or other regulatory bodies in the other markets in which we compete, or may compete in the future, may materially adversely affect us. The laws and regulations in the markets in which we operate are subject to change, which may materially adversely affect us.

As mandated by the U.S. Department of Energy, TransAlta Centralia Generation LLC has received an Order requiring Centralia Unit 2 in Washington State remain available if called upon to operate for a period of 90 days, until March 16, 2026. The coal used to fuel the Centralia facility is sourced from the Powder River Basin in Montana and Wyoming through contracts to purchase and transport such coal to the facility. The loss of our suppliers or inability to receive coal at Centralia under our existing coal contracts at sufficient quantities, or at all, could also significantly affect our ability to serve our customers and have an adverse impact on our financial condition and results of operations. As we approach the planned conversion of Centralia following the conclusion of the mandated coal operation period ending March 16, 2026, we will continue to monitor and adapt our fuel supply risk management strategies to support operational reliability and financial stability throughout the transition.

The reduction, elimination or expiration of government subsidies and economic incentives could adversely affect our prospects for growth.

We seek to access government policies that promote power generation and enhance the economic feasibility of power projects. Over recent years, the focus of programs has largely been on renewable energy projects. Renewable power generation sources have and in some cases continue to benefit from various incentives in the form of feed-in tariffs, rebates, tax credits, renewable portfolio standards (such as the U.S. government policy mechanism that supports the adoption of renewable power by setting a targeted percentage of a jurisdiction's total electricity procurement from renewable power) and other incentives throughout the markets in which we participate or intend to participate. As incentives have been reduced or eliminated, we have seen some reduction in development opportunities, but given that this impacts all developers and generators, we are seeing a common impact.

We may be adversely affected if our supply of water is materially reduced.

Our hydroelectric and natural gas facilities and our coal-fired facility require continuous water flow for their operation. Shifts in weather or climate patterns, seasonable precipitation, the timing and rate of melting, run-off and other factors beyond our control may reduce the water flow to our facilities. Any material reduction in the water flow to our facilities would limit our ability to produce and market electricity from these facilities and could have a material adverse effect on us. There is an increasing level of regulation respecting the use, treatment and discharge of water, and respecting the licensing of water rights in jurisdictions where we operate. Any change in regulations could have a material adverse effect on us.

Availability or disruption of fuel supply to our thermal plants could have an adverse impact on the operation of our facilities and our financial condition.

Our gas facilities rely on having adequate supplies of natural gas and our Centralia facility requires adequate supplies of coal to run the facility reliably and at full capacity. As a result, we face the risk of not having adequate fuel supplies available due to insufficient natural gas transportation service; disruptions in fuel supplies due to weather, strikes, lockouts, or equipment breakdowns; delays in receiving regulatory approvals; or if increases in the cost of fuel we must buy to generate electricity exceed the price we can obtain for the electricity we sell. Several factors affect the price of fuel, many of which are beyond our control, including:

- Prevailing market prices for fuel;
- Global demand for energy products;
- The cost of carbon and other environmental concerns;
- Weather-related disruptions affecting the ability to deliver fuels or near-term demand for fuels;
- Increases in the supply of energy products in the wholesale power markets;
- Political instability;
- The extent of fuel transportation capacity, cost of fuel transportation service into our markets or potential rail strikes; and
- The cost of mining or extraction that, in turn, depends on various factors such as labour market pressures, equipment replacement costs and permitting.

Changes in any of these factors may increase our cost of producing power or decrease the amount of revenue received from the sale of power, which could have a material adverse effect on us.

In the event the Company secures more natural gas than required to operate its facilities, it may have difficulty reselling the excess natural gas and could be exposed to the market price for natural gas for any such resales. There is no certainty that the Company will be successful in reselling or recovering its costs in respect of such resales of natural gas.

As well, the coal used to fuel the Centralia facility is sourced from the Powder River Basin in Montana and Wyoming through contracts to purchase and transport it to our Centralia facility. The loss of our suppliers or inability to receive coal at Centralia under our existing coal contracts at sufficient quantities, or at all, could also significantly affect our ability to serve our customers and have an adverse impact on our financial condition and results of operations.

We could face the risk of inadequate supply service due to our reliance on the Pioneer Pipeline and on the ATCO Pipeline as a significant provider of natural gas for our Sundance and Keephills units.

To manage gas supply risk, the Company enters into long term transportation service agreements to ensure that facilities have adequate gas supply. This could result in the additional risk of being in a surplus position where some of the transportation capacity may not be needed, yet the Company is still required to pay for the unused transportation. To manage this risk the Company will remarket excess natural gas transport capacity in the short-term while seeking long-term or permanent assignments.

Our facilities rely on national and regional transmission systems and related facilities that are owned and operated by third parties and have both regulatory and physical constraints that could impede access to electricity markets.

Our power generation facilities depend on electric transmission systems and related facilities owned and operated primarily by third parties to deliver the electricity that we generate to delivery points where ownership changes and we are paid. The risks associated with aging transmission infrastructure in the markets where we operate are increasing because new connections to the transmission system are consuming capacity faster than it is being added by new transmission developments.

Further, transmission systems operate with both regulatory and physical constraints that in certain circumstances may impede access to electricity markets. There may be instances in system emergencies in which our power generation facilities are physically disconnected from the power grid, or our production curtailed for periods of time. Most of our electricity sales contracts do not provide for payments to be made if electricity is not delivered.

Our power generation facilities may also be subject to changes in regulations governing the cost and characteristics of use of the transmission and distribution systems to which our power generation facilities are connected. In the future, our power generation facilities may not be able to secure access to this interconnection or transmission capacity at reasonable prices, in a timely fashion or at all, which could then cause delays and additional costs as we attempt to negotiate or renegotiate PPAs or construct new projects. In addition, we may not benefit from preferential arrangements in the future. Any such increased costs and delays could delay the commercial operation dates of any new projects and negatively impact our revenues and financial condition.

Cyberattacks may cause disruptions to our operations and could have a material adverse effect on our business.

We rely on information technology systems to process, transmit, and store data essential to the safe operation of our assets. Geopolitical tensions and the pandemic have contributed to a significant increase in both the frequency and complexity of cyberattacks. Threats now range from war-driven attacks on critical infrastructure to social-engineering schemes exploiting hybrid work environments. As the threat landscape continues to evolve—including ransomware, insider threats, supply chain compromises, targeted phishing and AI-enabled attacks—any breach of our systems could disrupt operations or compromise proprietary, confidential, or personal information.

Cyber threats originate from a variety of actors, including nation-states, organized groups, and malware developers. Attackers increasingly target users and internal systems rather than traditional perimeter defenses. A successful cyber incident could enable unauthorized access, destruction, or disclosure of information and may impact public safety, personnel, business operations, service delivery, reputation, or financial performance.

Our technology and systems for communication and monitoring may be vulnerable to security breaches or interruptions, which could result in increased operating expenses and other liabilities.

We rely on technology, mainly on computer, telephone, satellite, cellular and related networks and infrastructure, to conduct our business and monitor the production of our generation facilities. These systems and infrastructure could be vulnerable to unforeseen problems including, but not limited to, cyberattacks, breaches, vandalism and theft. Our operations are dependent upon our ability to protect our information and operating technology against damage from fire, power loss, telecommunications failure or a similar catastrophic event. While we have dedicated resources for maintaining appropriate levels of cybersecurity and we use third-party technology to help protect us against security breaches and cyber incidents, our measures may not be effective and our information technology and infrastructure may be vulnerable to attacks by hackers or breached due to employee error, malfeasance or other disruptions. Any such security breaches and cyber incidents or other disruptions could jeopardize the security of information stored in and transmitted through our systems and network infrastructure, and could result in significant setbacks and potential liabilities and deter future customers. Additionally, we must be able to protect our generation facility infrastructure against physical damage and any service disruptions.

Any damage or failure that causes an interruption in operations could have an adverse effect on our customers. While we have systems, policies, hardware, practices and procedures designed to prevent or limit the effect of failure or interruptions of our generation facilities and infrastructure, there can be no assurance that these measures will be sufficient and that any such failures or interruptions will not occur or, if they do occur, that they will be adequately addressed in a timely manner.

We operate in a highly competitive environment and may not be able to compete successfully.

We operate in a number of Canadian provinces, as well as in the U.S. and Western Australia. These areas of operation are affected by competition ranging from large utilities to small independent power producers, as well as private equity, pension funds, international conglomerates, traditional energy companies and technology firms. In addition, potential customers may look to deploy their own capital to self-supply their own electricity needs. Some competitors have significantly greater financial and other resources than we do. Such competition could have a material adverse effect on our business. Emerging technology affecting the demand, generation, distribution or storage of electricity may also significantly impact our business and ability to compete. Climate change and regulatory incentives are expected to drive innovation and transformation of the power generation sector, including energy production and consumption, and there can be no certainty that the Company will benefit from such innovation or transformation. Furthermore, older facilities may, over time, be unable to compete with newer, more efficient facilities that benefit from advances in power technologies and cost-efficient new technologies, including gas turbines with lower heat rates. In Alberta, some industrial customers rely on behind-the-fence generation; these customers are not being supplied electricity from the grid, which reduces the competitive load in the province and puts downward pressure on pool prices. Further, certain large industrial companies in Alberta operate significant cogeneration facilities, which generate steam required for their operations and often results in large amounts of excess generation being offered to the wholesale electricity market. These cogeneration facilities offer their energy into the market at low prices to ensure it is dispatched, which results in the facility realizing an achieved price close to the average pool price, which potentially puts downward pressure on the pool price and could result in certain of the Company's facilities not being dispatched.

Changes in general economic and market conditions may have a material adverse effect on us.

Adverse changes in general economic and market conditions could negatively impact demand for electricity as well as our revenue, operating costs, the timing and extent of capital expenditures, the net recoverable value of PP&E, financing costs, credit and liquidity risk and counterparty risk which could cause us to suffer a material adverse effect.

We may be unsuccessful in legal actions.

We are occasionally named as a party in various disputes, claims and legal or regulatory proceedings that arise during the normal course of our business. We review each of these claims, including the nature and merits of the claim, the amount in dispute or the remedy claimed and the availability of insurance coverage. There can be no assurance that any particular dispute, claim or proceeding will be resolved in our favour or that our liabilities with respect to such claims will not have a material adverse effect on us. Refer to the "Other Consolidated Analysis" section of this MD&A for further details.

We may have difficulty raising needed capital in the future, which could significantly harm our business.

If our sources of cash and cash flow from operations are insufficient to fund our activities or we are unable to divest assets to generate capital, we may need to raise additional funds. Additional financing may not be available when needed, and if such financing is available, it may not be available on terms that are favourable to our business.

Recovery of the capital investment in power projects generally occurs over a long period of time. As a result, we must obtain funds from equity or debt financings to help finance the acquisition and development of projects and to support the general and administrative costs of operating our business. Our ability to arrange financing, either at the corporate level or at the subsidiary level (including non-recourse project debt or tax equity), and the costs of such capital are dependent on numerous factors, including: (a) general economic and capital market conditions; (b) credit availability from banks and other financial institutions; (c) investor confidence and the markets in which we conduct operations; (d) our financial performance and/or the expected financial performance of certain assets; (e) our level of indebtedness and compliance with covenants in our debt agreements; (f) our cash flow and/or the expected cash flow of certain assets; and (g) our credit ratings. We are subject to certain financial covenants under our credit facility that could limit the amount of additional debt that the Company could raise in certain circumstances. An inability to raise debt could reduce the number of projects that we are able to finance. If we are unable to raise additional funds when needed, we could be required to delay the acquisition and construction of growth projects, reduce the scope of projects, abandon or sell some of our projects or generation facilities, or default on our contractual commitments in the future, any of which could adversely affect our business, financial condition and results of operations.

A downgrade of our credit ratings could affect us materially and adversely.

Rating agencies regularly evaluate us, basing their ratings of our long and short-term debt, along with our issuer rating, on a number of factors. There can be no assurance that one or more of our credit ratings and the corresponding outlooks will not be changed. Our borrowing costs and ability to raise funds are directly impacted by our credit ratings. Credit ratings may be important to suppliers or counterparties when they seek to engage in certain transactions with us. A credit rating downgrade could potentially impair our ability to enter into arrangements with suppliers or counterparties, to engage in certain transactions, and could limit our access to private and public credit markets and increase the costs of borrowing under our existing credit facilities.

Changes to our reputation may have a material adverse effect on us.

Reputation risk relates to the risk associated with our business because of changes in opinion from the general public, private stakeholders, governments, financiers and other entities. Our reputation is one of our most valued assets. The potential for harming our reputation exists in every business decision and all risks can have an impact on reputation, which in turn can negatively impact our business and securities. Reputational risk cannot be managed in isolation from other forms of risk. Negative impacts from a compromised reputation could include revenue loss, reduction in our customer base and the decreased value of our securities.

We may fail to meet financial expectations.

Our quarterly revenue, earnings, cash flows and results of operations are difficult to predict and fluctuate from quarter to quarter. Our quarterly results of operations are influenced by a number of factors, including the risks described in this MD&A, many of which are outside of our control and that may cause such results to fall below market expectations. Although we base our planned operating expenses in part on our expectations of future revenue, a significant portion of our expenses are relatively fixed in the short-term. If revenue for a particular quarter is lower than expected, we will likely be unable to proportionately reduce our operating expenses for that quarter, which will adversely affect our results of operations for that quarter.

Our cash dividend payments are not guaranteed.

The payment of dividends is not guaranteed and could fluctuate. The Board of Directors has the discretion to determine the amount and timing of any dividends to be declared and paid to our shareholders. In addition, the payment of dividends on common shares is, in all cases, subject to prior satisfaction of preferential dividends applicable to each series of our first preferred shares. We may alter our dividend on common shares at any time. The Board of Directors' determination to declare dividends will depend on, among other things: results of operations; financial condition; current and expected future levels of earnings; operating cash flow; liquidity requirements; market opportunities; income taxes; maintenance and growth capital expenditures; debt repayments; legal, regulatory and contractual constraints; working capital requirements; taxes payable; and other relevant factors. Our short- and long-term borrowings may prohibit us from paying dividends at any time at which a default or event of default would exist under such debt, or if a default or event of default would exist as a result of paying the dividend.

Over time, our capital and other cash needs may change significantly from our current needs, which could affect whether we pay dividends and the amount of any dividends we may pay in the future. If we continue to pay dividends at the current level, we may not retain a sufficient amount of cash to finance growth opportunities, meet any large unanticipated liquidity requirements or fund our operations in the event of a significant business downturn. The Board of Directors, subject to the requirements of our bylaws and other governance documents, may amend, revoke or suspend our dividends at any time. A decline in the market price or liquidity, or both, of our common shares could result if the Board of Directors reduces or eliminates the payment of dividends.

We are dependent on the operations of our facilities for our cash availability. The actual amount of cash available for dividends to holders of our common shares will depend upon numerous factors relating to each of our generation facilities including: their operating performance; profitability; changes in gross margin; fluctuations in working capital; capital expenditure levels; applicable laws; tax position; financing; compliance with contracts; and contractual restrictions contained in the instruments governing any indebtedness. Any reduction in the amount of cash available for distribution from our generation facilities will reduce the amount of cash available to pay dividends to holders of our common shares.

The market price for our common shares may be volatile.

The market price for our common shares may be volatile and subject to wide fluctuations in response to numerous factors, many of which are beyond our control, including: (a) actual or anticipated fluctuations in our results of operations; (b) recommendations by securities research analysts; (c) changes in the economic performance or market valuations of other companies that investors deem comparable; (d) the loss or resignation of executive officers and other key personnel; (e) sales or perceived sales of additional common shares; (f) significant acquisitions or business combinations, strategic partnerships, joint ventures or capital commitments by or involving us or our competitors; and (g) trends, concerns, technological or competitive developments, regulatory changes and other related issues in the power generation industry or our target markets.

Financial markets have experienced significant price and volume fluctuations that have particularly affected the market prices of equity securities of companies and these fluctuations have, in many cases, been unrelated to the operating performance, underlying asset values or prospects of such companies. Accordingly, the market price of our common shares may decline even if our operating results, underlying asset values or prospects have not changed. Additionally, these factors, as well as other related factors, may cause decreases in asset values that may result in impairment losses.

We may not be able to extend, renew or replace expiring or terminated PPAs, or other customer contracts at favourable rates or on a long-term basis.

Our ability to extend, renew or replace our existing PPAs or other customer contracts depends on a number of factors beyond our control, including, but not limited to: whether the PPA counterparty has a continued need for energy at the time of the agreement's expiration; the presence or absence of governmental incentives; prevailing market prices; the availability of other electricity sources; the satisfactory performance of our obligations under such PPAs; the age and condition of the facility and the forecasted maintenance and sustaining capital costs to continue operations; macroeconomic factors present at the time, such as population, business trends, international trade laws, regulations, agreements, treaties, policies and related impacts on energy demand; and the effects of regulation on our contractual counterparties.

If we are not able to extend, renew or replace existing PPAs on acceptable terms before the PPAs expire, or if such agreements are otherwise terminated before their expiration, we may not be able to sell electricity to the market or to other customers. If we are able to sell electricity on an uncontracted basis, we would sell electricity at prevailing market prices that could be materially lower than under the applicable contract. This could result in us having less stable cash flows. If there is no satisfactory market for a project's uncontracted energy, we may decommission the project before the end of its useful life. Any failure to extend, renew or replace a significant portion of our existing PPAs, or other customer contracts, or extending, renewing or replacing them at lower prices or with other unfavourable terms relative to the existing PPA, or the decommissioning of a project, could have a material adverse effect on our business, financial condition, results of operations and ability to pay dividends to our shareholders.

We may fail to fully or effectively hedge our supply and price risk exposure.

We closely monitor the risks associated with changes in electricity and input fuel prices on our future operations and, where we consider it appropriate, use various physical and financial instruments to hedge our assets and operations from such price risks. The efficacy of our risk management and hedging program may be adversely impacted by unanticipated events and costs that we are not able to effectively mitigate, including unanticipated events that impact supply and demand, such as extreme weather and unplanned outages. We may also be adversely impacted if we make incorrect assumptions that were relied upon in establishing our hedges. We are exposed to changes in electricity prices and natural gas prices on purchases of electricity or natural gas from the market to fulfil our supply obligations under these short- and long-term hedge contracts. If we are unable to produce or consume the amount of natural gas or electricity that we have hedged, we could incur losses as we could be required to purchase additional volumes in the market at higher prices to cover our hedge position. Comparably, if the market price for electricity is higher than the hedged price we would be subject to the opportunity cost associated with not realizing the higher market price.

We are also exposed to basis risk as certain of our generating facilities receives the "node" price for the electricity it delivers to the grid while the financial PPA for such generating facility settles at the "hub" price. The differences between the "node" and "hub" price can be significant from time to time.

Trading risks may have a material adverse effect on our business.

Our trading and marketing business frequently involves establishing trading positions in the wholesale energy markets on both a medium-term and short-term basis, and on both an asset and proprietary basis. To the extent that we have long positions in the energy markets, a downturn in market prices will result in losses from a decline in the value of these long positions. Conversely, to the extent that we enter into forward sales contracts to deliver energy that we do not own, or take short positions in the energy markets, an upturn in market prices will expose us to losses as we attempt to cover any short positions by acquiring energy in a rising market.

In addition, from time to time, we may have a trading strategy consisting of simultaneously holding a long position and a short position, from which we expect to earn a profit based on changes in the relative value of the two positions. If, however, the relative value of the two positions changes in a direction or manner that we did not anticipate, we would realize losses from such a paired position.

If the strategy that we use to hedge our exposures to these various risks is not effective, we could incur significant losses. Our trading positions can be impacted by volatility in the energy markets that, in turn, depend on various factors, including weather in various geographical areas and short-term supply and demand imbalances, which cannot be predicted with any certainty. A shift in the energy markets could adversely affect our positions, which could also have a material adverse effect on our business.

Our risk management group uses a number of risk management controls to limit our exposure to risks arising from our trading activities. These controls include risk capital limits, Value at Risk, Gross Margin at Risk, tail risk scenarios, position limits, concentration limits, credit limits and approved product controls. We cannot guarantee that losses will not occur and such losses may be outside the parameters of our risk controls.

Certain of the contracts to which we are a party require that we provide collateral against our obligations.

We are exposed to risk under certain arrangements, including financial derivative contracts and electricity and natural gas purchase and sale contracts entered into for the purposes of hedging and proprietary trading. The terms and conditions of these contracts may require us to provide collateral when the fair value of these contracts exceeds any credit limits granted by our counterparties and the contract obliges that we provide the collateral. The change in fair value of these contracts often occurs due to changes in commodity prices. These contracts include: (a) financial derivative contracts when forward commodity prices are more or less than contracted prices, depending on the transactions; (b) purchase agreements, when forward commodity prices are less than contracted prices; and (c) sales agreements, when forward commodity prices exceed contracted prices. Downgrades in our creditworthiness by certain credit rating agencies may decrease the credit limits granted by our counterparties and, accordingly, increase the amount of collateral we may have to provide. Any increase in the amount of collateral provided by the Company could reduce our liquidity and materially adversely affect us.

If counterparties to our contracts are unable to meet their obligations, we may be materially and adversely affected.

If purchasers of our electricity and steam or other contractual counterparties default on their obligations, we may be materially and adversely affected. While we have procedures and controls in place to manage counterparty credit risk before entering into contracts, all contracts inherently contain default risk. Moreover, while we seek to monitor trading activities to ensure that the credit limits for counterparties are not exceeded, we cannot guarantee that a party will not default. If counterparties to our contracts are unable to meet their obligations, we could suffer a reduction in revenue that could have a material adverse effect on our business.

If established credit exposure limits are exceeded, we take steps to reduce this exposure, such as by requesting collateral, if applicable, or by halting commercial activities with the affected counterparty. However, there can be no assurances that we will be successful in avoiding losses as a result of a contract counterparty not meeting its obligations.

As needed, additional risk mitigation tactics will be taken to reduce the risk to TransAlta. These risk mitigation tactics may include, but are not limited to, immediate follow-up on overdue amounts, adjusting payment terms to ensure a portion of funds are received sooner, requiring additional collateral, reducing transaction terms and working closely with impacted counterparties on negotiated solutions.

Our credit risk management profile and practices have not changed materially from Dec. 31, 2024. We had no material counterparty losses in 2025. We continue to keep a close watch on changes and trends in the market and the impact these changes could have on our energy trading business and hedging activities and will take appropriate actions as required, although no assurance can be given that we will always be successful.

The following table outlines our maximum exposure to credit risk without taking into account collateral held or right of set-off, including the distribution of credit ratings, as at Dec. 31, 2025:

	Investment grade (per cent)	Non-investment grade (per cent)	Total (per cent)	Total amount ($)
Trade and other receivables[(1)]	84	16	100	**699**
Long-term finance lease receivables	100	—	100	**277**
Risk management assets[(1)]	53	47	100	**194**
Long-term financial assets[(2)]	—	100	100	**140**
Loans receivable[(3)]	—	100	100	**31**
Total				**1,341**

(1) Letters of credit and cash and cash equivalents are the primary types of collateral held as security related to these amounts.
(2) Included within long-term financial assets with counterparties that have no external credit rating.
(3) Includes $31 million loans receivable included within other assets with a counterparty that has no external credit rating.

The maximum credit exposure to any one customer for commodity trading operations, including the fair value of open trading positions net of any collateral held, is $51 million (2024 – $77 million).

Because of our multinational operations, we are subject to currency rate, tax, regulatory and political risks.

We are exposed to various currencies as a result of our investments and operations in foreign jurisdictions, the earnings from those operations, the acquisition of equipment and services and foreign-denominated commodities from foreign suppliers, and our U.S. and Australian dollar-denominated debt. Our exposures are primarily to the U.S. and Australian currencies, and changes in the values of these currencies relative to the Canadian dollar could negatively impact our operating cash flows or the value of our foreign investments.

While we attempt to manage this risk by using hedging instruments, including cross-currency interest rate swaps, forward exchange contracts and matching revenues and expenses by currency at the corporate level, there can be no assurance that these risk management efforts will be effective, and fluctuations in these exchange rates may have a material adverse effect on our business.

In addition to currency rate risk, our foreign operations may be subject to tax, regulatory and political risk. Any change to the regulations governing power generation or the political climate in the countries where we have operations could impose additional costs and have a material adverse effect on us.

The sensitivity of our net (loss) earnings to changes in foreign exchange rates has been prepared using management's assessment that an average $0.03 increase or decrease in the U.S. or Australian currencies relative to the Canadian dollar is a reasonable potential change over the next quarter and is shown below:

Factor	Increase or decrease	Approximate impact on net (loss) earnings (millions)
Exchange rate	$0.03	**$17**

We are not able to insure against all potential risks and may become subject to higher insurance premiums.

Our business is exposed to the risks inherent in the construction and operation of electricity generation facilities, such as breakdowns, manufacturing defects, natural disasters, injury, damage to third parties, theft, terrorist attacks, cyberattacks and sabotage. We are also exposed to environmental risks. We maintain insurance policies, covering usual and customary risks associated with our business, with creditworthy insurance carriers. Our insurance policies, however, may not cover losses, or may be subject to limitations in coverage as a result of force majeure, natural disasters, terrorist or cyberattacks or sabotage, armed hostilities, or other perils. Our insurance policies may be subject to increase resulting from climate change, for example due to increased storm severity and frequency. In addition, we generally do not maintain insurance for certain environmental risks, such as environmental contamination. Our insurance policies are subject to annual review by the respective insurers and may not be renewed at all or on similar or favourable terms. A significant uninsured loss or a loss significantly exceeding the limits of our insurance policies or the failure to renew such insurance policies on similar or favourable terms could have a material adverse effect on our business, financial condition and results of operations.

Our insurance coverage may not be available in the future on commercially reasonable terms or adequate insurance limits may not be available in the market. In addition, the insurance proceeds received for loss or damage to any of our generation facilities may not be sufficient to permit us to continue to make payments on our debt.

Provision for income taxes may not be sufficient.

Our operations are complex and located in several countries, and the computation of the provision for income taxes involves tax interpretations, regulations and legislation that are continually changing. In addition, our tax filings are subject to audit by taxation authorities. While we believe that our tax filings have been made in material compliance with all applicable tax interpretations, regulations and legislation, we cannot guarantee that we will not have disagreements with taxation authorities with respect to our tax filings that could have a material adverse effect on our business.

The Company and its subsidiaries are subject to changing laws, treaties and regulations in and between countries. Various tax proposals in the countries where we operate could result in changes to the basis on which deferred taxes are calculated or could result in changes to income or non-income tax expense. There has recently been an increased focus on issues related to the taxation of multinational corporations. A change in tax laws, treaties or regulations, or in the interpretation thereof, could result in a materially higher income or non-income tax expense that could have a material adverse impact on us.

The sensitivity of changes in income tax rates upon our net earnings is shown below:

Factor	Increase or decrease (per cent)	Approximate impact on net (loss) earnings (millions)
Tax rate	1	**$1**

If we fail to attract and retain key personnel, we could be materially adversely affected.

The loss of any of our key personnel or our inability to attract, train, retain and motivate additional qualified management and other personnel could have a material adverse effect on our business. Competition for these personnel is intense and there can be no assurance that we will be successful in this regard.

If we are unable to successfully negotiate new collective bargaining agreements with our unionized workforce, as required, we will be adversely affected. While we believe we have a satisfactory relationship with our unionized employees, we cannot guarantee that we will be able to successfully negotiate or renegotiate our collective bargaining agreements on terms agreeable to

TransAlta. In 2025 we successfully renegotiated one collective bargaining agreement.

We expect to renegotiate four collective bargaining agreements in 2026. Any hurdles in negotiating these collective bargaining agreements could lead to higher employee costs and a work stoppage or strike, which could have a material adverse effect on us.

We are subject to risks associated with our ownership interests in projects that are under construction, which could result in our inability to complete construction projects on time or at all, and make projects too expensive to complete or cause the return on an investment to be less than expected.

TransAlta has interests in certain projects that have not yet started operations or are under construction. There may be delays or unexpected developments in completing any future construction projects, which could cause the construction costs of these projects to exceed our expectations, result in substantial delays or prevent the project from commencing commercial operations. Various factors could contribute to construction-cost overruns, construction halts or delays or the failure to commence commercial operations, including: delays in obtaining, or the inability to obtain, necessary land rights, permits and licences; delays and increased costs related to the interconnection of new projects to the transmission system; the inability to acquire or maintain land use and access rights; the failure to receive contracted third-party services; interruptions to dispatch at the projects; supply chain disruptions, including as a result of changes in international trade laws, regulations, agreements, treaties,

taxes, tariffs, duties or policies of Canada, the U.S. or other countries in which the Company's suppliers are located; work stoppages; labour disputes; weather interferences; unforeseen engineering, environmental and geological problems, including, but not limited to, discoveries of contamination, protected plant or animal species or habitat, archaeological or cultural resources or other environment-related factors; unanticipated cost overruns in excess of budgeted contingencies; and failure of contracting parties to perform under contracts.

In addition, if we or one of our subsidiaries has an agreement for a third party to complete construction of any project, TransAlta is subject to the viability and performance of the third party. Our inability to find a replacement contracting party, if the original contracting party has failed to perform, could result in the abandonment of the construction of such project, while we could remain obligated under other agreements associated with the project, including, but not limited to, offtake PPA's.

New technology and artificial intelligence may present emerging risks that could have a material adverse effect on the Company.

We are introducing artificial intelligence and robotics at some of our facilities. The use of artificial intelligence and robotics at our facilities may not yield materially better results, higher outputs or increased productivity and there is no certainty that we will realize benefits from investments in these technologies. Additionally, the use of artificial intelligence is subject to the risk that privacy concerns relating to such technology could deter current and potential customers.

Changes in interest rates can impact our borrowing costs and affect our interest rate risk.

Changes in interest rates can impact our borrowing costs. Changes in our cost of capital may also affect the feasibility of new growth initiatives.

At Dec. 31, 2025, approximately 10 per cent (2024 – 23 per cent) of our total long-term debt was subject to changes in floating interest rates through a combination of floating rate debt and interest rate swaps.

We manage interest rate risk by establishing and adhering to policies that include:

- Employing a combination of fixed and floating rate debt instruments;
- Monitoring the mixture of floating and fixed rate debt and adjusting to ensure efficiency; and
- Opportunistically hedging probable debt issuances and outstanding variable rate borrowings using interest rate swaps.

The sensitivity of changes in interest rates upon our net earnings is shown below:

Factor	Increase or decrease (per cent)	Approximate impact on net earnings (millions)
Interest rate	50	**$1**

Disclosure Controls and Procedures

Management is responsible for establishing and maintaining adequate internal control over financial reporting (ICFR) and disclosure controls and procedures (DC&P). For the year ended Dec. 31, 2025, the majority of our workforce supporting and executing our ICFR and DC&P continue to work on a hybrid basis. The Company has implemented appropriate controls and oversight for both in-office and remote work. There has been minimal impact to the design and performance of our internal controls.

ICFR is a framework designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements for external purposes in accordance with IFRS. Management has used the Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) to assess the effectiveness of the Company's ICFR.

DC&P refer to controls and other procedures designed to ensure that information required to be disclosed in the reports we file or submit under securities legislation is recorded, processed, summarized and reported within the time frame specified in applicable securities legislation. DC&P include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in our reports that we file or submit under applicable securities legislation is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding our required disclosure.

Together, the ICFR and DC&P frameworks provide internal control over financial reporting and disclosure. In designing and evaluating our ICFR and DC&P, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives and as such may not prevent or detect all misstatements and management is required to apply its judgment in evaluating and implementing possible controls and procedures. Further, the effectiveness of ICFR is subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with policies or procedures may change.

Management has evaluated, with the participation of our Chief Executive Officer and Chief Financial Officer, the effectiveness of our ICFR and DC&P as of the end of the period covered by this MD&A. Based on the foregoing evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as at Dec. 31, 2025, the end of the period covered by this MD&A, our ICFR and DC&P were effective.

Consolidated Financial Statements

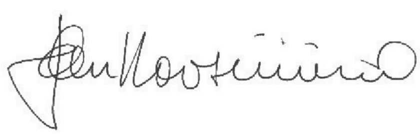
Management's Report

To the Shareholders of TransAlta Corporation

The Consolidated Financial Statements and other financial information included in the Annual Report have been prepared by management. It is management's responsibility to ensure that sound judgment, appropriate accounting principles and methods, and reasonable estimates have been used to prepare this information. Management also ensures that all information presented is consistent.

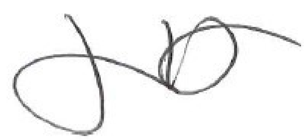
Management is also responsible for establishing and maintaining internal controls and procedures over the financial reporting process. The internal control system includes an internal audit function and an established business conduct policy that applies to all employees. In addition, TransAlta Corporation (TransAlta or the Company) has a Corporate Code of Conduct that applies to all employees and is signed annually and can be viewed on the Company's website (www.transalta.com). Management believes the system of internal controls, review procedures and established policies provides reasonable assurance as to the reliability and relevance of financial reports. Management also believes that TransAlta's operations are conducted in conformity with the law and with a high standard of business conduct.

The Board of Directors (the Board) is responsible for ensuring that management fulfils its responsibilities for financial reporting and internal controls. The Board carries out its responsibilities principally through its Audit, Finance and Risk Committee (the Committee). The Committee, which consists solely of independent directors, reviews the financial statements and annual report and recommends them to the Board for approval. The Committee meets with management and internal and external auditors to discuss internal controls, auditing matters and financial reporting issues. Internal and external auditors have full and unrestricted access to the Committee. The Committee also recommends the firm of external auditors to be appointed by shareholders.



John Kousinioris

President and Chief Executive Officer



Joel Hunter

Executive Vice President, Finance and
Chief Financial Officer

February 26, 2026

Management's Annual Report on Internal Control Over Financial Reporting

To the Shareholders of TransAlta Corporation

The following report is provided by management in respect of TransAlta Corporation's (TransAlta or the Company) internal control over financial reporting (as defined in Rules 13a-15f and 15d-15f under the United States Securities Exchange Act of 1934 and National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings (NI 51-109)).

TransAlta's management is responsible for establishing and maintaining adequate internal control over financial reporting for the Company.

Management uses the Committee of Sponsoring Organizations of the Treadway Commission (COSO) 2013 framework to evaluate the effectiveness of TransAlta's internal control over financial reporting. Management believes that the COSO 2013 framework is appropriate for its evaluation of TransAlta's internal control over financial reporting because it is free from bias, permits reasonably consistent qualitative and quantitative measurements of internal controls, is sufficiently complete so any relevant factors that would alter a conclusion about the effectiveness of the Company's internal controls are not omitted, and is relevant to an evaluation of internal control over financial reporting.

Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives due to its inherent limitations. Internal control over financial reporting includes processes that involve human diligence and compliance that are subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting can also be circumvented by collusion or improper overrides. As a result of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis. These inherent limitations are known features of the financial reporting process and it is possible to design safeguards into the process to reduce, though not eliminate, this risk.

TransAlta equity accounts for our investment in the SP Skookumchuck Investment, LLC (Skookumchuck) in accordance with International Financial Reporting Standards. Management does not have the contractual ability to assess the internal controls of this equity investment. Once the financial information is obtained from Skookumchuck, it falls within the scope of TransAlta's internal controls framework. Management's conclusion regarding the effectiveness of internal controls does not extend to the internal controls at the transactional level of this associate.

Included in the 2025 Consolidated Financial Statements of TransAlta for equity-accounted investments are one per cent and eight per cent of the Company's total and net assets, respectively, as at Dec. 31, 2025, and zero per cent and (5) per cent of the Company's revenues and net loss, respectively, for the year ended Dec. 31, 2025.

Changes in Internal Control over Financial Reporting

There has been no change in the Company's internal control over financial reporting that occurred during the year covered by the Annual Report that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

Management has assessed the effectiveness of TransAlta's internal control over financial reporting as at Dec. 31, 2025, and has concluded that such internal control over financial reporting was effective.

Ernst & Young LLP, who has audited the Consolidated Financial Statements of TransAlta for the year ended Dec. 31, 2025, has also issued a report on internal control over financial reporting under the standards of the Public Company Accounting Oversight Board. This report is located on the following page of the Annual Report.

John Kousinioris
President and Chief Executive Officer

Joel Hunter
Executive Vice President, Finance and
Chief Financial Officer

February 26, 2026

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors of TransAlta Corporation

Opinion on Internal Control Over Financial Reporting

We have audited TransAlta Corporation's internal control over financial reporting as of December 31, 2025, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the "COSO criteria"). In our opinion, TransAlta Corporation (the "Company") maintained, in all material respects, effective internal control over financial reporting as of December 31, 2025, based on the COSO criteria.

As indicated in the accompanying Management's Annual Report on Internal Control over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of the equity accounted joint venture of SP Skookumchuck Investment, LLC which is included in the 2025 consolidated financial statements of the Company and constituted 1% and 8% of total and net assets, respectively, as of December 31, 2025, and 0% and (5)% of revenues and net earnings, respectively, for the year then ended. Our audit of internal control over financial reporting of the Company also did not include an evaluation of the internal control over financial reporting of the equity accounted joint venture of SP Skookumchuck Investment, LLC.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated statements of financial position of TransAlta Corporation as of December 31, 2025 and 2024, the related consolidated statements of (loss) earnings, comprehensive (loss) income, changes in equity and cash flows for the years then ended, and the related notes and our report dated February 26, 2026 expressed an unqualified opinion thereon.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/Ernst & Young LLP

Chartered Professional Accountants

Calgary, Canada

February 26, 2026

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors of TransAlta Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated statements of financial position of TransAlta Corporation (the "Company") as of December 31, 2025 and 2024, the related consolidated statements of (loss) earnings, comprehensive (loss) income, changes in equity and cash flows for the years then ended, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2025 and 2024, and its financial performance and its cash flows for the years then ended, in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2025, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("2013 framework"), and our report dated February 26, 2026 expressed an unqualified opinion thereon.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Valuation of Long-Lived Assets related to certain cash generating units ("CGU"s) and Goodwill related to the Wind & Solar segment	
Description of the Matter	As disclosed in notes 2(G), 2(H), 2(Q)(II), 7, 19, and 22 of the consolidated financial statements, the Company owns significant Wind & Solar generation assets and has recognized goodwill from historical acquisitions which must be tested for impairment at least annually or when indicators of impairment are present. The carrying value of Goodwill related to the Wind & Solar segment as at December 31, 2025 was $177 million and the recoverable amount of long-lived assets in the Wind & Solar segment that had indicators of impairment or impairment reversal during the year was $596 million. Determining the recoverable amounts for the Wind & Solar segment for the purposes of the goodwill impairment test and of certain CGUs in the Wind & Solar segment with indicators of impairment or impairment reversal ("Wind & Solar CGUs") for the asset impairment test was identified as a critical audit matter due to the significant estimation uncertainty and judgment applied by management in determining the recoverable amount, primarily due to the sensitivity of the significant assumptions to the future cash flows and the effect that changes in these assumptions would have on the recoverable amount. The estimates with a high degree of subjectivity include electricity production, sales prices, cost inputs, and determining the appropriate discount rate.
How We Addressed the Matter in Our Audit	We obtained an understanding of management's process for estimating the recoverable amount of the Wind & Solar segment and the Wind & Solar CGUs. We evaluated the design and tested the operating effectiveness of controls over the Company's processes to determine the recoverable amount. Our audit procedures to test the Company's recoverable amount of the Wind & Solar segment and the Wind & Solar CGUs with indicators of impairment or impairment reversal included, among others, comparing the significant assumptions used to estimate cash flows to current contracts with external parties and historical trends and obtaining historical electricity generation data to evaluate future electricity production forecasts. We assessed the historical accuracy of management's forecasts by comparing them with actual results and performed a sensitivity analysis to evaluate the assumptions that were most significant to the determination of the recoverable amount. We evaluated the Company's determination of future sales prices by comparing them to externally available third-party future electricity price estimates. We also involved our internal valuation specialist to assist in our evaluation of the discount rates, which involved benchmarking the inputs against available market data.

Valuation of Level III Derivative Instruments	
Description of the Matter	As disclosed in notes 2(B), 2(Q)(V) and 14 of the consolidated financial statements, the Company enters into transactions that are accounted for as derivative financial instruments and are recorded at fair value. The valuation of derivative instruments classified as level III are determined using assumptions that are not readily observable. As at December 31, 2025 the fair value of the Company's derivative financial instruments classified as level III was a $65 million risk management asset and a $512 million risk management liability. Auditing the determination of fair value of level III derivative instruments that rely on significant unobservable inputs can be complex and relies on judgments and estimates concerning future prices, discount rates, credit value adjustments, liquidity and delivery volumes, and can fluctuate significantly depending on market conditions. Therefore, such determination of fair value was identified as a critical audit matter.
How We Addressed the Matter in Our Audit	We obtained an understanding of the Company's processes and we evaluated and tested the design and operating effectiveness of internal controls addressing the determination and review of inputs used in establishing level III fair values. Our audit procedures included, among others, testing a sample of level III derivative instrument internal models used by management and evaluating the significant assumptions utilized. We also compared management's future pricing assumptions, credit value adjustments, and liquidity assumptions to third-party data as well as comparing terms such as delivery volumes and timing to executed commodity contracts. We compared the delivery volume assumptions to historical information. We performed a sensitivity analysis to evaluate assumptions including future commodity prices, delivery volumes and discount rates. For a sample of level III derivative instruments, we involved our internal valuation specialist to assist in our evaluation of the appropriateness of the fair value by evaluating the key assumptions and methodologies.

/s/Ernst & Young LLP

Chartered Professional Accountants

We have served as auditors of TransAlta Corporation and its predecessor entities since 1947.

Calgary, Canada

February 26, 2026

Consolidated Statements of (Loss) Earnings

(in millions of Canadian dollars except where noted)

Year ended Dec. 31	2025	2024
Revenues (Note 5)	**2,405**	2,845
Fuel and purchased power (Note 6)	**935**	939
Carbon compliance costs (Note 16)	**50**	112
Gross margin	**1,420**	1,794
Operations, maintenance and administration (Note 6)	**711**	655
Depreciation and amortization (Note 19, 20, 21 and 27)	**579**	531
Asset impairment (reversals) charges (Note 7)	**(13)**	46
Taxes, other than income taxes	**50**	36
Net other operating income (Note 8)	**(47)**	(59)
Operating income	**140**	585
Equity income (Note 9)	**6**	5
Fair value change in contingent consideration payable (Note 7)	**37**	—
Finance lease income (Note 17)	**23**	14
Interest income	**28**	30
Interest expense (Note 10)	**(347)**	(324)
Foreign exchange (loss) gain	**(21)**	5
(Loss) gain on sale of assets and other	**(7)**	4
(Loss) earnings before income taxes	**(141)**	319
Income tax expense (Note 11)	**17**	80
Net (loss) earnings	**(158)**	239
Net (loss) earnings attributable to:		
Common shareholders	**(138)**	229
Non-controlling interests (Note 12)	**(20)**	10
	(158)	239
Net (loss) earnings attributable to TransAlta shareholders	**(138)**	229
Preferred share dividends (Note 29)	**52**	52
Net (loss) earnings attributable to common shareholders	**(190)**	177
Weighted average number of common shares outstanding in the year (*millions*)	**297**	302
Net (loss) earnings per share attributable to common shareholders, basic and diluted (Note 28)	**(0.64)**	0.59

See accompanying notes.

Consolidated Statements of Comprehensive (Loss) Income

(in millions of Canadian dollars)

Year ended Dec. 31	2025	2024
Net (loss) earnings	**(158)**	239
Other comprehensive (loss) income		
Net actuarial gains on defined benefit plans, net of tax(1)	**5**	9
Total items that will not be reclassified subsequently to net (loss) earnings	**5**	9
(Losses) gains on translating net assets of foreign operations	**(12)**	30
Gains (losses) on financial instruments designated as hedges of foreign operations, net of tax(2)	**11**	(28)
(Losses) gains on derivatives designated as cash flow hedges, net of tax(3)	**(1)**	213
Reclassification of gains on derivatives designated as cash flow hedges to net (loss) earnings, net of tax(4)	**(68)**	(19)
Total items that will be reclassified subsequently to net (loss) earnings	**(70)**	196
Other comprehensive (loss) income	**(65)**	205
Total comprehensive (loss) income	**(223)**	444
Total comprehensive (loss) income attributable to:		
TransAlta shareholders	**(203)**	434
Non-controlling interests (Note 12)	**(20)**	10
	(223)	444

(1) Net of income tax expense of $1 million for the year ended Dec. 31, 2025 (2024 — $3 million expense).

(2) Net of income tax expense of $1 million for the year ended Dec. 31, 2025 (2024 — $4 million recovery).

(3) Net of income tax expense of nil million for the year ended Dec. 31, 2025 (2024 — $57 million expense).

(4) Net of reclassification of income tax recovery of $14 million for the year ended Dec. 31, 2025 (2024— $4 million recovery).

See accompanying notes.

Consolidated Statements of Financial Position

(in millions of Canadian dollars)

As at Dec. 31	2025	2024
Current assets		
Cash and cash equivalents	**205**	337
Restricted cash (Note 25)	**78**	69
Trade and other receivables (Note 13)	**699**	767
Prepaid expenses and other	**51**	68
Risk management assets (Note 14 and 15)	**162**	318
Inventory (Note 16)	**111**	134
Assets held for sale (Note 4 and 18)	**30**	80
	1,336	1,773
Non-current assets		
Investments (Note 9)	**144**	159
Long-term portion of finance lease receivables (Note 17)	**277**	305
Risk management assets (Note 14 and 15)	**32**	93
Property, plant and equipment (Note 19)	**5,665**	6,020
Right-of-use assets (Note 20)	**111**	120
Intangible assets (Note 21)	**243**	281
Goodwill (Note 22)	**516**	517
Deferred income tax assets (Note 11)	**41**	52
Long-term financial assets (Note 14)	**140**	—
Other assets (Note 23)	**156**	179
Total assets	**8,661**	9,499
Current liabilities		
Bank overdraft	**—**	1
Accounts payable, accrued liabilities and other current liabilities (Note 13)	**613**	756
Current portion of decommissioning and other provisions (Note 24)	**84**	83
Risk management liabilities (Note 14 and 15)	**156**	277
Dividends payable (Note 28 and 29)	**52**	49
Exchangeable securities (Note 26)	**750**	750
Contingent consideration payable (Note 4 and 7)	**—**	81
Current portion of long-term debt and lease liabilities (Note 25)	**175**	572
	1,830	2,569
Non-current liabilities		
Credit facilities, long-term debt and lease liabilities (Note 25)	**3,418**	3,236
Decommissioning and other provisions (Note 24)	**807**	850
Deferred income tax liabilities (Note 11)	**423**	470
Risk management liabilities (Note 14 and 15)	**519**	305
Contract liabilities (Note 5)	**26**	24
Defined benefit obligation and other long-term liabilities (Note 27)	**173**	202
Total liabilities	**7,196**	7,656
Equity		
Common shares (Note 28)	**3,169**	3,179
Preferred shares (Note 29)	**942**	942
Contributed surplus	**42**	42
Deficit	**(2,730)**	(2,458)
Accumulated other comprehensive (loss) income (Note 30)	**(24)**	41
Equity attributable to shareholders	**1,399**	1,746
Non-controlling interests (Note 12)	**66**	97
Total equity	**1,465**	1,843
Total liabilities and equity	**8,661**	9,499

Commitments and contingencies (Note 36)
Subsequent events (Note 38)

See accompanying notes.

On behalf of the Board:

John P. Dielwart
Director

Thomas M. O'Flynn
Chair of Audit, Finance and Risk Committee

Consolidated Statements of Changes in Equity

(in millions of Canadian dollars)

	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income (loss)[1]	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec. 31, 2023	3,285	942	41	(2,567)	(164)	1,537	127	1,664
Net earnings	—	—	—	229	—	229	10	239
Other comprehensive income:								
Net gains on translating net assets of foreign operations, net of hedges and of tax	—	—	—	—	2	2	—	2
Net gains on derivatives designated as cash flow hedges, net of tax	—	—	—	—	194	194	—	194
Net actuarial gains on defined benefits plans, net of tax	—	—	—	—	9	9	—	9
Total comprehensive income	—	—	—	229	205	434	10	444
Common share dividends (Note 28)	—	—	—	(71)	—	(71)	—	(71)
Preferred share dividends (Note 29)	—	—	—	(52)	—	(52)	—	(52)
Shares purchased under normal course issuer bid (NCIB) (Note 28)	(146)	—	—	3	—	(143)	—	(143)
Reversal of provision for repurchase of shares under the automatic share purchase plan (Note 28)	19	—	—	—	—	19	—	19
Share-based payment plans and stock options exercised (Note 31)	21	—	1	—	—	22	—	22
Distributions declared to non-controlling interests (Note 12)	—	—	—	—	—	—	(40)	(40)
Balance, Dec. 31, 2024	3,179	942	42	(2,458)	41	1,746	97	1,843
Net loss	**—**	**—**	**—**	**(138)**	**—**	**(138)**	**(20)**	**(158)**
Other comprehensive loss:								
Net loss on translating net assets of foreign operations, net of hedges and tax	**—**	**—**	**—**	**—**	**(1)**	**(1)**	**—**	**(1)**
Net losses on derivatives designated as cash flow hedges, net of tax	**—**	**—**	**—**	**—**	**(69)**	**(69)**	**—**	**(69)**
Net actuarial gains on defined benefits plans, net of tax	**—**	**—**	**—**	**—**	**5**	**5**	**—**	**5**
Total comprehensive loss	**—**	**—**	**—**	**(138)**	**(65)**	**(203)**	**(20)**	**(223)**
Common share dividends (Note 28)	**—**	**—**	**—**	**(78)**	**—**	**(78)**	**—**	**(78)**
Preferred share dividends (Note 29)	**—**	**—**	**—**	**(52)**	**—**	**(52)**	**—**	**(52)**
Shares purchased under NCIB (Note 28)	**(20)**	**—**	**—**	**(4)**	**—**	**(24)**	**—**	**(24)**
Share-based payment plans and stock options exercised (Note 31)	**10**	**—**	**—**	**—**	**—**	**10**	**—**	**10**
Distributions declared to non-controlling interests (Note 12)	**—**	**—**	**—**	**—**	**—**	**—**	**(11)**	**(11)**
Balance, Dec. 31, 2025	**3,169**	**942**	**42**	**(2,730)**	**(24)**	**1,399**	**66**	**1,465**

(1) Refer to Note 30 for details on components of and changes in accumulated other comprehensive income (loss).

See accompanying notes.

Consolidated Statements of Cash Flows

(in millions of Canadian dollars)

Year ended Dec. 31	2025	2024
Operating activities		
Net (loss) income	**(158)**	239
Depreciation and amortization (Note 19, 20, 21 and 27)	**579**	531
Gain on sale of assets and other	**(1)**	(1)
Accretion of provisions (Note 10 and 24)	**57**	50
Decommissioning and restoration costs settled (Note 24)	**(39)**	(41)
Deferred income tax recovery (Note 11)	**(32)**	(63)
Unrealized loss from risk management activities	**289**	2
Unrealized foreign exchange loss (gain)	**6**	(29)
Provisions and contract liabilities	**(32)**	23
Asset impairment (reversals) charges (Note 7)	**(13)**	46
Equity income, net of distributions from investments (Note 9)	**(1)**	—
Other non-cash items	**(12)**	1
Cash flow from operations before changes in working capital	**643**	758
Change in non-cash operating working capital balances (Note 33)	**3**	38
Cash flow from operating activities	**646**	796
Investing activities		
Additions to property, plant and equipment (Note 19 and 37)	**(249)**	(311)
Additions to intangible assets (Note 21 and 37)	**(11)**	(10)
Restricted cash (Note 25)	**(7)**	(1)
Loan advances (Note 23)	**(6)**	(1)
Acquisitions, net of cash acquired (Note 4)	**—**	(217)
Increase in long-term financial assets (Note 14)	**(145)**	—
Investments (Note 9)	**(7)**	(5)
Proceeds on sale of property, plant and equipment	**8**	4
Realized (loss) gain on financial instruments	**(2)**	1
Decrease in finance lease receivable (Note 17)	**30**	21
Development expenditures	**(2)**	(6)
Other	**(4)**	25
Change in non-cash investing working capital balances	**(23)**	(20)
Cash flow used in investing activities	**(418)**	(520)
Financing activities		
Net (decrease) increase in borrowings under credit facilities (Note 25 and 33)	**(448)**	143
Repayment of long-term debt (Note 25 and 33)	**(736)**	(131)
Issuance of long-term debt (Note 25 and 33)	**991**	—
Dividends paid on common shares (Note 28)	**(74)**	(71)
Dividends paid on preferred shares (Note 29)	**(52)**	(52)
Repurchase of common shares under NCIB (Note 28)	**(24)**	(143)
Proceeds on issuance of common shares	**3**	12
Realized gain on financial instruments	**2**	4
Distributions paid to subsidiaries' non-controlling interests (Note 12)	**(11)**	(40)
Decrease in lease liabilities (Note 25 and 33)	**(4)**	(6)
Financing fees and other	**(8)**	(1)
Change in non-cash financing working capital balances	**(1)**	(6)
Cash flow used in financing activities	**(362)**	(291)
Cash flow used in operating, investing and financing activities	**(134)**	(15)
Effect of translation on foreign currency cash	**2**	4
Decrease in cash and cash equivalents	**(132)**	(11)
Cash and cash equivalents, beginning of year	**337**	348
Cash and cash equivalents, end of year	**205**	337
Cash taxes paid	**85**	104
Cash interest paid	**282**	269
Cash interest received	**28**	30

See accompanying notes.

Notes to the Consolidated Financial Statements

(Tabular amounts in millions of Canadian dollars, except as otherwise noted)

1. Corporate Information

A. Description of the Business

TransAlta Corporation (TransAlta or the Company) was incorporated under the *Canada Business Corporations Act* in March 1985 and became a public company in December 1992. The Company's head office is located in Calgary, Alberta.

Operating Segments

Generation Segments

The Company is comprised of four generation segments: Hydro, Wind and Solar, Gas, and Energy Transition. The Company directly or indirectly owns and operates hydro, wind and solar, and natural gas-fired facilities, along with a coal-fired facility and natural gas pipeline operations in Canada, the United States (U.S.) and Western Australia. Transmission in Canada and Western Australia is included within the Hydro and Gas segments in Canada and Western Australia, respectively. The Wind and Solar segment includes the financial results, on a proportionate basis, of our investment in SP Skookumchuck Investment, LLC (Skookumchuck). Segment revenues are derived from the availability and production of electricity and steam as well as ancillary services.

Energy Marketing Segment

The Energy Marketing segment derives revenue and earnings from the trading of electricity, natural gas and environmental products across a variety of North American markets, excluding Alberta.

The Energy Marketing segment also performs services on behalf of certain assets outside of Alberta for the marketing of available generating capacity as well as the procurement of the fuel and transmission needs for the fleet. Contracts of various durations for the forward sales of electricity and for the purchase of natural gas and transmission capacity are used and these activities are included in the gross margin of the related generation segment.

Corporate Segment

The Corporate segment includes the Company's central finance, legal, administrative, corporate development, and investor relations functions. Activities and charges directly or reasonably attributable to other segments are allocated to them.

B. Basis of Preparation

These Consolidated Financial Statements have been prepared by management in compliance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB).

The Consolidated Financial Statements have been prepared on a historical cost basis except for financial instruments, which are measured at fair value, as explained in the following accounting policies.

These Consolidated Financial Statements were authorized for issue by TransAlta's Board of Directors (the Board) on Feb. 26, 2026.

C. Basis of Consolidation

The Consolidated Financial Statements include the accounts of the Company and the subsidiaries that it controls. Control exists when the Company is exposed, or has rights, to variable returns from its involvement with the subsidiary and has the ability to affect the returns through its power over the subsidiary. The financial statements of the subsidiaries are prepared for the same reporting period and apply consistent accounting policies as the parent company.

2. Material Accounting Policies

The Company has reviewed its material accounting policies. The definition of material that management has used to judgmentally determine disclosure is that information is deemed material if omitting or misstating it could influence decisions users make on the basis of financial information.

A. Revenue Recognition

I. Revenue from Contracts with Customers

The majority of the Company's revenues from contracts with customers are derived from the sale of generation capacity, electricity, thermal energy, environmental attributes and byproducts of power generation. The Company evaluates whether the contracts it enters into meet the definition of a contract with a customer at the inception of the contract and on an ongoing basis if there is an indication of significant changes in facts and circumstances. Contract modifications are accounted for as separate contracts when the consideration for the additional promised goods reflects a stand-alone selling price. Otherwise, contract modifications are accounted for as part of the existing contract. If the additional goods are not considered distinct the transaction price can be affected and adjustments to previously recognized revenue can occur. If the additional goods are distinct, the existing and modified contracts are treated together as a new contract, with impacts reflected prospectively from the modification date, which can include the blending of contract prices. Revenue is measured based on the transaction price specified in a contract with a customer. Revenue is recognized when the control of the goods or services is transferred to the customer. For certain contracts, revenue may be recognized at the invoiced amount, as permitted using the invoice practical expedient, if such amount corresponds directly with the Company's performance to date. The Company excludes amounts collected on behalf of third parties from revenue.

Performance Obligations

Each promised good or service is accounted for separately as a performance obligation if it is distinct. The Company's contracts may contain more than one performance obligation.

Transaction Price

The Company allocates the transaction price in the contract to each performance obligation. The transaction price allocated to performance obligations may include variable consideration. Variable consideration is included in the transaction price for each performance obligation when it is highly probable that a significant reversal of the cumulative variable revenue will not occur. Variable consideration that has previously been constrained is assessed at each reporting period to determine whether the constraint is lifted. The consideration contained in some of the Company's contracts with customers is primarily variable and may include both variability in quantity and pricing, such as: revenues can be dependent upon future production volumes that are driven by customer or market demand or by the operational ability of a plant; revenues can be dependent upon the variable cost of producing energy; revenues can be dependent upon market prices; and revenues can be subject to various indices and escalators.

When multiple performance obligations are present in a contract, the transaction price is allocated to each performance obligation in an amount that depicts the consideration the Company expects to be entitled to in exchange for transferring the good or service. The Company estimates the amount of the transaction price to allocate to individual performance obligations based on their relative stand-alone selling prices, which is primarily estimated based on the amounts that would be charged to customers under similar market conditions.

Recognition

The nature, timing of recognition of satisfied performance obligations and payment terms for the Company's goods and services are described below:

Good or service	Description
Capacity	Capacity refers to the availability of an asset to deliver goods or services. Customers typically pay for capacity for each defined time period (e.g., monthly) in an amount representative of the availability of the asset for the defined time period. Obligations to deliver capacity are satisfied over time and revenue is recognized using a time-based measure. Contracts for capacity are typically long-term in nature and payments are typically received on a monthly basis.
Contract power	The sale of contract power refers to the delivery of units of electricity to a customer under the terms of a contract. Customers pay a contractually specified price for the output at the end of predefined contractual periods (e.g., monthly). Obligations to deliver electricity are satisfied over time and revenue is recognized using a units-based output measure (i.e., megawatt hours). Contracts for power are typically long-term in nature and payments are typically received on a monthly basis.
Thermal energy	Thermal energy refers to the delivery of units of steam to a customer under the terms of a contract. Customers pay a contractually specified price for the output at the end of predefined contractual periods (e.g., monthly). Obligations to deliver steam are satisfied over time and revenue is recognized using a units-based output measure (i.e., gigajoules). Contracts for thermal energy are typically long-term in nature and payments are typically received on a monthly basis.
Environmental attributes	Environmental attributes refers to the delivery of renewable energy certificates, green attributes and other similar items. Customers may contract for environmental attributes in conjunction with the purchase of power, in which case the customer pays for the attributes in the month subsequent to the delivery of the power. Alternatively, customers pay upon delivery of the environmental attributes. Obligations to deliver environmental attributes are satisfied at a point in time, generally upon delivery of the item.
Generation byproducts	Generation byproducts refers to the sale of byproducts from the use of coal in the Company's current U.S. and previous Canadian coal operations. Obligations to deliver byproducts are satisfied at a point in time, generally upon delivery of the item. Payments are received upon satisfaction of delivery of the byproducts.

A contract liability is recorded when the Company receives consideration before the performance obligations have been satisfied. A contract asset is recorded when the Company has rights to consideration for the completion of a performance obligation before it has invoiced the customer. The Company recognizes unconditional rights to consideration separately as a receivable. Contract assets and receivables are evaluated at each reporting period to determine whether there is any objective evidence that they are impaired.

II. Revenue from Other Sources

Merchant Revenue

Revenues from non-contracted capacity (i.e., merchant) include energy payments, at market price, for each MWh produced and are recognized upon delivery.

Lease Revenue

In certain situations, a long-term electricity or thermal sales contract may contain, or be considered, a lease. Revenues associated with non-lease elements are recognized as goods or services revenues as outlined above. Where the terms and conditions of the contract result in the customer assuming the principal risks and rewards of ownership of the underlying asset, the contractual arrangement is considered a finance lease, which results in the recognition of finance lease income. Where the Company retains the principal risks and rewards, the contractual arrangement is an operating lease. Rental income, including contingent rents where applicable, is recognized over the term of the contract.

Revenue from derivatives and other trading activities

Commodity risk management activities involve the use of derivatives such as physical and financial swaps, forward sales contracts, futures contracts and options, which are used to earn revenues and gain market information. The Company also enters into contracts for differences and Virtual Power Purchase Agreements (VPPA). Contracts for differences are financial contracts whereby the Company receives a fixed price per MWh and pays the prevailing real-time energy market price per MWh. With a VPPA, the Company receives the difference between the fixed contract price per MWh and the settled market price. These arrangements meet the definition of a derivative and judgment is applied to determine if the contract meets the "own use" exemption or if derivative treatment is required.

These derivatives are accounted for using fair value accounting. The initial recognition and subsequent changes in fair value affect reported net earnings in the period the change occurs and are presented on a net basis in revenue. The fair values of instruments that remain open at the end of the reporting period represent unrealized gains or losses and are presented on the Consolidated Statements of Financial Position as risk management assets or liabilities. Some of the derivatives used by the Company in trading activities are not traded on an active exchange or have terms that extend beyond the time period for which exchange-based quotes are available. The fair values of these derivatives are determined using internal valuation techniques or models.

B. Financial Instruments and Hedges

I. Financial Instruments

Classification and Measurement

IFRS 9 introduced the requirement to classify and measure financial assets based on their contractual cash flow characteristics and the Company's business model for the financial asset. All financial assets and liabilities, including derivatives, are recognized at fair value on the Consolidated Statements of Financial Position when the Company becomes party to the contractual provisions of a financial instrument or non-financial derivative contract. Financial assets must be classified and measured at either amortized cost, at fair value through profit or loss (FVTPL), or at fair value through other comprehensive income (loss) (FVTOCI).

Financial assets with contractual cash flows arising on specified dates, consisting solely of principal and interest, and that are held within a business model whose objective is to collect the contractual cash flows, are subsequently measured at amortized cost. Financial assets measured at FVTOCI are those that have contractual cash flows, arising on specific dates, consisting solely of principal and interest, and that are held within a business model whose objective is to collect the contractual cash flows and to sell the financial asset and investments in equity instruments. All other financial assets are subsequently measured at FVTPL.

Financial liabilities are classified as FVTPL when the financial liability is held for trading. All other financial liabilities are subsequently measured at amortized cost.

Funds received under tax equity investment arrangements are classified as long-term debt. These arrangements are used in the U.S. when project investors acquire an equity investment in a project entity, and in return for their investment, are allocated substantially all of the earnings, cash flows and tax benefits (such as production tax credits, investment tax credits, accelerated tax depreciation, as applicable) until they have achieved the agreed upon target rate of return. Once achieved, the arrangements flip, with the Company then receiving the majority of earnings, cash flows and tax benefits. At that time, the tax equity investor's investment is subsequently considered residual equity ownership, with distributions classified as non-controlling interest. In applying the effective interest method to tax equity financings, the Company has made an accounting policy choice to recognize the impacts of the tax attributes in net interest expense.

The Company enters into a variety of derivative financial instruments to manage its exposure to commodity price risk, interest rate risk and foreign currency exchange risk, including fixed price financial swaps, long-term physical power sale contracts, foreign exchange forward contracts, interest rate swap contracts, and designating foreign currency debt as a hedge of net investments in foreign operations.

Derivatives are initially recognized at fair value at the date the derivative contracts are entered into and are subsequently remeasured to their fair value at the end of each reporting period. The resulting gain or loss is recognized in net earnings immediately, unless the derivative is designated and effective as a hedging instrument, in which case the timing of the recognition in net earnings is dependent on the nature of the hedging relationship.

Derivatives embedded in non-derivative host contracts that are not financial assets within the scope of IFRS 9 (e.g., financial liabilities) are treated as separate derivatives when they meet the definition of a derivative, their risks and characteristics are not closely related to those of the host contracts and the host contracts are not measured at FVTPL. Derivatives embedded in hybrid contracts that contain financial asset hosts within the scope of IFRS 9 are not separated, and the entire contract is measured at either FVTPL or amortized cost, as appropriate.

Financial assets are derecognized when the contractual rights to receive cash flows expire. Financial liabilities are derecognized when the obligation is discharged, cancelled or expired.

Financial assets are also derecognized when the Company has transferred its rights to receive cash flows from the asset or has assumed an obligation to pay the received cash flows to a third party under a "pass-through" arrangement and either transferred substantially all the risks and rewards of the asset, or transferred control of the asset. TransAlta will continue to recognize the asset and any associated liability if it retains substantially all of the risks and rewards of the asset, or retains control of the asset. Continuing involvement that takes the form of a guarantee over the transferred asset is measured at the lower of the original carrying amount of the asset and the maximum amount of consideration that TransAlta could be required to repay.

Financial assets and liabilities are offset and the net amount is reported in the Consolidated Statements of Financial Position if there is a currently enforceable legal right to offset the recognized amounts and there is an intention to settle on a net basis or realize the assets and settle the liabilities simultaneously.

Transaction costs are expensed as incurred for financial instruments classified or designated as FVTPL. For other financial instruments, such as debt instruments, transaction costs are recognized as part of the carrying amount of the financial instrument. The Company uses the effective interest method of amortization for any transaction costs or fees, premiums or discounts earned or incurred for financial instruments measured at amortized cost.

Impairment of Financial Assets

TransAlta recognizes an allowance for expected credit losses for financial assets measured at amortized cost as well as certain other instruments. The loss allowance for a financial asset is measured at an amount equal to the lifetime expected credit loss if its credit risk has increased significantly since initial recognition or if the financial asset is a purchased or originated credit-impaired financial asset. If the credit risk on a financial asset has not increased significantly since initial recognition, its loss allowance is measured at an amount equal to the 12-month expected credit loss.

For trade receivables, lease receivables and contract assets recognized under IFRS 15, TransAlta applies a simplified approach for measuring the loss allowance. Therefore, the Company does not track changes in credit risk but instead recognizes a loss allowance at an amount equal to the lifetime expected credit losses at each reporting date.

The assessment of the expected credit loss is based on historical data and adjusted by forward-looking information that includes third-party default rates over time, dependent on credit ratings.

II. Hedges

Where hedge accounting can be applied and the Company chooses to seek hedge accounting treatment, a hedge relationship is designated as a fair value hedge, a cash flow hedge or a hedge of foreign currency exposures of a net investment in a foreign operation.

A relationship qualifies for hedge accounting if, at inception, it is formally designated and documented as a hedge and the hedging instrument and the hedged item have values that generally move in opposite direction because of the hedged risk. The documentation includes identification of the hedging instrument and hedged item or transaction, the nature of the risk being hedged, the Company's risk management objectives and strategy for undertaking the hedge and how hedge effectiveness will be assessed. The process of hedge accounting includes linking derivatives to specific recognized assets and liabilities or to specific firm commitments or highly probable anticipated transactions.

The Company formally assesses, both at the hedge's inception and on an ongoing basis, whether the derivatives used are highly effective in offsetting changes in fair values or cash flows of hedged items. If hedge criteria are not met or the Company does not apply hedge accounting, the derivative is recognized at fair value on the Consolidated Statements of Financial Position, with subsequent changes in fair value recorded in net earnings in the period of change.

Fair Value Hedges

In a fair value hedging relationship, the carrying amount of the hedged item is adjusted for changes in fair value attributable to the hedged risk, with the changes being recognized in net earnings. Changes in the fair value of the hedged item, to the extent that the hedging relationship is effective, are offset by changes in the fair value of the hedging derivative, which is also recorded in net earnings.

For fair value hedges relating to items carried at amortized cost, any adjustment to carrying value is amortized through profit or loss over the remaining term of the hedge using the effective interest rate (EIR) method. The EIR amortization may begin as soon as an adjustment exists and no later than when the hedged item ceases to be adjusted for changes in its fair value attributable to the risk being hedged.

If the hedged item is derecognized, the unamortized fair value is recognized immediately in net earnings.

Cash Flow Hedges

In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in other comprehensive income (loss) (OCI) while any ineffective portion is recognized in net earnings. The cash flow hedge reserve is adjusted to the lower of the cumulative gain or loss on the hedging instrument and the cumulative change in fair value of the hedged item.

If cash flow hedge accounting is discontinued, the amounts previously recognized in accumulated other comprehensive income (loss) (AOCI) must remain in AOCI if the hedged future cash flows are still expected to occur. Otherwise, the amount will be immediately reclassified to net earnings as a reclassification adjustment. After discontinuation, once the hedged cash flow occurs, any amount remaining in AOCI must be accounted for depending on the nature of the underlying transaction.

Hedges of Foreign Currency Exposures of a Net Investment in a Foreign Operation

When hedging the foreign currency exposure of a net investment in a foreign operation, the effective portion of foreign exchange gains and losses on the hedging instrument is recognized in OCI and the ineffective portion is recognized in net earnings. The related fair values are recorded in risk management assets or liabilities, as appropriate. The amounts previously recognized in AOCI are recognized in net earnings when there is a reduction in the hedged net investment as a result of a disposal, partial disposal or loss of control.

C. Cash and Cash Equivalents

Cash and cash equivalents comprises cash and highly liquid investments with original maturities of three months or less.

D. Inventory

I. Fuel

The Company's inventory balance is composed of coal and natural gas used as fuel, which is measured at the lower of weighted average cost and net realizable value. The cost of natural gas and purchased coal inventory includes all applicable expenditures and charges incurred in bringing the inventory to its existing condition and location.

II. Energy Marketing

Commodity inventories held in the Energy Marketing segment for trading purposes are measured at fair value less costs to sell. Changes in fair value less costs to sell are recognized in net earnings in the period of change.

III. Parts, Materials and Supplies

Parts, materials and supplies are recorded at the lower of cost and measured at moving average costs and net realizable value.

IV. Emission Credits and Allowances

Emission credits and allowances are recorded as inventory at cost. Those purchased for use by the Company are recorded at cost and are carried at the lower of weighted average cost and net realizable value. For emission credits that are not ordinarily interchangeable, the Company records the credits using the specific identification method. Credits granted to or internally generated by TransAlta are recorded at nil. Emission liabilities are recorded at the estimated compliance cost required by the Company to settle its obligation in excess of government-established caps and targets. Compliance costs that are recoverable under the terms of the contracts with third parties are recognized as revenue from contracts with customers.

Emission credits and allowances that are held for trading and that meet the definition of a derivative are accounted for using the fair value method of accounting. Emission credits and allowances that do not satisfy the criteria of a derivative are accounted for using the accrual method.

E. Property, Plant and Equipment

The Company's investment in property, plant and equipment (PP&E) is initially measured at the original cost of each component at the time of construction, purchase or acquisition. A component is a tangible portion of an asset that can be separately identified and depreciated over its own expected useful life and is expected to provide a benefit for a period in excess of one year. Original cost includes items such as materials, labour, borrowing costs and other directly attributable costs, including the initial estimate of the cost of decommissioning and restoration. Costs are recognized as PP&E if it is probable that future economic benefits will be realized and the cost of the item can be measured reliably. The cost of major spare parts is capitalized and classified as PP&E, as these items can only be used in connection with an item of PP&E.

Planned maintenance is performed at regular intervals. Planned major maintenance includes inspection, repair and maintenance of existing components and the replacement of existing components. Costs incurred for planned major maintenance activities are capitalized in the period maintenance activities occur and are amortized on a straight-line basis over the term until the next major maintenance event. Expenditures incurred for the replacement of components during major maintenance are capitalized and amortized over the estimated useful life of such components.

The cost of routine repairs and maintenance and the replacement of minor parts is charged to net earnings as incurred. Subsequent to initial recognition and measurement at cost, all classes of PP&E continue to be measured using the cost model and are reported at cost less accumulated depreciation and impairment losses, if any. An item of PP&E or a component is derecognized upon disposal or when no future economic benefits are expected from its use or disposal. Any gain or loss arising on derecognition is included in net earnings when the asset is derecognized. The estimate of the useful life of each component of PP&E is based on current facts and past experience and takes into consideration existing long-term sales agreements and contracts, current and forecasted demand and the potential for technological obsolescence. The useful life is used to estimate the rate at which the component of PP&E is depreciated. PP&E assets are subject to depreciation when the asset is considered to be available for use, which is typically at the start of commercial operations. Insurance spares that are designated as critical for uninterrupted operation in a particular facility are depreciated over the life of that facility, even if the item is not in service. Capital spares begin to be depreciated when the item is put into service. Each significant component of an item of PP&E is depreciated to its residual value over its estimated useful life, generally using straight-line or unit-of-production methods. Estimated useful lives, residual values and depreciation methods are reviewed annually and are subject to revision based on new or additional information. The effect of a change in useful life, residual value or depreciation method is accounted for prospectively.

Estimated remaining useful lives of the components of depreciable assets, categorized by asset class, are as follows:

Hydro generation	1-47 years
Wind and Solar generation	1-29 years
Gas generation	1-32 years
Energy Transition	1-8 years
Capital spares and other	1-47 years

TransAlta capitalizes borrowing costs on capital invested in projects under construction. Upon commencement of commercial operations, capitalized borrowing costs, as a portion of the total cost of the asset, are depreciated over the estimated useful life of the related asset.

F. Intangible Assets

Intangible assets acquired in a business combination are recognized separately from goodwill at their fair value at the date of acquisition. Intangible assets acquired separately are recognized at cost. Internally generated intangible assets arising from development projects are recognized when certain criteria related to the feasibility of internal use or sale and probable future economic benefits of the intangible asset, are demonstrated.

Intangible assets are initially recognized at cost, which is composed of all directly attributable costs necessary to create, produce and prepare the intangible asset to be capable of operating in the manner intended by management.

Software-as-a-service, such as cloud-based software, that do not meet the criteria of an intangible asset are expensed as incurred, including implementation costs.

Subsequent to initial recognition, intangible assets continue to be measured using the cost model and are reported at cost less accumulated amortization and impairment losses, if any. Amortization is included in depreciation and amortization in the Consolidated Statements of Earnings.

Amortization commences when the intangible asset is available for use and is computed on a straight-line basis over the intangible asset's estimated useful life. Estimated useful lives of intangible assets may be determined, for example, with reference to the term of the related contract or licence agreement. The estimated useful lives and amortization methods are reviewed annually with the effect of any changes being accounted for prospectively.

Intangible assets consist of power sale contracts with fixed prices higher than market prices at the date of acquisition, software and intangibles under development. Estimated remaining useful lives of intangible assets are as follows:

Software	1-6 years
Power sale contracts	1-16 years

G. Impairment of Tangible and Intangible Assets Excluding Goodwill

At the end of each reporting period, the Company assesses whether there is any indication that PP&E and finite life intangible assets are impaired.

Factors that could indicate that an impairment exists include: significant underperformance relative to historical or projected operating results; significant changes in the manner in which an asset is used, or in the Company's overall business strategy; or significant negative industry or economic trends. In some cases, these events are clear. However, in many cases, a clearly identifiable event indicating possible impairment does not occur. Instead, a series of individually insignificant events occur over a period of time leading to an indication that an asset may be impaired. This can be further complicated in situations where the Company is not the operator of the facility. Events can occur in these situations that may not be known until a date subsequent to their occurrence.

The Company's operations, the market and business environment are routinely monitored and judgments and assessments are made to determine whether an event has occurred that indicates a possible impairment. If such an event has occurred, an estimate is made of the recoverable amount of the asset or cash-generating unit (CGU) to which the asset belongs. The recoverable amount is the higher of an asset's fair value less costs of disposal and its value in use. Fair value is the price that would be received if the asset was sold in an orderly transaction between market participants at the measurement date. In determining fair value, recent market transactions are taken into account. If no such transactions can be identified, an appropriate valuation model such as discounted cash flow is used. Value in use is the present value of the estimated future cash flows expected to be derived from the asset from its continued use and ultimate disposal by the Company. If the recoverable amount is less than the carrying amount of the asset or CGU, an asset impairment charge is recognized in net earnings and the asset's carrying amount is reduced to its recoverable amount.

At each reporting date, an assessment is made whether there is any indication that an impairment charge previously recognized may no longer exist or may have decreased. If such indication exists, the recoverable amount of the asset or CGU to which the asset belongs is estimated and, if there has been an increase in the recoverable amount, the impairment charge previously recognized is reversed. If an impairment charge is subsequently reversed, the carrying amount of the asset is increased to the lesser of the revised estimate of its recoverable amount or the carrying amount that would have been determined (net of depreciation) had no impairment charge been recognized previously. A reversal of an impairment charge is recognized in net earnings.

H. Goodwill

Goodwill arising in a business combination is recognized as an asset at the date control is acquired. Goodwill is measured as the cost of an acquisition plus the amount of any non-controlling interest in the acquiree (if applicable) less the fair value of the related identifiable assets acquired and liabilities assumed.

Goodwill is not subject to amortization, but is tested for impairment at least annually, or more frequently, if an analysis of events and circumstances indicates that a possible impairment may exist. These events could include a significant change in financial position of the CGUs or groups of CGUs to which the goodwill relates or significant negative industry or economic trends. For impairment purposes, goodwill is allocated to each of the Company's CGUs or groups of CGUs that are expected to benefit from the synergies of the business combination in which the goodwill arose. Accordingly, the Company performs its test for impairment, where the recoverable amount of the CGUs or groups of CGUs to which the goodwill relates is compared to its carrying amount for each operating segment. If the recoverable amount is less than the carrying amount, an impairment charge is immediately recognized in net earnings, by first reducing the carrying amount of the goodwill and then by reducing the carrying amount of the other assets in the unit. An impairment charge recognized for goodwill is not reversed in subsequent periods.

I. Income Taxes

The Company uses the liability method of accounting for income taxes. Under the liability method, deferred income tax assets and liabilities are recognized on the differences between the carrying amounts of assets and liabilities and their respective income tax basis (temporary differences). A deferred income tax asset may also be recognized for the benefit expected from unused tax credits and losses available for carryforward, to the extent that it is probable that future taxable earnings will be available against which the tax credits and losses can be applied. Deferred income tax assets and liabilities are measured based on income tax rates and tax laws that are enacted or substantively enacted by the end of the reporting period and that are expected to apply in the years in which temporary differences are expected to be realized or settled. Deferred income tax is charged or credited to net earnings, except when related to items charged or credited to either OCI or directly to equity. The carrying amount of deferred income tax assets is evaluated at the end of each reporting period and is reduced to the extent that it is no longer probable that sufficient taxable income will be available to allow all or part of the asset to be realized. Unrecognized deferred tax assets are reassessed at each reporting date and are recognized to the extent that it has become probable that future taxable income will allow the deferred income tax asset to be recovered.

Deferred income tax liabilities are recognized for taxable temporary differences arising on investments in subsidiaries, except where the Company is able to control the reversal of the temporary difference and it is probable that the temporary difference will not reverse in the foreseeable future.

Cash taxes paid disclosed on the Consolidated Statements of Cash Flows includes income taxes and taxes paid related to the Part VI.1 tax in Canada for the period.

J. Employee Future Benefits

The Company has defined benefit pension and other post-employment benefit plans. The current service cost of providing benefits under the defined benefit plans is determined using the projected unit credit method prorated based on service. The net interest cost is determined by applying the discount rate to the net defined benefit liability. The discount rate used to determine the present value of the defined benefit obligation and the net interest cost, is determined by reference to market yields at the end of the reporting period on high-quality corporate bonds with terms and currencies that match the estimated terms and currencies of the benefit obligations. Remeasurements, which include actuarial gains and losses and the return on plan assets (excluding net interest), are recognized through OCI in the period in which they occur. Actuarial gains and losses arise from experience adjustments and changes in actuarial assumptions. Remeasurements are not reclassified to profit or loss, from OCI, in subsequent periods.

Gains or losses arising from either a curtailment or settlement of a defined benefit plan are recognized when the curtailment or settlement occurs. When the restructuring of a benefit plan gives rise to a curtailment and a settlement of obligations, the curtailment is accounted for before the settlement.

In determining whether statutory minimum funding requirements of the Company's defined benefit pension plans give rise to recording an additional liability, letters of credit provided by the Company as security are considered to alleviate the funding requirements. No additional liability results in these circumstances.

Contributions payable under defined contribution pension plans are recognized as a liability and an expense in the period in which the services are rendered.

K. Provisions

Provisions are recognized when the Company has a present obligation (legal or constructive) as a result of a past event, it is probable that the Company will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. A legal obligation can arise through a contract, legislation or other operation of law. A constructive obligation arises from an entity's actions whereby through an established pattern of past practice, published policies or a sufficiently specific current statement, the entity has indicated it will accept certain responsibilities and has thus created a valid expectation that it will discharge those responsibilities. The amount recognized as a provision is the best estimate, remeasured at each period-end, of the expenditures required to settle the present obligation, considering the risks and uncertainties associated with the obligation. Where expenditures are expected to be incurred in the future, the obligation is measured at its present value using a current market-based, risk-adjusted discount rate.

The Company records a decommissioning and restoration provision for all generating facilities and mine sites for which it is legally or constructively required to remove the facilities at the end of their useful lives and restore the plant or mine sites. For some hydro facilities, the Company is required to remove the generating equipment, but is not required to remove the structures.

Initial decommissioning provisions are recognized at their present value when incurred. Each reporting date, the Company determines the present value of the provision using the current discount rates that reflect the time value of money and associated risks. The Company recognizes the initial decommissioning and restoration provisions, as well as changes resulting from revisions to cost estimates and period-end revisions to the market-based, risk-adjusted discount rate, as a cost of the related PP&E (see Note 2(E)) to the extent the related PP&E asset is still in use. Where the related PP&E asset has reached the end of its useful life, changes in the decommissioning and restoration provision are recognized in net earnings. Where the Company expects to receive reimbursement from a third party for a portion of future decommissioning costs, the reimbursement is recognized as a separate asset when it is virtually certain that the reimbursement will be received.

Changes in other provisions resulting from revisions to estimates of expenditures required to settle the obligation or period-end revisions to the market-based, risk-adjusted discount rate are recognized in net earnings.

The accretion of the net present value discount for both the decommissioning and restoration provision and other provisions are charged to net earnings each period and is included in interest expense.

L. Leases

Under IFRS 16, a contract contains a lease when the customer obtains the right to control the use of an identified asset for a period of time in exchange for consideration.

I. Lessee

The Company enters into lease arrangements with respect to land, building and office space, vehicles and site machinery and equipment. For all contracts that meet the definition of a lease under IFRS 16 in which the Company is the lessee and which are not exempt as short-term or low-value leases, the Company:

- Recognizes right-of-use assets and lease liabilities in the Consolidated Statements of Financial Position;
- Recognizes depreciation of the right-of-use assets and interest expense on lease liabilities in the Consolidated Statements of Earnings; and
- Recognizes the principal repayments on lease liabilities as financing activities and interest payments on lease liabilities as operating activities in the Consolidated Statements of Cash Flows.

For short-term and low-value leases, the Company recognizes the lease payments as operating expenses.

Variable lease payments that do not depend on an index or a rate are not included in the measurement of the lease liability and the right-of-use asset and are recognized as an expense in the period in which the event or condition that triggers the payments occurs.

Right-of-use assets are initially measured at an amount equal to the lease liability and adjusted for any payments made at or before the commencement date, plus any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset, or to restore the underlying asset or the site on which it is located, less any lease incentives received.

Lease liabilities are initially measured at the present value of the lease payments that are not paid at commencement and discounted using the Company's incremental borrowing rate or the rate implicit in the lease. The lease liability is remeasured when there is a change in future lease payments arising from a change in an index or rate, or if there is a change in the Company's estimate or assessment of whether it will exercise an extension, termination or purchase option. A corresponding adjustment is made to the carrying amount of the right-of-use asset, or is recorded in profit or loss if the carrying amount of the right-of-use asset has been reduced to zero.

The lease term includes periods covered by an option to extend if the Company is reasonably certain to exercise that option and periods covered by an option to terminate if the Company is reasonably certain not to exercise that option.

Right-of-use assets are depreciated over the shorter period of either the lease term or the useful life of the underlying asset. If a lease transfers ownership of the underlying asset or the cost of the right-of-use asset reflects that the Company expects to exercise the purchase option, the related right-of-use asset is depreciated over the useful life of the underlying asset.

The Company has elected to apply the practical expedient that permits a lessee not to separate non-lease components and instead account for any lease and associated non-lease components as a single arrangement.

II. Lessor

Power Purchase Agreements (PPAs) and other long-term contracts may contain, or may be considered, leases where the fulfillment of the arrangement is dependent on the use of a specific asset (e.g., a generating unit) and the arrangement conveys to the customer the right to control the use of that asset.

If the Company determines that the contractual provisions of a contract contain, or are, a lease and result in the customer assuming the principal risks and rewards of ownership of the asset, the arrangement is a finance lease. Assets subject to finance leases are not reflected as PP&E and the net investment in the lease, represented by the present value of the amounts due from the lessee, is recorded in the Consolidated Statements of Financial Position as a financial asset, classified as a finance lease receivable. The payments considered to be part of the leasing arrangement are apportioned between a reduction in the lease receivable and finance lease income. The finance lease income element of the payments is recognized using a method that results in a constant rate of return on the net investment in each period and is reflected in finance lease income on the Consolidated Statements of Earnings.

Where the Company determines that the contractual provisions of a contract contain, or are, a lease and result in the Company retaining the principal risks and rewards of ownership of the asset, the arrangement is an operating lease. For operating leases, the asset is, or continues to be, capitalized as PP&E and depreciated over its useful life.

M. Non-Controlling Interests

Non-controlling interests arise from business combinations in which the Company acquires less than a 100 per cent interest. Non-controlling interests are initially measured at either fair value or at the non-controlling interest's proportionate share of the acquiree's identifiable net assets. The Company determines which measurement is used on a transaction-by-transaction basis. Non-controlling interests also arise from other contractual arrangements between the Company and other parties, whereby the other party has acquired an equity interest in a subsidiary and the Company retains control.

Subsequent to acquisition, the carrying amount of non-controlling interests is increased or decreased by the non-controlling interest's share of subsequent changes in equity and payments to the non-controlling interest. Total comprehensive income (loss) is attributed to the non-controlling interests even if this results in the non-controlling interests having a negative balance.

When the proportion of the equity held by non-controlling interests changes, the carrying amounts of the controlling and non-controlling interests are adjusted to reflect the changes in their relative interests in the subsidiary. Any difference between the amount by which the non-controlling interests are adjusted and the fair value of the consideration paid or received, is recognized directly in equity and attributed to shareholders.

N. Joint Arrangements

A joint arrangement is a contractual arrangement that establishes the terms by which two or more parties agree to undertake and jointly control an economic activity. The Company's joint arrangements are generally classified as two types: joint operations and joint ventures.

A joint operation arises when the parties that have joint control have rights to the assets and obligations for the liabilities relating to the arrangement. Generally, each party takes a share of the output from the asset and each bears an agreed upon share of the costs incurred in respect of the joint operation. The Company reports its interests in joint operations in its Consolidated Financial Statements using the proportionate consolidation method by recognizing its share of the assets, liabilities, revenues and expenses in respect of its interest in the joint operation.

In a joint venture, the venturers do not have rights to individual assets or obligations of the venture. Rather, each venturer has rights to the net assets of the arrangement. The Company reports its interests in joint ventures using the equity method. Under the equity method, the investment is initially recognized at cost and the carrying amount is increased or decreased to recognize the Company's share of the joint venture's net earnings or loss after the date of acquisition. The impact of transactions between the Company and joint ventures is eliminated based on the Company's ownership interest. Distributions received from joint ventures reduce the carrying amount of the investment. Any excess of the cost of an acquisition less the fair value of the recognized identifiable assets, liabilities and contingent liabilities of an acquired joint venture is recognized as goodwill and is included in the carrying amount of the investment and is assessed for impairment as part of the investment.

Investments in joint ventures are evaluated for impairment at each reporting date by first assessing whether there is objective evidence that the investment is impaired. If such objective evidence is present, an impairment charge is recognized if the investment's recoverable amount is less than its carrying amount. The investment's recoverable amount is determined as the higher of value in use and fair value less costs of disposal.

O. Assets Held for Sale

Assets and disposal groups (assets and liabilities disposed of together) are classified as held for sale if their carrying amount will be recovered primarily through a sale as opposed to continued use by the Corporation. Assets and disposal groups classified as held for sale are measured at the lower of their carrying amount and fair value less costs of disposal. Any impairment is recognized in net earnings. Depreciation and equity accounting ceases when an asset or equity investment, respectively, is classified as held for sale. Assets and disposal groups classified as held for sale are reported as current assets and current liabilities in the Consolidated Statements of Financial Position.

P. Business Combinations

Transactions in which the acquisition constitutes a business are accounted for using the acquisition method. Identifiable assets acquired and liabilities assumed, including contingent consideration, are measured at their acquisition date fair values. A business consists of inputs and processes applied to those inputs that have the ability to contribute to the creation of outputs. Goodwill is measured as the excess of the fair value of consideration transferred less the fair value of the net assets acquired. Acquisition-related costs to effect the business combination, with the exception of costs to issue debt or equity securities, are recognized in net earnings as incurred.

The optional fair value concentration test is applied on a transaction-by-transaction basis to permit a simplified assessment of whether an acquired set of activities and assets is not a business. Where substantially all of the fair value of the gross assets acquired is concentrated in a single identifiable asset or group of similar identifiable assets, the Company may elect to treat the acquisition as an asset acquisition and not as a business combination.

Q. Significant Accounting Judgments and Key Sources of Estimation Uncertainty

The preparation of financial statements requires management to make judgments, estimates and assumptions that could affect the reported amounts of assets, liabilities, revenues, expenses and disclosures of contingent assets and liabilities during the period. These estimates are subject to uncertainty. Actual results could differ from those estimates due to factors such as fluctuations in interest rates, foreign exchange rates, inflation and commodity prices and changes in economic conditions, legislation and regulations.

In the process of applying the Company's accounting policies, management has to make judgments and estimates about matters that are highly uncertain at the time the estimate is made and that could significantly affect the amounts recognized in the Consolidated Financial Statements. Different estimates with respect to key variables used in the calculations, or changes to estimates, could potentially have a material impact on the Company's financial position or performance. The key judgments and sources of estimation uncertainty are described below:

I. Fair Value of Assets Acquired and Liabilities Assumed in Business Combination

The fair value of assets acquired and liabilities assumed, including contingent consideration, is estimated based on information available at the date of acquisition. While management uses best estimates and assumptions to accurately value assets acquired and liabilities assumed at the date of acquisition, as well as any contingent consideration, estimates are inherently uncertain and subject to refinement.

Accounting for business combinations requires significant judgment, estimates and assumptions at the acquisition date. In developing estimates of fair values at the acquisition date, management uses a variety of factors including market data, market prices, capacity, historical and future expected cash flows, growth rates and discount rates. Information regarding business combinations has been included in Note 4.

II. Impairment of PP&E and Goodwill

Impairment exists when the carrying amount of an asset, CGU or group of CGUs to which goodwill relates exceeds its recoverable amount, which is the higher of its fair value less costs of disposal and its value in use. An assessment is made at each reporting date as to whether there is any indication that an impairment charge may exist or that a previously recognized impairment charge may no longer exist or may have decreased. In determining fair value less costs of disposal, information about third-party transactions for similar assets is used and if this information is not available, other valuation techniques, such as discounted cash flows, are used. Value in use is computed using the present value of management's best estimates of future cash flows based on the current use and present condition of the asset.

In estimating either fair value less costs of disposal or value in use using discounted cash flow methods, estimates and assumptions must be made about sales prices, cost of sales, production, fuel consumed, capital expenditures, retirement costs and other related cash inflows and outflows over the life of the facilities. In developing these assumptions, management uses estimates of contracted and future market prices based on expected market supply and demand in the region in which the plant operates, anticipated production levels, planned and unplanned outages, changes to regulations and transmission capacity or constraints for the remaining life of the facilities.

Discount rates are determined by employing a weighted average cost of capital methodology that is based on capital structure, cost of equity and cost of debt assumptions based on comparable companies with similar risk characteristics and market data as the asset, CGU or group of CGUs subject to the test. These estimates and assumptions are susceptible to change from period to period and actual results can and often do, differ from the estimates and can have either a positive or negative impact on the estimate of the impairment charge and may be material.

The impairment outcome can also be impacted by the determination of CGUs or groups of CGUs for asset and goodwill impairment testing. A CGU is the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets and goodwill is allocated to each CGU or group of CGUs that is expected to benefit from the synergies of the acquisition from which the goodwill arose. The allocation of goodwill is reassessed upon changes in the composition of segments, CGUs or groups of CGUs. To determine CGUs, significant judgment is required to determine what constitutes independent cash flows between power plants that are connected to the same system. The Company evaluates the market design, transmission constraints and the contractual profile of each facility, as well as the Company's own commodity price risk management plans and practices, in order to inform this determination.

With regard to the allocation or reallocation of goodwill, significant judgment is required to evaluate synergies and their impacts. The Company evaluates synergies with regard to opportunities from combined talent and technology, functional organization and future growth potential and considers its own performance measurement processes to make this determination. Information regarding significant judgments and estimates in respect of impairment during 2024 to 2025 is disclosed in Notes 7, 19 and 22.

III. Leases

To determine whether the Company's contracts contain, or are, leases, management must use judgment in assessing whether the contract provides the customer with the right to substantially all of the economic benefits from the use of the asset during the lease term and whether the customer obtains the right to direct the use of the asset during the lease term. For those agreements considered to contain, or be, leases, further judgment is required to determine the lease term by assessing whether termination or extension options are reasonably certain to be exercised. Judgment is also applied in identifying in-substance fixed payments (included) and variable payments that are based on usage or performance factors (excluded) and in identifying lease and non-lease components (services that the supplier performs) of contracts and in allocating contract payments to lease and non-lease components.

For leases where the Company is a lessor, judgment is required to determine if substantially all of the significant risks and rewards of ownership are transferred to the customer or remain with the Company to appropriately account for the agreement as either a finance or operating lease. These judgments can be significant and impact how the Company classifies amounts related to the arrangement as either PP&E or as a finance lease receivable on the Consolidated Statements of Financial Position and therefore the amount of certain items of revenue and expense is dependent upon such classifications. In 2025 and 2024, finance lease receivables were recognized, when it was determined that the significant risks and rewards of ownership of the facilities were transferred to the customer. Information regarding finance leases is disclosed in Note 17.

IV. Income Taxes

Preparation of the Consolidated Financial Statements involves determining an estimate of, or provision for, income taxes in each of the jurisdictions in which the Company operates. The process also involves making an estimate of income taxes currently payable and income taxes expected to be payable or recoverable in future periods, referred to as deferred income taxes. Deferred income taxes result from the effects of temporary differences due to items that are treated differently for tax and accounting purposes. The tax effects of these differences are reflected in the Consolidated Statements of Financial Position as deferred income tax assets and liabilities. An assessment must also be made to determine the likelihood that the Company's future taxable income will be sufficient to permit the recovery of deferred income tax assets. To the extent that such recovery is not probable, deferred income tax assets must be reduced. Management uses the Company's long-range forecasts as a basis for evaluation of recovery of deferred income tax assets. Management must exercise judgment in its assessment of continually changing tax interpretations, regulations and legislation to ensure deferred income tax assets and liabilities are complete and fairly presented. Differing assessments and applications than the Company's estimates could materially impact the amounts recognized for deferred income tax assets and liabilities. Information regarding the impacts of the Company's tax policies is disclosed in Note 11.

V. Financial Instruments and Derivatives

The Company's financial instruments and derivatives are accounted for at fair value, with the initial and subsequent changes in fair value affecting earnings in the period the change occurs. The fair values of financial instruments and derivatives are classified within three levels, with Level III fair values determined using inputs for the asset or liability that are not readily observable. Transfers between levels of the fair value hierarchy are deemed to have occurred at the end of the reporting period in which the event or change in circumstances that caused the transfer occurred. These fair value levels are outlined and discussed in more detail in Note 14. Some of the Company's fair values are included in Level III because they are not traded on an active exchange or have terms that extend beyond the time period for which exchange-based quotes are available and require the use of internal valuation techniques or models to determine fair value.

The determination of the fair value of these contracts and derivative instruments can be complex and relies on judgments and estimates concerning future prices, volatility and liquidity, among other factors. These fair value estimates may not necessarily be indicative of the amounts that could be realized or settled and changes in these assumptions could affect the reported fair value of financial instruments. Fair values can fluctuate significantly and can be favourable or unfavourable depending on current market conditions. Judgment is also used to determine whether a highly probable forecasted transaction designated in a cash flow hedge is expected to occur based on the Company's estimates of pricing and production to allow the future transaction to be fulfilled.

When the Company enters into contracts to buy or sell non-financial items, such as certain commodities, and the contracts can be settled net in cash, the Company must use judgment to evaluate whether such contracts were entered into and continue to be held for the purposes of the receipt or delivery of the commodity in accordance with the Company's expected purchase, sale or usage requirements (i.e., normal purchase and sale). If this assertion cannot be supported, initially at contract inception and on an ongoing basis, the contracts must be accounted for as derivatives and measured at fair value, with changes in fair value recognized in net earnings. In supporting the normal purchase and sale assertion, the Company considers the nature of the contracts, the forecasted demand and supply requirements to which the contracts relate and its past practice of net settling other similar contracts, which may taint the normal purchase and sale assertion. The Company also enters into PPAs and contracts for differences and judgment is applied to determine if the contract meets the "own use" exemption or if derivative treatment is required.

VI. Provisions for Decommissioning and Restoration Activities

TransAlta recognizes provisions for decommissioning and restoration obligations as outlined in Note 2(K). Initial decommissioning provisions and subsequent changes thereto are determined using the Company's best estimate of the required cash expenditures, adjusted to reflect the risks and uncertainties inherent in the timing and amount of settlement. The estimated cash expenditures are present valued using a current, risk-adjusted, market-based, pre-tax discount rate. A change in estimated cash flows, market interest rates or timing could have a material impact on the carrying amount of the provision. Information regarding significant judgments and estimates made during 2024 to 2025 regarding decommissioning and restoration provisions is disclosed in Notes 7, 19 and 24.

VII. Useful Life of PP&E

Each significant component of an item of PP&E is depreciated over its estimated useful life. Estimated useful lives are determined based on current facts and past experience and take into consideration the anticipated physical life of the asset, existing long-term sales agreements and contracts, current and forecasted demand, the potential for technological obsolescence and regulations. The useful lives of PP&E are reviewed at least annually to ensure they continue to be appropriate. Information on changes in useful lives of facilities is disclosed in Note 19.

VIII. Employee Future Benefits

The Company provides pension and other post-employment benefits, such as health and dental benefits, to employees. The cost of providing these benefits is dependent upon many factors, including actual plan experience and estimates and assumptions about future experience.

The liability for pension and post-employment benefits and associated costs included in annual compensation expenses are impacted by estimates related to:

- Employee demographics, including age, compensation levels, employment periods, the level of contributions made to the plans and earnings on plan assets;
- The effects of changes to the provisions of the plans; and
- Changes in key actuarial assumptions, including rates of compensation and health-care cost increases and discount rates.

Due to the complexity of the valuation of pension and post-employment benefits, a change in the estimate of any one of these factors could have a material effect on the carrying amount of the liability for pension and other post-employment benefits or the related expense. These assumptions are reviewed annually to ensure they continue to be appropriate. Disclosures on employee future benefits are disclosed in Note 32.

IX. Other Provisions

Where necessary, the Company recognizes provisions arising from ongoing business activities, such as interpretation and application of contract terms, ongoing litigation and force majeure claims. These provisions and subsequent changes thereto, are determined using the Company's best estimate of the outcome of the underlying event and can also be impacted by determinations made by third parties, in compliance with contractual requirements. The actual amount of the provisions that may be required could differ materially from the amount recognized. More information is disclosed in Note 24 with respect to other provisions.

X. Revenue from Contracts with Customers

Where contracts contain multiple promises for goods or services, management exercises judgment in determining whether goods or services constitute distinct goods or services or a series of distinct goods that are substantially the same and that have the same pattern of transfer to the customer. The determination of a performance obligation affects whether the transaction price is recognized at a point in time or over time. Management considers both the mechanics of the contract and the economic and operating environment of the contract to determine whether the goods or services in a contract are distinct.

In determining the transaction price and estimates of variable consideration, management considers the past history of customer usage in estimating the goods and services to be provided to the customer. The Company also considers the historical production levels and operating conditions for its variable generating assets. The Company's contracts generally outline a specific amount to be invoiced to a customer associated with each performance obligation in the contract. Where contracts do not specify amounts for individual performance obligations, the Company estimates the amount of the transaction price to allocate to individual performance obligations based on their stand-alone selling price, which is primarily estimated based on the amounts that would be charged to customers under similar market conditions.

The satisfaction of performance obligations requires management to make judgments as to when control of the underlying good or service transfers to the customer. Determining when a performance obligation is satisfied affects the timing of revenue recognition. Management considers both customer acceptance of the good or service and the impact of laws and regulations such as certification requirements, to determine when this transfer occurs.

When contracts are modified, management must exercise judgment to determine, depending upon the facts and circumstances of the changes to the contract, whether the modification is accounted for as a new contract or as part of the existing contract. If it is required to be accounted for as part of the existing contract the transaction price can be affected and adjustments to previously recognized revenue can occur, or the impacts can be reflected prospectively from the modification date.

Management also applies judgment in determining whether the invoice practical expedient permits recognition of revenue at the invoiced amount if that invoiced amount corresponds directly with the entity's performance to date.

XI. Classification of Joint Arrangements

Upon entering into, or acquiring an interest in, a joint arrangement, the Company must classify it as either a joint operation or joint venture, and this classification affects the accounting for the joint arrangement. In making this classification, the Company exercises judgment in evaluating the terms and conditions of the arrangement to determine whether the parties have rights to the assets and obligations or rights to the net assets. Factors such as the legal structure, contractual arrangements and other facts and circumstances, such as where the purpose of the arrangement is primarily for the provision of the output to the parties and when the parties are substantially the only source of cash flows for the arrangement, must be evaluated to understand the rights of the parties to the arrangement.

XII. Significant Influence

Upon entering into an investment, the Company must classify it as either an investment in an associate or an investment under IFRS 9. In making this classification, the Company exercises judgment in evaluating whether it has significant influence over the investee. Significant influence is the power to participate in the financial and operating policy decisions of the investee, but is not control or joint control over those policies. If the Company holds 20 per cent or more of the voting rights in the investee, it is presumed that the entity has significant influence, unless it can be clearly demonstrated that this is not the case. Other factors such as representation on the Board, participation in policy-making processes, material transactions between the Company and investee, interchange of managerial personnel or providing essential technical information are considered when assessing if the Company has significant influence over an investee.

XIII. Change in Estimates

During the year ended Dec. 31, 2025, there were changes in estimates relating to asset impairment (reversals) charges (Note 7), decommissioning and other provisions (Note 24) and defined benefit obligation (Note 27). During the year ended Dec. 31, 2024, there were changes in estimates relating to asset impairment (reversals) charges (Note 7), useful lives (Note 19), decommissioning and other provisions (Note 24) and defined benefit obligation (Note 27).

3. Accounting Changes

A. Current Accounting Changes

There were no changes in accounting policies during the year ended December 31, 2025.

B. Future Accounting Changes

The Company closely monitors both new accounting standards and amendments to existing accounting standards issued by the IASB. The following standards have been issued but are not yet in effect.

Amendments to IFRS 9 and IFRS 7 — Nature-Dependent Electricity Contracts

On Dec. 18, 2024, the IASB issued amendments to IFRS 9 Financial Instruments and IFRS 7 Financial Instruments: Disclosure to improve reporting of the financial effects of nature-dependent electricity (e.g., wind and solar) contracts, which are often structured as power purchase agreements. Under these contracts, the amount of electricity generated can vary based on uncontrollable factors such as weather conditions. The amendments clarify the application of own-use requirements, permit hedge accounting if these contracts are used as hedging instruments and add new disclosure requirements about the effect of these contracts on a company's financial performance and cash flows. The amendments are effective for annual reporting periods beginning on or after Jan. 1, 2026.

Starting in the first quarter of 2026, the Company has designated certain pre-existing VPPAs within the Wind and Solar segment as held for hedging and has applied hedge accounting. As a result, the effective portion of changes in the fair value of these hedging derivatives, arising on or after Jan. 1, 2026, will be recognised in OCI while any ineffective portion will be recognized in net (loss) earnings. Retrospective designation is not permitted.

Amendments to IFRS 7 and IFRS 9 — Classification and Measurement of Financial Instruments

On May 29, 2024, the IASB issued Amendments to the Classification and Measurement of Financial Instruments effective Jan. 1, 2026 impacting IFRS 7 and 9. The IASB amended the requirements related to settling financial liabilities using an electronic payment system and assessing contractual cash flow characteristics of financial assets, including those with ESG-linked features. This amendment is not expected to have a material impact on the consolidated financial statements.

IFRS 18 — Presentation and Disclosure in Financial Statements

On April 9, 2024, the IASB issued a new standard, IFRS 18 *Presentation and Disclosure in Financial Statements*, which introduced new requirements for improved comparability in the statement of profit or loss, enhanced transparency of management-defined performance measures and more useful grouping of information in the financial statements. The standard is effective for annual reporting periods beginning on or after Jan. 1, 2027. The Company is currently evaluating the impacts to the financial statements.

C. Comparative Figures

Certain comparative figures have been reclassified to conform to the current period's presentation. These reclassifications did not impact previously reported net (loss) earnings.

4. Business Acquisitions

Acquisition of Heartland Generation

On Dec. 4, 2024, the Company acquired all issued and outstanding common shares of Heartland Generation Ltd. and Alberta Power (2000) Ltd. (collectively, Heartland) from Energy Capital Partners (ECP) (the Acquisition). The Acquisition, which includes Heartland's entire business operations in Alberta and British Columbia, was completed for an aggregate purchase price of $493 million, including the assumption of long-term debt of $232 million. The Acquisition was funded through a combination of cash on hand and borrowings under the Company's credit facilities.

On Aug. 1, 2025 and Oct. 2, 2025, the Company completed the sale of its 100 per cent interest in the 48 MW Poplar Hill facility and 50 per cent interest in the 97 MW Rainbow Lake facility, respectively, pursuant to the requirements of the federal Competition Bureau, which required the Company to enter into a consent agreement with the Commissioner of Competition to divest Heartland's Poplar Hill and Rainbow Lake assets (the Required Divestitures). Refer to Notes 7 and 18 for details.

The purchase price allocation was completed before the end of the measurement period and reflects management's best estimate of the fair value of the acquired assets and liabilities. There were no subsequent adjustments made to the original purchase price allocation and goodwill on acquisition was attributable to the Gas segment. The $51 million of goodwill recognized on the transaction is a result of deferred tax liabilities recognized on the transaction, which are recorded at the Company's effective tax rate without discounting, and from value attributed to the assembled workforce. None of the goodwill is expected to be deductible for tax purposes.

The following table summarizes the purchase price allocation representing the consideration paid and the estimated fair value of the net assets acquired as at Dec. 4, 2024.

	Dec. 4, 2024
Current and Non-Current Assets	
Cash and cash equivalents	276
Trade and other receivables	126
Risk management assets	16
Prepaid expenses and other assets	106
Assets held for sale (Note 18)	80
Long-term portion of finance lease receivables (Note 17)	107
Property, plant and equipment and Right-of-use assets (Note 19 and 20)	413
Intangible assets (Note 21)	57
Deferred income tax assets (Note 11)	41
Current and Non-Current Liabilities	
Accounts payable and accrued liabilities	193
Risk management liabilities	4
Credit facilities, long-term debt and lease liabilities (Note 25)	232
Decommissioning and other provisions (Note 24)	156
Deferred income tax liabilities (Note 11)	108
Contract liabilities	6
Total identifiable net assets at fair value	523
Goodwill arising on acquisition (Note 22)	51
Net assets acquired	574
Cash consideration	493
Contingent consideration payable	81
Total purchase consideration transferred	574

5. Revenue

A. Disaggregation of Revenue

The majority of the Company's revenues are derived from the sale of power, capacity and environmental and tax attributes, and from asset optimization activities, which the Company disaggregates into the following groups to determine how economic factors affect the recognition of revenue.

Year ended Dec. 31, 2025	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing	Corporate[1]	Total
Revenues from contracts with customers							
Power and other	42	264	671	13	9	—	999
Environmental and tax attributes[2]	70	106	11	—	—	(68)	119
Revenue from contracts with customers	112	370	682	13	9	(68)	1,118
Revenue from derivatives and other trading activities[3]	34	(251)	172	248	121	7	331
Revenue from merchant sales	203	71	393	233	—	—	900
Other[4]	19	16	20	1	—	—	56
Total revenue	368	206	1,267	495	130	(61)	2,405
Revenues from contracts with customers							
Timing of revenue recognition							
At a point in time	70	42	11	13	—	(68)	68
Over time	42	328	671	—	9	—	1,050
Total revenue from contracts with customers	112	370	682	13	9	(68)	1,118

(1) The elimination of intercompany sales is reflected in the Corporate segment.

(2) The environmental and tax attributes represent environmental attributes and production tax transfer sales not bundled with power and other sales.

(3) Represents realized and unrealized gains or losses from hedging and derivative positions. Volatility and pricing in commodity markets can vary significantly from period to period and impact movements in derivative positions.

(4) Other revenue includes production tax credits related to U.S. wind facilities subject to tax equity financing arrangements, total lease income from long-term contracts that meet the criteria of operating leases and other miscellaneous revenues.

Year ended Dec. 31, 2024	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing	Corporate(1)	Total
Revenues from contracts with customers							
Power and other	36	242	494	12	—	—	784
Environmental and tax attributes(2)	61	77	2	—	—	(34)	106
Revenue from contracts with customers	97	319	496	12	—	(34)	890
Revenue from derivatives and other trading activities(3)	16	(69)	282	311	168	—	708
Revenue from merchant sales	287	71	546	291	—	—	1,195
Other(4)	9	15	26	2	—	—	52
Total revenue	409	336	1,350	616	168	(34)	2,845
Revenues from contracts with customers							
Timing of revenue recognition							
At a point in time	61	28	—	12	—	(34)	67
Over time	36	291	496	—	—	—	823
Total revenue from contracts with customers	97	319	496	12	—	(34)	890

(1) The elimination of intercompany sales is reflected in the Corporate segment.

(2) The environmental and tax attributes represent environmental attributes and production tax transfer sales not bundled with power and other sales.

(3) Represents realized and unrealized gains or losses from hedging and derivative positions. Volatility and pricing in commodity markets can vary significantly from period to period and impact movements in derivative positions.

(4) Other revenue includes production tax credits related to U.S. wind facilities subject to tax equity financing arrangements, total lease income from long-term contracts that meet the criteria of operating leases and other miscellaneous revenues.

B. Performance Obligations

The performance obligations in the Company's contracts with its customers include the provision of electricity and steam capacity; the delivery of electricity, thermal energy and environmental attributes; the provision of operation and maintenance services and water management services; and the supply of byproducts from coal generation.

The aggregate amount of transaction prices allocated to remaining performance obligations (contract revenues that have not yet been recognized) as at Dec. 31, 2025, is approximately $2,524 million, with approximately $566 million expected to be recognized during the period 2026-2028; $493 million during the period of 2029-2031; $745 million during the period of 2032-2036; and $720 million for 2037 and thereafter.

These amounts exclude future revenues that are related to constrained variable consideration. In many of the Company's contracts, elements of the transaction price are considered constrained, such as for variable revenues dependent upon future production volumes that are driven by customer or market demand or market prices that are subject to factors outside the Company's influence. As a result, the amounts of future revenues disclosed above represent only a portion of future revenues that are expected to be realized by the Company from its contractual portfolio.

Contract liabilities of $43 million as at Dec. 31, 2025 represent the consideration received from customers in advance of satisfying the related performance obligation by supplying the related goods or services. Revenue is recognized when the performance obligation is satisfied.

C. Significant Customer

For the year ended Dec. 31, 2025, sales to the Alberta Electric System Operator represented 20 per cent of the Company's total revenue (2024 – 24 per cent). There were no other companies that accounted for more than 10 per cent of the Company's total revenue.

6. Expenses by Nature

Fuel, Purchased Power and Operations, Maintenance and Administration (OM&A)

Fuel and purchased power and OM&A expenses classified by nature are as follows:

	2025		2024	
Year ended Dec. 31	**Fuel and purchased power**	**OM&A**	**Fuel and purchased power**	**OM&A**
Gas fuel costs	**464**	**—**	369	—
Coal fuel costs	**134**	**—**	123	—
Royalty, land lease, other direct costs	**28**	**—**	28	—
Purchased power	**309**	**—**	419	—
Salaries and benefits	**—**	**317**	—	296
Other operating expenses[1]	**—**	**394**	—	359
Total	**935**	**711**	939	655

(1) Other operating expenses include contracted manpower, materials, insurance, office costs and other administrative and overhead costs.

7. Asset Impairment (Reversals) Charges

As part of the Company's monitoring controls, long-range forecasts are prepared for each CGU. The long-range forecast estimates are used to assess the significance of potential indicators of impairment and provide criteria to evaluate adverse changes in operations. The Company also considers the relationship between its market capitalization and its book value, among other factors, when reviewing for indicators of impairment. When indicators of impairment are present, the Company estimates a recoverable amount (the higher of value in use or fair value less costs of disposal) for the affected CGUs using discounted cash flow projections. The valuations are subject to measurement uncertainty from assumptions and inputs to the discount rates, power price forecasts, useful lives of the assets (extending to the last planned asset retirement in 2072) and long-range forecasts, which include changes to production, fuel costs, operating costs and capital expenditures. The Company recognized the following asset impairment (reversals) charges:

Year ended Dec. 31	Segment	2025	2024
Impairment charge, net of impairment reversals	Wind and Solar	**20**	—
Impairment charge related to the Required Divestitures	Gas	**37**	—
Impairment reversal related to generation equipment (Note 18)	Energy Transition	**(30)**	—
Changes in decommissioning and restoration provisions(1) (Note 24)	Energy Transition	**(44)**	24
Project development costs(2)	Corporate	**4**	22
Asset impairment (reversals) charges		**(13)**	46

(1) Changes relate to changes in discount rates, revisions in estimated cash flows and timing of cash flows.

(2) The Company recognized an impairment charge in the Corporate segment related to projects that are no longer proceeding.

Wind and Solar facilities Impairment Charge

During the year ended Dec. 31, 2025, internal valuations indicated the carrying values of four wind facilities exceeded their fair value less costs of disposal primarily due to updated production profiles and lower power price assumptions, which unfavourably impacted estimated future cash flows and resulted in an impairment charge of $37 million. The recoverable amount of $363 million for these four facilities was estimated based on fair value less costs of disposal using a discounted cash flow model and was categorized as a Level III fair value measurement. The discount rates used in the fair value measurements were in the range of 5.53 to 7.24 per cent.

During the year ended Dec. 31, 2025, the Company recognized impairment reversals for one wind facility and one solar facility, which had been previously impaired. The impairment reversals of $17 million were primarily due to changes in power price assumptions that favourably impacted estimated future cash flows. The recoverable amount of $233 million for these two facilities was estimated based on fair value less costs of disposal using a discounted cash flow model and was categorized as a Level III fair value measurement. The discount rates used in the fair value measurements were in the range of 6.10 to 7.24 per cent.

Required Divestitures

To meet the requirements of the federal Competition Bureau related to the acquisition of Heartland, the Company entered into a consent agreement with the Commissioner of Competition, under which the Company agreed to divest Heartland's Poplar Hill and Rainbow Lake facilities following the closing of the acquisition on Dec. 4, 2024.

During the year ended Dec. 31, 2025, the Company recognized an impairment loss in the amount of $37 million related to the Required Divestitures, with a corresponding fair value change in contingent consideration payable recognized in the statement of (loss) earnings for the period.

8. Net Other Operating Income

Net other operating income includes the following:

Year ended Dec. 31	2025	2024
Alberta Off-Coal Agreements	**(43)**	(40)
Other	**(4)**	(19)
Net other operating income	**(47)**	(59)

Alberta Off-Coal Agreements (OCA)

Under the terms of the OCA, the Company receives annual cash payments of approximately $43 million from the Government of Alberta if it ceases coal-fired emissions on or before Dec. 31, 2030. The Company achieved the cessation of all coal-fired emissions by Dec. 31, 2021.

The Company receives OCA payments on or before July 31, which are recognized in net other operating income evenly throughout the year. Under the terms of the OCA, the affected facilities may continue to generate electricity using non-coal-fired methods after Dec. 31, 2030.

Other

The Company receives liquidated damages related to the requirements to be met by the contractors on turbine availability guarantees at our Wind sites.

During the year ended Dec. 31, 2024, the Company also received reimbursement of $9 million from the Balancing Pool for TransAlta's decommissioning costs for Sundance A.

9. Investments

Investments

The change in investments is as follows:

	Skookumchuck	Other investments[(1)(2)]	Total
Balance, Dec. 31, 2023	104	34	138
Investment	—	8	8
Equity income (loss)	10	(5)	5
Distributions received	(5)	—	(5)
Changes in foreign exchange rates	9	2	11
Net change in fair value recognized in earnings	—	2	2
Balance, Dec. 31, 2024	118	41	159
Investment	**—**	**7**	**7**
Equity income (loss)	**8**	**(2)**	**6**
Distributions received	**(5)**	**—**	**(5)**
Changes in foreign exchange rates	**(6)**	**(2)**	**(8)**
Net change in fair value recognized in loss	**—**	**(1)**	**(1)**
Acquisition of control of previously equity-accounted investment	**—**	**(14)**	**(14)**
Balance, Dec. 31, 2025	**115**	**29**	**144**

(1) Other investments include EMG International, LLC accounted for using the equity method and Energy Impact Partners accounted for at FVTPL.

(2) On Feb. 28, 2025, the Company acquired the remaining 40 per cent interest in Tent Mountain, previously accounted for using the equity method. Tent Mountain became a wholly-owned subsidiary as at Dec. 31, 2025.

Skookumchuck Wind Project

TransAlta holds a 49 per cent membership interest in SP Skookumchuck Investment, LLC, which is accounted for using the equity method. Skookumchuck is a 136.8 MW wind project located in Lewis and Thurston counties near Centralia in Washington state. The project has a 20-year PPA with Puget Sound Energy that ends in 2040.

Other Investments

EMG International, LLC

TransAlta holds a 30 per cent interest in EMG, a wastewater treatment processing company, which is accounted for using the equity method. Earnings are derived from the design and construction of wastewater treatment facilities.

Energy Impact Partners

On May 6, 2022, the Company entered into a commitment to invest US$25 million over the next four years in Energy Impact Partners Deep Decarbonization Frontier Fund 1 (the Frontier Fund). The investment in the Frontier Fund provides the Company with a portfolio approach to investing in emerging technologies and the opportunity to identify, pilot, commercialize and bring to market emerging technologies that will facilitate the transition to net-zero emissions. The investment is accounted for at FVTPL.

Summarized financial information on the results of operations relating to the Company's pro-rata interests in Skookumchuck is as follows:

Year ended Dec. 31	2025	2024
Results of operations		
Revenues and other operating income	**21**	21
Expenses	**(13)**	(12)
Proportionate share of net earnings	**8**	9

Summarized financial information on the assets and liabilities relating to the Company's pro-rata interests in Skookumchuck is as follows:

As at Dec. 31	2025	2024
Current assets	**14**	15
Non-current assets	**314**	342
Current liabilities	**(18)**	(20)
Non-current liabilities	**(74)**	(97)
Net assets	**236**	240

10. Interest Expense

The components of interest expense are as follows:

Year ended Dec. 31	2025	2024
Interest on debt	**203**	197
Interest on exchangeable debentures (Note 26)	**25**	31
Interest on exchangeable preferred shares (Note 26)	**28**	28
Capitalized interest (Note 19)	**—**	(16)
Net gain on redemption of senior notes[1] (Note 25)	**(5)**	—
Interest on lease liabilities	**10**	10
Credit facility fees, bank charges and other interest	**29**	21
Tax shield on tax equity financing (Note 25)	**—**	3
Accretion of provisions (Note 24)	**57**	50
Interest expense	**347**	324

(1) Consists of a $31 million gain on interest rate derivatives designated as cash flow hedges, partially offset by a $21 million prepayment premium and $5 million accelerated amortization of deferred financing costs. Refer to Note 25 for details.

11. Income Taxes

Consolidated Statements of Earnings

I. Rate Reconciliation

Year ended Dec. 31	2025	2024
(Loss) earnings before income taxes	**(141)**	319
Net loss (earnings) attributable to non-controlling interests not subject to tax	**20**	(10)
Adjusted (Loss) Earnings before income taxes	**(121)**	309
Statutory Canadian federal and provincial income tax rate (%)	**23.3%**	23.3%
Expected income tax (recovery) expense	**(28)**	72
Increase (decrease) in income taxes resulting from:		
Differences in effective foreign tax rates	**13**	(6)
Non-deductible expense[1]	**7**	46
Non-taxable income	**(14)**	(10)
Taxable capital (gain) loss	**(17)**	1
Deferred income tax recovery related to temporary difference on investment in subsidiaries	**—**	(5)
Writedown (reversal of writedown) of unrecognized deferred income tax assets	**54**	(13)
Statutory and other rate differences	**(1)**	(1)
Adjustments in respect of deferred income tax of previous years	**(5)**	(11)
Other	**8**	7
Income tax expense	**17**	80
Effective tax rate (per cent)	**(14)**	26

(1) This amount is related to current tax adjustments in the U.S. to mitigate cash tax relating to the Base Erosion and Anti-Abuse Tax, Canadian non-deductible penalties, and a tax adjustment relating to dividends on preferred shares, treated as interest for accounting purposes.

Global Minimum Tax Act

In response to the OECD Pillar Two Model Rules, Canada enacted the *Global Minimum Tax Act* (GMTA) on June 19, 2024. The GMTA provides for a minimum tax of 15 per cent to be applied on a jurisdictional basis. The adoption of the GMTA did not have a material impact on the Company's tax expense. IAS 12 contains a mandatory temporary exception to recognizing and disclosing information about deferred taxes related to Pillar Two. The Company has applied this exception.

II. Components of Income Tax Expense

The components of income tax expense are as follows:

Year ended Dec. 31	2025	2024
Current income tax expense	**49**	143
Deferred income tax recovery related to the origination and reversal of temporary differences	**(86)**	(45)
Deferred income tax recovery related to temporary difference on investment in subsidiaries	**—**	(5)
Writedown (reversal of writedown) of unrecognized deferred income tax assets(1)	**54**	(13)
Income tax expense	**17**	80
Current income tax expense	**49**	143
Deferred income tax recovery	**(32)**	(63)
Income tax expense	**17**	80

(1) During the year ended Dec. 31, 2025, the Company wrote-down deferred tax assets of $54 million (2024 — $13 million recovery). The deferred income tax assets mainly relate to the tax benefits associated with tax losses related to the Company's directly owned U.S. operations and other deductible differences. The Company has not recognized $199 million (2024 — $152 million) of deferred tax assets on the basis that it is not probable that sufficient future taxable income will be available to utilize them.

Consolidated Statements of Changes in Equity

The aggregate current and deferred income tax related to items charged or credited to equity are as follows:

Year ended Dec. 31	2025	2024
Income tax (recovery) expense related to:		
Net impact related to cash flow hedges	**(14)**	53
Net impact related to hedges of foreign operations	**1**	(4)
Net impact related to net actuarial gains	**1**	3
Income tax (recovery) expense reported in equity	**(12)**	52

Consolidated Statements of Financial Position

Significant components of the Company's deferred income tax assets (liabilities) are as follows:

As at Dec. 31	2025	2024
Loss carryforwards[1]	**182**	149
Future decommissioning and restoration costs	**181**	184
Property, plant and equipment	**(655)**	(646)
Investment in subsidiaries	**(70)**	(60)
Risk management assets and liabilities, net	**105**	40
Employee future benefits and compensation plans	**53**	52
Foreign exchange differences	**12**	16
Other taxable temporary differences	**9**	(1)
Net deferred income tax liabilities, before unrecognized deferred income tax assets	**(183)**	(266)
Unrecognized deferred income tax assets	**(199)**	(152)
Net deferred income tax liabilities	**(382)**	(418)

(1) U.S. net operating losses generated before 2018 and Canadian non-capital losses have expiry dates ranging from 2031 to 2045. U.S. net operating losses generated from 2018 onward have no expiration.

The net deferred income tax liability is presented in the Consolidated Statements of Financial Position as follows:

As at Dec. 31	2025	2024
Deferred income tax assets[1]	**41**	52
Deferred income tax liabilities	**(423)**	(470)
Net deferred income tax liabilities	**(382)**	(418)

(1) The deferred income tax assets presented on the Consolidated Statements of Financial Position are recoverable based on estimated future earnings and tax planning strategies. The assumptions used in the estimate of future earnings are based on the Company's long-range forecasts.

Contingencies

As of Dec. 31, 2025, the Company had recognized a net liability of nil (2024 – nil) related to uncertain tax positions.

12. Non-Controlling Interests

The Company's subsidiaries and operations that have non-controlling interests are as follows:

Subsidiary/Operation	Non-controlling interest owner	Non-controlling interest as at Dec. 31, 2025	Non-controlling interest as at Dec. 31, 2024
TransAlta Cogeneration LP	Canadian Power Holdings Inc.	**49.99%**	49.99%
Kent Hills Wind LP	Natural Forces Technologies Inc.	**17%**	17%

TransAlta Cogeneration, LP (TA Cogen) operates a portfolio of cogeneration facilities in Canada and owns 50 per cent of Sheerness Units 1 and 2, a natural-gas-fired generating facility.

Kent Hills Wind LP, a subsidiary, owns and operates the 167 MW Kent Hills (1, 2 and 3) wind facilities located in New Brunswick.

Summarized financial information relating to subsidiaries with significant non-controlling interests is as follows:

TA Cogen

Year ended Dec. 31	2025	2024
Revenues	**94**	167
Net (loss) earnings and total comprehensive (loss) income	**(52)**	9
Amounts attributable to the non-controlling interest:		
Net (loss) earnings	**(20)**	9
Total comprehensive (loss) income	**(20)**	9
Distributions paid to Canadian Power Holdings Inc.	**11**	40

As at Dec. 31	2025	2024
Current assets	**49**	47
Long-term assets	**56**	130
Current liabilities	**(35)**	(48)
Long-term liabilities	**(36)**	(32)
Total equity	**(34)**	(97)
Equity attributable to Canadian Power Holdings Inc.	**(15)**	(46)
Non-controlling interest share (per cent)	**49.99**	49.99

Kent Hills Wind LP

Year ended Dec. 31	2025	2024
Revenues	**36**	34
Net earnings and total comprehensive income	**3**	7
Amounts attributable to the non-controlling interest:		
Net earnings and total comprehensive income	**—**	1

As at Dec. 31	2025	2024
Current assets	**12**	33
Long-term assets	**466**	463
Current liabilities	**(18)**	(26)
Long-term liabilities	**(160)**	(174)
Total equity	**(300)**	(296)
Equity attributable to non-controlling interests	**(51)**	(51)
Non-controlling interest share (per cent)	**17**	17

13. Trade and Other Receivables and Accounts Payable, Accrued Liabilities and Other Current Liabilities

As at Dec. 31	2025	2024
Trade accounts receivable	**507**	570
Collateral provided (Note 15)	**92**	124
Current portion of finance lease receivables (Note 17)	**30**	30
Current portion of loan receivable (Note 23)	**1**	1
Income taxes receivable	**69**	42
Trade and other receivables	**699**	767

As at Dec. 31	2025	2024
Accounts payable and accrued liabilities	**548**	694
Income taxes payable	**11**	23
Interest payable	**23**	17
Current portion of contract liabilities (Note 5)	**17**	12
Liabilities held for sale (Note 18)	**6**	1
Collateral held (Note 15)	**3**	9
Contingent consideration payable	**5**	—
Accounts payable, accrued liabilities and other current liabilities	**613**	756

14. Financial Instruments

A. Financial Assets and Liabilities — Classification and Measurement

Financial assets and financial liabilities are measured on an ongoing basis at cost, fair value or amortized cost.

Carrying value as at Dec. 31, 2025	Derivatives used for hedging	Derivatives held for trading (FVTPL)	Amortized cost	Other financial assets and liabilities (FVTPL)	Other financial assets (FVOCI)	Total
Financial assets						
Cash and cash equivalents[1]	—	—	205	—	—	205
Restricted cash	—	—	78	—	—	78
Trade and other receivables[2]	—	—	630	—	—	630
Long-term financial assets	—	—	—	140	—	140
Long-term portion of finance lease receivables	—	—	277	—	—	277
Long-term portion of loan receivable[3]	—	—	30	—	—	30
Other investments[4]	—	—	—	25	1	26
Risk management assets						
Current	—	162	—	—	—	162
Long-term	—	32	—	—	—	32
Financial liabilities						
Accounts payable, accrued liabilities and other current liabilities[5]	—	—	574	—	—	574
Dividends payable	—	—	52	—	—	52
Risk management liabilities						
Current	—	156	—	—	—	156
Long-term	—	519	—	—	—	519
Credit facilities, long-term debt and lease liabilities[6]	—	—	3,593	—	—	3,593
Exchangeable securities	—	—	750	—	—	750

(1) Includes cash equivalents of nil.

(2) Excludes income taxes receivable.

(3) Included in other assets. Refer to Note 23.

(4) Excludes EMG International, LLC and Tent Mountain. Refer to Note 9.

(5) Excludes the current portion of contract liabilities, current income taxes payable, liabilities held for sale and contingent consideration payable.

(6) Includes current portion.

Carrying value as at Dec. 31, 2024	Derivatives used for hedging	Derivatives held for trading (FVTPL)	Amortized cost	Other financial assets (FVTPL)	Other financial assets (FVTOCI)	Total
Financial assets						
Cash and cash equivalents(1)	—	—	337	—	—	337
Restricted cash	—	—	69	—	—	69
Trade and other receivables(2)	—	—	725	—	—	725
Long-term portion of finance lease receivables	—	—	305	—	—	305
Long-term portion of loan receivable(3)	—	—	24	—	—	24
Other investments(4)	—	—	—	22	1	23
Risk management assets						
Current	45	273	—	—	—	318
Long-term	—	93	—	—	—	93
Financial liabilities						
Bank overdraft	—	—	1	—	—	1
Accounts payable, accrued liabilities and other current liabilities(5)	—	—	720	—	—	720
Contingent consideration	—	—	—	81	—	81
Dividends payable	—	—	49	—	—	49
Risk management liabilities						
Current	—	277	—	—	—	277
Long-term	—	305	—	—	—	305
Credit facilities, long-term debt and lease liabilities(6)	—	—	3,808	—	—	3,808
Exchangeable securities	—	—	750	—	—	750

(1) Includes cash equivalents of nil.

(2) Excludes income taxes receivable.

(3) Included in other assets. Refer to Note 23.

(4) Excludes EMG International, LLC and Tent Mountain. Refer to Note 9.

(5) Excludes the current portion of contract liabilities, current income taxes payable and liabilities held for sale.

(6) Includes current portion.

B. Fair Value of Financial Instruments

The fair value of a financial instrument is the price that would be received when selling the asset or paid to transfer the associated liability in an orderly transaction between market participants at the measurement date. Fair values can be determined by observing quoted prices for the instrument in active markets to which the Company has access. In the absence of an active market, the Company determines fair values based on valuation models or by reference to other similar products in active markets. Fair values determined using valuation models require the use of assumptions. In determining those assumptions, the Company looks primarily to external readily observable market inputs. However, if these are not available, the Company uses inputs that are not based on observable market data.

I. Level I, II and III Fair Value Measurements

The Level I, II and III classifications in the fair value hierarchy used by the Company are defined below. The fair value measurement of a financial instrument is included in only one of the three levels, the determination of which is based on the lowest level input that is significant to the derivation of the fair value. The Level III classification is the lowest level classification in the fair value hierarchy.

a. Level I

Level I fair values are determined using inputs that are quoted prices (unadjusted) in active markets for identical assets or liabilities that the Company has the ability to access at the measurement date. In determining Level I fair values, the Company uses quoted prices for identically traded commodities obtained from active exchanges such as the New York Mercantile Exchange.

b. Level II

Level II fair values are determined, directly or indirectly, using inputs that are observable for the asset or liability.

Fair values falling within the Level II category are determined through the use of quoted prices in active markets, which in some cases are adjusted for factors specific to the asset or liability, such as basis, credit valuation and location differentials.

The Company's commodity risk management Level II financial instruments include over-the-counter derivatives with values based on observable commodity futures curves and derivatives with inputs validated by broker quotes or other publicly available market data providers. Level II fair values are also determined using valuation techniques, such as option pricing models and interpolation formulas, where the inputs are readily observable.

In determining Level II fair values of other risk management assets and liabilities, the Company uses observable inputs other than unadjusted quoted prices that are observable for the asset or liability, such as interest rate yield curves and currency rates. For certain financial instruments where there is insufficient trading volume or a lack of recent trades, the Company relies on similar interest or currency rate inputs and other third-party information such as credit spreads.

c. Level III

Level III fair values are determined using inputs for the assets or liabilities that are not readily observable.

The Company may enter into commodity transactions for which market-observable data is not available. In these cases, Level III fair values are determined using valuation techniques such as mark-to-forecast and mark-to-model. For mark-to-model valuations, derivative pricing models, regression-based models and scenario analysis simulation models may be employed.

The model inputs may be based on historical data such as unit availability, transmission congestion, demand profiles for individual non-standard deals and structured products and/or volatility and correlations between products derived from historical price relationships. For assets and liabilities that are recognized at fair value on a recurring basis, the Company determines whether transfers have occurred between levels in the hierarchy by re-assessing categorization (based on the lowest level input that is significant to the fair value measurement as a whole) at the end of each reporting period.

Other than the long-term financial assets discussed in Section IV below, there were no changes in the Company's valuation processes, valuation techniques and types of inputs used in the fair value measurements during the period.

The Company also has various commodity contracts with terms that extend beyond a liquid trading period. As forward market prices are not available for the full period of these contracts, the value of these contracts is derived by reference to a forecast that is based on a combination of external and internal fundamental modelling, including discounting. As a result, these contracts are classified in Level III.

II. Commodity Risk Management Assets and Liabilities

Commodity risk management assets and liabilities include risk management assets and liabilities that are used in the energy marketing and generation segments in relation to trading activities and certain contracting activities. To the extent applicable, changes in net risk management assets and liabilities for non-hedge positions are reflected within earnings of these businesses.

Commodity risk management assets and liabilities classified by fair value levels as at Dec. 31, 2025, are as follows: Level I – $10 million net liability (Dec. 31, 2024 – $12 million net liability), Level II – $33 million net liability (Dec. 31, 2024 – $2 million net liability) and Level III – $447 million net liability (Dec. 31, 2024 – $153 million net liability).

Significant changes in commodity net risk management assets (liabilities) during the year ended Dec. 31, 2025, are primarily attributable to volatility in market prices across multiple markets on both existing contracts and new contracts and contract settlements.

The following table summarizes the key factors impacting the fair value of the Level III commodity risk management assets and liabilities by classification during the years ended Dec. 31, 2025 and 2024, respectively:

	Year ended Dec. 31, 2025			Year ended Dec. 31, 2024		
	Hedge	Non-hedge	Total	Hedge	Non-hedge	Total
Opening balance	**—**	**(153)**	**(153)**	—	(147)	(147)
Changes attributable to:						
New contracts added	**—**	**—**	**—**	—	3	3
Market price changes on existing contracts	**—**	**(261)**	**(261)**	—	(49)	(49)
Market price changes on new contracts	**—**	**17**	**17**	—	27	27
Contracts settled	**—**	**(48)**	**(48)**	—	23	23
Change in foreign exchange rates	**—**	**(2)**	**(2)**	—	(10)	(10)
Net risk management liabilities at end of year	**—**	**(447)**	**(447)**	—	(153)	(153)
Additional Level III information:						
Total losses included in (loss) earnings before income taxes	**—**	**(246)**	**(246)**	—	(32)	(32)
Unrealized losses included in (loss) earnings before income taxes relating to net assets (liabilities) held at year end	**—**	**(294)**	**(294)**	—	(9)	(9)

The Company's Commodity Exposure Management Policy governs both the commodity transactions undertaken in its proprietary trading business and those undertaken to manage commodity price exposures in its generation business. This policy defines and specifies the controls and management responsibilities associated with commodity trading activities, as well as the nature and frequency of required reporting of such activities.

The Company's risk management department determines methodologies and procedures regarding commodity risk management Level III fair value measurements. Level III fair values are primarily calculated within the Company's energy trading risk management processes. These calculations are based on underlying contractual data as well as observable and non-observable inputs. Development of non-observable inputs requires the use of judgment. To ensure reasonability, the Level III fair value measurements are reviewed and validated by the risk management and finance departments. Review occurs formally on a quarterly basis or more frequently if daily review and monitoring procedures identify unexpected changes to fair value or changes to key parameters.

As at Dec. 31, 2025, the total Level III risk management asset balance was \$65 million (Dec. 31, 2024 – \$110 million) and the Level III risk management liability balance was \$512 million (Dec. 31, 2024 – \$263 million). The net risk management liabilities increased mainly due to volatility in market prices across multiple markets on existing contracts and contract settlements.

The information on risk management contracts or groups of risk management contracts that are included in Level III measurements and the related unobservable inputs and sensitivities are outlined in the following table.

These include the effects on fair value of discounting, liquidity and credit value adjustments. Sensitivity ranges for the base fair values are determined using reasonably possible alternative assumptions for the key unobservable inputs, which may include forward commodity prices, volatility in commodity prices and correlations, delivery volumes, escalation rates and cost of supply.

Included in the Level III classification are several long-term wind energy sales agreements, including contracts for differences and virtual power purchase agreements, that are recognized as derivatives for accounting purposes. The sensitivity reflects the potential impacts on the fair value of these long-term wind agreements. These long-term wind energy sales are backed by physical assets to effectively reduce our market risk.

As at	Dec. 31, 2025			
Description	**Valuation technique**	**Unobservable input**	**Reasonably possible change**	**Potential change in fair value**[1]
Long-term wind energy sale — Eastern U.S.	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of US$6 or increase of US$6	**+26 -43**
		Illiquid future REC[2] prices (per unit)	Price decrease of US$4 or increase of US$17	
		Wind discounts	0% decrease or 5% increase	
Long-term wind energy sale — Canada	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of $21 or increase of $10	**+55 -22**
		Wind discounts	5% decrease or 5% increase	
Long-term wind energy sale — Central U.S.	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of US$7 or increase of US$3	**+47 -52**
		Wind discounts	2% decrease or 6% increase	

(1) Potential change in fair value represents the total increase or decrease in recognized fair value that could arise from the use of the reasonably possible changes of all unobservable inputs.

(2) Renewable energy credits

As at	Dec. 31, 2024			
Description	**Valuation technique**	**Unobservable input**	**Reasonably possible change**	**Potential change in fair value**[1]
Long-term wind energy sale — Eastern U.S.	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease or increase of US$6	+42 -30
		Illiquid future REC[2] prices (per unit)	Price decrease of US$12 or increase of US$8	
		Wind discounts	0% decrease or 6% increase	
Long-term wind energy sale — Canada	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of $57 or increase of $10	+53 -17
		Wind discounts	15% decrease or 5% increase	
Long-term wind energy sale — Central U.S.	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of US$4 or increase of US$3	+84 -77
		Wind discounts	2% decrease or 2% increase	

(1) Potential change in fair value represents the total increase or decrease in recognized fair value that would arise from the use of the reasonably possible changes of all unobservable inputs.

(2) Renewable energy credits

a. Long-Term Wind Energy Sale – Eastern U.S.

The Company is party to a long-term contract for differences (CFD) for the offtake of 100 per cent of the generation from its 90 MW Big Level wind facility. The CFD, together with the sale of electricity generated into the PJM Interconnection at the prevailing real-time energy market price, achieve the fixed contract price per MWh on proxy generation. Under the CFD, if the market price is lower than the fixed contract price, the customer pays the Company the difference and if the market price is higher than the fixed contract price, the Company refunds the difference to the customer. The customer is also entitled to the physical delivery of environmental attributes. The contract expires in December 2034. The contract is accounted for as a derivative with changes in fair value presented in revenue.

The key unobservable inputs used in the valuation of the contract are expected proxy generation volumes and non-liquid forward prices for power, renewable energy credits and wind discounts.

b. Long-Term Wind Energy Sale – Canada

The Company is party to two Virtual Power Purchase Agreements (VPPAs) for the offtake of 100 per cent of the generation from its 130 MW Garden Plain wind facility. The VPPAs, together with the sale of electricity generated into the Alberta power market at the pool price, achieve the fixed contract prices per MWh. Under the VPPAs, if the pool price is lower than the fixed contract price, the customer pays the Company the difference and if the pool price is higher than the fixed contract price, the Company refunds the difference to the customer. Customers are also entitled to the physical delivery of environmental attributes. Both VPPAs commenced on commercial operation of the facility in August 2023 and extend for a weighted average period of approximately 17 years.

The energy components of these contracts are accounted for as derivatives, with changes in fair value presented in revenue.

The key unobservable inputs used in the valuations of the contracts are the non-liquid forward prices for power and monthly wind discounts.

c. Long-Term Wind Energy Sale – Central U.S.

The Company is party to two long-term VPPAs for the offtake of 100 per cent of the generation from its 302 MW White Rock East and White Rock West wind power facilities. The VPPAs, together with the sale of electricity generated into the U.S. Southwest Power Pool (SPP) market at the relevant price nodes, achieves the fixed contract prices per MWh. Under the VPPAs, if the SPP pricing is lower than the fixed contract price the customer pays the Company the difference, and if the SPP pricing is higher than the fixed contract price, the Company refunds the difference to the customer. The customer is also entitled to the physical delivery of environmental attributes. The VPPAs commenced on commercial operation of the facilities in the first quarter of 2024.

The Company is also party to a VPPA for the offtake of 100 per cent of the generation from its 202 MW Horizon Hill wind power project. The VPPA, together with the sale of electricity generated into the SPP market at the relevant price node, achieve the fixed contract price per MWh. Under the VPPA, if the SPP pricing is lower than the fixed contract price, the customer pays the Company the difference and if the SPP pricing is higher than the fixed contract price, the Company refunds the difference to the customer. The customer is also entitled to the physical delivery of environmental attributes. The VPPA commenced on commercial operation of the facility in the second quarter of 2024.

The energy components of these contracts are accounted for as derivatives, with changes in fair value presented in revenue.

The key unobservable inputs used in the valuation of the contracts are the non-liquid forward prices for power and wind discounts.

III. Other Risk Management Assets and Liabilities

Other risk management assets and liabilities primarily include risk management assets and liabilities that are used to manage exposures on non-energy marketing transactions such as interest rates, the net investment in foreign operations and other foreign currency risks. Hedge accounting is not always applied.

Other risk management assets and liabilities with a total net asset fair value of $9 million as at Dec. 31, 2025 (Dec. 31, 2024 – $4 million net liability) are classified as Level II fair value measurements. The changes in other net risk management assets and liabilities during the year ended Dec. 31, 2025, are attributable to contracts settled during 2025.

IV. Other Financial Assets and Liabilities

The fair value of financial assets and liabilities measured at other than fair value is as follows:

	Fair value[2]				Total carrying value[2]
	Level I	Level II	Level III	Total	
Long-term debt — Dec. 31, 2025	**—**	**3,255**	**—**	**3,255**	**3,447**
Exchangeable securities — Dec. 31, 2025	**—**	**752**	**—**	**752**	**750**
Long-term financial asset — Dec. 31, 2025	**—**	**—**	**140**	**140**	**140**
Loan receivable — Dec. 31, 2025[1]	**—**	**31**	**—**	**31**	**31**
Long-term debt — Dec. 31, 2024	—	3,447	—	3,447	3,657
Exchangeable securities — Dec. 31, 2024	—	739	—	739	750
Loan receivable — Dec. 31, 2024[1]	—	25	—	25	25

(1) Included within Other assets.

(2) Includes current and non-current portions.

The fair values of the Company's debentures, senior notes and exchangeable securities are determined using prices observed in secondary markets. Non-recourse and other long-term debt fair values are determined by calculating an implied price based on a current assessment of the yield to maturity.

The carrying amount of other short-term financial assets and liabilities (cash and cash equivalents, restricted cash, trade accounts receivable, collateral provided, bank overdraft, accounts payable and accrued liabilities, collateral held and dividends payable) approximates fair value due to the liquid nature of the asset or liability. The fair values of the finance lease receivables approximate the carrying amounts as the amounts receivable represent cash flows from repayments of principal and interest.

Long-term Financial Asset

During the year ended Dec. 31, 2025, the Company made available a US$75 million term loan, which is convertible to equity at any time, and a US$100 million revolving facility (collectively, the Nova facilities) to Nova Clean Energy, LLC (Nova), a developer of renewable energy projects.

The outstanding principal under the term loan and the revolving facility bear interest of seven per cent per annum with interest paid quarterly. The terms of the term loan and the revolving facility are six and five years, respectively, unless accelerated. The term loan is convertible to equity at any time at the option of the Company and any remaining unused term loan commitments at the time of conversion would be terminated. The term loan and revolving facility are subject to customary financing conditions and covenants that may restrict Nova's ability to access funds. This investment in Nova provides the Company with the exclusive right to purchase Nova's late-stage development projects in the western U.S. The Nova facilities are classified as financial assets measured at FVTPL. The fair value of the Nova facilities are categorized as Level III in the fair value hierarchy as their fair value is determined using a binomial model with multiple inputs such as volatility and equity value for which observable market data is not available. A reasonably possible change in inputs would not result in a material impact in the fair value of the Nova facilities.

The following table summarizes the key factors impacting the fair value of the Level III long-term financial assets by classification during the year ended Dec. 31, 2025:

Year ended Dec. 31, 2025	Total
Opening balance	—
Changes attributable to:	
Draws	170
Repayments	(19)
Fair value changes	(5)
Change in foreign exchange rates	(6)
Transfers out of Level III	—
Balance, Dec. 31, 2025	140
Additional Level III information:	
Losses recognized in other comprehensive loss	—
Total losses included in loss before income taxes	(11)
Unrealized losses included in earnings before income taxes	(11)

C. Inception Gains and Losses

The majority of derivatives traded by the Company are based on adjusted quoted prices on an active exchange or extend beyond the time period for which exchange-based quotes are available. The fair values of these derivatives are determined using inputs that are not readily observable. Refer to section B of this Note 14 above for a description of the fair value Level III valuation techniques used. In some instances, a difference may arise between the fair value of a financial instrument at initial recognition (the transaction price) and the amount calculated through a valuation model. This unrealized gain or loss at inception is recognized in net earnings (loss) only if the fair value of the instrument is evidenced by a quoted market price in an active market, observable current market transactions that are substantially the same, or a valuation technique that uses observable market inputs. Where these criteria are not met, the difference is deferred on the Consolidated Statements of Financial Position in risk management assets or liabilities and is recognized in net earnings (loss) over the term of the related contract. Effective Jan. 1, 2025, the difference is calibrated at initial recognition and no inception gains or losses are recognized.

The difference between the transaction price and the fair value determined using a valuation model, yet to be recognized in net (loss) earnings and a reconciliation of changes is as follows:

As at Dec. 31	2025	2024
Unamortized net gain at beginning of year	**11**	3
New inception gains (1)	**—**	31
Change in foreign exchange rates	**1**	(3)
Amortization recorded in net (loss) earnings during the year	**(33)**	(20)
Unamortized net (loss) gain at end of year	**(21)**	11

(1) During 2024, the Company entered into long-term fixed price power sale contracts with certain of its U.S. customers that resulted in new inception losses due to the difference between the fixed PPA price and future estimated market prices. There are other key factors, such as project economics and incentives, that influence the long-term power price for renewable projects outside of the power price curve, which is not liquid for the majority of the duration of the PPA.

15. Risk Management

A. Risk Management Strategy

The Company is exposed to market risk from changes in commodity prices, foreign exchange rates, interest rates, credit risk and liquidity risk. These risks affect the Company's earnings and the value of associated financial instruments that the Company holds. In certain cases, the Company seeks to minimize the effects of these risks by using derivatives to hedge its risk exposures. The Company's risk management strategy, policies and controls are designed to ensure that the risks it assumes comply with the Company's internal objectives and risk tolerance.

The Company has two primary streams of risk management activities: (i) financial exposure management; and (ii) commodity exposure management. Within these activities, risks identified for management include commodity risk, interest rate risk, liquidity risk, equity price risk and foreign currency risk.

The Company seeks to minimize the effects of commodity risk, interest rate risk and foreign currency risk by using derivative financial instruments to hedge risk exposures. Of these derivatives, the Company may apply hedge accounting to those hedging commodity price risk, interest rate risk and foreign currency risk.

The use of financial derivatives is governed by the Company's policies approved by the Board, which provide written principles on commodity risk, interest rate risk, liquidity risk, equity price risk and foreign currency risk, as well as the use of financial derivatives and non-derivative financial instruments.

Liquidity risk, credit risk and equity price risk are managed through means other than derivatives or hedge accounting.

The Company enters into various derivative transactions as well as other contracting activities that do not qualify for hedge accounting or where a choice was made not to apply hedge accounting. As a result, the related assets and liabilities are classified as derivatives at fair value through profit and loss. The net realized and unrealized gains or losses from changes in the fair value of these derivatives are reported in net earnings in the period the change occurs.

The Company designates certain derivatives as hedging instruments to hedge commodity price risk, foreign currency exchange risk in cash flow hedges and hedges of net investments in foreign operations. Hedges of foreign exchange risk on firm commitments are accounted for as cash flow hedges.

At the inception of the hedge relationship, the Company documents the relationship between the hedging instrument and the hedged item, along with its risk management objectives and its strategy for undertaking various hedge transactions. At the inception of the hedge and on an ongoing basis, the Company also documents whether the hedging instrument is effective in offsetting changes in fair values or cash flows of the hedged item attributable to the hedged risk, which is when the hedging relationships meet all of the following hedge effectiveness requirements:

- There is an economic relationship between the hedged item and the hedging instrument;
- The effect of credit risk does not dominate the value changes that result from that economic relationship; and
- The hedge ratio of the hedging relationship is the same as that resulting from the quantity of the hedged item that the Company actually hedges and the quantity of the hedging instrument that the entity actually uses to hedge that quantity of hedged item.

If a hedging relationship ceases to meet the hedge effectiveness requirement relating to the hedge ratio, but the risk management objective for that designated hedging relationship remains the same, the Company adjusts the hedge ratio of the hedging relationship so that it continues to meet the qualifying criteria.

B. Net Risk Management Assets and Liabilities

Aggregate net risk management assets (liabilities) are as follows:

As at Dec. 31, 2025

	Cash flow hedges	Not designated as a hedge	Total
Commodity risk management			
Current	—	**4**	**4**
Long-term	—	**(494)**	**(494)**
Net commodity risk management liabilities	—	**(490)**	**(490)**
Other			
Current	—	**2**	**2**
Long-term	—	**7**	**7**
Net other risk management assets	—	**9**	**9**
Total net risk management liabilities	—	**(481)**	**(481)**

As at Dec. 31, 2024

	Cash flow hedges	Not designated as a hedge	Total
Commodity risk management			
Current	45	8	53
Long-term	—	(220)	(220)
Net commodity risk management assets (liabilities)	45	(212)	(167)
Other			
Current	—	(12)	(12)
Long-term	—	8	8
Net other risk management liabilities	—	(4)	(4)
Total net risk management assets (liabilities)	45	(216)	(171)

Netting Arrangements

Information about the Company's financial assets and liabilities that are subject to enforceable master netting arrangements or similar agreements is as follows:

As at Dec. 31, 2025	Gross amounts of recognized financial assets (liabilities)	Amounts set off	Net amounts included on the statement of financial position	Master netting arrangements[1]	Net amount
Current risk management assets	**487**	**(334)**	**153**	**(5)**	**148**
Long-term risk management assets	**59**	**(28)**	**31**	**(3)**	**28**
Current risk management liabilities	**(470)**	**334**	**(136)**	**5**	**(131)**
Long-term risk management liabilities	**(45)**	**28**	**(17)**	**3**	**(14)**
Trade and other receivables[2]	**1,474**	**(1,338)**	**136**	**(18)**	**118**
Accounts payable and accrued liabilities[2]	**(1,451)**	**1,338**	**(113)**	**18**	**(95)**

As at Dec. 31, 2024	Gross amounts of recognized financial assets (liabilities)	Amounts set off	Net amounts included on the statement of financial position	Master netting arrangements[1]	Net amount
Current risk management assets	686	(421)	265	(18)	247
Long-term risk management assets	153	(59)	94	(1)	93
Current risk management liabilities	(662)	421	(241)	18	(223)
Long-term risk management liabilities	(128)	59	(69)	1	(68)
Trade and other receivables[2]	1,519	(1,273)	246	(7)	239
Accounts payable and accrued liabilities[2]	(1,470)	1,273	(197)	7	(190)

(1) Amounts not set off in the Consolidated Statements of Financial Position.

(2) The trade and other receivables and accounts payable and accrued liabilities include amounts related to collateral provided and held. Refer to Note 15(E) below for further details.

C. Nature and Extent of Risks Arising from Financial Instruments

I. Market Risk

a. Commodity Price Risk Management

The Company has exposure to movements in certain commodity prices in both its electricity generation and proprietary trading businesses, including the market price of electricity and fuels used to produce electricity. Most of the Company's electricity generation and related fuel supply contracts are considered to be contracts for delivery or receipt of a non-financial item in accordance with the Company's expected own use requirements and are not considered to be financial instruments. As such, the discussion related to commodity price risk is limited to the Company's proprietary trading business, VPPAs and other long-term contracts that are derivatives and commodity derivatives used in hedging relationships associated with the Company's electricity generating activities.

To mitigate the risk of adverse commodity price changes, the Company uses three tools:

- A framework of risk controls;
- A predefined hedging plan, including fixed price financial power swaps and long-term physical power sale contracts to hedge commodity price for electricity generation; and
- A committee dedicated to overseeing the risk and compliance program in trading and ensuring the existence of appropriate controls, processes, systems and procedures to monitor adherence to the program.

The Company may, at times, execute hedges for its electricity price exposure in Alberta using fixed price financial swaps or other similar instruments. This hedging strategy falls under the Company's risk management strategy used to hedge commodity price risk.

Market risk exposures are measured using Value at Risk (VaR) supplemented by sensitivity analysis. There has been no change to the Company's exposure to market risks or the manner in which these risks are managed or measured. Position sizes and trade strategies were adjusted to remain within the Company's risk framework.

i. Commodity Price Risk Management – Proprietary Trading

The Company's Energy Marketing segment conducts proprietary trading activities and uses a variety of instruments to manage risk, earn trading revenue and gain market information.

In compliance with the Company's Commodity Exposure Management Policy, proprietary trading activities are subject to limits and controls, including VaR limits. The Board approves the limit for total VaR from proprietary trading activities. VaR is the most commonly used metric employed to track and manage the market risk associated with trading positions.

A VaR measure gives, for a specific confidence level, an estimated maximum pre-tax loss that could be incurred over a specified period of time. VaR is used to determine the potential change in value of the Company's proprietary trading portfolio, over a three-day period within a 95 per cent confidence level, resulting from normal market fluctuations. VaR is estimated using the historical variance/covariance approach. This measure has inherent limitations. VaR relies on historical data, assuming that past price movements will reflect future market risks. Consequently, it may only be meaningful under normal market conditions and does not account for extreme market events. In addition, the use of a three-day measurement period implies that positions can be unwound or hedged within three days, although this may not be possible if the market becomes illiquid.

Changes in market prices associated with proprietary trading activities affect net earnings in the period that the price changes occur. VaR at Dec. 31, 2025, associated with the Company's proprietary trading activities was $1 million (2024 – $3 million).

ii. Commodity Price Risk – Generation

The generation segments use various commodity contracts to manage the commodity price risk associated with electricity generation, fuel purchases, emissions and byproducts, as considered appropriate. A Commodity Exposure Management Policy, prepared and approved annually, outlines the intended hedging strategies associated with the Company's generation assets and related commodity price risks. Controls also include restrictions on authorized instruments, management reviews on individual portfolios and approval of asset transactions that could add potential volatility to the Company's reported net earnings.

VaR at Dec. 31, 2025, associated with the Company's commodity derivative instruments used in generation hedging activities was nil (2024 – $8 million). For positions and economic hedges that do not meet hedge accounting requirements or for short-term optimization transactions such as buybacks entered into to offset existing hedge positions, these transactions are marked to the market value with changes in market prices associated with these transactions affecting net earnings in the period in which the price change occurs. VaR at Dec. 31, 2025, associated with these transactions was $9 million (2024 – $13 million).

For the market risk related to long-term power sale and long-term wind energy sales contracts, refer to the Level III measurements table and the related unobservable inputs and sensitivities in Note 14(B)(II).

iii. Commodity Price Risk Management – Hedges

At Dec. 31, 2025, the Company had no outstanding commodity derivative instruments designated as hedging instruments, as the long-term power sale contract for Centralia reached its maturity.

iv. Commodity Price Risk Management – Non-Hedges

The Company's outstanding commodity derivative instruments not designated as hedging instruments are as follows:

As at Dec. 31	2025		2024	
Type (thousands)	Notional amount sold	Notional amount purchased	Notional amount sold	Notional amount purchased
Electricity (MWh)	**46,274**	**4,244**	47,593	8,416
Natural gas (GJ)	**13,374**	**66,414**	2,122	79,194
Transmission (MWh)	**—**	**377**	—	292
Emissions (MWh)	**95**	**55**	167	370
Emissions (tonnes)	**3,150**	**650**	1,850	150
Coal (tonnes)	**—**	**—**	—	1,728

b. Interest Rate Risk Management

Changes in interest rates can impact the Company's borrowing costs and cost of capital. Changes in the cost of capital could affect the feasibility of new growth initiatives. Interest rate risk also arises as the fair value of future cash flows from a financial instrument fluctuates due to changes in market interest rates.

The Company's syndicated credit facility, Heartland term facility and the Poplar Creek non-recourse bond are subject to floating interest rates, which represent 10 per cent of the Company's total long-term debt as at Dec. 31, 2025 (2024 – 23 per cent). Interest rate risk is managed with the use of derivatives.

As at Dec. 31, 2025, 86 per cent of the $201 million outstanding under the Heartland term facility was hedged at an average rate of 4.4 per cent.

c. Currency Rate Risk

The Company has exposure to various currencies, such as the U.S. dollar and the Australian dollar, as a result of investments and operations in foreign jurisdictions, the net earnings from those operations and the acquisition of equipment and services from foreign suppliers.

The Company may enter into the following hedging strategies to mitigate currency rate risk, including:

- Foreign exchange forward contracts to mitigate adverse changes in foreign exchange rates on project-related expenditures and distributions received in foreign currencies;
- Foreign exchange forward contracts and cross-currency swaps to manage foreign exchange exposure on foreign-denominated debt not designated as a net investment hedge; and
- Designating foreign currency debt as a hedge of the net investment in foreign operations to mitigate the risk due to fluctuating exchange rates related to certain foreign subsidiaries.

The Company's target is to hedge a minimum of 60 per cent of our forecasted foreign operating cash flows over a four-year period. The U.S. exposure is managed with a combination of interest expense on our U.S.-dollar-denominated debt and forward foreign exchange contracts and the Australian exposure is managed with a combination of interest expense on Australian-dollar-denominated debt and forward foreign exchange contracts.

i. Net Investment Hedges

When designating foreign currency debt as a hedge of the Company's net investment in foreign subsidiaries, the Company has determined that the hedge is effective if the foreign currency of the net investment is the same as the currency of the hedge and therefore an economic relationship is present.

The Company's hedges of its net investment in foreign operations were comprised of U.S. dollar denominated long-term debt with a face value of US$300 million (2024 – US$300 million).

The Company also uses foreign currency contracts to manage its expected foreign operating cash flows and foreign exchange forward contracts to manage foreign exchange exposure on foreign-denominated debt not designated as a net investment hedge. Hedge accounting is not applied to these foreign currency contracts.

ii. Non-Hedges

As at Dec. 31	2025				2024			
	Notional amount sold	Notional amount purchased	Fair value (liability) asset	Maturity	Notional amount sold	Notional amount purchased	Fair value (liability) asset	Maturity
Foreign exchange forward contracts – foreign-denominated receipts/expenditures								
	AUD12	**CAD7**	**(2)**	**2026-2029**	AUD14	CAD10	(1)	2025-2028
	USD277	**CAD377**	**—**	**2026-2029**	USD419	CAD585	(13)	2025-2028
	USD99	**AUD152**	**4**	**2026**	USD101	AUD153	(9)	2025
Foreign exchange forward contracts – foreign-denominated debt								
	CAD195	**USD140**	**(4)**	**2026**	CAD192	USD140	8	2025

iii. Impacts of Currency Rate Risk

The possible effect on net earnings and OCI, due to changes in foreign exchange rates associated with financial instruments denominated in currencies other than the Company's functional currency, is outlined below. The sensitivity analysis has been prepared using management's assessment that an average three cents (2024 – three cents) increase or decrease in these currencies relative to the Canadian dollar is a reasonable potential change over the next quarter.

Year ended Dec. 31	2025		2024	
Currency	Net earnings decrease(1)	OCI gain(1)(2)	Net earnings decrease(1)	OCI gain(1)(2)
USD	**(14)**	**—**	(17)	—
AUD	**(3)**	**—**	(3)	—
Total	**(17)**	**—**	(20)	—

(1) These calculations assume an increase in the value of these currencies relative to the Canadian dollar. A decrease would have the opposite effect.

(2) The foreign exchange impact related to financial instruments designated as hedging instruments in net investment hedges has been excluded.

II. Credit Risk

Credit risk is the risk that customers or counterparties will cause a financial loss for the Company by failing to discharge their obligations and the risk to the Company associated with changes in creditworthiness of entities with which commercial exposures exist. The Company actively manages its exposure to credit risk by assessing the ability of counterparties to fulfil their obligations under the related contracts before entering into such contracts. The Company makes detailed assessments of the credit quality of all counterparties and, where appropriate, obtains corporate guarantees, cash collateral, third-party credit insurance and/or letters of credit to support the ultimate collection of these receivables. For commodity trading and origination, the Company sets strict credit limits for each counterparty and monitors exposures on a daily basis. TransAlta uses standard agreements that allow for the netting of exposures and often include margining provisions. If credit limits are exceeded, TransAlta will request collateral from the counterparty or halt trading activities with the counterparty.

The Company uses external credit ratings, as well as internal ratings in circumstances where external ratings are not available, to establish credit limits for customers and counterparties.

The following table outlines the Company's maximum exposure to credit risk without taking into account collateral held, including the distribution of credit ratings, as at Dec. 31, 2025:

	Investment grade (per cent)	Non-investment grade (per cent)	Total (per cent)	Total amount
Trade and other receivables(1)	84	16	100	**699**
Long-term finance lease receivable	100	—	100	**277**
Risk management assets(1)	53	47	100	**194**
Long-term financial assets(2)	—	100	100	**140**
Loans receivable(3)	—	100	100	**31**
Total				**1,341**

(1) Letters of credit and cash and cash equivalents are the primary types of collateral held as security related to these amounts.

(2) Included within long-term financial assets with counterparties that have no external credit rating. Refer to Note 14 for further details.

(3) Includes $31 million loans receivable included within other assets with counterparties that have no external credit rating.

An impairment analysis is performed at each reporting date using a provision matrix to measure expected credit losses. The provision rates are based on segment historical rates of default of trade receivables and they incorporate forward-looking credit ratings and forecasted default rates. In addition to calculating expected credit losses, TransAlta monitors key forward-looking information to determine if historical bad debt percentages, forward-looking S&P credit ratings and forecasted default rates continue to be representative of future expected credit losses. The calculation reflects the probability-weighted outcome, the time value of money and reasonable and supportable information that is available at the reporting date about past events, current conditions and forecasts of future economic conditions.

TransAlta evaluates the concentration of risk with respect to trade receivables as low, as its customers are located in several jurisdictions and industries. The Company did not have material expected credit losses as at Dec. 31, 2025.

The Company's maximum exposure to credit risk at Dec. 31, 2025, without taking into account collateral held or right of set-off, is represented by the current carrying amounts of receivables and risk management assets as per the Consolidated Statements of Financial Position. Letters of credit and cash are the primary types of collateral held as security related to these amounts. The maximum credit exposure to any one customer for commodity trading operations and hedging, including the fair value of open trading, net of any collateral held, at Dec. 31, 2025, was $51 million (Dec. 31, 2024 – $77 million).

III. Liquidity Risk

Liquidity risk relates to the Company's ability to access capital to be used for capital projects, debt refinancing, proprietary trading activities, commodity hedging and general corporate purposes. As at Dec. 31, 2025, TransAlta maintains an investment grade rating from one credit rating agency and one notch below investment grade ratings from two credit rating agencies. Between 2026 and 2028, the Company has $664 million of scheduled non-recourse debt and tax equity principal payments.

Collateral is posted based on negotiated terms with counterparties, which can include the Company's senior unsecured credit rating as determined by certain major credit rating agencies. Some of the Company's derivative instruments contain financial assurance provisions that require collateral to be posted only if a material adverse credit-related event occurs.

TransAlta manages liquidity risk by monitoring liquidity on trading positions; preparing and revising longer-term financing plans to reflect changes in business plans and the market availability of capital; reporting liquidity risk exposure for proprietary trading activities on a regular basis to the Risk Management Committee, senior management and the Audit, Finance and Risk Committee (on behalf of the Board); and maintaining sufficient undrawn committed credit lines to support potential liquidity requirements. The Company does not use derivatives to manage liquidity risk.

A maturity analysis of the Company's financial liabilities is as follows:

	2026	2027	2028	2029	2030	2031 and thereafter	Total
Accounts payable, accrued liabilities and other current liabilities	613	—	—	—	—	—	613
Long-term debt[1]							
Credit facilities[1]	—	—	—	98	—	—	98
Debentures	—	—	—	110	141	450	701
Senior notes	—	—	—	—	—	959	959
Non-recourse – Hydro	—	—	—	—	—	39	39
Non-recourse – Wind & Solar	67	70	74	43	45	202	501
Non-recourse and Recourse – Gas	61	65	66	74	95	549	910
Non-recourse Heartland term facility	24	176	—	—	—	—	200
Tax equity financing	18	20	23	18	—	—	79
Exchangeable securities[2]	—	—	—	—	—	750	750
Commodity risk management (assets) liabilities[3]	(4)	16	23	28	26	401	490
Other risk management (assets) liabilities	(2)	1	1	—	—	(9)	(9)
Lease liabilities	5	5	5	5	5	121	146
Interest on long-term debt and lease liabilities[4]	179	184	167	156	138	705	1,529
Interest on exchangeable securities[2][4]	53	53	53	52	53	457	721
Dividends payable	52	—	—	—	—	—	52
Total	**1,066**	**590**	**412**	**584**	**503**	**4,624**	**7,779**

(1) Excludes impact of hedge accounting and derivatives.

(2) The exchangeable debentures are due May 1, 2039 and the exchangeable preferred shares are perpetual. However, a cash payment could occur after Dec. 31, 2028, at the Company's option, if the exchangeable securities are not exchanged by Brookfield Renewable Partners or its affiliates (collectively Brookfield). At Brookfield's option, the exchangeable securities are currently exchangeable into an equity ownership interest in TransAlta's Alberta Hydro Assets after Dec. 31, 2024. (Note 26).

(3) Negative amount represents a receivable position or cash inflow.

(4) Not recognized as a financial liability on the Consolidated Statements of Financial Position and excludes the impact of interest rate swaps.

IV. Equity Price Risk

Total Return Swaps

The Company has certain compensation, deferred and restricted share unit programs, the values of which depend on the common share price of the Company. The Company has fixed a portion of the settlement cost of these programs by entering into a total return swap for which hedge accounting has not been applied. The total return swap is cash settled every quarter based upon the difference between the fixed price and the market price of the Company's common shares at the end of each quarter.

D. Effects of Hedge Accounting on Financial Position and Performance

I. Effect of Hedges

The impact of the hedging instruments on the statement of financial position is as follows:

As at Dec. 31, 2025	Notional amount	Carrying amount	Line item in the statement of financial position	Change in fair value used for measuring ineffectiveness
Commodity price risk				
Cash flow hedges				
Physical power sales[(1)]	**—**	**—**	**Risk management liabilities**	**(2)**
Foreign currency risk				
Net investment hedges				
Foreign-denominated debt	**USD300**	**CAD411**	**Credit facilities, long-term debt and lease liabilities**	**—**

(1) In thousands of MWh.

As at Dec. 31, 2024	Notional amount	Carrying amount	Line item in the statement of financial position	Change in fair value used for measuring ineffectiveness
Commodity price risk				
Cash flow hedges				
Physical power sales[(1)]	2,628	45	Risk management assets	114
Foreign currency risk				
Net investment hedges				
Foreign-denominated debt	USD300	CAD431	Credit facilities, long-term debt and lease liabilities	—

(1) In thousands of MWh.

The impact of the hedged items on the statement of financial position is as follows:

	2025		2024	
As at Dec. 31	Change in fair value used for measuring	Cash flow hedge reserve[(1)]	Change in fair value used for measuring	Cash flow hedge reserve[(1)]
Commodity price and interest rate risk				
Cash flow hedges[(2)]	**(2)**	**(4)**	114	65
	Change in fair value used for measuring	Foreign currency translation	Change in fair value used for measuring	Foreign currency translation reserve[(1)]
Foreign currency risk				
Net investment hedges				
Net investment in foreign subsidiaries	**—**	**(35)**	—	(34)

(1) Included in AOCI, net of tax.

(2) During the fourth quarter of 2025, the Company's commodity price hedges for Centralia, including a long-term physical power sale contract, reached its maturity, and hedge accounting was therefore discontinued.

The hedging gain or loss recognized in OCI before tax is equal to the change in fair value used for measuring effectiveness for the net investment hedge. Ineffectiveness of nil in after-tax losses was reclassified from OCI to net earnings during the year ended Dec. 31, 2025. (2024 – after-tax losses reclassified of $4 million)

The impact of designated cash flow hedges on OCI and net earnings is:

Year ended Dec. 31, 2025

	Effective portion			Ineffective portion	
Derivatives in cash flow hedging relationships	**Pre-tax gain recognized in OCI**	**Location of gain reclassified from OCI**	**Pre-tax (gain) loss reclassified from OCI**	**Location of (gain) loss reclassified from OCI**	**Pre-tax (gain) loss recognized in earnings**
Commodity contracts	**(1)**	Revenue	**(43)**	Revenue	—
Forward starting interest rate swaps	**—**	Interest expense	**(39)**	Interest expense	—
OCI impact	**(1)**	**OCI impact**	**(82)**	**Net earnings impact**	—

Over the next 12 months, the Company estimates that no after-tax losses will be reclassified from AOCI to net earnings. These estimates assume constant interest rates and exchange rates over time; however, the actual amounts that will be reclassified may vary based on changes in these factors.

Year ended Dec. 31, 2024

	Effective portion			Ineffective portion	
Derivatives in cash flow hedging relationships	**Pre-tax gain (loss) recognized in OCI**	**Location of (gain) loss reclassified from OCI**	**Pre-tax (gain) loss reclassified from OCI**	**Location of (gain) loss reclassified from OCI**	**Pre-tax (gain) loss recognized in earnings**
Commodity contracts	270	Revenue	(15)	Revenue	—
Forward starting interest rate swaps	—	Interest expense	(8)	Interest expense	—
OCI impact	270	OCI impact	(23)	Net earnings impact	—

II. Effect of Non-Hedges

For the year ended Dec. 31, 2025, the Company recognized a net unrealized loss of $289 million (2024 – loss of $7 million) related to commodity derivatives.

For the year ended Dec. 31, 2025, a loss of $25 million (2024 – loss of $63 million) related to foreign exchange and other derivatives was recognized, which consists of net unrealized losses of $18 million (2024 – loss of $36 million) and net realized losses of $7 million (2024 – loss of $27 million), respectively.

E. Collateral

I. Financial Assets Provided as Collateral

At Dec. 31, 2025, the Company provided $92 million (Dec. 31, 2024 – $124 million) in cash and cash equivalents as collateral to regulated clearing agents as security for commodity trading activities. These funds are held in segregated accounts by the clearing agents. Collateral provided is included within trade and other receivables in the Consolidated Statements of Financial Position. At Dec. 31, 2025, the Company provided $20 million (Dec. 31, 2024 – $21 million) in surety bonds as security for commodity trading activities.

II. Financial Assets Held as Collateral

At Dec. 31, 2025, the Company held $3 million (Dec. 31, 2024 – $9 million) in cash collateral associated with counterparty obligations. Under the terms of the contracts, the Company may be obligated to pay interest on the outstanding balances and to return the principal when the counterparties have met their contractual obligations or when the amount of the obligation declines as a result of changes in market value. Interest payable to the counterparties on the collateral received is calculated in accordance with each contract. Collateral held is related to physical and financial derivative transactions in a net asset position and is included in accounts payable and accrued liabilities in the Consolidated Statements of Financial Position.

III. Contingent Features in Derivative Instruments

Collateral is posted in the normal course of business based on the Company's senior unsecured credit rating as determined by certain major credit rating agencies. Certain of the Company's derivative instruments contain financial assurance provisions that require collateral to be posted only if a material adverse credit-related event occurs.

At Dec. 31, 2025, the Company had posted collateral of $338 million (Dec. 31, 2024 – $424 million) in the form of letters of credit on physical and financial derivative transactions in a net liability position. Certain derivative agreements contain credit-risk-contingent features, which if triggered could result in the Company having to post an additional $92 million (Dec. 31, 2024 – $128 million) of collateral to its counterparties.

16. Inventory

The components of inventory are as follows:

As at Dec. 31	2025	2024
Parts, materials and supplies	**87**	85
Coal	**6**	27
Emission credits	**14**	18
Natural gas	**4**	4
Total	**111**	134

No inventory was pledged as security for liabilities.

As at Dec. 31, 2025, the Company holds 383,192 emission credits in inventory that were purchased externally with a recorded book value of $14 million (Dec. 31, 2024 – 460,585 emission credits with a recorded book value of $18 million). The Company also has 1,860,384 (Dec. 31, 2024 – 2,109,491) of internally generated eligible emission credits from the Company's Wind and Solar and Hydro segments that have no recorded book value.

Emission credits can be sold externally or can be used to offset future emission obligations from our gas facilities located in Alberta, where the compliance price of carbon is expected to increase, resulting in a reduced cash cost for carbon compliance in the year of settlement.

During the year ended Dec. 31, 2025 the Company utilized 1,498,447 emission credits (Dec. 31, 2024 – 978,894 emission credits) with a carrying value of $17 million (Dec. 31, 2024 – $22 million) to settle a portion of the 2024 carbon compliance obligation (Dec. 31, 2024 – 2023 carbon compliance obligation). During the year ended Dec. 31, 2025, $103 million was recognized as a reduction in the Company's carbon compliance costs (Dec. 31, 2024 – $42 million). The compliance price of carbon for the 2024 obligation settled was $80 per tonne rising to $95 per tonne in 2025.

17. Finance Lease Receivables

Amounts receivable under the Company's finance leases relating to the Mount Keith 132kV expansion, Northern Goldfields solar facilities, the Poplar Creek cogeneration facility, the Muskeg River and the Primrose cogeneration plants are as follows:

	2025		2024	
As at Dec. 31	Minimum lease receipts	Present value of minimum lease receipts	Minimum lease receipts	Present value of minimum lease receipts
Within one year	**48**	**47**	48	47
Second to fifth years inclusive	**183**	**156**	185	159
More than five years	**206**	**104**	247	129
	437	**307**	480	335
Less: unearned finance lease income	**131**	**—**	146	—
Add: unguaranteed residual value	**1**	**—**	1	—
Total finance lease receivables	**307**	**307**	335	335

Included in the Consolidated Statements of Financial Position as:		
Current portion of finance lease receivables (Note 13)	**30**	30
Long-term portion of finance lease receivables	**277**	305
Total finance lease receivables	**307**	335

18. Assets and Liabilities Held for Sale

The change in assets held for sale is as follows:

	2025	2024
As at Jan. 1	**80**	—
Additions from acquisition of Heartland related to Required Divestitures (Note 4)	**—**	80
Transfers from property, plant and equipment (Notes 7 and 19)	**30**	—
Derecognition of Required Divestitures (Notes 7)	**(80)**	—
Balance, Dec. 31	**30**	80

The liabilities held for sale as at Dec. 31, 2025 totalling $6 million are related to the Energy Transition equipment. The amount was transferred from the decommissioning and other provisions and was included within accounts payable, accrued liabilities and other current liabilities.

19. Property, Plant and Equipment

A reconciliation of the changes in the carrying amount of PP&E is as follows:

	Assets under construction	Land	Hydro	Wind and Solar	Gas generation	Energy Transition	Capital spares and other[1]	Total
Cost								
As at Dec. 31, 2023	1,234	90	884	3,593	4,423	3,914	306	14,444
Additions[2]	279	—	—	—	10	—	22	311
Acquisitions (Note 4)	11	—	—	—	401	—	—	412
Disposals	—	(2)	—	—	(1)	(3)	—	(6)
Changes to decommissioning and restoration costs (Note 24)	—	—	16	9	13	—	—	38
Retirement of assets	—	—	(10)	(12)	(16)	—	—	(38)
Change in foreign exchange rates	28	2	—	124	—	146	2	302
Transfer to intangible assets (Note 21)	—	—	—	—	(163)	—	—	(163)
Transfers of assets[3]	(1,432)	—	43	1,205	163	14	7	—
Transfers to finance lease receivable (Note 17)	—	—	—	—	(48)	—	—	(48)
As at Dec. 31, 2024	120	90	933	4,919	4,782	4,071	337	15,252
Additions	**243**	**—**	**—**	**2**	**—**	**—**	**4**	**249**
Disposals	**—**	**(2)**	**—**	**—**	**—**	**(2)**	**—**	**(4)**
Impairment reversals (charges) (Note 7)	**31**	**—**	**—**	**(17)**	**—**	**—**	**—**	**14**
Changes to decommissioning and restoration costs (Note 24)	**—**	**—**	**—**	**19**	**16**	**1**	**—**	**36**
Retirement of assets	**—**	**—**	**(8)**	**(10)**	**(15)**	**(8)**	**—**	**(41)**
Change in foreign exchange rates	**2**	**(1)**	**—**	**(93)**	**13**	**(86)**	**—**	**(165)**
Transfers of assets[3]	**(214)**	**17**	**66**	**30**	**106**	**—**	**(5)**	**—**
Transfers to assets held for sale (Note 18)	**(30)**	**—**	**—**	**—**	**—**	**—**	**—**	**(30)**
As at Dec. 31, 2025	**152**	**104**	**991**	**4,850**	**4,902**	**3,976**	**336**	**15,311**
Accumulated depreciation								
As at Dec. 31, 2023	—	—	499	1,337	3,049	3,743	102	8,730
Depreciation	—	—	37	170	221	62	28	518
Retirement of assets	—	—	(9)	(9)	(15)	—	—	(33)
Disposals	—	—	—	—	—	(2)	—	(2)
Change in foreign exchange rates	—	—	—	23	1	138	—	162
Transfers to intangible assets (Note 21)	—	—	—	—	(143)	—	—	(143)
As at Dec. 31, 2024	—	—	527	1,521	3,113	3,941	130	9,232
Depreciation	**—**	**—**	**35**	**180**	**269**	**45**	**18**	**547**
Retirement of assets	**—**	**—**	**(7)**	**(7)**	**(14)**	**(8)**	**—**	**(36)**
Disposals	**—**	**—**	**—**	**—**	**—**	**(3)**	**—**	**(3)**
Change in foreign exchange rates	**—**	**—**	**—**	**(12)**	**2**	**(84)**	**—**	**(94)**
As at Dec. 31, 2025	**—**	**—**	**555**	**1,682**	**3,370**	**3,891**	**148**	**9,646**
Carrying amount								
As at Dec. 31, 2024	120	90	406	3,398	1,669	130	207	6,020
As at Dec. 31, 2025	**152**	**104**	**436**	**3,168**	**1,532**	**85**	**188**	**5,665**

(1) Includes major spare parts and standby equipment available, but not in service.

(2) In 2024, the Company capitalized $16 million of interest to PP&E at a weighted average rate of 6.52 per cent.

(3) Includes transfers of assets upon commissioning to assets in service and other movements.

Mothballing of Sheerness Unit 1 and Sundance Unit 6

On Dec. 18, 2025, the Company provided notice to the Alberta Electric System Operator that Sheerness Unit 1 will be temporarily mothballed effective April 1, 2026, for a period of up to two years.

On April 1, 2025, the Company mothballed the Sundance Unit 6 facility for a period of up to two years depending on market conditions.

The Company maintains the flexibility to return the mothballed units to service when market fundamentals improve or opportunities to contract are secured.

Assets under Construction

During the year ended Dec. 31, 2024, the Company achieved commercial operations at the White Rock and Horizon Hill wind facilities. Costs were transferred from assets under construction to the Wind and Solar segment.

20. Right-of-Use Assets

The Company leases various properties and types of equipment. Lease contracts are typically made for fixed periods. Leases are negotiated on an individual basis and contain a wide range of terms and conditions.

The lease agreements do not impose covenants, but leased assets may not be used as security for borrowing purposes.

A reconciliation of the changes in the carrying amount of the right-of-use assets is as follows:

	Land	Buildings	Vehicles	Equipment	Total
As at Dec. 31, 2023	97	12	3	5	117
Additions[1]	1	3	1	—	5
Depreciation	(5)	(1)	(1)	(1)	(8)
Change in foreign exchange rates	6	—	—	—	6
As at Dec. 31, 2024	99	14	3	4	120
Additions	**—**	**—**	**1**	**—**	**1**
Depreciation	**(5)**	**(2)**	**(1)**	**(1)**	**(9)**
Change in foreign exchange rates	**(1)**	**—**	**—**	**—**	**(1)**
As at Dec. 31, 2025	**93**	**12**	**3**	**3**	**111**

(1) Additions to buildings include right-of-use assets of $1 million acquired from Heartland.

For the year ended Dec. 31, 2025, TransAlta paid $14 million (2024 – $16 million) related to recognized lease liabilities, consisting of $4 million (2024 – $6 million) of principal repayments and $10 million (2024 – $10 million) of interest expense.

Some of the Company's land leases that met the definition of a lease were not recognized as they require variable payments based on production or revenue.

Additionally, certain land leases require payments to be made on the basis of the greater of the minimum fixed payments and variable payments based on production or revenue. For these leases, lease liabilities have been recognized on the basis of the minimum fixed payments. For the year ended Dec. 31, 2025, the Company expensed $8 million (2024 – $9 million) in variable land lease payments for these leases.

21. Intangible Assets

A reconciliation of the changes in the carrying amount of intangible assets is as follows:

	Power sale and other contracts	Software and other	Intangibles under development	Coal rights	Total
Cost					
As at Dec. 31, 2023	270	446	27	132	875
Additions	—	—	10	—	10
Acquisitions (Note 4)	57	—	—	—	57
Change in foreign exchange rates	5	7	1	—	13
Transfers	20	35	(33)	—	22
As at Dec. 31, 2024	352	488	5	132	977
Additions	**—**	**—**	**11**	**—**	**11**
Acquisitions[(1)]	**—**	**—**	**12**	**—**	**12**
Retirement of assets	**—**	**(110)**	**—**	**—**	**(110)**
Asset impairment charges	**(2)**	**(1)**	**—**	**—**	**(3)**
Change in foreign exchange rates	**(4)**	**(5)**	**—**	**—**	**(9)**
Transfers	**—**	**6**	**(6)**	—	**—**
As at Dec. 31, 2025	**346**	**378**	**22**	**132**	**878**
Accumulated amortization					
As at Dec. 31, 2023	174	346	—	132	652
Amortization	19	19	—	—	38
Change in foreign exchange rates	4	3	—	—	7
Transfers	—	(1)	—	—	(1)
As at Dec. 31, 2024	197	367	—	132	696
Amortization	**28**	**23**	**—**	**—**	**51**
Retirement of assets	**—**	**(110)**	**—**	**—**	**(110)**
Change in foreign exchange rates	**(1)**	**(1)**	**—**	**—**	**(2)**
As at Dec. 31, 2025	**224**	**279**	**—**	**132**	**635**
Carrying amount					
As at Dec. 31, 2024	155	121	5	—	281
As at Dec. 31, 2025	**122**	**99**	**22**	**—**	**243**

(1) Relates to the acquisition of the remaining 40 per cent interest in Tent Mountain, which was previously accounted for using the equity method. Refer to Note 9 for further details.

22. Goodwill

Goodwill acquired through business combinations has been allocated to groups of CGUs that are expected to benefit from the synergies of the acquisitions. Goodwill by segments is as follows:

As at Dec. 31	2025	2024
Hydro	**258**	258
Wind and Solar	**177**	178
Gas (Note 4)	**51**	51
Energy Marketing	**30**	30
Total goodwill	**516**	517

For the purposes of the 2025 goodwill impairment review, the Company determined the recoverable amounts of the Hydro, Wind and Solar, Gas and Energy Marketing segments (2024 goodwill impairment review - Wind and Solar segment) by calculating the fair value less costs of disposal using discounted cash flow projections. The recoverable amounts are based on the Company's long-range forecasts for the periods extending to the last planned asset retirement in 2072. The resulting fair value measurements are categorized within Level III of the fair value hierarchy. No impairment of goodwill arose for any segment in 2025 and 2024.

In 2024, the Company relied on the recoverable amounts determined in 2022 for the Hydro and Energy Marketing segments in performing the 2024 goodwill impairment review.

The significant assumptions impacting the determination of the 2025 fair value for the Hydro, Wind and Solar, Gas and Energy Marketing segments, with a high degree of subjectivity, are the following:

- Forecasts of sales prices for each facility are determined by taking into consideration contract prices for facilities subject to short- or long-term contracts, forward price curves for merchant plants and regional supply-demand balances. Where forward price curves are not available for the duration of the facility's useful life, prices are determined by extrapolation techniques using historical industry and Company-specific data.
- Merchant electricity prices used in the Hydro, Wind and Solar, Gas and Energy Marketing segment models ranged between \$24 per MWh and \$339 per MWh during the forecast period (2024 — merchant electricity prices used in the Wind and Solar segment models ranged between \$40 per MWh and \$225 per MWh).
- Discount rates used for the Hydro, Wind and Solar, Gas and Energy Marketing segments ranged from 5.7 to 7.6 per cent (2024 — discount rates used for the for the Wind and Solar segment ranged from 6.4 to 7.3 per cent). A 0.5 per cent increase in the discount rate would not impact the results of the impairments tests performed.
- The White Rock and the Horizon Hill wind facilities are subject to location-specific price basis, sourced from third-party analysis. This analysis is based on models of the transmission system, including assumptions around potential system upgrades as well as forecasted generation and load in the area.

23. Other Assets

The components of other assets are as follows:

As at Dec. 31	2025	2024
South Hedland prepaid transmission access and distribution costs	**56**	58
TransAlta Energy Transition Bill commitment	**19**	30
Long-term prepaids and other assets	**21**	35
Project development costs	**14**	15
Loans receivable	**31**	25
Transmission infrastructure	**16**	17
Total other assets	**157**	180
Included in the Consolidated Statements of Financial Position as:		
Total current other assets (Note 13)	**1**	1
Total long-term other assets	**156**	179
Total other assets	**157**	180

South Hedland prepaid transmission access and distribution costs are costs that are amortized on a straight-line basis over the South Hedland PPA contract life.

As part of the TransAlta Energy Transition Bill signed into law in the State of Washington, the Company committed to fund US$55 million in total over the remaining life of the Centralia coal plant to support economic and community development, promote energy efficiency and develop energy technologies related to the improvement of the environment.

Long-term prepaids and other assets include contractually required prepayments and deposits.

Project development costs primarily include the pre-construction project costs, which met the criteria for capitalization.

As at Dec. 31, 2025, $31 million of the loans receivable (2024 – $25 million) related to an unsecured loan advanced by the Company's subsidiary, Kent Hills Wind LP, from the net financing proceeds of the Kent Hills Wind Bond, to its 17 per cent partner. The loan bears interest at 4.55 per cent, with interest payable quarterly. No scheduled principal repayments are required until the maturity date of October 2027.

Transmission infrastructure was constructed by the Company and then transferred to a transmission provider upon completion. The balance relates to the Garden Plain and Windrise wind facilities and will be amortized to net earnings over the useful life of the facilities.

24. Decommissioning and Other Provisions

The change in decommissioning and other provision balances is as follows:

	Decommissioning and restoration	Other provisions	Total
Dec. 31, 2023	656	33	689
Liabilities acquired (Note 4)	101	55	156
Liabilities incurred	6	12	18
Liabilities settled	(41)	(4)	(45)
Accretion (Note 10)	50	—	50
Transfer to accounts payable	—	(31)	(31)
Transfer to assets held for sale (Note 18)	(1)	—	(1)
Revisions in estimated cash flows	21	20	41
Revisions in discount rates	35	—	35
Change in foreign exchange rates	21	—	21
Balance, Dec. 31, 2024	848	85	933
Liabilities incurred	**—**	**18**	**18**
Liabilities settled	**(39)**	**(51)**	**(90)**
Accretion (Note 10)	**53**	**4**	**57**
Transfer to assets held for sale (Note 18)	**(6)**	**—**	**(6)**
Revisions in estimated cash flows	**(71)**	**19**	**(52)**
Revisions in discount rates	**63**	**1**	**64**
Reversals	**—**	**(17)**	**(17)**
Change in foreign exchange rates	**(16)**	**—**	**(16)**
Balance, Dec. 31, 2025	**832**	**59**	**891**

Included in the Consolidated Statements of Financial Position as:

As at	Dec. 31, 2025	Dec. 31, 2024
Current portion	**84**	83
Non-current portion	**807**	850
Total decommissioning and other provisions	**891**	933

A. Decommissioning and Restoration

A provision has been recognized for all generating facilities and mines for which TransAlta is legally, or constructively, required to remove at the end of their useful lives and restore the sites to their original condition. TransAlta estimates that the undiscounted amount of cash flow required to settle these obligations is approximately $1.8 billion, which will be incurred between 2026 and 2072. The majority of the costs will be incurred between 2026 and 2050.

During the year ended Dec. 31, 2025, the decommissioning and restoration provision decreased by $71 million primarily due to revisions in estimated cash flows and the timing of cash flows for certain Energy Transition assets, with a corresponding offset recognized in net (loss) earnings.

During the year ended Dec. 31, 2025, the revisions in discount rates increased the decommissioning and restoration provision by $63 million due to lower discount rates, largely driven by decreases in long-term market benchmark rates. On average, discount rates decreased compared to 2024, with rates ranging from 4.5 to 7.3 per cent as at Dec. 31, 2025. This has resulted in a corresponding increase in PP&E of $36 million related to operating assets and the recognition of $27 million of impairment charges in net (loss) earnings related to certain Energy Transition assets.

During the year ended Dec. 31, 2024, the decommissioning and restoration provision increased by $21 million due to revisions in estimated cash flows and the timing of cash flows for certain Gas and Hydro assets. The timing of cash flows was adjusted to optimize and maximize efficiencies by staging required reclamation work. Operating assets included in PP&E increased by $14 million and $7 million was recognized as an impairment charge in net earnings related to retired assets.

During the year ended Dec. 31, 2024, revisions in discount rates increased the decommissioning and restoration provision by $35 million due to a decrease in discount rates, largely driven by decreases in long-term market benchmark rates. On average, discount rates decreased compared to 2023, with rates ranging from 5.3 to 8.4 per cent as at Dec. 31, 2024. This has resulted in a corresponding increase in PP&E of $18 million on operating assets and the recognition of a $17 million impairment charge in net earnings related to retired assets.

At Dec. 31, 2025, the Company has provided a surety bond in the amount of US$147 million (2024 – US$147 million) in support of future decommissioning obligations at the Centralia coal mine. At Dec. 31, 2025, the Company had provided a surety bond and letters of credit in the amount of $193 million (2024 – $194 million) in support of future decommissioning obligations at the Highvale mine.

B. Other Provisions

Other provisions include provisions arising from ongoing business activities, amounts related to commercial disputes between the Company and customers or suppliers and onerous contract provisions.

As part of the acquisition of Heartland, the Company recognized an onerous contract provision of $47 million related to certain natural gas transportation contracts assumed. Payments required under the contracts continue through the first quarter of 2031.

25. Credit Facilities, Long-Term Debt and Lease Liabilities

A. Amounts Outstanding

The amounts outstanding are as follows:

				2025			2024		
As at Dec. 31	Segment	Maturity	Currency	Carrying value	Face value	Interest[1]	Carrying value	Face value	Interest
Credit facilities									
Committed syndicated bank facility[2]	Corporate	2029	CAD	**95**	**98**	**4.2%**	143	145	5.3%
Term facility	Corporate	2025	CAD	**—**	**—**	**—%**	400	400	5.6%
Debentures									
7.3% Medium term notes	Corporate	2029	CAD	**110**	**110**	**7.3%**	110	110	7.3%
6.9% Medium term notes	Corporate	2030	CAD	**141**	**141**	**6.9%**	141	141	6.9%
5.6% Medium term notes	Corporate	2032	CAD	**446**	**450**	**5.6%**	—	—	—%
Senior notes[3]									
5.9% Senior notes	Corporate	2034	USD	**539**	**548**	**5.9%**	—	—	—%
7.8% Senior notes	Corporate	2029	USD	**—**	**—**	**—%**	569	575	7.8%
6.5% Senior notes	Corporate	2040	USD	**403**	**411**	**6.5%**	426	431	6.5%
Non-recourse									
Melancthon Wolfe Wind LP bond	Wind & Solar	2028	CAD	**98**	**98**	**3.8%**	133	134	3.8%
New Richmond Wind LP bond	Wind & Solar	2032	CAD	**83**	**84**	**4.0%**	93	94	4.0%
Kent Hills Wind LP bond	Wind & Solar	2033	CAD	**164**	**166**	**4.5%**	179	182	4.5%
Windrise Wind LP bond	Wind & Solar	2041	CAD	**150**	**152**	**3.4%**	157	160	3.4%
Pingston bond	Hydro	2043	CAD	**39**	**39**	**6.2%**	39	39	6.2%
TAPC Holdings LP bond (Poplar Creek)	Gas	2030	CAD	**65**	**66**	**6.7%**	75	76	8.3%
TEC Hedland PTY Ltd bond[4]	Gas	2042	AUD	**671**	**677**	**4.1%**	675	683	4.1%
Heartland term facility	Corporate	2027	CAD	**201**	**201**	**5.3%**	224	224	6.6%
Recourse									
TransAlta OCP LP bond	Gas	2030	CAD	**166**	**167**	**4.5%**	192	193	4.5%
Tax equity financing									
Big Level & Antrim[5]	Wind & Solar	2029	USD	**70**	**73**	**6.6%**	90	94	6.6%
Lakeswind[6]	Wind & Solar	2030	USD	**4**	**4**	**10.5%**	7	7	10.5%
North Carolina Solar[7]	Wind & Solar	2030	USD	**2**	**2**	**7.3%**	4	4	7.3%
Total long-term debt				**3,447**	**3,487**		3,657	3,692	
Lease liabilities				**146**			151		
Total credit facilities, long-term debt and lease liabilities				**3,593**			3,808		
Less: current portion of long-term debt				**(170)**			(567)		
Less: current portion of lease liabilities				**(5)**			(5)		
Total current credit facilities, long-term debt and lease liabilities				**(175)**			(572)		
Total non-current credit facilities, long-term debt and lease liabilities				**3,418**			3,236		

(1) Interest rate reflects the stipulated rate or the average rate weighted by principal amounts outstanding and is before the effect of hedging.

(2) Composed of swing line loans and other commercial borrowings under long-term committed credit facilities.

(3) US$700 million face value at Dec. 31, 2025 (2024 — US$700 million).

(4) AU$737 million face value at Dec. 31, 2025 (2024 — AU$761 million).

(5) US$54 million face value at Dec. 31, 2025 (2024 — US$65 million).

(6) US$3 million face value at Dec. 31, 2025 (2024 — US$5 million).

(7) US$1 million face value at Dec. 31, 2025 (2024 — US$3 million).

The Company's credit facilities are summarized in the table below:

As at Dec. 31, 2025		Utilized			
Credit facilities	Facility size	Outstanding letters of credit(1)	Cash drawings	Available capacity	Maturity date
Committed					
Syndicated credit facility	1,900	438	98	1,364	Q2 2029
Bilateral credit facilities	240	146	—	94	Q2 2027
Heartland EDC letter of credit facility	30	14	—	16	Q1 2026
Heartland DSR letter of credit facility	27	8	—	19	Q4 2027
Heartland revolving facility	25	—	—	25	Q4 2027
Total committed	**2,222**	**606**	**98**	**1,518**	
Non-committed					
Demand facility	400	223	—	177	N/A
Total Non-committed	**400**	**223**	**—**	**177**	

(1) TransAlta has obligations to issue letters of credit and cash collateral to secure potential liabilities to certain parties, including those related to potential environmental obligations, commodity risk management and hedging activities, pension plan obligations, construction projects and purchase obligations. Letters of credit drawn against the non-committed facilities reduce the available capacity under the committed syndicated credit facilities. At Dec. 31, 2025, TransAlta provided cash collateral of $92 million.

US$400 million Senior Notes Offering and Early Redemption of the 7.8 per cent Senior Notes

On Dec. 22, 2025, the Company issued US$400 million senior notes with a fixed annual coupon rate of 5.9 per cent, maturing on Feb. 1, 2034. The notes are unsecured and rank equally in right of payment with all existing and future senior indebtedness and senior in right of payment to all future subordinated indebtedness. The notes were issued at 99.4 per cent of par, resulting in net proceeds of $541 million (US$393 million) and are callable in three years. Interest payments on the notes are made semi-annually, on Feb. 1 and Aug. 1, with the first payment commencing Aug. 1, 2026.

On Dec. 22, 2025 the Company redeemed all of its outstanding 7.8 per cent US$400 million senior notes in advance of the scheduled maturity date of Nov. 15, 2029. The redemption price was $573 million (US$416 million) in aggregate, including a $21 million prepayment premium recognized in interest expense. The Company also recognized $5 million accelerated amortization of deferred financing costs in interest expense and an offsetting gain of $31 million on interest rate derivatives designated as cash flow hedges, which were reclassified from other comprehensive income to interest expense upon redemption of the notes. Realized foreign exchange loss on redemption totalled $19 million and was included under the foreign exchange (loss) gain in the statement of (loss) earnings for the period.

$450 million Senior Notes Offering

On March 24, 2025, the Company issued $450 million of senior notes with a fixed annual coupon of 5.6 per cent, maturing on March 24, 2032. The notes are unsecured and rank equally in right of payment with all existing and future senior indebtedness and senior in right of payment to all future subordinated indebtedness. Interest payments on the notes are made semi-annually, on March 24 and Sept. 24.

Term Loan Facility Early Repayment

On March 25, 2025, the Company repaid its $400 million variable rate term loan facility in advance of the scheduled maturity date of Sept. 7, 2025, with the proceeds received from the $450 million senior notes offering.

Syndicated and Bilateral Credit Facilities

During the year ended Dec. 31, 2025 the Syndicated credit facility was reduced from $1.95 billion to $1.9 billion and the maturity was extended by one year to June 30, 2029.

During the year ended Dec. 31, 2025 the maturity of the Bilateral credit facilities in the aggregate amount of $240 million was extended by one year to June 30, 2027.

The credit facilities are the primary source of short-term liquidity after the cash flow generated from the Company's business.

Senior Notes

As at Dec. 31, 2025 a total of US$300 million (2024 – US$300 million) of the senior notes has been designated as a hedge of the Company's net investment in U.S. operations.

Tax Equity

Tax equity financings are typically represented by the initial equity investments made by the project investors at each project (net of financing costs incurred), except for the Lakeswind and North Carolina Solar acquired tax equity financings, which were initially recognized at their fair values. Tax equity financing balances are reduced by the value of tax benefits (production tax credits, tax depreciation and investment tax credits) allocated to the investor and by cash distributions paid to the investor for their share of net earnings and cash flow generated at each project. Tax equity financing balances are increased by interest recognized at the implicit interest rate. The maturity dates of each financing are subject to change and are primarily dependent upon when the project investor achieves the agreed upon targeted return. The Company anticipates the maturity dates of the tax equity financings will be: Lakeswind in March 2030; North Carolina Solar in December 2030; and Big Level and Antrim in December 2029.

Other

TransAlta's short- and long-term debt has terms and conditions, including financial covenants, that are considered normal and customary. As at Dec. 31, 2025, the Company was in compliance with all debt covenants.

The Heartland credit facilities are not subject to any maintenance or financial covenants but do contain certain covenants that limit Heartland's ability to, among other things, incur additional indebtedness, create or permit liens to exist, make certain acquisitions or dispositions, make distributions and enter into certain hedging agreements.

The Company is in compliance with its terms of the credit facilities and all undrawn amounts are fully available. Letters of credit in the amount of $223 million were issued from non-committed demand facilities as at Dec. 31, 2025. In addition to the net $1.5 billion of committed capacity available under the credit facilities, the Company had $205 million of available cash and cash equivalents as at Dec. 31, 2025.

B. Restrictions Related to Non-Recourse Debt and Other Debt

All non-recourse debt, the TransAlta OCP LP bond, and the Heartland credit facilities, with a total carrying value of $1.6 billion as at Dec. 31, 2025 (2024 – $1.8 billion), are subject to customary financing conditions and covenants that may restrict the Company's ability to access funds generated by the facilities' operations.

Upon meeting certain distribution tests, typically performed once per quarter, the funds can be distributed by the subsidiary entities to their respective parent entity. These conditions include meeting a debt service coverage ratio prior to distribution, which was met by these entities in the fourth quarter of 2025 with the exception of Windrise Wind LP. The funds in Windrise will remain there until the next debt service coverage ratio can be performed in the first quarter of 2026. At Dec. 31, 2025, $101 million (2024 – $117 million) of cash was subject to these financial restrictions.

At Dec. 31, 2025, $8 million (AU$9 million) of funds held by TEC Hedland Pty Ltd. cannot be accessed by other corporate entities as the funds must be solely used by the project entities, to pay major maintenance costs. Additionally, certain non-recourse bonds require that certain reserve accounts be established and funded through cash held on deposit and/or by providing letters of credit.

C. Security

Non-recourse debt totalling $1.4 billion as at Dec. 31, 2025 (2024 – $1.5 billion) is secured by a first ranking charge over all of the respective assets of the Company's subsidiaries that issued the debt, which include PP&E with total carrying amounts of $1.57 billion at Dec. 31, 2025 (2024 – $1.75 billion) and intangible assets with total carrying amounts of $55 million (2024 – $84 million). At Dec. 31, 2025, non-recourse debt of approximately $65 million (2024 – $75 million) was secured by a first ranking charge over the equity interests of the issuer that issued the non-recourse debt.

The TransAlta OCP bonds have a carrying value of $166 million (2024 – $192 million) and are secured by the assets of TransAlta OCP, including the right to annual capital contributions and OCA payments from the Government of Alberta related to TransAlta's legacy coal facilities (the TransAlta OCA). Under the TransAlta OCA, the Company receives annual cash payments on or before July 31 of approximately $40 million (approximately $37 million, net to the Company), commencing on Jan. 1, 2017, and terminating at the end of 2030.

D. Principal Repayments

	2026	2027	2028	2029	2030	2031 and thereafter	Total
Principal repayments[1]	170	331	163	343	281	2,199	**3,487**
Lease liabilities	5	5	5	5	5	121	**146**

(1) Excludes impact of hedge accounting and derivatives.

E. Restricted Cash

As at Dec. 31, 2025, the Company had $17 million (2024 – $17 million) of restricted cash related to the TransAlta OCP bonds, which is required to be held in a debt service reserve account to fund scheduled future debt repayments. The Company also had $4 million of restricted cash related to holdbacks associated with the Required Divestitures and $57 million (2024 – $52 million) of restricted cash related to the TEC Hedland Pty Ltd. bond. These cash reserves are required to be held under commercial arrangements and for debt service, which may be replaced by letters of credit in the future.

F. Letters of Credit

Letters of credit are issued to counterparties as required by various contractual arrangements with the Company and certain subsidiaries of the Company. If the Company or its subsidiary does not perform under such contracts, the counterparty may present its claim for payment to the financial institution through which the letter of credit was issued. All letters of credit expire within one year and are expected to be renewed, as needed, in the normal course of business. The total outstanding letters of credit as at Dec. 31, 2025, was $829 million (2024 – $865 million) with nil (2024 – nil) amounts exercised by third parties under these arrangements.

G. Currency Impacts

The weakening of the U.S. dollar has decreased the U.S. dollar-denominated long-term debt balances, mainly the senior notes and tax equity financings, by $28 million as at Dec. 31, 2025 (2024 – increased $90 million due to the strengthening of the U.S. dollar). Almost all of the U.S.-dollar-denominated debt is hedged either through financial contracts or a hedge of net investments in U.S. operations.

Additionally, the strengthening of the Australian dollar has increased the Australian-dollar-denominated non-recourse senior secured notes balance by approximately $16 million as at Dec. 31, 2025 (2024 – $5 million). As this debt is issued by an Australian subsidiary, the foreign currency translation impacts are recognized within other comprehensive income (loss).

26. Exchangeable Securities

On March 22, 2019, the Company entered into an Investment Agreement whereby Brookfield Renewable Partners or its affiliates (collectively Brookfield) agreed to invest $750 million in TransAlta through the purchase of exchangeable securities, which are exchangeable into an equity ownership interest in TransAlta's Alberta Hydro Assets after Dec. 31, 2024 at a value based on a multiple of the Alberta Hydro Assets' future-adjusted EBITDA (Option to Exchange).

The Company classified the Exchangeable Securities as current liabilities, as the conversion option has been exercisable at any time after Dec. 31, 2024, although there is no obligation to deliver cash equivalent resources and the holder cannot call for repayment.

A. $750 Million Exchangeable Securities

	Dec. 31, 2025			Dec. 31, 2024		
As at	Carrying value	Face value	Interest	Carrying value	Face value	Interest
Exchangeable debentures – due May 1, 2039[1]	350	350	7%	350	350	7%
Exchangeable preferred shares[2]	400	400	7%	400	400	7%
Total exchangeable securities	750	750		750	750	

(1) Seven per cent unsecured subordinated debentures due May 1, 2039.

(2) Redeemable, retractable first preferred shares (Series I). Exchangeable preferred share dividends are reported as interest expense.

On Dec. 12, 2025, the Company declared a dividend of $7 million, in aggregate, for the Exchangeable Preferred Shares at the fixed rate of 1.764 per cent, per share, payable on March 2, 2026. The Exchangeable Preferred Shares are considered debt for accounting purposes and, as such, dividends are reported as interest expense (Note 10).

B. Option to Exchange

As at	Dec. 31, 2025		Dec. 31, 2024	
Description	Base fair value	Sensitivity	Base fair value	Sensitivity
Option to exchange – embedded derivative	—	+nil -41	—	+nil -30

The Investment Agreement allows Brookfield the option to exchange all of the outstanding exchangeable securities after Dec. 31, 2024, into an equity ownership interest of up to a maximum 49 per cent in an entity that has been formed to hold the Alberta Hydro Assets. The fair value of the option to exchange is considered a Level III fair value measurement as there is no available market-observable data. It is therefore valued using a mark-to-forecast model with inputs that are based on historical data and changes in underlying discount rates only when it represents a long-term change in the value of the option to exchange.

Sensitivity ranges for the base fair value are determined using reasonably possible alternative assumptions for key unobservable inputs, which is mainly the change in the implied discount rate of future cash flows. The sensitivity analysis has been prepared using the Company's assessment that a change in the implied discount rate of 7.9 per cent (2024 – 10.5 per cent) of future cash flows of one per cent is a reasonably possible change.

The maximum equity interest Brookfield can own with respect to the Alberta Hydro Assets is 49 per cent. If Brookfield's ownership interest is less than 49 per cent at conversion, Brookfield has a one-time option payable in cash to increase its ownership to up to 49 per cent, exercisable up until Dec. 31, 2028, provided Brookfield holds at least 8.5 per cent of TransAlta's common shares. Under this top-up option, Brookfield will be able to acquire an additional 10 per cent interest in the entity holding the Alberta Hydro Assets, provided the 20-day volume-weighted average price (VWAP) of TransAlta's common shares is not less than $14 per share prior to the exercise of the option, and up to the full 49 per cent if the 20-day VWAP of TransAlta's common shares at that time is not less than $17 per share. To the extent the value of the investment would exceed a 49 per cent equity interest, Brookfield will be entitled to receive the balance of the redemption price in cash.

In connection with the Investment Agreement, Brookfield is entitled to nominate two directors for election to the Board.

27. Defined Benefit Obligation and Other Long-Term Liabilities

The components of defined benefit obligation and other long-term liabilities are as follows:

As at Dec. 31	2025	2024
Defined benefit obligation (Note 32)	**143**	146
Retail power contract liability	**17**	45
Other	**13**	11
Total	**173**	202

The liability for pension and post-employment benefits and associated costs included in compensation expenses are impacted by estimates related to changes in key actuarial assumptions, including discount rates.

A one per cent increase in discount rates would result in a $31 million decrease in the defined benefit obligation. Refer to Note 32 for additional sensitivities impacting the defined benefit obligation.

The retail power contract liability represents an obligation arising from the purchase and sale agreement for customer retail contracts to deliver power, gas and power and gas financial swaps. The retail power contracts represent certain off-market customer contracts, where the value of the contract is based on the differential between the contractual and market rates on the closing date. The retail contract liability is amortized to depreciation over the remaining term of the contracts based on volumes that will be delivered each month.

28. Common Shares

A. Issued and Outstanding

TransAlta is authorized to issue an unlimited number of voting common shares without nominal or par value.

	2025		2024	
As at Dec. 31	Common shares (millions)	Amount	Common shares (millions)	Amount
Issued and outstanding, beginning of period	**297.5**	**3,179**	306.9	3,285
Reversal of provision for repurchase of common shares under the automatic share purchase plan	**—**	**—**	1.7	19
Purchased and cancelled under the NCIB(1)(2)	**(1.9)**	**(20)**	(13.5)	(146)
Share-based payment plans	**0.8**	**7**	0.8	9
Stock options exercised	**0.3**	**3**	1.6	12
Issued and outstanding, end of year	**296.7**	**3,169**	297.5	3,179

(1) 2025 includes nil of tax on share buybacks (2024 — 2 million) on the fair value of the shares repurchased.

(2) Shares purchased by the Company under the NCIB (as defined below) are recognized as a reduction to share capital equal to the average carrying value of the common shares. Any difference between the aggregate purchase price and the average carrying value of the common shares is recorded in retained earnings (deficit).

B. Normal Course Issuer Bid (NCIB) Program

The effects of the Company's purchase and cancellation of common shares during the period are as follows:

For the year ended Dec. 31	2025	2024
Total shares purchased	**1,932,800**	13,467,400
Average purchase price per share	**12.42**	10.59
Total cost (millions)	**24**	143
Book value of shares cancelled	**20**	146
Amount recorded in deficit	**(4)**	3

On May 27, 2025, the Company announced that it had received approval from the Toronto Stock Exchange to repurchase up to a maximum of 14 million common shares during the 12-month period that commenced May 31, 2025 and terminates on the earlier of May 30, 2026 or such earlier date on which the maximum number of Common Shares are purchased under the NCIB or the NCIB is terminated at the Company's election. Any common shares purchased under the NCIB will be cancelled.

C. Shareholder Rights Plan

The Company initially adopted the Shareholder Rights Plan in 1992, which was amended and restated on April 28, 2022. As required, the Shareholder Rights Plan must be put before the Company's shareholders every three years for approval. It was last approved on April 24, 2025, and will need to be approved at the annual meeting of shareholders in 2028. The primary objective of the Shareholder Rights Plan is to encourage a potential acquirer to meet certain minimum standards designed to promote the fair and equal treatment of all common shareholders. When an acquiring shareholder acquires 20 per cent or more of the Company's common shares, except in limited circumstances including by way of a “permitted bid” or a "competing permitted bid" (as defined in the Shareholder Rights Plan), the rights granted under the Shareholder Rights Plan become exercisable by all shareholders except those held by the acquiring shareholder. Each right will entitle a shareholder, other than the acquiring shareholder, to purchase additional common shares at a significant discount to market, thus exposing the person acquiring 20 per cent or more of the shares to substantial dilution of their holdings.

D. (Loss) Earnings per Share

Year ended Dec. 31	2025	2024
Net (loss) earnings attributable to common shareholders	**(190)**	177
Basic and diluted weighted average number of common shares outstanding (millions)	**297**	302
Net (loss) earnings per share attributable to common shareholders, basic and diluted	**(0.64)**	0.59

E. Dividends

On Dec. 12, 2025, the Company declared a quarterly dividend of $0.065 per common share, payable on April 1, 2026.

On Feb. 25, 2026, the Company declared a quarterly dividend of $0.070 per common share, payable on July 1, 2026.

There have been no transactions involving common shares between the reporting date and the date of completion of these Consolidated Financial Statements.

29. Preferred Shares

A. Issued and Outstanding

All preferred shares issued and outstanding are non-voting cumulative redeemable fixed or floating rate first preferred shares.

As at Dec. 31	2025		2024	
Series[1]	Number of shares (millions)	Amount	Number of shares (millions)	Amount
Series A	**9.6**	**235**	9.6	235
Series B	**2.4**	**58**	2.4	58
Series C	**10.0**	**243**	10.0	243
Series D	**1.0**	**26**	1.0	26
Series E	**9.0**	**219**	9.0	219
Series G	**6.6**	**161**	6.6	161
Issued and outstanding, end of year	**38.6**	**942**	38.6	942

(1) The Series I Preferred Shares are accounted for as debt. Refer to Note 26.

Series G Cumulative Redeemable Rate Reset Preferred Shares

During the third quarter of 2024, after taking into account all election notices received for the conversion of the Cumulative Redeemable Rate Reset Preferred Shares, Series G (Series G shares), 20,607 Series G shares out of 6.6 million outstanding, were tendered for conversion, which is less than the 1 million shares required to give effect to conversion into Series H shares. As a result, none of the Series G Shares were converted into Series H Shares on Sept. 30, 2024 and the next conversion date was reset to Sept. 30, 2029.

Preferred Share Series Information

Holders of preferred shares are entitled to receive cumulative fixed quarterly cash dividends at specified rates, as approved by the Board. After an initial period of approximately five years from issuance and every five years thereafter (Rate Reset Date), the fixed rate for the preferred shares resets to the sum of the five-year Government of Canada bond yield (the fixed rate Benchmark) plus a specified spread. Upon each Rate Reset Date, the shares are also:

- Redeemable at the option of the Company, in whole or in part, for $25.00 per share, plus all declared and unpaid dividends at the time of redemption.
- Convertible at the holder's option into a specified series of non-voting cumulative redeemable floating rate first preferred shares that pay cumulative floating rate quarterly cash dividends, as approved by the Board, based on the sum of the Government of Canada 90-day Treasury Bill rate (the floating rate Benchmark) plus a specified spread. The cumulative floating rate first preferred shares are also redeemable at the option of the Company and convertible back into each original cumulative fixed rate first preferred share series, at each subsequent Rate Reset Date, on the same terms as noted above.

Characteristics specific to each first preferred share series as at Dec. 31, 2025, are as follows:

Series[1]	Rate during term	Annual dividend rate per share ($)[2]	Next conversion date	Rate spread over benchmark (per cent)	Convertible to Series
A	Fixed	0.71924	March 31, 2026	2.03	B
B	Floating	1.15541	March 31, 2026	2.03	A
C	Fixed	1.46352	June 30, 2027	3.10	D
D	Floating	1.42290	June 30, 2027	3.10	C
E	Fixed	1.72352	Sept. 30, 2027	3.65	F
G	Fixed	1.69324	Sept. 30, 2029	3.80	H

(1) The Series I Preferred Shares are accounted for as debt. Refer to Note 26.

(2) The annual dividend rate per share represents dividends declared in 2025.

B. Dividends

The following table summarizes the preferred share dividends declared in 2025 and 2024:

	Total dividends declared	
Series	2025	2024
A	**7**	7
B[1]	**3**	4
C	**15**	15
D[2]	**1**	2
E	**16**	15
G	**10**	9
Total for the year	**52**	52

(1) Series B Preferred Shares pay quarterly dividends at a floating rate based on the 90-day Government of Canada Treasury Bill rate, plus 2.03 per cent.

(2) Series D Preferred Shares pay quarterly dividends at a floating rate based on the 90-day Government of Canada Treasury Bill rate, plus 3.10 per cent.

On Dec. 12, 2025, the Company declared a quarterly dividend of $0.17981 per share on the Series A preferred shares, $0.26186 per share on the Series B preferred shares, $0.36588 per share on the Series C preferred shares, $0.32782 per share on the Series D preferred shares, $0.43088 per share on the Series E preferred shares and $0.42331 per share on the Series G preferred shares, payable on March 31, 2026.

30. Accumulated Other Comprehensive (Loss) Income

The components of and changes in, accumulated other comprehensive (loss) income are as follows:

	2025	2024
Currency translation adjustment		
Opening balance, Jan. 1	**(34)**	(36)
(Losses) gains on translating net assets of foreign operations, net of reclassifications to net earnings	**(12)**	30
Gains (losses) on financial instruments designated as hedges of foreign operations, net of reclassifications to net earnings, net of tax(1)	**11**	(28)
Balance, Dec. 31	**(35)**	(34)
Cash flow hedges		
Opening balance, Jan. 1	**65**	(129)
(Losses) gains on derivatives designated as cash flow hedges, net of reclassifications to net earnings, net of tax(2)	**(69)**	194
Balance, Dec. 31	**(4)**	65
Employee future benefits		
Opening balance, Jan. 1	**12**	3
Net actuarial gains on defined benefit plans, net of tax(3)	**5**	9
Balance, Dec. 31	**17**	12
Other		
Opening balance, Jan. 1	**(2)**	(2)
Balance, Dec. 31	**(2)**	(2)
Accumulated other comprehensive (loss) income	**(24)**	41

(1) Net of income tax expense of $1 million for the year ended Dec. 31, 2025 (Dec. 31, 2024 – $4 million recovery).

(2) Net of income tax recovery of $14 million for the year ended Dec. 31, 2025 (Dec. 31, 2024 – $53 million expense).

(3) Net of income tax expense of $1 million for the year ended Dec. 31, 2025 (Dec. 31, 2024 – $3 million expense).

31. Share-Based Payment Plans

The Company has the following share-based payment plans:

A. Performance Share Unit (PSU) and Restricted Share Unit (RSU) Plan

Under the Share Unit Plan, grants of PSUs and RSUs may be made annually, but are measured and assessed over a three-year performance period. Grants are determined as a percentage of participants' base pay and are converted to PSUs or RSUs on the basis of the Company's common share price at the time of grant. Vesting of PSUs is subject to achieving, over a three-year period, specific performance measures that are established at the time of each grant. RSUs are subject to a three-year cliff-vesting requirement. RSUs and PSUs track the Company's share price over the three-year period and accrue dividends as additional units at the same rate as dividends paid on the Company's common shares.

The pre-tax compensation expense related to PSUs and RSUs in 2025 was $26 million (2024 – $23 million), which is included in OM&A in the consolidated statements of (loss) earnings.

B. Deferred Share Unit (DSU) Plan

Under the Share Unit Plan, members of the Board and executives may, at their option, purchase DSUs using certain components of their fees or pay. A DSU is a notional share that has the same value as one common share of the Company and fluctuates based on the changes in the value of the Company's common shares in the marketplace. DSUs accrue dividends as additional DSUs at the same rate as dividends are paid on the Company's common shares. DSUs are redeemable in cash and may not be redeemed until the termination or retirement of the director or executive from the Company.

The Company accrues a liability and expense for the appreciation in the common share value in excess of the DSU's purchase price and for dividend equivalents earned.

The pre-tax compensation expense related to the DSUs was $2 million in 2025 (2024 – $8 million).

C. Stock Option Plan

In 2025, the Company granted executive officers of the Company a total of 0.3 million stock options with a weighted average exercise price of $20.40 that vest over a three-year period and expire seven years after issuance (2024 – 0.7 million stock options at $10.88). The expense recognized relating to these grants during 2025 was $3 million (2024 – $1 million).

The total options outstanding and exercisable under the Stock Option Plan at Dec. 31, 2025, are outlined below:

	Options outstanding		
Range of exercise prices ($ per share)	Number of options (millions)[(1)]	Weighted average remaining contractual life (years)	Weighted average exercise price ($ per share)
9.28-20.46	**1.6**	**4.3**	**12.91**

(1) Includes 1.2 million options exercisable as at Dec. 31, 2025.

32. Employee Future Benefits

A. Description

The Company sponsors registered pension plans in Canada and the U.S. covering substantially all employees of the Company in both countries and specific named employees working internationally. The Canadian plans have defined benefit and defined contribution options, as well as a non-registered supplemental plan for eligible employees whose annual earnings exceed the Canadian income tax limit. The U.S. plan has a defined contribution option only.

As of June 30, 2025, all Canadian and U.S. defined benefit pension plans were closed to new members, following closure of the Sunhills plan. The U.S. defined benefit pension plan was frozen effective Dec. 31, 2010, resulting in no future benefits being earned. The supplemental pension plan was closed as of Dec. 31, 2015, and a new defined contribution supplemental pension plan commenced for executive members effective Jan. 1, 2016. Executives current as of Dec. 31, 2015, were grandfathered into the old supplemental plan.

The Company's U.S. defined benefit pension plan was terminated effective June 30, 2024 and annuitized in October 2024.

The measurement date used for all plans to determine the fair value of plan assets and the present value of the defined benefit obligation was Dec. 31, 2025.

Funding of the registered pension plans complies with applicable regulations that require actuarial valuations of the pension funds at least once every three years in Canada, or more, depending on funding status. The supplemental pension plan is solely the obligation of the Company. The Company is not obligated to fund the supplemental plan but is obligated to pay benefits under the terms of the plan as they come due. The Company posted a letter of credit in March 2025 in the amount of $92 million, and provided $62 million in surety bonds, to secure the obligations under the supplemental plan and the Canadian defined benefit plan, respectively.

The Company provides other health and dental benefits to certain eligible employees to the age of 65 for both disabled members and retired members through its other post-employment benefits plans. The measurement date used to determine the present value obligation for both plans was Dec. 31, 2025.

The Company provides several defined contribution plans, including the acquired Heartland plan, an Australian superannuation plan and a U.S. 401(k) savings plan, that provide for company contributions from 5.0 to 11.5 per cent, depending on the plan.

Optional employee contributions are allowed for all the defined contribution plans.

The Company's Canadian registered pension Plan was amended effective April 26, 2025 following TransAlta's acquisition of Heartland.

Pursuant to this amendment, certain employees of Heartland, who started their employment with the Company between December 4, 2024 to April 26, 2025 and met eligibility provisions, commenced their participation with the plan.

During the year ended Dec. 31, 2025, the Heartland members' balances in their previous plan were transferred to the Company's plan.

B. Costs Recognized

The costs recognized in net (loss) earnings during the year on the defined benefit, defined contribution and other post-employment benefits plans are as follows:

Year ended Dec. 31, 2025	Registered	Supplemental	Other	Total
Current service cost	**1**	**—**	**—**	**1**
Administration expenses	**1**	**—**	**—**	**1**
Interest cost on defined benefit obligation	**13**	**4**	**—**	**17**
Interest on plan assets	**(11)**	**(1)**	**—**	**(12)**
Defined benefit expense	**4**	**3**	**—**	**7**
Defined contribution expense	**14**	**—**	**—**	**14**
Net expense	**18**	**3**	**—**	**21**

Year ended Dec. 31, 2024	Registered	Supplemental	Other	Total
Current service cost	1	1	1	3
Administration expenses	1	—	—	1
Interest cost on defined benefit obligation	14	4	1	19
Interest on plan assets	(12)	(1)	—	(13)
Defined benefit expense	4	4	2	10
Defined contribution expense	12	—	—	12
Net expense	16	4	2	22

C. Status of Plans

The status of the defined benefit pension and other post-employment benefit plans is as follows:

Year ended Dec. 31, 2025	Registered	Supplemental	Other	Total
Fair value of plan assets	**229**	**16**	**—**	**245**
Present value of defined benefit obligation	**(285)**	**(88)**	**(17)**	**(390)**
Funded status – plan deficit	**(56)**	**(72)**	**(17)**	**(145)**
Amount recognized in the Consolidated Financial Statements:				
Accrued current liabilities	**(1)**	**—**	**(1)**	**(2)**
Other long-term liabilities	**(55)**	**(72)**	**(16)**	**(143)**
Total amount recognized	**(56)**	**(72)**	**(17)**	**(145)**

Year ended Dec. 31, 2024	Registered	Supplemental	Other	Total
Fair value of plan assets	241	16	—	257
Present value of defined benefit obligation	(303)	(90)	(18)	(411)
Funded status – plan deficit	(62)	(74)	(18)	(154)
Amount recognized in the Consolidated Financial Statements:				
Accrued current liabilities	(1)	(6)	(1)	(8)
Other long-term liabilities	(61)	(68)	(17)	(146)
Total amount recognized	(62)	(74)	(18)	(154)

D. Plan Assets

The fair value of the plan assets of the defined benefit pension and other post-employment benefit plans is as follows:

	Registered	Supplemental	Other	Total
As at Dec. 31, 2023	269	15	—	284
Interest on plan assets	12	1	—	13
Net return on plan assets	13	(1)	—	12
Contributions(1)	1	6	1	8
Benefits paid	(31)	(5)	(1)	(37)
Administration expenses	(1)	—	—	(1)
Effect of settlement from annuitization of the U.S. defined benefit plan	(23)	—	—	(23)
Change in foreign exchange rates	1	—	—	1
As at Dec. 31, 2024	241	16	—	257
Interest on plan assets	**11**	**1**	**—**	**12**
Net return on plan assets	**2**	**(1)**	**—**	**1**
Contributions(1)	**4**	**6**	**1**	**11**
Benefits paid	**(28)**	**(6)**	**(1)**	**(35)**
Administration expenses	**(1)**	**—**	**—**	**(1)**
As at Dec. 31, 2025	**229**	**16**	**—**	**245**

(1) The Company made a voluntary contribution of $4 million (2024 – nil) to further improve the funded status of its defined benefit pension plan.

The fair value of the Company's defined benefit plan assets by major category is as follows:

As at Dec. 31, 2025	Level I	Level II	Level III	Total
Equity securities				
Canadian	—	11	—	11
International	—	52	—	52
Private	—	—	1	1
Bonds				
A - AAA	—	16	80	96
BBB	—	1	11	12
Below BBB	—	—	6	6
Loans(1)	—	2	—	2
Other				
Alternative funds(2)	—	—	42	42
Money market and cash and cash equivalents	18	3	2	23
Total	18	85	142	245

(1) Includes A credit rating loans of $1 million.

(2) Alternative funds include investments in infrastructure and real estate funds.

As at Dec. 31, 2024	Level I	Level II	Level III	Total
Equity securities				
Canadian	—	12	—	12
International	—	53	—	53
Private	—	—	1	1
Bonds				
A - AAA	—	18	81	99
BBB	—	1	16	17
Below BBB	—	—	5	5
Loans(1)	—	1	—	1
Other				
Alternative funds(2)	—	—	46	46
Money market and cash and cash equivalents	2	19	2	23
Total	2	104	151	257

(1) Includes A credit rating loans of $1 million.

(2) Alternative funds include investments in infrastructure and real estate funds.

Plan assets did not include any common shares of the Company as at Dec. 31, 2025 and Dec. 31, 2024.

E. Defined Benefit Obligation

The present value of the obligation for the defined benefit pension and other post-employment benefit plans is as follows:

	Registered	Supplemental	Other	Total
Present value of defined benefit obligation as at Dec. 31, 2023	340	89	17	446
Current service cost	1	—	1	2
Interest cost	14	4	1	19
Benefits paid	(31)	(5)	(1)	(37)
Actuarial loss arising from financial assumptions	1	1	—	2
Actuarial loss arising from experience adjustments	—	1	—	1
Effect of settlement from the termination of the U.S. defined benefit plan	(23)	—	—	(23)
Change in foreign exchange rates	1	—	—	1
Present value of defined benefit obligation as at Dec. 31, 2024	303	90	18	411
Current service cost	**1**	**—**	**—**	**1**
Interest cost	**13**	**4**	**—**	**17**
Benefits paid	**(28)**	**(5)**	**(1)**	**(34)**
Actuarial gain arising from financial assumptions	**(5)**	**(2)**	**—**	**(7)**
Actuarial loss arising from experience adjustments	**1**	**1**	**—**	**2**
Present value of defined benefit obligation as at Dec. 31, 2025(1)	**285**	**88**	**17**	**390**

(1) The weighted average duration of the defined benefit plan obligation as at Dec. 31, 2025, is 9.4 years.

F. Contributions

The expected employer contributions for 2026 for the defined benefit pension and other post-employment benefit plans are as follows:

	Registered	Supplemental	Other	Total
Expected employer contributions	**1**	**—**	**1**	**2**

G. Assumptions

The significant actuarial assumptions used in measuring the Company's defined benefit obligation for the defined benefit pension and other post-employment benefit plans are as follows:

	2025			2024		
As at Dec. 31 (per cent)	**Registered**	**Supplemental**	**Other**	**Registered**	**Supplemental**	**Other**
Accrued benefit obligation						
Discount rate	**4.7**	**4.7**	**4.8**	4.5	4.5	4.8
Rate of compensation increase	**2.9**	**3.0**	**—**	2.9	3.0	—
Assumed health-care cost trend rate						
Health-care cost escalation(1)(3)	**—**	**—**	**6.5**	—	—	6.7
Dental-care cost escalation	**—**	**—**	**4.1**	—	—	4.1
Benefit cost for the year						
Discount rate	**4.5**	**4.5**	**4.8**	4.6	4.6	4.7
Rate of compensation increase	**2.9**	**3.0**	**—**	2.9	3.0	—
Assumed health-care cost trend rate						
Health-care cost escalation(2)(4)	**—**	**—**	**6.5**	—	—	6.7
Dental-care cost escalation	**—**	**—**	**4.6**	—	—	4.6

(1) 2025 Post- and pre-65 rates: decreasing gradually to 4.5 per cent by 2035 and remaining at that level thereafter for the U.S. and decreasing gradually by 0.3 per cent per year to 4.5 per cent in 2030 for Canada.

(2) 2025 Post- and pre-65 rates: decreasing gradually to 4.5 per cent by 2034 and remaining at that level thereafter for the U.S. and decreasing gradually by 0.3 per cent per year to 4.5 per cent in 2030 for Canada.

(3) 2024 Post- and pre-65 rates: decreasing gradually to 4.5 per cent by 2034 and remaining at that level thereafter for the U.S. and decreasing gradually by 0.3 per cent per year to 4.5 per cent in 2030 for Canada.

(4) 2024 Post- and pre-65 rates: decreasing gradually to 4.5 per cent by 2033 and remaining at that level thereafter for the U.S. and decreasing gradually by 0.3 per cent per year to 4.5 per cent in 2030 for Canada.

H. Sensitivity Analysis

The following table outlines the estimated increase in the net defined benefit obligation assuming certain changes in key assumptions:

	Canadian plans			U.S. plans
As at Dec. 31, 2025	**Registered**	**Supplemental**	**Other**	**Pension**
1 per cent decrease in the discount rate	**25**	**10**	**1**	**—**
1 per cent increase in the salary scale	**1**	**—**	**—**	**—**
1 per cent increase in the health-care cost trend rate	**—**	**—**	**2**	**—**
10 per cent improvement in mortality rates	**12**	**3**	**—**	**—**

33. Cash Flow Information

A. Change in Non-Cash Operating Working Capital

Year ended Dec. 31	2025	2024
Source (use):		
Accounts receivable	**75**	155
Prepaid expenses	**19**	85
Income taxes receivable	**(41)**	22
Inventory	**22**	34
Accounts payable, accrued liabilities and provisions	**(78)**	(273)
Income taxes payable	**6**	15
Change in non-cash operating working capital	**3**	38

B. Changes in Liabilities from Financing Activities

	Balance Dec. 31, 2024	Cash issuances[1]	Repayments and dividends paid[2]	Dividends declared	Foreign exchange impact	Other	Balance Dec. 31, 2025
Long-term debt and lease liabilities[2]	3,809	**991**	**(1,188)**	**—**	**(12)**	**(7)**	**3,593**
Exchangeable securities	750	**—**	**—**	**—**	**—**	**—**	**750**
Dividends payable (common and preferred)	49	**—**	**(127)**	**130**	**—**	**—**	**52**
Total liabilities from financing activities	4,608	**991**	**(1,315)**	**130**	**(12)**	**(7)**	**4,395**

(1) Includes the issuance of US$400 million 5.9 per cent senior notes at $541 million and $450 million 5.6 per cent senior notes. Refer to Note 25.

(2) Repayments of long-term debt and lease liabilities include the repayment of US$400 million 7.8 per cent senior notes at $573 million, repayment of the $400 million term facility, $175 million of long-term debt repayments, a $48 million of repayments, net of cash drawings, under the under the syndicated credit facility, and a decrease in finance lease obligations of $4 million.

	Balance Dec. 31, 2023	Debt assumed	Repayments and dividends paid[1]	New leases	Dividends declared	Foreign exchange impact	Other	Balance Dec. 31, 2024
Long-term debt and lease liabilities[2]	3,469	232	6	5	—	86	11	3,809
Exchangeable securities	744	—	—	—	—	—	6	750
Dividends payable (common and preferred)	49	—	(123)	—	123	—	—	49
Total liabilities from financing activities	4,262	232	(117)	5	123	86	17	4,608

(1) Includes a decrease of $131 million related to the repayment of long-term debt, a $143 million net increase in borrowings under credit facilities and a decrease in finance lease obligations of $6 million.

(2) Includes bank overdraft of $1 million and new debt assumed of $232 million as part of the Heartland acquisition. Refer to Note 4.

34. Capital

TransAlta's capital is comprised of the following:

As at Dec. 31	2025	2024	Increase/ (decrease)
Long-term debt[1]	**3,593**	3,808	**(215)**
Exchangeable securities	**750**	750	**—**
Bank overdraft	**—**	1	**(1)**
Equity			
Common shares	**3,169**	3,179	**(10)**
Preferred shares	**942**	942	**—**
Contributed surplus	**42**	42	**—**
Deficit	**(2,730)**	(2,458)	**(272)**
Accumulated other comprehensive (loss) income	**(24)**	41	**(65)**
Non-controlling interests	**66**	97	**(31)**
Less: Available cash and cash equivalents[2]	**(205)**	(337)	**132**
Less: Principal portion of restricted cash on TransAlta OCP bonds[3]	**(17)**	(17)	**—**
Less: Fair value of hedging instruments on long-term debt, liability (asset)[4]	**4**	(7)	**11**
Total capital	**5,590**	6,041	**(451)**

(1) Includes lease liabilities, amounts outstanding under credit facilities, tax equity liabilities and current portion of long-term debt.

(2) The Company includes available cash and cash equivalents, as a reduction in the calculation of capital, as capital is managed using a net debt position. These funds may be available and used to facilitate repayment of debt.

(3) The Company includes the principal portion of restricted cash on TransAlta OCP bonds as this cash is restricted specifically to repay outstanding debt.

(4) The Company includes the fair value of economic and designated hedging instruments on debt in an asset, or liability position as a reduction, or an increase, in the calculation of capital, as the carrying value of the related debt has either increased, or decreased, due to changes in foreign exchange rates.

The Company's overall capital management strategy and its objectives in managing capital are as follows:

A. Maintain a Strong Financial Position

The Company operates in a long-cycle and capital-intensive commodity business and it is therefore a priority to maintain a strong financial position that enables the Company to access capital markets at reasonable interest rates. Maintaining a strong balance sheet also allows our commercial team to contract the Company's portfolio with a variety of counterparties on terms and prices that are favourable to the Company's financial results and provides the Company with better access to capital markets through commodity and credit cycles. The Company has an investment grade credit rating from Morningstar DBRS. In 2025, Moody's reaffirmed the Company's long-term rating of Ba1 with a stable outlook. Morningstar DBRS reaffirmed the Company's issuer rating and unsecured debt/medium-term notes rating of BBB (low) and the Company's preferred shares rating of Pfd-3 (low), all with stable outlooks, and S&P Global Ratings reaffirmed the Company's senior unsecured debt rating and issuer credit rating of BB+ with a stable outlook. The Company remains focused on maintaining a strong financial position and cash flow coverage ratios. Credit ratings provide information relating to the Company's financing costs, liquidity and operations and affect the Company's ability to obtain short and long-term financing and/or the cost of such financing. Management routinely monitors forecasted net earnings, cash flows, capital expenditures and scheduled repayment of debt with a goal of maintaining its credit ratings and to meet dividend and PP&E expenditure requirements.

B. Liquidity

The Company manages variations in working capital using existing liquidity under credit facilities to ensure sufficient cash and credit are available to fund operations, pay dividends, distribute payments to subsidiaries' non-controlling interests and invest in PP&E.

For the years ended Dec. 31, 2025 and 2024, cash inflows and outflows are summarized below.

Year ended Dec. 31	2025	2024	Increase (decrease)
Cash flow from operating activities	**646**	796	**(150)**
Change in non-cash working capital	**(3)**	(38)	**35**
Cash flow from operations before changes in working capital	**643**	758	**(115)**
Dividends paid on common shares	**(74)**	(71)	**(3)**
Dividends paid on preferred shares	**(52)**	(52)	**—**
Distributions paid to subsidiaries' non-controlling interests	**(11)**	(40)	**29**
Property, plant and equipment expenditures	**(249)**	(311)	**62**
Inflow	**257**	284	**(27)**

TransAlta maintains sufficient cash balances and committed credit facilities to fund periodic net cash outflows related to its business. At Dec. 31, 2025, $1.5 billion (2024 – $1.5 billion) of the Company's credit facilities were fully available. From time to time, TransAlta accesses capital markets, as required, to help fund some of these periodic net cash outflows to maintain its available liquidity and maintain its capital structure and credit metrics within targeted ranges.

35. Related-Party Transactions

Details of the Company's principal operating subsidiaries at Dec. 31, 2025, are as follows:

Subsidiary	Country	Ownership (per cent)	Principal activity
TransAlta Generation Partnership	Canada	100	Generation and sale of electricity
TransAlta Cogeneration, L.P.	Canada	50.01	Generation and sale of electricity
TransAlta Centralia Generation, LLC	U.S.	100	Generation and sale of electricity
TransAlta Energy Marketing Corp.	Canada	100	Energy marketing
TransAlta Energy Marketing (U.S.), Inc.	U.S.	100	Energy marketing
TransAlta Energy (Australia), Pty Ltd.	Australia	100	Generation and sale of electricity
TransAlta Renewables Inc.	Canada	100	Generation and sale of electricity
Heartland Generation Ltd.	Canada	100(1)	Generation and sale of electricity
Alberta Power (2000) Ltd.	Canada	100(1)	Generation and sale of electricity

(1) On Dec. 4, 2024, the Company completed the acquisition of Heartland. Refer to Note 4 for more details.

Transactions between the Company and its subsidiaries have been eliminated on consolidation and are not disclosed.

Joint arrangements at Dec. 31, 2025, included the following:

Joint operations	Segment	Ownership (per cent)	Description
Goldfields Power	Gas	50	Gas-fired facility in Western Australia operated by TransAlta
Fort Saskatchewan	Gas	60	Cogeneration facility in Alberta, of which TA Cogen has a 60 per cent interest, operated by TransAlta
Fortescue River Gas Pipeline	Gas	43	Natural gas pipeline in Western Australia, operated by DBP Development Group
McBride Lake	Wind and Solar	50	Wind generation facility in Alberta operated by TransAlta
Soderglen	Wind and Solar	50	Wind generation facility in Alberta operated by TransAlta
Pingston	Hydro	50	Hydro facility in British Columbia operated by TransAlta
Joffre	Gas	40	Cogeneration plant in Alberta operated by TransAlta
McMahon	Gas	50	Cogeneration plant in British Columbia operated by NorthRiver Midstream Inc.
Primrose	Gas	50	Cogeneration plant in Alberta operated by Canadian Natural Resources Limited

Joint venture	Segment	Ownership (per cent)	Description
Skookumchuck	Wind and Solar	49	Wind generation facility in Washington operated by Southern Power

Associates and joint ventures have been equity accounted for by the Company.

A. Transactions with Key Management Personnel

TransAlta's key management personnel include the President and Chief Executive Officer (CEO), members of the senior management team and the members of the Board. Key management personnel compensation is as follows:

Year ended Dec. 31	2025	2024
Total compensation	**22**	36
Comprising:		
Short-term employee benefits	**12**	13
Post-employment benefits	**1**	1
Termination benefits	**1**	4
Share-based payments	**8**	18

B. Transactions with Associates

In connection with the exchangeable securities issued to Brookfield, the Investment Agreement entitles Brookfield to nominate two directors to the TransAlta Board. This allows Brookfield to participate in the financial and operating policy decisions of the Company, and as such, they are considered associates of the Company.

In addition to the exchangeable securities disclosed in Note 26, the Company may, in the normal course of operations, enter into transactions on market terms with associates that have been measured at exchange value and recognized in the Consolidated Financial Statements, including power purchase and sale agreements, derivative contracts and asset management fees. Transactions and balances between the Company and associates do not eliminate.

Transactions with Brookfield include the following:

Year ended Dec. 31	2025	2024
Power sales	**98**	58
Purchased power	**2**	4

36. Commitments and Contingencies

In addition to the commitments disclosed elsewhere in the financial statements, the Company has incurred the following contractual commitments, either directly or through its interests in joint operations and joint ventures.

Approximate future payments under these agreements are as follows:

	2026	2027	2028	2029	2030	2031 and thereafter	Total
Natural gas, transportation and other contracts	83	67	67	63	62	350	692
Transmission	29	31	22	20	21	114	237
Long-term service agreements	55	44	21	14	15	105	254
Operating leases	5	2	2	2	2	59	72
Growth	7	—	11	—	—	—	18
Total	**179**	**144**	**123**	**99**	**100**	**628**	**1,273**

Commitments

Natural Gas, Transportation and Other Contracts

The Company has natural gas transportation contracts, for a total of up to 400 terajoules (TJ) per day on a firm basis, related to the Sundance and Keephills facilities, ending in 2036 to 2038. In addition, the Company has natural gas transportation agreements for approximately 150 TJ per day for Sheerness. The Company currently expects to use approximately 160 TJ per day on average and up to approximately 450 TJ per day during peak periods, while remarketing excess capacity.

Transmission

The Company has several agreements to purchase transmission network capacity in the Pacific Northwest. Provided certain conditions for delivering the service are met, the Company is committed to the transmission at the supplier's tariff rate whether it is awarded immediately or delivered in the future after additional facilities are constructed.

Transmission commitments also include multi-year U.S.-dollar-denominated contracts to secure transmission capacity. The majority of the transmission capacity supports a dedicated revenue capacity agreement, held with a counterparty in the U.S., for similar duration as the associated transmission capacity.

Long-Term Service Agreements

TransAlta has various service agreements in place, primarily for inspections, repairs and maintenance that may be required on natural gas facilities, equipment for gas and turbines at various wind facilities.

Operating Leases

Operating leases include lease commitments not recognized under IFRS 16 and lease commitments that have not yet commenced, mainly related to buildings, vehicles and land. Certain lease commitments extend out to 2072 which is the end of life of the related facilities.

Growth

Commitments for growth include primarily payments towards early-stage development projects in Alberta.

Contingencies

TransAlta is occasionally named as a party in various claims and legal and regulatory proceedings that arise during the normal course of its business. TransAlta reviews each of these claims, including the nature of the claim, the amount in dispute or claimed and the availability of insurance coverage. There can be no assurance that any particular claim will be resolved in the Company's favour or that such claims may not have a material adverse effect on TransAlta. Inquiries from regulatory bodies may also arise in the normal course of business, to which the Company responds as required.

The Company conducts internal reviews of its offers and offer behaviour in both the energy and ancillary services markets in Alberta on an ongoing basis and will self-report suspected contraventions or respond to inquiries from regulatory agencies as required. There currently is no certainty that any particular matter will be resolved in the Company's favour or that such matters may not have a material adverse effect on TransAlta.

Brazeau Facility — Well Licence Applications to Consider Hydraulic Fracturing Activities

The Alberta Energy Regulator (AER) issued a subsurface order on May 27, 2019, which does not permit any hydraulic fracturing within three kilometres of the Brazeau facility, but permits hydraulic fracturing in all formations (except the Duvernay) within three to five kilometres of the Brazeau facility.

Subsequently, two oil and gas operators submitted applications to the AER for 10 well licences (which include hydraulic fracturing activities) within three to five kilometres of the Brazeau facility.

The Company's position, based on independent expert analysis commissioned by the Government of Alberta, is that hydraulic fracturing activities within five kilometres of the Brazeau facility pose an unacceptable risk and that the applications should be denied. The regulatory hearing to consider these applications - Proceeding 379 - has been adjourned to the fourth quarter of 2026.

Brazeau Facility — Claim against the Government of Alberta

On Sept. 9, 2022, the Company filed a Statement of Claim against the Government of Alberta in the Alberta Court of King's Bench seeking a declaration that: (a) granting mineral leases within five kilometres of the Brazeau facility is a breach of a 1960 agreement between the Company and the Government of Alberta; and (b) the Government of Alberta is required to indemnify the Company for any costs or damages that result from the risks of hydraulic fracturing near the Brazeau facility. On Sept. 29, 2022, the Government of Alberta filed its Statement of Defence, which asserts, among other things, that the Company: (a) is trying to usurp the jurisdiction of the AER; and (b) is out of time under the *Limitations Act* (Alberta). The trial is scheduled to be heard in the second or third quarter of 2026 if the parties are unable to resolve the dispute before then.

37. Segment Disclosures

A. Description of Reportable Segments

The Company has six reportable segments as described in Note 1.

The following tables provides each segment's results in the format that the TransAlta's President and Chief Executive Officer (the chief operating decision maker) (CODM) reviews the Company's segments to make operating decisions and assess performance. The CODM assesses the performance of the operating segments based on a measure of adjusted EBITDA. This measurement basis represents (loss) earnings before income taxes, adjusted for the effects of: depreciation of property, plant and equipment and amortization of intangibles, depreciation of right-of-use assets, finance lease income, unrealized mark-to-market gains or losses, unrealized foreign exchange gains or losses on commodity transactions, Brazeau penalties, acquisition-related transaction and restructuring costs, ERP integration costs, termination, restructuring and facility shutdown costs, revenues and fuel and purchased power related to the Required Divestitures, items within the Energy Transition segment that may not be reflective of ongoing operations including certain costs related to decisions made to accelerate our transition off-coal in Alberta and our planned transition off-coal for Centralia, fair value change in contingent consideration, Sundance A decommissioning costs reimbursement, insurance recoveries, asset impairment (reversals) charges, share of profit or loss of joint venture and other costs or income adjustments.

For internal reporting purpose, the earnings information from the Company's investment in Skookumchuck has been presented in the Wind and Solar segment on a proportionate basis. Information on a proportionate basis reflects the Company's share of Skookumchuck's statement of earnings on a line-by-line basis. Proportionate financial information is not and is not intended to be, presented in accordance with IFRS. Under IFRS, the investment in Skookumchuck has been accounted for as a joint venture using the equity method.

The tables below show the reconciliation of the total segmented results and Adjusted EBITDA to the statement of earnings reported under IFRS.

B. Reported Adjusted Segment Earnings and Segment Assets

I. Reconciliation of Adjusted EBITDA to Earnings before Income Tax

Year ended Dec. 31, 2025	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	368	227	1,267	495	130	(61)	2,426	(21)	—	2,405
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	(4)	265	26	9	(8)	—	288	—	(288)	—
Decrease in finance lease receivable	—	3	27	—	—	—	30	—	(30)	—
Finance lease income	—	5	18	—	—	—	23	—	(23)	—
Revenues from Required Divestitures	—	—	(11)	—	—	—	(11)	—	11	—
Unrealized foreign exchange gain on commodity	—	—	1	—	—	—	1	—	(1)	—
Adjusted Revenue	364	500	1,328	504	122	(61)	2,757	(21)	(331)	2,405
Fuel and purchased power	(20)	(31)	(549)	(328)	—	(7)	(935)	—	—	(935)
Reclassifications and adjustments:										
Fuel and purchased power related to Required Divestitures	—	—	2	—	—	—	2	—	(2)	—
Adjusted Fuel and Purchased Power	(20)	(31)	(547)	(328)	—	(7)	(933)	—	(2)	(935)
Carbon compliance (costs) recovery	—	(3)	(115)	—	—	68	(50)	—	—	(50)
Adjusted Gross Margin	344	466	666	176	122	—	1,774	(21)	(333)	1,420
OM&A	(56)	(106)	(257)	(75)	(37)	(185)	(716)	5	—	(711)
Reclassifications and adjustments:										
Termination, restructuring and facility shutdown costs	—	—	1	2	—	12	15	—	(15)	—
OM&A related to required divestitures	—	—	5	—	—	—	5	—	(5)	—
ERP integration costs	—	—	—	—	—	25	25	—	(25)	—
Acquisition-related transaction and restructuring costs	—	—	—	—	—	7	7		(7)	—
Adjusted OM&A	(56)	(106)	(251)	(73)	(37)	(141)	(664)	5	(52)	(711)
Taxes, other than income taxes	(3)	(23)	(21)	(3)	—	(1)	(51)	1	—	(50)
Net other operating income	—	3	44	—	—	—	47	—	—	47
Reclassifications and adjustments:										
Insurance recovery	—	(2)	—	—	—	—	(2)	—	2	—
Adjusted Net Other Operating Income	—	1	44	—	—	—	45	—	2	47
Adjusted EBITDA[2]	285	338	438	100	85	(142)	1,104			
Equity income										6
Finance lease income										23
Depreciation and amortization										(579)
Asset impairment reversals										13
Interest income										28
Interest expense										(347)
Foreign exchange loss										(21)
Fair value change in contingent consideration										37
Loss on sale of assets and other										(7)
Loss before income taxes										(141)

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.

(2) Adjusted EBITDA is not defined, has no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers.

Year ended Dec. 31, 2024	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	409	357	1,350	616	168	(34)	2,866	(21)	—	2,845
Reclassifications and adjustments:										
Unrealized mark-to-market loss (gain)	1	84	(60)	(36)	14	—	3	—	(3)	—
Decrease in finance lease receivable	—	2	19	—	—	—	21	—	(21)	—
Finance lease income	—	6	8	—	—	—	14		(14)	—
Revenues from Required Divestitures	—	—	(1)	—	—	—	(1)	—	1	—
Brazeau penalty	(20)	—	—	—	—	—	(20)	—	20	—
Unrealized foreign exchange gain on commodity	—	—	(2)	—	—	—	(2)	—	2	—
Adjusted Revenues	390	449	1,314	580	182	(34)	2,881	(21)	(15)	2,845
Fuel and purchased power	(16)	(30)	(475)	(418)	—	—	(939)	—	—	(939)
Reclassifications and adjustments:										
Fuel and purchased power related to the Required Divestitures	—	—	1	—	—	—	1	—	(1)	—
Adjusted Fuel and Purchased Power	(16)	(30)	(474)	(418)	—	—	(938)	—	(1)	(939)
Carbon compliance costs	—	—	(145)	(1)	—	34	(112)	—	—	(112)
Adjusted Gross Margin	374	419	695	161	182	—	1,831	(21)	(16)	1,794
OM&A	(86)	(97)	(198)	(69)	(36)	(173)	(659)	4	—	(655)
Reclassifications and adjustments:										
Brazeau penalties	31	—	—	—	—	—	31	—	(31)	—
ERP integration costs	—	—	—	—	—	14	14	—	(14)	—
Acquisition-related transaction and restructuring costs	—	—	—	—	—	24	24	—	(24)	—
Adjusted OM&A	(55)	(97)	(198)	(69)	(36)	(135)	(590)	4	(69)	(655)
Taxes, other than income taxes	(3)	(16)	(13)	(3)	—	(1)	(36)	—	—	(36)
Net other operating income	—	10	40	9	—	—	59	—	—	59
Reclassifications and adjustments:										
Sundance A decommissioning cost	—	—	—	(9)	—	—	(9)	—	9	—
Adjusted Net Other Operating Income	—	10	40	—	—	—	50	—	9	59
Adjusted EBITDA[2][3]	316	316	524	89	146	(136)	1,255			
Equity income										5
Finance lease income										14
Depreciation and amortization										(531)
Asset impairment charges										(46)
Interest income										30
Interest expense										(324)
Foreign exchange gain										5
Gain on sale of assets and other										4
Earnings before income taxes										319

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.

(2) Adjusted EBITDA is not defined, has no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers.

(3) During the first quarter of 2025, our Adjusted EBITDA composition was amended to exclude the impact of realized gain (loss) on closed exchange positions and Australian interest income. Therefore, the Company has applied this composition to all previously reported periods.

II. Selected Consolidated Statements of Financial Position Information

As at Dec. 31, 2025	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
PP&E	**514**	**3,223**	**1,664**	**163**	**—**	**101**	**5,665**
Right-of-use assets	**8**	**88**	**5**	**—**	**—**	**10**	**111**
Intangible assets	**14**	**113**	**79**	**3**	**1**	**33**	**243**
Goodwill	**258**	**177**	**51**	**—**	**30**	**—**	**516**

As at Dec. 31, 2024	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
PP&E	501	3,428	1,805	206	—	80	6,020
Right-of-use assets	7	96	6	—	—	11	120
Intangible assets	3	133	108	4	3	30	281
Goodwill	258	178	51	—	30	—	517

III. Selected Consolidated Statements of Cash Flows Information

Additions to non-current assets are as follows:

Year ended Dec. 31, 2025	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
Additions to non-current assets:							
PP&E	**50**	**57**	**106**	**9**	**—**	**27**	**249**
Intangible assets	**—**	**—**	**—**	**—**	**—**	**11**	**11**

Year ended Dec. 31, 2024	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
Additions to non-current assets:							
PP&E(1)	64	97	100	13	—	37	311
Intangible assets(1)	—	—	—	—	—	10	10

(1) Excludes additions attributable to the Heartland acquisition on Dec. 4, 2024.

C. Geographic Information

I. Revenues

Year ended Dec. 31	2025	2024
Canada	**1,759**	2,009
U.S.	**497**	676
Western Australia	**149**	160
Total revenue	**2,405**	2,845

II. Non-Current Assets

	Property, plant and equipment		Right-of-use assets		Intangible assets		Other assets	
As at Dec. 31	2025	2024	2025	2024	2025	2024	2025	2024
Canada	**3,624**	3,828	**39**	41	**149**	170	**73**	85
U.S.	**1,677**	1,852	**67**	74	**70**	86	**24**	36
Western Australia	**364**	340	**5**	5	**24**	25	**59**	58
Total	**5,665**	6,020	**111**	120	**243**	281	**156**	179

38. Subsequent Events

Acquisition of Far North

On Feb. 2, 2026, the Company acquired all issued and outstanding common shares of Far North Corporation (Far North) from an affiliate of Hut 8 Corp. (the Far North Acquisition). The Far North Acquisition, which includes Far North and its subsidiaries' entire business operations in Ontario consisting of four natural gas-fired generation facilities totaling 310 MW, was completed for an aggregate purchase price of $95 million, subject to working capital and other adjustments. The Far North Acquisition was funded through a combination of cash on hand and draws on the Company's credit facilities.

The Far North Acquisition will be accounted for as a business combination using the acquisition method where the acquired tangible assets and intangible assets, if any, and assumed liabilities are recorded at their estimated fair values at the date of acquisition. Any amount less than or exceeding the purchase price will be presented as goodwill or a bargain purchase gain, respectively.

The fair values of Far North's identifiable assets and liabilities to be assumed and the impact of applying acquisition accounting have not been fully determined. Due to the proximity of the acquisition date to the release date of the Company's Consolidated Financial Statements, the preliminary purchase price allocation will be disclosed in the Consolidated Financial Statements for the three months ended March 31, 2026.