

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 unaudited interim condensed consolidated financial statements as at and for the three and nine months ended Sept. 30, 2025 and 2024, and should be read in conjunction with the audited annual consolidated financial statements and MD&A (2024 Annual MD&A) contained within our 2024 Integrated Report. In this MD&A, unless the context otherwise requires, "we", "our", "us", the "Company" and "TransAlta" refer to TransAlta Corporation and its subsidiaries. The unaudited interim condensed 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 Sept. 30, 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 Nov. 5, 2025. Additional information respecting TransAlta, including our Annual Information form (AIF) for the year ended Dec. 31, 2024, 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. These statements are not guarantees of our future performance, events or results and are subject to risks, uncertainties and other important factors that could cause our actual performance, events or results to be materially different from those set out in or implied by the forward-looking statements.

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 2025 Outlook;
- Our financial and operational performance, including our hedge position;
- The optimization and diversification of our generating assets;
- The increasingly contracted nature of our fleet;
- Expectations about strategies for growth and expansion;
- Expectations regarding ongoing and future transactions, including the divestitures of our Poplar Hill and Rainbow Lake facilities;
- Expected costs and schedules for planned projects;
- Expected regulatory processes and outcomes, including in relation to the Alberta restructured energy market;
- The power generation industry and the supply and demand of electricity;
- The cyclicity 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;
- No unexpected delays in obtaining required regulatory 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 rates or foreign exchange rates;
- No significant changes to the demand for, and growth of, renewables and thermal 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; and
- Realization of expected impacts from ongoing and future transactions.

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;
- Failure to complete acquisitions or divestitures on the terms and conditions specified or at all;
- Any difficulty raising needed capital in the future on reasonable terms or at all;
- Our ability to achieve our targets relating to environmental, social and governance (ESG) performance;
- Long-term commitments on gas transportation capacity that may not be fully utilized over time;
- Changes to the legislative, regulatory and political environments;
- 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;
- Reductions in production including lower wind resource;
- 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 and ability to continue to staff our operations and facilities;
- Disruptions to our supply chains;
- Climate-change related risks;
- Reductions to our generating units' relative efficiency or capacity factors;
- General economic risks, including deterioration of equity markets, increasing interest rates or rising inflation;
- General domestic and international economic and political developments, including potential trade tariffs;
- Industry risk and competition;
- 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;
- Reliance on key personnel; and
- Labour relations matters.

The foregoing risk factors, among others, are described in further detail in the Governance and Risk Management section of this MD&A and the Risk Factors section in our AIF for the year ended Dec. 31, 2024.

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 hereof 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 hereof 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 herein 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 and Western Australia. Our portfolio includes hydro, wind, solar, battery storage, natural gas and coal, complemented by our exceptional asset optimization and energy marketing capabilities. As one of Canada's largest producers of wind and thermal generation and Alberta's largest producer of hydro power, TransAlta remains committed to a balanced, technology-agnostic 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.

The Company's goal is to deliver solutions to meet our customers' needs for reliable, sustainable power. With over a century of experience, TransAlta is a trusted partner delivering tailored solutions. Our strategic priorities include optimizing our Alberta portfolio, executing our growth plan, realizing the value of our legacy generating facilities, maintaining financial strength and capital discipline, defining the next generation of power solutions and leading in ESG and market policy development. We are primarily focused on opportunities within our core markets of Canada, the United States and Western Australia.

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

In Alberta, the Company manages its merchant exposure by executing hedging strategies that include a significant base of commercial and industrial (C&I) customers, supplemented with financial hedges. A major portion of our thermal and hydro generation capacity in Alberta may be hedged to provide greater cash flow certainty while also capturing higher shareholder returns through the optimization of our merchant generation portfolio. Refer to the 2025 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 of Sept. 30, 2025:

As at Sept. 30, 2025	Hydro		Wind & Solar		Gas		Energy Transition		Total	
	Gross Installed Capacity (MW)	Number of facilities	Gross Installed Capacity (MW) ⁽¹⁾	Number of facilities	Gross Installed Capacity (MW) ⁽¹⁾⁽²⁾	Number of facilities ⁽²⁾	Gross Installed Capacity (MW)	Number of facilities ⁽³⁾	Gross Installed Capacity (MW)	Number of facilities
Alberta	834	17	764	14	3,650	15	—	—	5,248	46
Canada, excluding Alberta	88	7	751	9	705	4	—	—	1,544	20
U.S.	—	—	1,024	10	29	1	671	2	1,724	13
Western Australia	—	—	48	3	450	6	—	—	498	9
Total	922	24	2,587	36	4,834	26	671	2	9,014	88

(1) Gross installed capacity for consolidated reporting is based on a proportionate interest held in a facility.

(2) Excludes the gross installed capacity attributable to the Required Divestitures.

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

Contracted Capacity

The following table provides our contracted capacity by segment in MW and as a percentage of total gross installed capacity of our facilities across the regions in which we operate as of Sept. 30, 2025:

As at Sept. 30, 2025	Hydro	Wind & Solar	Gas ⁽¹⁾	Energy Transition	Total
Alberta	—	336	887	—	1,223
Canada, excluding Alberta	88	751	705	—	1,544
U.S.	—	1,024	29	301	1,354
Western Australia	—	48	450	—	498
Total contracted capacity (MW)	88	2,159	2,071	301	4,619
Contracted capacity as a % of total capacity (%)	10	83	43	45	51

(1) The figures exclude the contracted capacity related to the Required Divestitures.

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

The following table provides the weighted average contract life by segment of our contracted capacity across the regions in which we operate as of Sept. 30, 2025:

As at Sept. 30, 2025	Hydro	Wind & Solar	Gas ⁽¹⁾	Energy Transition	Total
Alberta	—	16	9	—	11
Canada, excluding Alberta	14	8	6	—	8
U.S.	—	12	—	0.3	9
Western Australia	—	13	13	—	13
Total weighted average contract life (years)	14	11	9	0.3	9

(1) Excludes the contracts pertaining to the Required Divestitures.

Highlights

	3 months ended Sept. 30		9 months ended Sept. 30	
(in millions of Canadian dollars except where noted)	2025	2024	2025	2024
Operational information⁽¹⁾				
Availability (%)	92.7	94.5	93.1	92.5
Production (GWh)	6,151	5,712	17,796	16,612
Select financial information⁽¹⁾				
Revenues	615	638	1,806	2,167
Adjusted EBITDA ⁽²⁾	238	315	857	973
Adjusted earnings before income taxes ⁽²⁾	17	102	167	358
(Loss) earnings before income taxes	(53)	9	(99)	370
Adjusted net (loss) earnings attributable to common shareholders ⁽²⁾	(8)	35	76	233
Net (loss) earnings attributable to common shareholders	(62)	(36)	(128)	242
Cash flows⁽¹⁾				
Cash flow from operating activities	251	229	415	581
Funds from operations ⁽²⁾	156	191	587	681
Free cash flow ⁽²⁾	105	131	421	529
Per share⁽¹⁾				
Weighted average number of common shares outstanding	297	296	297	303
Adjusted net (loss) earnings attributable to common shareholders per share ⁽²⁾⁽³⁾	(0.02)	0.12	0.26	0.77
Net (loss) earnings per share attributable to common shareholders, basic and diluted	(0.20)	(0.12)	(0.43)	0.80
Dividends declared per common share	0.065	0.060	0.130	0.120
Cash flow from operating activities per share ⁽⁴⁾	0.85	0.77	1.40	1.92
Funds from operations per share ⁽²⁾⁽³⁾	0.53	0.65	1.98	2.25
Free cash flow per share ⁽²⁾⁽³⁾	0.35	0.44	1.42	1.75

(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 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, pursuant to 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. 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. 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	Sept. 30, 2025	Dec. 31, 2024
Liquidity and capital resources		
Available liquidity ⁽¹⁾	1,553	1,616
Adjusted net debt to adjusted EBITDA (times) ⁽²⁾⁽³⁾	3.9	3.6
Total consolidated net debt ⁽²⁾⁽⁴⁾	3,785	3,798
Assets and liabilities		
Total assets	8,892	9,499
Total long-term liabilities ⁽⁵⁾	5,430	5,087
Total liabilities	7,280	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. We believe that presenting these items 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 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 total credit facilities, long-term debt and lease liabilities of \$3,665 million (Dec. 31, 2024 — \$3,808 million) divided by loss before income taxes for the last four quarters of \$150 million (Dec. 31, 2024 — \$319 million) and is equal to (24) times (Dec. 31, 2024 — 12 times). Refer to 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 \$3,665 million (Dec. 31, 2024 — \$3,808 million). Refer to the table in the Financial Capital 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 condensed consolidated statements of financial position under IFRS.

Significant and Subsequent Events

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 (Board) has 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

Subsequent to the quarter, the Company entered into a 230 MW Demand Transmission Service Contract with the Alberta Electric System Operator (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 is entitled to receive the proceeds from the sale of both facilities, net of certain adjustments, following completion of the divestitures.

Credit Facility Extension

On July 16, 2025, the Company executed agreements to extend its committed credit facilities totalling \$2.1 billion with a syndicate of lenders. The revised agreements reduced the Syndicated facility size from \$1.95 to \$1.90 billion, and extended its maturity from June 30, 2028 to June 30, 2029. The bilateral credit facilities of \$240 million were extended by one year to June 30, 2027.

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 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 having been 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 \$450 million 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 of Sept. 30, 2025, US\$90 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 annum 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.

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.

Declared Increase in Common Share Dividend

On Feb. 19, 2025, the Company's Board of Directors approved a \$0.02 annualized increase to the common share dividend, an increase of eight per cent, and declared a dividend of \$0.065 per common share payable on July 1, 2025 to shareholders of record at the close of business on June 1, 2025. The quarterly dividend of \$0.065 per common share represents an annualized dividend of \$0.26 per common share.

On Oct. 22, 2025, the Company declared a quarterly dividend of \$0.065 per common share, payable on Jan. 1, 2026.

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.

During the nine months ended Sept. 30, 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.

Operating and Financial Performance

Operating Performance

Availability

The following table provides availability (%) by segment:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2025	2024	2025	2024
Hydro	82.9	94.3	91.1	92.3
Wind and Solar	94.3	93.7	94.3	93.8
Gas	95.4	96.3	93.7	95.4
Energy Transition	83.3	90.0	87.2	76.1
Availability (%)	92.7	94.5	93.1	92.5

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 dedicated time (planned outages) to maintain, repair or make improvements to the facilities at a time that will minimize the impact to operations. In high price environments, actual outage schedules may shift or change to accelerate the return to service of the unit.

Availability for the three months ended Sept. 30, 2025, was 92.7 per cent compared to 94.5 per cent in the same period in 2024. Lower availability compared to the prior period was primarily due to:

- Higher planned maintenance outages in the Hydro segment;
- Higher unplanned outages at the Centralia facility in the Energy Transition segment; and
- Higher derates in the Gas segment.

Availability for the nine months ended Sept. 30, 2025 was 93.1 per cent compared to 92.5 per cent in the same period in 2024. Higher availability compared to the same period in 2024 was primarily due to:

- Lower planned and unplanned outages at the Centralia facility in the Energy Transition segment; and
- 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 during the current period; partially offset by
- Higher planned and unplanned outages in the Gas segment; and
- Higher planned maintenance outages in the Hydro 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 Sept. 30	Actual production (GWh)	LTA generation (GWh)	Production as a % of LTA	Actual production (GWh)	LTA generation (GWh)	Production as a % of LTA
Hydro	623	573	109%	494	573	86%
Wind and Solar	1,028	1,472	70%	1,121	1,472	76%
Gas	3,514			3,119		
Energy Transition	986			978		
Total	6,151			5,712		

	2025			2024		
9 months ended Sept. 30	Actual production (GWh)	LTA generation (GWh)	Production as a % of LTA	Actual production (GWh)	LTA generation (GWh)	Production as a % of LTA
Hydro	1,578	1,568	101%	1,271	1,568	81%
Wind and Solar ⁽¹⁾	4,446	5,282	84%	4,118	4,701	88%
Gas	9,504			9,442		
Energy Transition	2,268			1,781		
Total	17,796			16,612		

(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 the renewable facilities, whereby actual production levels are compared against the expected long-term average. In the short term, for each of the Hydro and Wind and Solar segments, 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 models 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 is largely dependent on market conditions and merchant demand.

Total production for the three months ended Sept. 30, 2025, increased by 439 GWh, or eight per cent, compared to the same period in 2024, primarily due to:

- Production from the Heartland gas facilities acquired in December 2024; and
- Higher production from higher Alberta water reserves in the Hydro segment due to higher precipitation during the quarter; partially offset by
- Higher dispatch optimization in Alberta in the Gas segment due to lower market prices;
- Lower production in Australia due to lower customer demand; and
- Lower wind resource across Canada and United States.

Total production for the nine months ended Sept. 30, 2025, increased by 1,184 GWh, or seven per cent, compared to the same period in 2024, primarily due to:

- Production from the Heartland gas facilities acquired in December 2024;
- Improved availability at Centralia;
- Production impact from the White Rock and Horizon Hill wind facilities which achieved commercial operation in the first half of 2024; and
- Higher production in the Hydro segment due to higher water reserves and optimization of water supply; partially offset by
- Higher dispatch optimization in Alberta in the Gas segment due to lower market prices; and
- Lower production in Australia due to lower customer demand.

Market Pricing

	3 months ended Sept. 30		9 months ended Sept. 30	
	2025	2024	2025	2024
Alberta spot power price (\$/MWh)	51	55	44	67
Mid-Columbia spot power price (US\$/MWh)	47	50	44	61
Ontario spot power price ⁽¹⁾ (\$/MWh)	64	34	54	32
Natural gas price (AECO) per GJ (\$)	0.63	0.67	1.43	1.24

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

For the three and nine months ended Sept. 30, 2025, spot power prices in Alberta were seven and 34 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 and nine months ended Sept. 30, 2025, Mid-Columbia spot power prices in the Pacific Northwest were six and 28 per cent lower, respectively, compared to the same periods in 2024, due to lower natural gas prices and the impact of a milder weather on the nine months ended Sept. 30, 2025.

Ontario spot power prices were higher on average compared to the same periods in 2024, due to nuclear

refurbishments occurring in 2025 and higher natural gas prices.

For the three months ended Sept. 30, 2025, AECO natural gas prices were six per cent lower, compared to the same period in 2024, mainly due to higher gas production in Alberta and throughout North America.

For the nine months ended Sept. 30, 2025, AECO natural gas prices were 15 per cent higher, compared to the same period in 2024, mainly due to lower storage levels in Alberta and throughout North America, as well as stronger demand.

Financial Performance Review of Consolidated Information

	3 months ended Sept. 30		9 months ended Sept. 30	
	2025	2024	2025	2024
Revenues	615	638	1,806	2,167
Fuel and purchased power	(227)	(213)	(677)	(690)
Carbon compliance costs	(35)	(41)	(10)	(73)
Operations, maintenance and administration	(179)	(143)	(525)	(421)
Depreciation and amortization	(135)	(133)	(431)	(388)
Asset impairment charges	(27)	(20)	(55)	(26)
Fair value change in contingent consideration payable	3	—	37	—
Interest expense	(85)	(83)	(266)	(232)
Foreign exchange gain (loss)	3	(6)	(18)	(12)
(Loss) earnings before income taxes	(53)	9	(99)	370
Income tax expense	(1)	(31)	(19)	(88)
Net (loss) earnings attributable to common shareholders	(62)	(36)	(128)	242
Net (loss) earnings attributable to non-controlling interests	(5)	1	(16)	14

Three months ended Sept. 30, 2025 Variance Analysis (2025 versus 2024)

Revenues for the three months ended Sept. 30, 2025 decreased by \$23 million, or four 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;
- Lower realized mark-to-market gains on settled trades in the Energy Marketing and Gas segments; partially offset by
- The full quarter impact from the addition of the Heartland facilities in the fourth quarter of 2024.

Fuel and purchased power costs for the three months ended Sept. 30, 2025 increased by \$14 million, or seven per cent, compared to the same period in 2024, primarily due to:

- Full quarter impact from the addition of the Heartland facilities in the fourth quarter of 2024; partially offset by
- Lower purchased power in the Energy Transition segment due to fewer repurchases to fulfill contractual obligations during outages.

Carbon compliance costs for the three months ended Sept. 30, 2025 decreased by \$6 million compared to the same period in 2024, primarily due to:

- Favourable impact on carbon compliance cost due to an increase of production from lower carbon-emitting cogeneration facilities; partially offset by
- The addition of carbon compliance costs from the addition of 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 for the three months ended Sept. 30, 2025 increased by \$36 million, or 25 per cent, compared to the same period in 2024, primarily due to:

- Full quarter impact from the addition of the Heartland facilities in the fourth quarter of 2024 and associated corporate costs; and
- Higher spending related to the implementation of an upgrade to our enterprise resource planning (ERP) system.

Asset impairment charges for the the three months ended Sept. 30, 2025 increased by \$7 million, or 35 per cent, compared to the same period in 2024, primarily due to:

- An impairment charge, net of impairment reversals related to the Wind and Solar facilities driven by changes in expected production volumes and price assumptions; partially offset by
- Lower decommissioning and restoration provisions on retired assets driven by lower discount rates compared to the same period in 2024.

Foreign exchange gains for the three months ended Sept. 30, 2025 increased by \$9 million compared to foreign exchange losses in the same period in 2024, primarily due to:

- Higher unrealized foreign exchange gains due to favourable changes in foreign currency rates; partially offset by
- Higher realized foreign exchange losses due to hedges settled during the period at unfavourable foreign currency rates.

Loss before income taxes for the three months ended Sept. 30, 2025 increased by \$62 million from earnings before income taxes in the same period in 2024, due to the above noted items. Refer to the Segment Financial Performance and Operating Results section for additional information.

Income tax expense for the three months ended Sept. 30, 2025 decreased by \$30 million, or 97 per cent, compared to the same period in 2024, due to the increase in loss before income taxes.

Net loss attributable to non-controlling interests for the three months ended Sept. 30, 2025 increased by \$6 million compared to net earnings of \$1 million for the same period in 2024, primarily due to lower net earnings for TransAlta Cogeneration, LP (TA Cogen) resulting from lower merchant pricing in the Alberta market.

Nine months ended Sept. 30, 2025 Variance Analysis (2025 versus 2024)

Revenues for the nine months ended Sept. 30, 2025 decreased by \$361 million, or 17 per cent, compared to the same period in 2024, primarily due to:

- Higher unrealized mark-to-market losses in the Wind and Solar segment driven by long-term wind energy sales related to the Garden Plain and Oklahoma facilities, primarily due to lower forecasted power prices, partially offset by mark-to-market gains related to Big Level facility;
- Higher unrealized mark-to-market losses in the Gas and Energy Transition segments primarily related to unfavourable changes in forward prices in the current period;
- Lower Alberta and Mid-Columbia power prices;
- Higher dispatch optimization in the Gas segment driven by lower power prices in Alberta;
- Lower realized mark-to-market gains on settled trades in the Energy Marketing segment; partially offset by
- The full three quarter impact from the addition of the Heartland facilities in the fourth quarter of 2024;
- The impact from the White Rock and Horizon Hill wind facilities which achieved commercial operation in the first half of 2024; and
- Higher realized mark-to-market gains on settled trades in the Gas segment.

Fuel and purchased power costs for the nine months ended Sept. 30, 2025 decreased by \$13 million, or two per cent, compared to the same period in 2024 primarily due to:

- Lower purchased power costs driven by higher availability, which resulted in fewer repurchases to fulfill contractual obligations during outages in the Energy Transition segment; partially offset by
- The full three quarter impact from the addition of the Heartland facilities in the fourth quarter of 2024; and
- Higher production in the Energy Transition segment due to higher availability.

Carbon compliance costs for the nine months ended Sept. 30, 2025 decreased by \$63 million, or 86 per cent, compared to the same period in 2024, primarily due:

- 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 2024 GHG obligation and a portion of the GHG obligation assumed with the Heartland acquisition; and

- Favourable impact on carbon compliance cost due to an increase of 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 for the nine months ended Sept. 30, 2025 increased by \$104 million, or 25 per cent, compared to the same period in 2024, primarily due to:

- The full three quarter 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 impact from the White Rock and Horizon Hill wind facilities which achieved commercial operation in the first half of 2024.

Depreciation and amortization for the nine months ended Sept. 30, 2025 increased by \$43 million, or 11 per cent, compared to the same period in 2024, primarily due to:

- The full three quarter impact from the addition of the Heartland facilities in the fourth 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.

Asset impairment charges for the nine months ended Sept. 30, 2025 increased by \$29 million, or 112 per cent, compared to the same period in 2024, primarily due to:

- An impairment charge on Required Divestiture assets classified as Assets Held for Sale;
- An Impairment charge, net of impairment reversals, related to certain Wind and Solar facilities due to changes in expected production volumes and price assumptions; and
- An increase in decommissioning and restoration provisions on retired assets driven by lower discount rates; partially offset by
- An impairment reversal related to certain Energy Transition assets reclassified to Assets held for sale.

Fair value change in contingent consideration payable totalling \$37 million was driven by updated expected sale proceeds related to the Required Divestitures.

Interest expense for the nine months ended Sept. 30, 2025 increased by \$34 million, or 15 per cent, compared to the same period in 2024, primarily due to:

- Lower capitalized interest resulting from lower construction activity during 2025 compared to the same period in 2024;
- Higher accretion of provisions; and
- Higher interest on debt driven by the addition of Heartland term facility.

Loss before income taxes for the nine months ended Sept. 30, 2025 increased by \$469 million from earnings before income taxes compared to the same period in 2024, due to the above noted items. Refer to the Segment

Financial Performance and Operating Results section for additional information.

Income tax expense for the nine months ended Sept. 30, 2025 decreased by \$69 million, or 78 per cent, compared to the same period in 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 for the nine months ended Sept. 30, 2025 decreased by \$30 million from net earnings attributable to non-controlling interests in the same period in 2024, primarily due to lower net earnings for TA Cogen resulting from lower merchant pricing in the Alberta market.

Adjusted EBITDA

For the three and nine months ended Sept. 30, 2025, the Company's Adjusted EBITDA was \$238 million and \$857 million, respectively, compared to \$315 million and \$973

million, respectively, in 2024, a decrease of \$77 million and \$116 million, respectively, or 24 and 12 per cent, respectively.

The major factors impacting Adjusted EBITDA are summarized in the following tables:

	3 months ended Sept. 30
Adjusted EBITDA for the three months ended Sept. 30, 2024 ⁽¹⁾	315
Hydro: Lower primarily due to lower ancillary services revenue due to lower availability and production optimization between the Gas and Hydro segments, lower environmental and tax attributes revenue due to lower sales of emission credits to third parties, lower spot power prices in the Alberta market, partially offset by higher merchant volumes and higher regulated transmission revenues related to the reimbursement of costs incurred in prior periods.	(16)
Wind and Solar: Higher due to higher environmental and tax attributes revenue driven by an increase in sales of emission credits to third parties and favourable pricing for Oklahoma facilities, partially offset by lower wind resource across Canada and United States and lower net other operating income due to no liquidated damages recognized in the current period.	1
Gas: Lower primarily due to higher dispatch optimization driven by lower market prices, lower spot power prices in the Alberta market and an increase in the carbon price, partially offset by the positive contribution from the addition of Heartland facilities, favourable hedge positions settled, which generated positive contributions over settled spot prices in Alberta and higher ancillary revenue due to production optimization between the Gas and Hydro segments.	(31)
Energy Transition: Lower primarily due to lower revenue driven by lower Mid-Columbia prices, partially offset by lower purchased power costs due to fewer repurchases to fulfill contractual obligations during outages and higher volume of favourable hedge positions settled.	(6)
Energy Marketing: Lower primarily due to comparatively subdued market volatility across North American natural gas and power markets and lower realized trades.	(25)
Corporate: Comparable to the same period in 2024.	—
Adjusted EBITDA⁽²⁾ for the three months ended Sept. 30, 2025	238

(1) 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 for more details.

(2) 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 \$53 million for the three months ended Sept. 30, 2025 (earnings before income taxes — \$9 million for the three months ended Sept. 30, 2024). Refer to Reconciliation of Non-IFRS Measures on a Consolidated Basis by Segments section of this MD&A.

9 months ended
Sept. 30

Adjusted EBITDA for the nine months ended Sept. 30, 2024 ⁽¹⁾	973
Hydro: Lower primarily due to lower ancillary revenue due to lower availability and production optimization between the Gas and Hydro segments, lower spot power prices in the Alberta market, partially offset by higher merchant and contract volumes, 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 fulfill our 2024 GHG obligation and higher volume of favourable hedge positions settled, which generated positive contributions over settled spot prices in Alberta.	(13)
Wind and Solar: Higher primarily due to positive contribution from 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 attribute revenue due to increased sales of emission credits to third parties and intercompany sales to the Gas segment, higher production volumes in Eastern Canada due to higher wind resource, partially offset by lower spot power prices and lower wind resource in Alberta.	15
Gas: Lower primarily due to higher dispatch optimization due to lower market prices, lower spot power prices in the Alberta market 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 by 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.	(66)
Energy Transition: Higher primarily due to lower purchased power costs driven by higher availability, which resulted in fewer repurchases to fulfill contractual obligations during outages 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.	21
Energy Marketing: Lower primarily due to comparatively subdued market volatility across North American natural gas and power markets and lower realized trades in the nine months ended Sept. 30, 2025 compared to the same period in 2024.	(56)
Corporate: Lower primarily due to increased spending to support strategic and growth initiatives and the addition of corporate costs related to Heartland.	(17)
Adjusted EBITDA⁽²⁾ for the nine months ended Sept. 30, 2025	857

(1) 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 for more details.

(2) 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 \$99 million for the nine months ended Sept. 30, 2025 (earnings before income taxes — \$370 million for the nine months ended Sept. 30, 2024). Refer to Reconciliation of Non-IFRS Measures on a Consolidated Basis by Segments section of this MD&A.

Free Cash Flow

For the three and nine months ended Sept. 30, 2025, the Company's FCF decreased compared to the same period in 2024. Refer to the Non-IFRS and Supplementary Financial Measures section in this MD&A for more details on this non-IFRS measure.

The major factors impacting FCF are summarized in the following tables:

	3 months ended Sept. 30
FCF for the three months ended Sept. 30, 2024	131
Lower Adjusted EBITDA ⁽¹⁾ due to the items noted above.	(77)
Lower current income tax expense due to the increase in loss before income taxes in 2025 compared to earnings before income taxes in the same period in 2024.	65
Higher net interest expense ⁽²⁾ primarily due to higher interest on debt driven by the addition of Heartland term facility.	(4)
Lower distributions paid to subsidiaries' non-controlling interests relating to lower TA Cogen net earnings resulting from lower merchant pricing in the Alberta market.	9
Other non-cash items ⁽³⁾	(8)
Other ⁽⁴⁾	(11)
FCF⁽⁵⁾ for the three months ended Sept. 30, 2025	105

(1) 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.

(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 Non-IFRS and Supplementary Financial Measures section of this MD&A for more information regarding this measure. The most directly comparable IFRS measure is total interest expense of \$85 million for the three months ended Sept. 30, 2025 (Sept. 30, 2024 — \$83 million).

(3) Other non-cash items consist of contract liabilities, onerous contracts and long-term incentive accruals.

(4) Other consists primarily of higher realized foreign exchange losses, higher decommissioning and restoration costs settled, higher sustaining capital expenditures and higher provisions accrued.

(5) 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 operations, which was \$251 million and \$229 million for the three months ended Sept. 30, 2025 and 2024, respectively. Refer to the Cash Flows section of this MD&A.

**9 months ended
Sept. 30**

FCF for the nine months ended Sept. 30, 2024	529
Lower Adjusted EBITDA ⁽¹⁾ due to the items noted above.	(116)
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, partially offset by no major maintenance occurring in the Energy Transition segment in the current period. In addition, the first quarter of 2024 was impacted by the receipt of a lease incentive related to the Company's head office.	(42)
Higher net interest expense ⁽²⁾ 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.	(37)
Lower distributions paid to subsidiaries' non-controlling interests relating to lower TA Cogen net earnings resulting from lower merchant pricing in the Alberta market.	31
Lower current income tax expense due to the increase in loss before income taxes in 2025 compared to earnings before income taxes in the same period in 2024.	66
Other non-cash items ⁽³⁾	(6)
Other ⁽⁴⁾	(4)
FCF⁽⁵⁾ for the nine months ended Sept. 30, 2025	421

- (1) 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.
- (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 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 \$266 million for the nine months ended Sept. 30, 2025 (Sept. 30, 2024 — \$232 million).
- (3) Other non-cash items consist of contract liabilities, onerous contracts and long-term incentive accruals.
- (4) Other consists primarily of lower realized foreign exchange losses, higher decommissioning and restoration costs settled, and higher provisions accrued.
- (5) 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 operations, which was \$415 million and \$581 million for the nine months ended Sept. 30, 2025 and 2024, respectively. Refer to the Cash Flows section of this MD&A.

2025 Outlook

The Company is tracking towards the low-end of its Adjusted EBITDA guidance and the mid-point of FCF and FCF per share guidance. The following table outlines our expectations on key financial targets and related assumptions for 2025 and should be read in conjunction with the narrative discussion that follows and the Governance and Risk Management section of this MD&A:

Measure	2025 Target ⁽²⁾	2024 Actual ⁽³⁾
Adjusted EBITDA ⁽¹⁾⁽⁴⁾	\$1,150 to \$1,250 million	\$1,255 million
FCF ⁽¹⁾	\$450 to \$550 million	\$569 million
FCF per share ⁽¹⁾	\$1.51 to \$1.85	\$1.88
Dividend per share	\$0.26 annualized	\$0.24 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 2024 amounts for the most directly comparable IFRS measures for Adjusted EBITDA and FCF were as follows: Earnings before income taxes \$319 million and Cash flow from operating activities \$796 million. The most directly comparable IFRS ratio to FCF per share is cash flow from operating activities per share of \$2.64, which is calculated as cash flow from operating activities for the period divided by weighted average number of common shares outstanding during the period. Refer to the Additional IFRS Measures and Non-IFRS Measures section of the 2024 Annual MD&A for additional information.

(4) 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.

The Company's outlook for 2025 may be impacted by a number of factors as detailed further below.

Range of key 2025 power and gas price assumptions

Market	2025 Assumptions
Alberta spot (\$/MWh)	\$40 to \$60
Mid-Columbia spot (US\$/MWh)	\$50 to \$70
AECO gas price (\$/GJ)	\$1.60 to \$2.10

Alberta spot price sensitivity: a +/- \$1 per MWh change in spot price is expected to have a +/- \$2 million impact on adjusted EBITDA for the balance of the year.

Other assumptions relevant to the 2025 outlook

Measure	2025 Expectations
Energy Marketing gross margin	\$110 to \$130 million
Sustaining capital	\$145 to \$165 million
Current income tax expense	\$95 to \$130 million
Net interest expense ⁽¹⁾	\$255 to \$275 million

(1) 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. The most directly comparable IFRS measure is total interest expense, which was \$324 million for the year ended Dec. 31, 2024.

Alberta Hedging

Range of hedging assumptions	Q4 2025	Full Year 2025	Full Year 2026
Hedged production (GWh)	1,898	8,661	7,813
Hedge price (\$/MWh)	\$72	\$69	\$66
Hedged gas volumes (GJ)	10.7 Million	46.2 Million	30.9 Million
Hedge gas prices (\$/GJ)	\$3.28	\$2.91	\$3.37

Refer to the 2025 Outlook section in our 2024 Annual MD&A for further details relating to our Outlook and related assumptions.

Liquidity and Capital Resources

We maintain adequate available liquidity under our committed credit facilities. As at Sept. 30, 2025, we had access to \$1.6 billion in liquidity, including \$211 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 and nine months ended Sept. 30:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2025	2024	2025	2024
Hydro	73	89	246	259
Wind and Solar	45	44	236	221
Gas	110	141	342	408
Energy Transition	28	34	84	63
Energy Marketing	17	42	64	120
Corporate	(35)	(35)	(115)	(98)
Adjusted EBITDA⁽¹⁾⁽²⁾	238	315	857	973
Adjusted earnings before income taxes⁽¹⁾	17	102	167	358
(Loss) earnings before income taxes	(53)	9	(99)	370
Adjusted net (loss) earnings attributable to common shareholders⁽¹⁾	(8)	35	76	233
Net (loss) earnings attributable to common shareholders	(62)	(36)	(128)	242

(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 Sept. 30, 2025 Variance Analysis (2025 versus 2024)

Adjusted earnings before income taxes for the three months ended Sept. 30, 2025 decreased by \$85 million, or 83 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; and
- Higher realized foreign exchange losses due to unfavourable foreign currency rates.

Adjusted net (loss) earnings attributable to common shareholders for the three months ended Sept. 30, 2025 decreased by \$43 million, or 123 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 lower earnings compared to the same period in 2024; and
- Lower calculated tax expense on adjustments and reclassifications compared to the same period in 2024.

Loss before income taxes for the three months ended Sept. 30, 2025, increased by \$62 million, compared to earnings before income taxes in the same period in 2024, primarily due to:

- Lower adjusted earnings before income taxes noted above; and
- Higher asset impairment charges, net of impairment reversals, related to the Wind and Solar facilities driven by changes in expected production volumes and price assumptions; partially offset by
- Lower asset impairment charges related to changes in decommissioning and restoration provisions on retired assets;
- Higher unrealized foreign exchange gains due to favourable changes in foreign currency rates; and
- Higher unrealized mark-to-market gains recorded in the Gas, Energy Marketing and Hydro segments primarily related to the favourable changes in forward prices.

Net loss attributable to common shareholders for the three months ended Sept. 30, 2025, increased by \$26 million from net loss attributable to common shareholders for the same period in 2024, primarily due to:

- The factors causing higher loss before income taxes above; partially offset by
- Lower income tax expense due to lower earnings compared to the same period in 2024; and
- Higher net loss attributable to non-controlling interests compared to the same period in 2024, primarily due to lower net earnings for TA Cogen resulting from lower merchant pricing in the Alberta market.

Nine months ended Sept. 30, 2025 Variance Analysis (2025 versus 2024)

Adjusted earnings before income taxes for the nine months ended Sept. 30, 2025 decreased by \$191 million, or 53 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 impact from the White Rock and Horizon Hill wind facilities which achieved commercial operation in the first half of 2024; and
- Higher interest expense due to higher interest on debt driven by the addition of Heartland term credit facility, lower capitalized interest resulting from lower construction activity in the current period compared to the same period in 2024 and higher accretion of provisions in the current period.

Adjusted net earnings attributable to common shareholders for the nine months ended Sept. 30, 2025 decreased by \$157 million, or 67 per cent, compared to the same period in 2024, primarily due to:

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

Loss before income taxes for the nine months ended Sept. 30, 2025 increased by \$469 million, or 127 per cent, from earnings before income taxes for the same period in 2024, primarily due to:

- Higher unrealized mark-to-market losses recorded in the Wind and Solar segment primarily related to 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;
- Higher unrealized mark-to-market losses recorded in the Gas and Energy Transition segments driven by unfavourable hedging positions in the current period;
- The factors causing lower adjusted earnings before income taxes noted above;
- An impairment charge on Required Divestiture assets classified as Assets Held for Sale;
- Higher spending related to the planning, design and implementation of an ERP system upgrade;
- Higher asset impairment charges due to an increase in decommissioning and restoration provisions on retired assets driven by lower discount rates; 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; partially offset by
- An impairment reversal related to certain energy transition assets reclassified to assets held for sale.

Net loss attributable to common shareholders for the nine months ended Sept. 30, 2025 increased by \$370 million, or 153 per cent, compared to net earnings attributable to common shareholders for the same period in 2024, primarily due to:

- The factors causing higher loss before income taxes above; partially offset by
- Lower income tax expense due to lower earnings compared to the same period in 2024, partially offset by higher valuation allowance on U.S. operations in the current period; and
- Higher net loss attributable to non-controlling interests compared the same period in 2024, primarily due to lower net earnings for TA Cogen resulting from lower merchant pricing in the Alberta market.

Hydro

	3 months ended Sept. 30				9 months ended Sept. 30			
	2025	2024	Change		2025	2024	Change	
Gross installed capacity (MW)	922	922	—	— %	922	922	—	— %
LTA generation (GWh)	573	573	—	— %	1,568	1,568	—	— %
Availability (%)	82.9	94.3	(11.4)	(12)%	91.1	92.3	(1.2)	(1)%
Production								
Contract production (GWh)	99	72	27	38 %	276	196	80	41 %
Merchant production (GWh)	524	422	102	24 %	1,302	1,075	227	21 %
Total energy production (GWh)	623	494	129	26 %	1,578	1,271	307	24 %
Ancillary service volumes (GWh)⁽¹⁾	674	878	(204)	(23)%	2,173	2,238	(65)	(3)%
Alberta Hydro Assets revenues ⁽²⁾	38	39	(1)	(3)%	103	111	(8)	(7)%
Other Hydro Assets revenues and other Hydro revenues ⁽³⁾	22	11	11	100 %	46	33	13	39 %
Alberta Hydro Assets ancillary services revenues ⁽¹⁾	32	48	(16)	(33)%	85	108	(23)	(21)%
Environmental and tax attributes revenues	—	8	(8)	(100)%	70	61	9	15 %
Adjusted revenues⁽⁴⁾	92	106	(14)	(13)%	304	313	(9)	(3)%
Fuel and purchased power	(5)	(4)	(1)	25 %	(16)	(13)	(3)	23 %
Adjusted gross margin⁽⁴⁾	87	102	(15)	(15)%	288	300	(12)	(4)%
OM&A	(14)	(13)	(1)	8 %	(40)	(39)	(1)	3 %
Taxes, other than income taxes	—	—	—	— %	(2)	(2)	—	— %
Adjusted EBITDA⁽⁴⁾	73	89	(16)	(18)%	246	259	(13)	(5)%
Depreciation and amortization	(9)	(8)	(1)	13 %	(26)	(23)	(3)	13 %
Adjusted earnings before income taxes⁽⁴⁾	64	81	(17)	(21)%	220	236	(16)	(7)%
Earnings before income taxes	67	80	(13)	(16)%	226	239	(13)	(5)%
Supplemental Information:								
Gross revenues per MWh								
Alberta Hydro Assets revenues (\$/MWh) ⁽²⁾	73	92	(19)	(21)%	79	103	(24)	(23)%
Alberta Hydro Assets ancillary services revenues (\$/MWh) ⁽¹⁾	47	55	(8)	(15)%	39	48	(9)	(19)%

(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 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 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 \$95 million and \$310 million for the three and nine months ended Sept. 30, 2025, respectively (Sept. 30, 2024 — \$105 million and \$316 million), to adjusted gross margin — gross margin of \$90 million and \$294 million for the three and nine months ended Sept. 30, 2025, respectively (Sept. 30, 2024 — \$101 million and \$303 million), to Adjusted EBITDA and Adjusted earnings before income taxes — earnings before income taxes of \$67 million and \$226 million for the three and nine months ended Sept. 30, 2025, respectively (Sept. 30, 2024 — \$80 million and \$239 million).

Adjusted revenues for the three months ended Sept. 30, 2025 decreased compared to the same period in 2024, primarily due to:

- Lower ancillary services revenue due to lower availability and production optimization between the Gas and Hydro segments;
- Lower environmental and tax attributes revenue due to lower sales of emission credits to third parties; and
- Lower spot power prices in the Alberta market; partially offset by
- Higher merchant and contract volumes; and
- Higher regulated transmission revenues related to the reimbursement of costs incurred in prior periods.

Adjusted EBITDA and Adjusted earnings before income taxes for the three months ended Sept. 30, 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 Sept. 30, 2025 decreased compared to the same period in 2024 due to:

- Lower adjusted earnings before income taxes; partially offset by
- Higher unrealized mark-to-market gains due to favourable forward pricing changes.

Adjusted revenues for the nine months ended Sept. 30, 2025 decreased compared to the same period in 2024, primarily due to:

- Lower ancillary services revenue due to lower availability and production optimization between the Gas and Hydro segments; and
- Lower spot power prices in Alberta; partially offset by
- Higher merchant and contract volumes;
- Higher regulated transmission revenues related to the reimbursement of costs incurred in prior periods;
- Higher environmental and tax attributes revenues due to increased intercompany sales of emission credits to the Gas segment to fulfill our 2024 GHG obligation; and
- Higher volume of favourable hedge positions settled, which generated positive contributions over settled spot prices in Alberta.

Adjusted EBITDA and Adjusted earnings before income taxes for the nine months ended Sept. 30, 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 nine months ended Sept. 30, 2025 decreased compared to the same period in 2024 due to lower adjusted earnings before income taxes.

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

Wind and Solar

	3 months ended Sept. 30				9 months ended Sept. 30			
	2025	2024	Change		2025	2024	Change	
Gross installed capacity (MW)⁽¹⁾	2,587	2,584	3	— %	2,587	2,584	3	— %
LTA generation (GWh)	1,472	1,472	—	— %	5,282	4,701	581	12 %
Availability (%)	94.3	93.7	0.6	1 %	94.3	93.8	0.5	1 %
Production								
Contract production (GWh)	897	949	(52)	(5)%	3,799	3,251	548	17 %
Merchant production (GWh)	131	172	(41)	(24)%	647	867	(220)	(25)%
Total production (GWh)	1,028	1,121	(93)	(8)%	4,446	4,118	328	8 %
Revenues ⁽²⁾	65	64	1	2 %	274	258	16	6 %
Environmental and tax attributes revenues ⁽²⁾	18	13	5	38 %	83	61	22	36 %
Adjusted revenues⁽³⁾⁽⁴⁾	83	77	6	8 %	357	319	38	12 %
Fuel and purchased power	(5)	(5)	—	— %	(24)	(22)	(2)	9 %
Carbon compliance	—	—	—	— %	(2)	—	(2)	— %
Adjusted gross margin⁽³⁾⁽⁴⁾	78	72	6	8 %	331	297	34	11 %
OM&A	(28)	(26)	(2)	8 %	(82)	(70)	(12)	17 %
Taxes, other than income taxes	(5)	(5)	—	— %	(15)	(13)	(2)	15 %
Adjusted net other operating income ⁽⁴⁾	—	3	(3)	(100)%	2	7	(5)	(71)%
Adjusted EBITDA⁽³⁾⁽⁴⁾	45	44	1	2 %	236	221	15	7 %
Depreciation and amortization	(52)	(53)	1	(2)%	(157)	(143)	(14)	10 %
Adjusted (loss) earnings before income taxes⁽³⁾⁽⁴⁾	(7)	(9)	2	(22)%	79	78	1	1 %
(Loss) earnings before income taxes⁽⁵⁾	(106)	(82)	(24)	29 %	(127)	7	(134)	(1914)%

(1) Gross installed capacity for 2025 increased due to the transmission adjustments for the White Rock East and Horizon Hill wind facilities of 2 MW each and Tower removal at Sinott in December 2024, which reduced gross installed capacity by 1 MW.

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

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

(4) Adjusted revenues, adjusted gross margin, adjusted net other operating income, adjusted EBITDA and adjusted (loss) 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 \$(1) million and \$155 million for the three and nine months ended Sept. 30, 2025, respectively (Sept. 30, 2024 — \$(1) million and \$239 million), to adjusted gross margin — gross margin of \$6 million and \$129 million for the three and nine months ended Sept. 30, 2025, respectively (Sept. 30, 2024— \$(6) million and \$217 million), to adjusted net other operating income — net other operating income of nil and \$4 million for the three and nine months ended Sept. 30, 2025, respectively (Sept. 30, 2024 — \$3 million and \$7 million), to adjusted EBITDA and adjusted earnings before income taxes — loss before income taxes of \$106 million and \$127 million for the three and nine months ended Sept. 30, 2025, respectively (Sept. 30, 2024 — loss before income taxes of \$82 million and earnings before income taxes of \$7 million).

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

Adjusted revenues for the three months ended Sept. 30, 2025 increased compared to the same period in 2024, primarily due to:

- Higher environmental and tax attributes revenue driven by an increase in sales of emission credits to third parties; and
- Favourable pricing for Oklahoma facilities; partially offset by
- Lower wind resource across Canada and United States.

Adjusted EBITDA for the three months ended Sept. 30, 2025 was comparable to the same period in 2024 primarily due to:

- Higher adjusted revenue; partially offset by
- Lower net other operating income due to no liquidated damages recognized in the current period.

Adjusted loss before income taxes for the three months ended Sept. 30, 2025 was comparable to the same period in 2024.

Loss before income taxes for the three months ended Sept. 30, 2025 increased compared to in the same period in 2024 due to an impairment charge, net of impairment reversals on certain facilities driven by changes in expected production volumes and price assumptions.

Adjusted revenues for the nine months ended Sept. 30, 2025 increased compared to the same period in 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 in Eastern Canada due to higher wind resource; partially offset by
- Lower Alberta spot power prices; and
- Lower production volumes in Alberta due to lower wind resource.

Adjusted EBITDA for the nine months ended Sept. 30, 2025 increased compared to the same period in 2024, primarily due to:

- Higher adjusted revenues as explained by the factors above; partially offset by
- Higher OM&A mainly due to the addition of new wind facilities in the first half of 2024.

Adjusted earnings before income taxes for the the nine months ended Sept. 30, 2025 were comparable to the same period in 2024, primarily due to:

- Higher adjusted EBITDA as explained above; 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 nine months ended Sept. 30, 2025 increased from earnings before income taxes in the same period 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 Sept. 30				9 months ended Sept. 30			
	2025	2024	Change		2025	2024	Change	
Gross installed capacity (MW)⁽¹⁾	4,834	3,087	1,747	57 %	4,834	3,087	1,747	57 %
Availability (%)	95.4	96.3	(0.9)	(1)%	93.7	95.4	(1.7)	(2)%
Production								
Contract sales volume (GWh)	2,337	1,603	734	46 %	7,084	4,942	2,142	43 %
Merchant sales volume (GWh)	1,402	1,736	(334)	(19)%	3,274	5,189	(1,915)	(37)%
Purchased power (GWh) ⁽²⁾	(225)	(220)	(5)	2 %	(854)	(689)	(165)	24 %
Total production (GWh)	3,514	3,119	395	13 %	9,504	9,442	62	1 %
Adjusted revenues⁽³⁾	321	317	4	1 %	969	963	6	1 %
Adjusted fuel and purchased power ⁽³⁾	(120)	(100)	(20)	20 %	(386)	(339)	(47)	14 %
Carbon compliance	(35)	(40)	5	(13)%	(76)	(106)	30	(28)%
Adjusted gross margin⁽³⁾	166	177	(11)	(6)%	507	518	(11)	(2)%
Adjusted OM&A ⁽³⁾	(62)	(43)	(19)	44 %	(183)	(131)	(52)	40 %
Taxes, other than income taxes	(5)	(3)	(2)	67 %	(15)	(9)	(6)	67 %
Net other operating income	11	10	1	10 %	33	30	3	10 %
Adjusted EBITDA⁽³⁾⁽⁴⁾	110	141	(31)	(22)%	342	408	(66)	(16)%
Depreciation and amortization	(59)	(52)	(7)	13 %	(197)	(163)	(34)	21 %
Adjusted earnings before income taxes⁽³⁾	51	89	(38)	(43)%	145	245	(100)	(41)%
Earnings before income taxes	63	88	(25)	(28)%	105	318	(213)	(67)%

(1) Gross installed capacity and availability for 2025 include the 1,747 MW Heartland gas facilities and exclude the Required Divestitures.

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

(3) 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 \$326 million and \$920 million for the three and nine months ended Sept. 30, 2025, respectively (Sept. 30, 2024 — \$314 million and \$1,031 million), to adjusted fuel and purchased power — fuel and purchased power of \$119 million and \$388 million for the three and nine months ended Sept. 30, 2025, respectively (Sept. 30, 2024 — \$100 million and \$339 million), to adjusted gross margin — gross margin of \$172 million and \$456 million for the three and nine months ended Sept. 30, 2025, respectively (Sept. 30, 2024 — \$174 million and \$586 million), to adjusted OM&A — OM&A of \$64 million and \$188 million for the three and nine months ended Sept. 30, 2025, respectively (Sept. 30, 2024 — \$43 million and \$131 million), to adjusted EBITDA and adjusted earnings before income taxes — earnings before income taxes of \$63 million and \$105 million for the three and nine months ended Sept. 30, 2025, respectively (Sept. 30, 2024 — \$88 million and \$318 million).

(4) 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.

Adjusted revenues for the three months ended Sept. 30, 2025 increased compared to the same period in 2024, primarily due to:

- Addition of gas facilities from Heartland;
- Higher ancillary revenue due to production optimization between the Gas and Hydro segments; 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.

Adjusted EBITDA for the three months ended Sept. 30, 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; and
- An increase in the carbon price from \$80 to \$95 per tonne, impacting gross margin from our Canadian gas facilities; partially offset by
- 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 three months ended Sept. 30, 2025 decreased compared to the same period in 2024 due to:

- Lower adjusted EBITDA as explained above; and
- Higher depreciation due to the addition of the Heartland facilities.

Earnings before income taxes for the three months ended Sept. 30, 2025 decreased 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 in the current period compared to the same period in 2024.

Adjusted revenues for the nine months ended Sept. 30, 2025 increased compared to the same period in 2024, primarily due to:

- Addition of gas facilities from Heartland; and
- Favourable hedge positions settled, which generated positive contributions over settled spot prices in Alberta; and

- Higher ancillary revenue due to production optimization between the Gas and Hydro segments; 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.

Adjusted EBITDA for the nine months ended Sept. 30, 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; 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 of prior year to settle a portion of our 2024 GHG obligation and a portion of the 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 nine months ended Sept. 30, 2025 decreased compared to the same period in 2024 due to:

- Lower adjusted EBITDA as explained above; and
- Higher depreciation due to the addition of the Heartland facilities.

Earnings before income taxes for the nine months ended Sept. 30, 2025 decreased due to:

- Higher unrealized mark-to-market losses due to less favourable hedges in the current period compared to the same periods in 2024;
- Lower adjusted earnings before income taxes compared to the same period in 2024; and
- An impairment charge on the Required Divestitures recognized in the first quarter of 2025; partially offset by
- Fair value gain on the contingent consideration payable driven by updated expected sale proceeds related to the Required Divestitures; and
- Higher lease income due to the addition of finance leases from the Heartland acquisition.

Energy Transition

	3 months ended Sept. 30				9 months ended Sept. 30			
	2025	2024	Change		2025	2024	Change	
Gross installed capacity (MW)	671	671	—	— %	671	671	—	— %
Availability (%)	83.3	90.0	(6.7)	(7)%	87.2	76.1	11.1	15 %
Production								
Contract sales volume (GWh)	662	840	(178)	(21)%	1,965	2,499	(534)	(21)%
Merchant sales volume (GWh)	1,130	1,087	43	4 %	2,516	2,064	452	22 %
Purchased power (GWh) ⁽¹⁾	(806)	(949)	143	(15)%	(2,213)	(2,782)	569	(20)%
Total production (GWh)	986	978	8	1 %	2,268	1,781	487	27 %
Adjusted revenues⁽²⁾	148	157	(9)	(6)%	389	433	(44)	(10)%
Fuel and purchased power	(98)	(104)	6	(6)%	(247)	(316)	69	(22)%
Carbon compliance	—	(1)	1	(100)%	—	(1)	1	— %
Adjusted gross margin⁽²⁾	50	52	(2)	(4)%	142	116	26	22 %
OM&A	(20)	(17)	(3)	18 %	(55)	(50)	(5)	10 %
Taxes, other than income taxes	(2)	(1)	(1)	100 %	(3)	(3)	—	100 %
Adjusted EBITDA⁽²⁾	28	34	(6)	(18)%	84	63	21	33 %
Depreciation and amortization	(11)	(17)	6	(35)%	(39)	(48)	9	(19)%
Adjusted earnings before income taxes⁽²⁾	17	17	—	— %	45	15	30	200 %
Earnings before income taxes	23	8	15	188 %	50	31	19	61 %
Supplemental information:								
Highvale mine reclamation spend ⁽³⁾	2	2	—	— %	8	8	—	— %
Centralia mine reclamation spend ⁽³⁾	4	5	(1)	(20)%	12	12	—	— %

(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 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 \$158 million and \$385 million for the three and nine months ended Sept. 30, 2025, respectively (Sept. 30, 2024 — \$165 million and \$461 million), to adjusted gross margin — gross margin \$60 million and \$138 million for the three and nine months ended Sept. 30, 2025, respectively (Sept. 30, 2024 — \$60 million and \$144 million), to adjusted EBITDA and adjusted earnings before income taxes — earnings before income taxes of \$23 million and \$50 million for the three and nine months ended Sept. 30, 2025, respectively (Sept. 30, 2024 — \$8 million and \$31 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.

Adjusted revenues for the three months ended Sept. 30, 2025 decreased compared to the same period in 2024, primarily due to:

- Lower Mid-Columbia prices; partially offset by
- Higher volume of favourable hedge positions settled.

Adjusted EBITDA for the three months ended Sept. 30, 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 fulfill contractual obligations during outages.

Adjusted earnings before income taxes for the three months ended Sept. 30, 2025 were comparable to the same period in 2024.

Earnings before income taxes for the three months ended Sept. 30, 2025 increased compared to the same period in 2024 due to lower asset impairment charges related to changes in decommissioning and restoration provision on retired assets.

Mine reclamation spend for the three months ended Sept. 30, 2025 was consistent with the same period in 2024.

Adjusted revenues for the nine months ended Sept. 30, 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 nine months ended Sept. 30, 2025 increased compared to the same period in 2024 due to:

- Lower purchased power costs driven by higher availability, which resulted in fewer repurchases to fulfill contractual obligations during outages; 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 nine months ended Sept. 30, 2025 increased compared to the same period in 2024 due to higher adjusted EBITDA as explained above.

Earnings before income taxes for the nine months ended Sept. 30, 2025 increased compared to the same period in 2024 due to:

- Higher adjusted earnings before income taxes as explained above; and
- Impairment reversal related to generation equipment in the current period; partially offset by
- Higher unrealized mark-to-market losses due to less favourable hedges in the current period; and
- Higher asset impairment charges related to an increase in decommissioning and restoration provision on retired assets driven by lower discount rates.

Mine reclamation spend for the nine months ended Sept. 30, 2025 was consistent with the same period in 2024.

Energy Marketing

	3 months ended Sept. 30				9 months ended Sept. 30			
	2025	2024	Change		2025	2024	Change	
Adjusted revenues ⁽¹⁾	30	52	(22)	(42)%	92	149	(57)	(38)%
OM&A	(13)	(10)	(3)	30 %	(28)	(29)	1	(3)%
Adjusted EBITDA⁽¹⁾⁽²⁾	17	42	(25)	(60)%	64	120	(56)	(47)%
Depreciation and amortization	—	—	—	— %	(2)	(2)	—	— %
Adjusted earnings before income taxes⁽¹⁾⁽²⁾	17	42	(25)	(60)%	62	118	(56)	(47)%
Earnings before income taxes	24	45	(21)	(47)%	72	123	(51)	(41)%

(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 and nine months ended Sept. 30, 2025 is revenues of \$37 million and \$102 million, respectively (Sept. 30, 2024 — \$55 million and \$154 million), to adjusted EBITDA and adjusted earnings before income taxes — earnings before income taxes of \$24 million and \$72 million, respectively (Sept. 30, 2024 — \$45 million and \$123 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.

Adjusted revenues and Adjusted EBITDA for the three and nine months ended Sept. 30, 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 trades in 2025 in comparison to the same periods in the prior year.

Adjusted earnings before income taxes for the three and nine months ended Sept. 30, 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 and nine months ended Sept. 30, 2025 decreased compared to the same periods in 2024 due to lower adjusted earnings before income taxes.

Corporate

	3 months ended Sept. 30				9 months ended Sept. 30			
	2025	2024	Change		2025	2024	Change	
Adjusted OM&A ⁽¹⁾	(34)	(34)	—	—%	(113)	(97)	(16)	16%
Taxes, other than income taxes	(1)	(1)	—	100%	(2)	(1)	(1)	100%
Adjusted EBITDA⁽¹⁾	(35)	(35)	—	—%	(115)	(98)	(17)	17%
Depreciation and amortization	(6)	(5)	(1)	20%	(15)	(14)	(1)	7%
Equity income from associate	(1)	—	(1)	—%	(2)	(1)	(1)	100%
Interest income	9	6	3	50%	21	21	—	—%
Interest expense	(87)	(86)	(1)	1%	(270)	(235)	(35)	15%
Realized foreign exchange (loss) gain ⁽²⁾	(5)	2	(7)	(350%)	(3)	(7)	4	(57%)
Adjusted loss before income taxes⁽¹⁾	(125)	(118)	(7)	6%	(384)	(334)	(50)	15%
Loss before income taxes	(124)	(130)	6	(5%)	(425)	(348)	(77)	22%

(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 and nine months ended Sept. 30, 2025 is OM&A of \$41 million and \$135 million, respectively (Sept. 30, 2024 — \$35 million and \$105 million). The most directly comparable IFRS measure to adjusted EBITDA and adjusted loss before income taxes is loss before income taxes of \$124 million and \$425 million for the three and nine months ended Sept. 30, 2025, respectively (Sept. 30, 2024 — \$130 million and \$348 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.

Adjusted EBITDA for the three months ended Sept. 30, 2025 was comparable to the same period in 2024.

Adjusted loss before income taxes for the three months ended Sept. 30, 2025 increased compared to the same period in 2024 due to higher realized foreign exchange losses driven by unfavourable changes in foreign currency rates.

Loss before income taxes for the three months ended Sept. 30, 2025 decreased compared to the same period in 2024 due to:

- Higher unrealized foreign exchange gains driven by favourable changes in foreign currency rates; partially offset by
- Higher adjusted loss before income taxes as explained above; and
- Higher spending related to the implementation of an upgrade to our ERP system.

Adjusted EBITDA for the nine months ended Sept. 30, 2025 decreased compared to the same period in 2024 primarily due to:

- Increased spending to support strategic and growth initiatives; and
- The addition of corporate costs related to Heartland.

Adjusted loss before income taxes for the nine months ended Sept. 30, 2025 increased compared to the same period in 2024 due to:

- Lower Adjusted EBITDA as explained above; and
- Higher interest expense due to higher interest on debt driven by the addition of Heartland term facility, lower capitalized interest resulting from lower construction activity during 2025 compared to the same period in 2024, and higher accretion of provisions in the current period.

Loss before income taxes for the nine months ended Sept. 30, 2025 increased compared to the same period in 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.

Performance by Segment with Supplemental Geographical Information

The following tables provide adjusted EBITDA by segment across the regions we operate in:

3 months ended Sept. 30, 2025	Hydro	Wind & Solar ⁽³⁾	Gas	Energy Transition	Energy Marketing	Corporate	Total
Alberta	68	—	55	(2)	17	(35)	103
Canada, excluding Alberta	5	15	27	—	—	—	47
US	—	28	4	30	—	—	62
Western Australia	—	2	24	—	—	—	26
Adjusted EBITDA ⁽¹⁾	73	45	110	28	17	(35)	238
Adjusted earnings (loss) before income taxes ⁽¹⁾	64	(7)	51	17	17	(125)	17
Earnings (loss) before income taxes	67	(106)	63	23	24	(124)	(53)

3 months ended Sept. 30, 2024	Hydro	Wind & Solar ⁽³⁾	Gas	Energy Transition	Energy Marketing	Corporate	Total
Alberta	86	3	92	(2)	42	(35)	186
Canada, excluding Alberta	3	12	22	—	—	—	37
US	—	27	3	36	—	—	66
Western Australia	—	2	24	—	—	—	26
Adjusted EBITDA ⁽¹⁾⁽²⁾	89	44	141	34	42	(35)	315
Adjusted earnings (loss) before income taxes ⁽¹⁾	81	(9)	89	17	42	(118)	102
Earnings (loss) before income taxes	80	(82)	88	8	45	(130)	9

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

9 months ended Sept. 30, 2025	Hydro	Wind & Solar ⁽³⁾	Gas	Energy Transition	Energy Marketing	Corporate	Total
Alberta	235	31	181	(7)	64	(115)	389
Canada, excluding Alberta	11	95	81	—	—	—	187
U.S.	—	104	9	91	—	—	204
Western Australia	—	6	71	—	—	—	77
Adjusted EBITDA ⁽¹⁾	246	236	342	84	64	(115)	857
Adjusted earnings (loss) before income taxes ⁽¹⁾	220	79	145	45	62	(384)	167
Earnings (loss) before income taxes	226	(127)	105	50	72	(425)	(99)

9 months ended Sept. 30, 2024	Hydro	Wind & Solar ⁽³⁾	Gas	Energy Transition	Energy Marketing	Corporate	Total
Alberta	253	43	259	(7)	120	(98)	570
Canada, excluding Alberta	6	80	72	—	—	—	158
U.S.	—	92	9	70	—	—	171
Western Australia	—	6	68	—	—	—	74
Adjusted EBITDA ⁽¹⁾⁽²⁾	259	221	408	63	120	(98)	973
Adjusted earnings (loss) before income taxes ⁽¹⁾	236	78	245	15	118	(334)	358
Earnings (loss) before income taxes	239	7	318	31	123	(348)	370

(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) Earnings (loss) 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 enhanced and further diversified TransAlta's competitive portfolio in the highly dynamic and shifting electricity landscape in Alberta, by adding 507 MW of contracted cogeneration capacity, 387 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 is 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 (C&I) 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 monetize its hedged or contract positions. This results in a change in revenue that is not correlated 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 C&I contracts 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. These services are provided in the event of a system-wide blackout in the province, as well as 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 intercompany to the Gas segment.

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

	2025					2024				
3 months ended Sept. 30	Hydro	Wind & Solar ⁽⁴⁾	Gas ⁽⁵⁾	Energy Transition	Total	Hydro	Wind & Solar	Gas	Energy Transition	Total
Gross installed capacity (MW)	834	764	3,650	—	5,248	834	766	1,963	—	3,563
Total production ⁽¹⁾ (GWh)	524	245	2,437	—	3,206	422	332	2,014	—	2,768
Contract production (GWh)	—	114	1,345	—	1,459	—	160	529	—	689
Merchant production (GWh)	524	131	1,092	—	1,747	422	172	1,485	—	2,079
Hedged volumes (GWh)	393	18	2,105	—	2,516	159	22	2,184	—	2,365
Production contracted or hedged (%)	75%	54%	142%	—%	124%	38%	55%	135%	—%	110%
Hedged volumes as a percentage of gross installed capacity (%)	22%	1%	26%	—%	22%	9%	1%	51%	—%	30%
Adjusted revenues ⁽²⁾⁽³⁾ (\$)	86	15	198	1	300	101	14	215	1	331
Fuel (\$)	2	2	70	—	74	2	2	65	—	69
Purchased power (\$)	1	1	14	—	16	1	—	12	—	13
Carbon compliance cost ⁽³⁾ (\$)	—	—	28	—	28	—	—	34	—	34
Adjusted gross margin ⁽²⁾ (\$)	83	12	86	1	182	98	12	104	1	215

(1) Total production includes contract and merchant production.

(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.

(4) Gross installed capacity for Wind and Solar was reduced due to tower removal at Sinott.

(5) Gross installed capacity for Alberta facilities in 2025 includes 1,687 MW from the acquisition of Heartland and excludes capacity from the Required Divestitures.

Three months ended Sept. 30, 2025 Variance Analysis (2025 versus 2024)

Total production for the Alberta portfolio for the three months ended Sept. 30, 2025 was 3,206 GWh compared to 2,768 GWh in the same period of 2024. The increase of 438 GWh, or 16 per cent was primarily due to:

- Higher contract production in the Gas segment due to the addition of Heartland gas facilities in the fourth quarter of 2024; and
- Higher production from the Hydro segment due to the optimization of water supply to facilitate generation during higher demand periods; partially offset by

- Lower merchant production in the Gas segment due to dispatch optimization driven by lower market prices; and
- Lower production volumes in the Wind and Solar segment due to lower wind resource in Alberta.

Hedged volumes for the three months ended Sept. 30, 2025 increased compared to the same period in 2024 in anticipation of the weakening spot market prices. 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 Sept. 30, 2025 was \$182 million compared

to \$215 million in the same period of 2024. The decrease of \$33 million, or 15 per cent, was primarily due to:

- The impact of lower Alberta spot prices;
- Lower merchant production in the Gas segment due to higher dispatch optimization driven by lower market prices;
- An increase in the carbon price per tonne from \$80 in 2024 to \$95 in 2025; and
- Lower gains realized on financial hedges; partially offset by

- Positive contribution from the addition of the Heartland facilities in the Gas segment;
- Higher production in the Hydro segment due to higher water reserves in Alberta due to higher precipitation during the quarter; and
- Favourable impact on carbon compliance cost due to an increase of production from lower carbon-emitting cogeneration facilities.

	2025					2024				
9 months ended Sept. 30	Hydro	Wind & Solar ⁽⁴⁾	Gas ⁽⁵⁾	Energy Transition	Total	Hydro	Wind & Solar	Gas	Energy Transition	Total
Gross installed capacity (MW)	834	764	3,650	—	5,248	834	766	1,963	—	3,563
Total production ⁽¹⁾ (GWh)	1,302	1,242	6,324	—	8,868	1,076	1,362	6,221	—	8,659
Contract production (GWh)	—	595	3,863	—	4,458	—	671	1,729	—	2,400
Merchant production (GWh)	1,302	647	2,461	—	4,410	1,076	691	4,492	—	6,259
Hedged volumes (GWh)	996	84	5,684	—	6,764	353	91	5,997	—	6,441
Production contracted or hedged (%)	76%	55%	151%	—%	127%	33%	56%	124%	—%	102%
Hedged volumes as a percentage of gross installed capacity (%)	18%	2%	24%	—%	20%	7%	2%	47%	—%	28%
Adjusted revenues ⁽²⁾⁽³⁾ (\$)	285	79	594	4	962	298	81	644	4	1,027
Fuel (\$)	5	9	231	—	245	5	8	211	—	224
Purchased power (\$)	8	2	39	—	49	6	2	46	—	54
Carbon compliance costs ⁽³⁾ (\$)	—	2	51	—	53	—	—	91	1	92
Adjusted gross margin ⁽²⁾ (\$)	272	66	273	4	615	287	71	296	3	657

(1) Total production includes contract and merchant production.

(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 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.

(4) Gross installed capacity for Wind and Solar was reduced due to tower removal at Sinott.

(5) Gross installed capacity for Alberta facilities in 2025 includes 1,687 MW from the acquisition of Heartland and excludes capacity from the Required Divestitures.

Nine months ended Sept. 30, 2025 Variance Analysis (2025 versus 2024)

Total production for the Alberta portfolio for the nine months ended Sept. 30, 2025 was 8,868 GWh compared to 8,659 GWh in the same period of 2024. The increase of 209 GWh, or two per cent was primarily due to:

- Higher contract production in the Gas segment due to the addition of 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.

Hedged volumes for the nine months ended Sept. 30, 2025 increased compared to the same period in 2024. The Company deployed a defensive strategy to increase 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 nine months ended Sept. 30, 2025 was \$615 million compared to \$657 million in the same period of 2024. The decrease of \$42 million, or six per cent, was primarily due to:

- The impact of lower Alberta spot and ancillary services prices;
- Lower merchant production in the Gas segment due to higher dispatch optimization driven by lower market prices;
- Higher fuel costs in the Gas segment due to higher natural gas prices;
- Lower favourable realized hedge positions; and
- An increase in the carbon price from \$80 per tonne in 2024 to \$95 per tonne in 2025; partially offset by
- Positive contribution from the addition of the Heartland facilities in the Gas segment;
- Lower carbon compliance costs in the current period due to utilization of internally generated and externally purchased emission credits in the current period compared to the same period of prior year to settle a portion of our 2024 GHG obligation and a portion of the GHG obligation assumed in the Heartland acquisition and favourable impact from an increase in 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 Sept. 30		9 months ended Sept. 30	
	2025	2024	2025	2024
Alberta Market				
Spot power price average per MWh	51	55	44	67
Natural gas price (AECO) per GJ	0.63	0.67	1.43	1.24
Carbon compliance price per tonne	95	80	95	80
Alberta Portfolio Results				
Realized merchant power price per MWh ⁽¹⁾	103	90	107	91
Hydro energy spot power price per MWh	76	83	76	95
Hydro ancillary services price per MWh	47	55	39	48
Wind energy spot power price per MWh	28	35	23	40
Gas spot power price per MWh	79	73	66	84
Hedged power price average per MWh ⁽²⁾	66	85	69	86
Hedged volume (GWh)	2,516	2,365	6,764	6,441
Fuel cost per MWh ⁽³⁾	30	34	39	36
Carbon compliance cost per MWh ⁽⁴⁾	11	17	8	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) 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 for the Alberta portfolio for the three and nine months ended Sept. 30, 2025 decreased from \$55 and \$67 per MWh, respectively, in 2024, to \$51 and \$44 per MWh, primarily due to the addition of increased supply from renewables and combined-cycle gas facilities into the market compared to the same periods in 2024 and the impact of a milder weather on the nine months ended Sept. 30, 2025.

The realized merchant power price per MWh of production for the Alberta portfolio for the three and nine months ended Sept. 30, 2025 increased by \$13 and \$16 per MWh, respectively, compared to the same periods in 2024, primarily due to:

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

Fuel cost per MWh for the three months ended Sept. 30, 2025 decreased by \$4 per MWh, compared to the same period in 2024, due to lower natural gas prices.

Fuel cost per MWh for the nine months ended Sept. 30, 2025 increased by \$3 per MWh, compared to the same period in 2024, due to higher natural gas prices.

Carbon compliance cost per MWh of production for the three months ended Sept. 30, 2025 decreased by \$6 per MWh, compared to the same period in 2024, primarily due to:

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

Carbon compliance cost per MWh of production for the nine months ended Sept. 30, 2025 decreased by \$7 per MWh, compared to the same period in 2024, primarily due to:

- Utilization of higher quantity of internally generated and externally purchased emission credits in the current period compared to the same period of prior year to settle a portion of our 2024 GHG obligation and a portion of the GHG obligation assumed in the Heartland acquisition; and
- Favourable impact on carbon compliance cost due to an increase of production from lower carbon-emitting cogeneration facilities; partially offset by
- An increase in the carbon price per tonne from \$80 in 2024 to \$95 in 2025.

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.

	Q4 2024	Q1 2025	Q2 2025	Q3 2025
Revenues	678	758	433	615
Carbon compliance costs (recovery)	39	49	(74)	35
OM&A	234	173	173	179
Depreciation and amortization	143	146	150	135
(Loss) earnings before income taxes	(51)	49	(95)	(53)
Net (loss) earnings attributable to common shareholders	(65)	46	(112)	(62)
Net (loss) earnings per share attributable to common shareholders, basic and diluted ⁽¹⁾	(0.22)	0.15	(0.38)	(0.20)
Cash flow from operating activities	215	7	157	251

	Q4 2023	Q1 2024	Q2 2024	Q3 2024
Revenues	624	947	582	638
Carbon compliance costs (recovery)	27	40	(8)	41
OM&A	150	134	144	143
Depreciation and amortization	132	124	131	133
(Loss) earnings before income taxes	(35)	267	94	9
Net (loss) earnings attributable to common shareholders	(84)	222	56	(36)
Net (loss) earnings per share attributable to common shareholders, basic and diluted ⁽¹⁾	(0.27)	0.72	0.18	(0.12)
Cash flow from operating activities	310	244	108	229

(1) Basic and diluted (loss) earnings 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 (loss) earnings per share for the four quarters making up the calendar year may sometimes differ from the annual (loss) earnings per share.

Operating results have been impacted by the following events:

- Acquisition of Heartland on Dec. 4, 2024; and
- Commissioning of the Northern Goldfields solar facilities in the fourth quarter of 2023, 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:

- Higher production in all three quarters of 2025 and the fourth quarter of 2024 compared to the same periods in the prior year;
- The effects of unrealized mark-to-market gains and losses from hedging and derivative positions;
- Lower realized pricing in the fourth quarter of 2024 primarily due to the impact of additions of new natural gas, wind and solar supply in the Alberta market; and
- Higher realized pricing in all three quarters of 2025 compared to the same periods in the prior year due to favourable realized hedge positions and optimization in the current period, which generated positive contributions over settled spot prices.

Carbon compliance costs (recovery) have been impacted by:

- 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 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; and
- In the second quarter of 2024, carbon compliance costs were reduced by 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;
- Return to service of the Kent Hills wind facilities and 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 three 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 all 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 Hydro ancillary services provided during 2021 and 2022.

Depreciation has been impacted by:

- Revisions in the useful lives of certain facilities that occurred in the third quarter 2024;
- 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.

Higher asset impairment charges due to:

- An impairment charge on the Required Divestitures classified as held for sale in the first quarter of 2025;
- Development projects that are no longer proceeding in the first and second quarters of 2025 and the third and fourth quarters of 2024;

- Increase in decommissioning provisions for retired assets due to changes in estimated cash flows in the third quarter of 2023 and 2024;
- Increase in decommissioning provisions for retired assets due to lower discount rates in the second and third quarter of 2025;
- Changes in the expected timing of when decommissioning occurs, impacting the calculation of decommissioning provision in the third and fourth quarters of 2024;
- Impairment reversal related to certain Energy Transition assets reclassified to Assets held for sale in the first 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.

(Loss) earnings before income taxes has been impacted by the following:

- The items described above;
- Fair value change in contingent consideration payable during 2025 driven by updated expected sale proceeds related to the Required Divestitures; and
- Higher interest expense due to higher interest on debt driven by the addition of Heartland term facility, lower capitalized interest during 2025 as a result of lower capital activity during the nine months ended Sept. 30, 2025, and higher accretion of provisions in the current period compared to the same periods in 2024.

Net (loss) earnings attributable to common shareholders has been impacted by fluctuations in current and deferred tax expense with (loss) earnings before tax across the quarters.

Cash flow from operating activities has been impacted by the following:

- The items described above;
- Favourable changes in non-cash operating working capital balances in the third and second quarters of 2025, compared to same periods in prior year, due to timing of cash receipts, partially offset by higher payables and accrued liabilities, and lower prepaid expense due to insurance driven timing of payments; and
- Lower provisions and other non-cash items in the second and first quarter of 2025 compared to the same periods in 2024.

Financial Position

The following table highlights significant changes in the Condensed Consolidated Statements of Financial Position from Dec. 31, 2024 to Sept. 30, 2025:

	Sept. 30, 2025	Dec. 31, 2024	Increase/(decrease)
Assets			
Current assets			
Cash and cash equivalents	211	337	(126)
Risk management assets	159	318	(159)
Assets held for sale	45	80	(35)
Other current assets ⁽¹⁾	1,043	1,038	5
Total current assets	1,458	1,773	(315)
Non-current assets			
Risk management assets	38	93	(55)
Property, plant and equipment, net	5,748	6,020	(272)
Long-term financial assets	125	—	125
Other non-current assets ⁽²⁾	1,523	1,613	(90)
Total non-current assets	7,434	7,726	(292)
Total assets	8,892	9,499	(607)
Liabilities			
Current liabilities			
Accounts payable, accrued liabilities and other current liabilities	637	756	(119)
Risk management liabilities	150	277	(127)
Decommissioning and other provisions (current)	110	83	27
Dividends payable	19	49	(30)
Credit facilities, long-term debt and lease liabilities	169	572	(403)
Contingent consideration payable	15	81	(66)
Other current liabilities ⁽³⁾	750	751	(1)
Total current liabilities	1,850	2,569	(719)
Non-current liabilities			
Credit facilities, long-term debt and lease liabilities	3,496	3,236	260
Decommissioning and other provisions (long-term)	871	850	21
Risk management liabilities (long-term)	441	305	136
Other non-current liabilities ⁽⁴⁾	622	696	(74)
Total non-current liabilities	5,430	5,087	343
Total liabilities	7,280	7,656	(376)
Equity			
Equity attributable to shareholders	1,534	1,746	(212)
Non-controlling interests	78	97	(19)
Total equity	1,612	1,843	(231)
Total liabilities and equity	8,892	9,499	(607)

(1) Other current assets is a supplementary financial measure and consists of restricted cash of \$70 million (Dec. 31, 2024 — \$69 million), trade and other receivables of \$768 million (Dec. 31, 2024 — \$767 million), prepaid expenses and other of \$66 million (Dec. 31, 2024 — \$68 million) and inventory of \$139 million (Dec. 31, 2024 — \$134 million).

(2) Other non-current assets is a supplementary financial measure and consists of the long-term portion of finance lease receivables of \$283 million (Dec. 31, 2024 — \$305 million), right-of-use assets of \$114 million (Dec. 31, 2024 — \$120 million), intangible assets of \$254 million (Dec. 31, 2024 — \$281 million), goodwill of \$517 million (Dec. 31, 2024 — \$517 million), deferred income tax assets of \$47 million (Dec. 31, 2024 — \$52 million), investments of \$144 million (Dec. 31, 2024 — \$159 million) and other assets of \$164 million (Dec. 31, 2024 — \$179 million).

(3) Other current liabilities is a supplementary financial measure and consists of bank overdraft of nil (Dec. 31, 2024 — \$1 million) and exchangeable securities of \$750 million (Dec. 31, 2024 — \$750 million).

(4) Other non-current liabilities is a supplementary financial measure and consists of contract liabilities of \$26 million (Dec. 31, 2024 — \$24 million), defined benefit obligation and other long-term liabilities of \$173 million (Dec. 31, 2024 — \$202 million) and deferred income taxes of \$423 million (Dec. 31, 2024 — \$470 million).

Significant changes in TransAlta's condensed consolidated statements of financial position were as follows:

Working Capital

The deficit of current assets over current liabilities, including the current portion of long-term debt and lease liabilities was \$392 million as at Sept. 30, 2025 (Dec. 31, 2024 — \$796 million). The deficit decreased 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.

Current assets decreased by \$315 million to \$1,458 million as at Sept. 30, 2025, from \$1,773 million as at Dec. 31, 2024, primarily due to:

- Lower risk management assets mainly due to decrease in market price volatility, lower trading activity and contract settlements;
- Lower cash and cash equivalents mainly due to lower cash flow from operating activities and higher cash used in investing activities; and
- A decrease in assets held for sale related to the Required Divestitures driven by the updated expectations of the fair value less costs to sell and the derecognition of one of the Required Divestitures.

Current liabilities decreased by \$719 million to \$1,850 million as at Sept. 30, 2025, from \$2,569 million as at Dec. 31, 2024, mainly due to:

- Lower current portion of credit facilities, long-term debt and lease liabilities mainly due to advance repayment of the variable rate term loan facility in the first quarter of 2025;
- Lower risk management liabilities due to lower market prices and contract settlements;
- Lower accounts payable, accrued liabilities and other current liabilities mainly due to a settlement of GHG obligation related to the year ended Dec. 31, 2024 during the second quarter of 2025 and lower GHG accruals for the current period due to lower volumes;
- Lower contingent consideration payable related to changes in fair value and the derecognition of one of the Required Divestitures; and
- Lower dividends payable due to the timing of payments; partially offset by
- An increase in the current portion of decommissioning and other provisions due to revisions in discount rates and estimated decommissioning costs.

Non-Current Assets

Non-current assets as at Sept. 30, 2025 were \$7,434 million, a decrease of \$292 million from \$7,726 million as at Dec. 31, 2024, primarily due to:

- Lower property, plant and equipment (PP&E) resulting from depreciation of \$407 million for the nine months ended Sept. 30, 2025, transfers to Assets held for sale related to Energy transition equipment of \$30 million, and an impairment charge, net of impairment reversals related to Wind and Solar facilities of \$20 million, partially offset by capital additions of \$158 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 to Nova, a developer of renewable energy projects.

Non-Current Liabilities

Non-current liabilities as at Sept. 30, 2025 were \$5,430 million, an increase of \$343 million from \$5,087 million as at Dec. 31, 2024, mainly due to:

- An increase in credit facilities, long-term debt and lease liabilities due to the \$450 million senior notes offering on March 24, 2025;
- Higher risk management liabilities due to forward price changes and volatility in market pricing across multiple markets; and
- An increase in decommissioning and other provisions due to revisions in discount rates and estimated decommissioning costs; partially offset by
- 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.

Total Equity

Total equity at Sept. 30, 2025 decreased by \$231 million compared to Dec. 31, 2024, due to:

- Net losses of \$118 million;
- Net losses on derivatives designated as cash flow hedges of \$32 million;
- Dividends declared on common and preferred shares of \$65 million; and
- Share repurchases under the NCIB of \$24 million.

Financial Capital

The Company is focused on maintaining a strong balance sheet and financial position to ensure access to sufficient financial capital.

Capital Structure

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

	Sept. 30, 2025		Dec. 31, 2024	
	\$	% of total	\$	% of total
<i>Net senior unsecured debt</i>				
Recourse debt — CAD debentures	697	12	251	4
Recourse debt — U.S. senior notes	965	17	995	16
Credit facilities	98	2	543	9
<i>Non-recourse debt</i>				
TAPC Holdings LP bond (Poplar Creek)	67	1	75	1
Pingston bond	39	1	39	1
Melancthon Wolfe Wind LP bond	116	2	133	2
New Richmond Wind LP bond	89	1	93	2
Kent Hills Wind LP bond	168	3	179	3
Windrise Wind LP bond	152	3	157	3
TEC Hedland PTY Ltd bond	671	12	675	11
Heartland term facility	204	4	224	4
<i>Recourse debt</i>				
TransAlta OCP LP bond	166	3	192	3
Tax equity financing	85	1	101	1
Lease liabilities	148	3	151	2
Credit facilities, long-term debt and lease liabilities⁽¹⁾	3,665		3,808	
Add: Exchangeable debentures	350	6	350	6
Add: Bank overdraft	—	—	1	—
Less: Cash and cash equivalents	(211)	(5)	(337)	(6)
Less: TransAlta OCP LP restricted cash ⁽²⁾	(17)	—	(17)	—
Less: Fair value of foreign exchange forward contracts on foreign-currency denominated debt ⁽³⁾	(2)	—	(7)	—
Total consolidated net debt⁽⁴⁾⁽⁵⁾⁽⁶⁾	3,785	66	3,798	62
Exchangeable preferred shares ⁽⁶⁾	400	7	400	7
Equity attributable to shareholders				
Common shares	3,169	55	3,179	53
Preferred shares	942	16	942	16
Contributed surplus, deficit and accumulated other comprehensive loss	(2,577)	(45)	(2,375)	(40)
Non-controlling interests	78	1	97	2
Total capital	5,797	100	6,041	100

(1) Credit facilities, long-term debt and lease liabilities consist of current and non-current portions in the the Condensed 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 outstanding debt.

(3) Represents the fair value of asset (liability) of the foreign exchange forward contracts used to manage the foreign exchange exposure on foreign-currency denominated debt.

(4) 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.

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

(6) Total consolidated net debt excludes the exchangeable preferred shares as they are considered equity with dividend payments for credit purposes.

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.

Between 2025 and 2027, the Company has a total of \$544

million of scheduled debt and tax equity repayments remaining.

The \$750 million of exchangeable securities are exchangeable into an equity ownership interest in TransAlta's Alberta Hydro Assets as of Dec. 31, 2024.

Credit Facilities

The Company's credit facilities are summarized in the table below:

As at Sept. 30, 2025	Utilized				
	Facility size	Outstanding letters of credit ⁽¹⁾	Cash drawings	Available capacity	Maturity date
Credit facilities					
Committed					
Syndicated credit facility	1,900	392	102	1,406	Q2 2029
Bilateral credit facilities	240	152	—	88	Q2 2027
Heartland credit facilities	256	8	204	44	Q4 2027
Heartland Export Development Canada letter of credit facility	30	14	—	16	Q4 2025
Total Committed	2,426	566	306	1,554	
Non-Committed					
Demand facilities	400	212	—	188	N/A
Total Non-Committed	400	212	—	188	

(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 available capacity under the committed syndicated credit facilities.

The Company maintains a strong financial position, with \$1.6 billion in liquidity as of Sept. 30, 2025. Credit facilities are the primary source of short-term liquidity after internally generated cash flow. The Company is in compliance with the terms of its credit facilities and all undrawn amounts are fully available.

Letters of credit in the amount of \$212 million were issued from non-committed demand facilities which are fully backstopped, thereby reducing the available capacity on the committed credit facilities. In addition to the net \$1.3 billion of committed capacity available under the credit facilities, the Company had \$211 million of available cash and cash equivalents as at Sept. 30, 2025.

TransAlta's debt has terms and conditions, including financial covenants, that are considered ordinary and customary. As at Sept. 30, 2025, the Company was in compliance with all of its debt covenants.

Credit Facility Extension

During the third quarter of 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 third quarter of 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.

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 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 having been made on Sept. 24, 2025.

Non-Recourse Debt and Other

All non-recourse debt, TransAlta OCP LP bond, and 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 are able to 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 third quarter of 2025, with the exception of Windrise Wind LP.

As at Sept. 30, 2025, \$6 million (AU\$6 million) of funds held by TEC Hedland Pty Ltd. are not able to be accessed by other corporate entities, as the funds must be solely used by the project entities for the purpose of paying 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.

Returns to Providers of Capital

Interest Income and Interest Expense

Interest income and the components of interest expense are shown below:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2025	2024	2025	2024
Interest income	7	4	18	19
Interest on debt	53	49	156	148
Interest on exchangeable debentures	6	7	18	22
Interest on exchangeable preferred shares	7	7	21	21
Capitalized interest	—	—	—	(16)
Interest on lease liabilities	1	2	8	7
Credit facility fees, bank charges and other interest	5	6	21	14
Accretion of provisions	13	12	42	36
Interest expense	85	83	266	232

For the nine months ended Sept. 30, 2025 interest expense was higher compared to the same period of 2024, primarily due to lower capitalized interest resulting from lower construction activity in the current period compared

to the same period in 2024, higher interest on debt driven by the addition of Heartland term facility, higher accretion of provisions and higher bank charges and other interest in the current period.

Share Capital

The following tables outline the common and preferred shares issued and outstanding:

As at	Number of shares (millions)		
	Nov. 5, 2025	Sept. 30, 2025	Dec. 31, 2024
Common shares issued and outstanding, end of period	296.7	296.7	297.5
Preferred shares			
Series A	9.6	9.6	9.6
Series B	2.4	2.4	2.4
Series C	10.0	10.0	10.0
Series D	1.0	1.0	1.0
Series E	9.0	9.0	9.0
Series G	6.6	6.6	6.6
Preferred shares issued and outstanding in equity	38.6	38.6	38.6
Series I — exchangeable securities ⁽¹⁾	0.4	0.4	0.4
Preferred shares issued and outstanding	39.0	39.0	39.0

(1) Brookfield invested \$400 million in consideration for redeemable, retractable, first preferred shares. For accounting purposes, these preferred shares are considered debt and disclosed as such in the consolidated financial statements.

Non-Controlling Interests

As at Sept. 30, 2025, the Company owned 50.01 per cent of TA Cogen (Sept. 30, 2024 — 50.01 per cent), which owns, operates or has an interest in three natural-gas-fired cogeneration facilities (Ottawa, Windsor and Fort Saskatchewan) and a 50 per cent interest in a natural-gas-fired facility (Sheerness). On Dec. 4, 2024, the Company acquired the remaining 50 per cent interest in Sheerness as part of the Heartland acquisition, increasing its effective interest from 25 to 75 per cent of the facility.

As at Sept. 30, 2025, the Company owned 83 per cent of Kent Hills Wind LP (Sept. 30, 2024 — 83 per cent), which owns and operates three wind facilities.

Since the Company owns a controlling interest in TA Cogen and Kent Hills Wind LP, we consolidated the entire earnings, assets and liabilities in relation to the subsidiaries.

The reported net earnings attributable to non-controlling interests for the three and nine months ended Sept. 30, 2025 decreased by \$6 and \$30 million, respectively, compared to the same periods in 2024, primarily as a result of lower TA Cogen net earnings attributable to non-controlling interests resulting from lower production and lower merchant pricing in the Alberta market.

Cash Flows

The following table highlights significant changes in the Condensed Consolidated Statements of Cash Flows for the nine months ended Sept. 30, 2025 and Sept. 30, 2024:

9 months ended Sept. 30	2025	2024	Increase/ (decrease)
Cash and cash equivalents, beginning of period	337	348	(11)
Provided by (used in):			
Operating activities	415	581	(166)
Investing activities	(302)	(198)	(104)
Financing activities	(241)	(335)	94
Translation of foreign currency cash	2	5	(3)
Cash and cash equivalents, end of period	211	401	(190)

Cash and cash equivalents for the nine months ended Sept. 30, 2025 decreased by \$190 million compared to the same period in 2024.

Cash Flow from Operating Activities

Cash from operating activities for the nine months ended Sept. 30, 2025 decreased compared with the same period in 2024, primarily due to the following:

	9 months ended Sept. 30
Cash flow from operating activities for the nine months ended Sept. 30, 2024	581
Lower gross margin due to lower revenues, partially offset by lower carbon compliance and lower fuel and purchased power costs in the current period.	(26)
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.	(104)
Higher interest expense primarily due to higher interest on debt driven by the addition of Heartland term facility, lower capitalized interest resulting from lower construction activity in the nine months ended Sept. 30, 2025, and higher accretion of provisions compared to the same period in 2024.	(34)
Unfavourable change in non-cash operating working capital balances due to lower accounts payable and accrued liabilities, higher accounts receivable, higher income taxes receivable, partially offset by lower collateral provided.	(35)
Other non-cash items	33
Cash flow from operating activities for the nine months ended Sept. 30, 2025	415

Cash Flow used in Investing Activities

Cash used in investing activities for the nine months ended Sept. 30, 2025 increased compared with the same period in 2024, primarily due to the following:

	9 months ended Sept. 30
Cash flow used in investing activities for the nine months ended Sept. 30, 2024	(198)
Lower additions to PP&E due to larger construction program in the nine months ended Sept. 30, 2024 compared to the current period.	42
Increase in long-term financial assets during the nine months ended Sept. 30, 2025 related to the Company's investment in Nova.	(128)
Other ⁽¹⁾	(18)
Cash flow used in investing activities for the nine months ended Sept. 30, 2025	(302)

(1) Mainly comprised of the change in non-cash investing working capital balance, restricted cash, payments under the loan receivable and other items in the investing activities section.

Cash Flow used in Financing Activities

Cash used in financing activities for the nine months ended Sept. 30, 2025 decreased compared with the same period in 2024, primarily due to the following:

	9 months ended Sept. 30
Cash flow used in financing activities for the nine months ended Sept. 30, 2024	(335)
Repayment of the \$400 million variable rate term facility.	(400)
Issuance of \$450 million senior notes during the first quarter of 2025.	450
Lower repurchases of common shares under the NCIB in the current period compared to the same period in prior year.	90
Repayments, net of cash drawings under the syndicated credit facility.	(44)
Lower distributions paid to non-controlling interests due to lower net earnings in the current period.	31
Higher amount of long-term debt repayments during the nine months ended Sept. 30, 2025.	(31)
Other	(2)
Cash flow used in financing activities for the nine months ended Sept. 30, 2025	(241)

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 condensed 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 Sept. 30		9 months ended Sept. 30	
	2025	2024	2025	2024
Hydro	22	21	32	34
Wind and Solar	7	5	18	12
Gas	5	6	56	20
Energy Transition	—	—	—	12
Corporate	3	3	11	(3)
Sustaining capital expenditures	37	35	117	75

Total sustaining capital expenditures during the three months ended Sept. 30, 2025 were comparable to the same period in 2024.

Total sustaining capital expenditures during the nine months ended Sept. 30, 2025 were \$42 million higher compared to the same period in 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.

Total sustaining capital expenditures for the nine months ended Sept. 30, 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 capital 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 Sept. 30		9 months ended Sept. 30	
	2025	2024	2025	2024
Hydro	1	—	2	6
Wind and Solar	—	6	—	54
Gas	17	22	43	38
Energy Transition	2	—	4	—
Growth and development expenditures	20	28	49	98

In the three and nine months ended Sept. 30, 2025, growth and development capital expenditures were lower compared to the same period in 2024, as many of the

growth projects achieved commercial operation in the first half of 2024.

Growth

Over the course of 2024 and first half of 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 840 MW of mid-stage projects and 3,109 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	1,970	609	190	340	3,109

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 mid-stage completion positions projects 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	—	—	100
United States	700	—	—	—	700
Western Australia	—	—	40	—	40
Total	700	100	40	—	840

Projects under Construction

Projects under construction will be financed through existing liquidity in the near term.

We will continue to explore permanent financing solutions on an asset-by-asset basis. We are continually monitoring the timing and costs of our projects under construction.

The following projects have been approved by the Board of Directors, have executed PPAs 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	n/a	AU\$40	—	AU\$42	AU\$37	Q4 2025	13
									- All major equipment delivered and installed - On-track to be completed on schedule
Total ⁽¹⁾			n/a	\$36	—	\$38	\$32		

(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

Commitments

The Company has not incurred any additional material contractual commitments in the nine months ended Sept. 30, 2025, either directly or through its interests in joint operations and joint ventures. There were reductions to the expected future payments under the Company's long-term service agreements during the nine months ended Sept. 30, 2025.

For the approximate future payments under the long-term service agreements as at Sept. 30, 2025, refer to Note 19 in the unaudited interim condensed consolidated financial statements as at and for the nine months ended Sept. 30, 2025.

Natural Gas Transportation 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 the excess capacity.

The Company may be required to recognize the natural gas transportation agreements as onerous contracts if any of the related facilities are retired in advance of the maturity of the transportation contracts.

Contingencies

For the current material outstanding contingencies, please refer to Note 37 of the 2024 audited annual consolidated financial statements. There were no material changes to the contingencies in the nine months ended Sept. 30, 2025.

Financial Instruments

For details on Financial instruments refer to Note 14 of the notes to the audited annual 2024 consolidated financial statements and Note 11 of our unaudited interim condensed consolidated financial statements as at and for the nine months ended Sept. 30, 2025.

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 unaudited interim condensed consolidated financial statements.

At Sept. 30, 2025, Level III instruments had a net liabilities carrying value of \$265 million (Dec. 31, 2024 – net liabilities \$234 million). The Level III liabilities increased during the nine months ended Sept. 30, 2025 from Dec. 31, 2024 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 one of the Required Divestitures. Our risk management profile and practices have not changed materially from Dec. 31, 2024.

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 we believe are not reflective of 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 in respect of such non-IFRS measures, including a reconciliation of such non-IFRS measures 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 is 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.

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:

- Acquisition-related transaction and restructuring costs, mainly comprised of 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.

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.

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 are not reflective of ongoing business performance.
- 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 provides the ability to evaluate cash flow trends in comparison with the 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 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
- Other current assets
- Other non-current assets
- Other current liabilities
- Other non-current liabilities

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

The following table reflects adjusted EBITDA and adjusted earnings before income taxes by segment and provides reconciliation to (loss) earnings before income taxes for the three months ended Sept. 30, 2025:

	Hydro	Wind & Solar ⁽¹⁾	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments ⁽¹⁾	Reclass adjustments	IFRS financials
Revenues	95	3	326	158	37	—	619	(4)	—	615
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	(3)	78	(12)	(10)	(8)	—	45	—	(45)	—
Decrease in finance lease receivable	—	1	7	—	—	—	8	—	(8)	—
Finance lease income	—	1	5	—	—	—	6	—	(6)	—
Revenues from Required Divestitures	—	—	(4)	—	—	—	(4)	—	4	—
Unrealized foreign exchange (gain) loss on commodity	—	—	(1)	—	1	—	—	—	—	—
Adjusted revenue	92	83	321	148	30	—	674	(4)	(55)	615
Fuel and purchased power	5	5	119	98	—	—	227	—	—	227
Reclassifications and adjustments:										
Fuel and purchased power related to Required Divestitures	—	—	1	—	—	—	1	—	(1)	—
Adjusted fuel and purchased power	5	5	120	98	—	—	228	—	(1)	227
Carbon compliance costs	—	—	35	—	—	—	35	—	—	35
Adjusted gross margin	87	78	166	50	30	—	411	(4)	(54)	353
OM&A	14	28	64	20	13	41	180	(1)	—	179
Reclassifications and adjustments:										
OM&A related to Required Divestitures	—	—	(2)	—	—	—	(2)	—	2	—
ERP integration costs	—	—	—	—	—	(6)	(6)	—	6	—
Acquisition-related transaction and restructuring costs	—	—	—	—	—	(1)	(1)	—	1	—
Adjusted OM&A	14	28	62	20	13	34	171	(1)	9	179
Taxes, other than income taxes	—	5	5	2	—	1	13	(1)	—	12
Net other operating income	—	—	(11)	—	—	—	(11)	—	—	(11)
Adjusted EBITDA⁽²⁾	73	45	110	28	17	(35)	238			
Depreciation and amortization	(9)	(52)	(59)	(11)	—	(6)	(137)	2	—	(135)
Equity loss	—	—	—	—	—	(1)	(1)	—	—	(1)
Interest income	—	—	—	—	—	9	9	(2)	—	7
Interest expense	—	—	—	—	—	(87)	(87)	2	—	(85)
Realized foreign exchange loss ⁽³⁾	—	—	—	—	—	(5)	(5)	—	—	(5)
Adjusted earnings (loss) before income taxes⁽²⁾	64	(7)	51	17	17	(125)	17			
Reclassifications and adjustments above	3	(80)	4	10	7	(7)	(63)			
Finance lease income	—	1	5	—	—	—	6	—	—	6
Fair value change in contingent consideration payable	—	—	3	—	—	—	3	—	—	3
Asset impairment charges	—	(20)	(3)	(4)	—	—	(27)	—	—	(27)
Gain on sale of assets and other	—	—	3	—	—	—	3	—	—	3
Unrealized foreign exchange gain ⁽³⁾	—	—	—	—	—	8	8	—	—	8
Earnings (loss) before income taxes	67	(106)	63	23	24	(124)	(53)	—	—	(53)

(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.

Management's Discussion and Analysis

The following table reflects adjusted EBITDA and adjusted earnings before income taxes by segment and provides reconciliation to (loss) earnings before income taxes for the three months ended Sept. 30, 2024:

	Hydro	Wind & Solar ⁽¹⁾	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments ⁽¹⁾	Reclass adjustments	IFRS financials
Revenues	105	2	314	165	55	—	641	(3)	—	638
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	1	74	(5)	(8)	(3)	—	59	—	(59)	—
Decrease in finance lease receivable	—	—	5	—	—	—	5	—	(5)	—
Finance lease income	—	1	2	—	—	—	3	—	(3)	—
Unrealized foreign exchange gain on commodity	—	—	1	—	—	—	1	—	(1)	—
Adjusted revenue	106	77	317	157	52	—	709	(3)	(68)	638
Fuel and purchased power	4	5	100	104	—	—	213	—	—	213
Carbon compliance costs	—	—	40	1	—	—	41	—	—	41
Adjusted gross margin	102	72	177	52	52	—	455	(3)	(68)	384
OM&A	13	26	43	17	10	35	144	(1)	—	143
Reclassifications and adjustments:										
Acquisition-related transaction and restructuring costs	—	—	—	—	—	(1)	(1)	—	1	—
Adjusted OM&A	13	26	43	17	10	34	143	(1)	1	143
Taxes, other than income taxes	—	5	3	1	—	1	10	—	—	10
Net other operating income	—	(3)	(10)	—	—	—	(13)	—	—	(13)
Adjusted EBITDA ⁽²⁾⁽³⁾	89	44	141	34	42	(35)	315			
Depreciation and amortization	(8)	(53)	(52)	(17)	—	(5)	(135)	2	—	(133)
Equity income	—	—	—	—	—	—	—	—	(1)	(1)
Interest income	—	—	—	—	—	6	6	(2)	—	4
Interest expense	—	—	—	—	—	(86)	(86)	3	—	(83)
Realized foreign exchange gain ⁽⁴⁾	—	—	—	—	—	2	2	—	—	2
Adjusted earnings (loss) before income taxes ⁽²⁾	81	(9)	89	17	42	(118)	102			
Reclassifications and adjustments above	(1)	(75)	(3)	8	3	(1)	(69)	—	—	—
Finance lease income	—	1	2	—	—	—	3	—	—	3
Skookumchuk earnings reclass to Equity income ⁽¹⁾	—	1	—	—	—	(1)	—	—	—	—
Asset impairment charges	—	—	—	(18)	—	(2)	(20)	—	—	(20)
Gain on sale of assets and other	—	—	—	1	—	—	1	—	—	1
Unrealized foreign exchange loss ⁽⁴⁾	—	—	—	—	—	(8)	(8)	—	—	(8)
Earnings (loss) before income taxes	80	(82)	88	8	45	(130)	9	—	—	9

(1) The Skookumchuk 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.

The following table reflects adjusted EBITDA and adjusted earnings before income taxes by segment and provides reconciliation to (loss) earnings before income taxes for the nine months ended Sept. 30, 2025:

	Hydro	Wind & Solar ⁽¹⁾	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments ⁽¹⁾	Reclass adjustments	IFRS financials
Revenues	310	169	920	385	102	(66)	1,820	(14)	—	1,806
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	(6)	182	27	4	(9)	—	198	—	(198)	—
Decrease in finance lease receivable	—	2	21	—	—	—	23	—	(23)	—
Finance lease income	—	4	13	—	—	—	17	—	(17)	—
Revenues from Required Divestitures	—	—	(11)	—	—	—	(11)	—	11	—
Unrealized foreign exchange gain on commodity	—	—	(1)	—	(1)	—	(2)	—	2	—
Adjusted revenue	304	357	969	389	92	(66)	2,045	(14)	(225)	1,806
Fuel and purchased power	16	24	388	247	—	2	677	—	—	677
Reclassifications and adjustments:										
Fuel and purchased power related to Required Divestitures	—	—	(2)	—	—	—	(2)	—	2	—
Adjusted fuel and purchased power	16	24	386	247	—	2	675	—	2	677
Carbon compliance costs (recovery)	—	2	76	—	—	(68)	10	—	—	10
Adjusted gross margin	288	331	507	142	92	—	1,360	(14)	(227)	1,119
OM&A	40	82	188	55	28	135	528	(3)	—	525
Reclassifications and adjustments:										
OM&A related to Required Divestitures	—	—	(5)	—	—	—	(5)	—	5	—
ERP integration costs	—	—	—	—	—	(16)	(16)	—	16	—
Acquisition-related transaction and restructuring costs	—	—	—	—	—	(6)	(6)	—	6	—
Adjusted OM&A	40	82	183	55	28	113	501	(3)	27	525
Taxes, other than income taxes	2	15	15	3	—	2	37	(1)	—	36
Net other operating income	—	(4)	(33)	—	—	—	(37)	—	—	(37)
Reclassifications and adjustments:										
Insurance recovery	—	2	—	—	—	—	2	—	(2)	—
Adjusted net other operating income	—	(2)	(33)	—	—	—	(35)	—	(2)	(37)
Adjusted EBITDA⁽²⁾	246	236	342	84	64	(115)	857			
Depreciation and amortization	(26)	(157)	(197)	(39)	(2)	(15)	(436)	5	—	(431)
Equity income	—	—	—	—	—	(2)	(2)	—	4	2
Interest income	—	—	—	—	—	21	21	(3)	—	18
Interest expense	—	—	—	—	—	(270)	(270)	4	—	(266)
Realized foreign exchange loss ⁽³⁾	—	—	—	—	—	(3)	(3)	—	—	(3)
Adjusted earnings (loss) before income taxes⁽²⁾	220	79	145	45	62	(384)	167			
Reclassifications and adjustments above	6	(186)	(56)	(4)	10	(22)	(252)			
Finance lease income	—	4	13	—	—	—	17	—	—	17
Skookumchuk earnings reclass to Equity income ⁽¹⁾	—	(4)	—	—	—	4	—	—	—	—
Fair value change in contingent consideration payable	—	—	37	—	—	—	37	—	—	37
Asset impairment (charges) reversals	—	(20)	(37)	9	—	(7)	(55)	—	—	(55)
Gain on sale of assets and other	—	—	3	—	—	(1)	2	—	—	2
Unrealized foreign exchange loss ⁽³⁾	—	—	—	—	—	(15)	(15)	—	—	(15)
Earnings (loss) before income taxes	226	(127)	105	50	72	(425)	(99)	—	—	(99)

(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.

Management's Discussion and Analysis

The following table reflects adjusted EBITDA and adjusted (loss) earnings before income taxes by segment and provides reconciliation to (loss) earnings before income taxes for the nine months ended Sept. 30, 2024:

	Hydro	Wind & Solar ⁽¹⁾	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments ⁽¹⁾	Reclass adjustments	IFRS financials
Revenues	316	253	1,031	461	154	(34)	2,181	(14)	—	2,167
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	(3)	61	(86)	(28)	(5)	—	(61)	—	61	—
Decrease in finance lease receivable	—	1	14	—	—	—	15	—	(15)	—
Finance lease income	—	4	5	—	—	—	9	—	(9)	—
Unrealized foreign exchange gain on commodity	—	—	(1)	—	—	—	(1)	—	1	—
Adjusted revenue	313	319	963	433	149	(34)	2,143	(14)	38	2,167
Fuel and purchased power	13	22	339	316	—	—	690	—	—	690
Carbon compliance costs (recovery)	—	—	106	1	—	(34)	73	—	—	73
Adjusted gross margin	300	297	518	116	149	—	1,380	(14)	38	1,404
OM&A	39	70	131	50	29	105	424	(3)	—	421
Reclassifications and adjustments:										
Acquisition-related transaction and restructuring costs	—	—	—	—	—	(8)	(8)	—	8	—
Adjusted OM&A	39	70	131	50	29	97	416	(3)	8	421
Taxes, other than income taxes	2	13	9	3	—	1	28	(1)	—	27
Net other operating income	—	(7)	(30)	—	—	—	(37)	—	—	(37)
Adjusted EBITDA ⁽²⁾⁽³⁾	259	221	408	63	120	(98)	973			
Depreciation and amortization	(23)	(143)	(163)	(48)	(2)	(14)	(393)	5	—	(388)
Equity income	—	—	—	—	—	(1)	(1)	—	4	3
Interest income	—	—	—	—	—	21	21	(2)	—	19
Interest expense	—	—	—	—	—	(235)	(235)	3	—	(232)
Realized foreign exchange loss ⁽⁴⁾	—	—	—	—	—	(7)	(7)	—	—	(7)
Adjusted earnings (loss) before income taxes ⁽²⁾	236	78	245	15	118	(334)	358			
Reclassifications and adjustments above	3	(66)	68	28	5	(8)	30			
Finance lease income	—	4	5	—	—		9	—	—	9
Skookumchuk earnings reclass to Equity income ⁽¹⁾	—	(4)	—	—	—	4	—	—	—	—
Asset impairment charges	—	(5)	—	(14)	—	(7)	(26)	—	—	(26)
Gain on sale of assets and other	—	—	—	2	—	2	4	—	—	4
Unrealized foreign exchange loss ⁽⁴⁾	—	—	—	—	—	(5)	(5)	—	—	(5)
Earnings (loss) before income taxes	239	7	318	31	123	(348)	370	—	—	370

(1) The Skookumchuk 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 and nine months ended Sept. 30, 2025 and Sept. 30, 2024:

(in millions of Canadian dollars except where noted)	3 months ended Sept. 30		9 months ended Sept. 30	
	2025	2024	2025	2024
(Loss) earnings before income taxes	(53)	9	(99)	370
Income tax expense	1	31	19	88
Net (loss) earnings	(54)	(22)	(118)	282
Net (loss) earnings attributable to non-controlling interests	(5)	1	(16)	14
Preferred share dividends	13	13	26	26
Net (loss) earnings attributable to common shareholders	(62)	(36)	(128)	242
Adjustments and reclassifications (pre-tax):				
Adjustments and reclassifications to Revenues	55	68	225	(38)
Adjustments and reclassifications to Fuel and purchased power	(1)	—	2	—
Adjustments and reclassifications to OM&A	9	1	27	8
Adjustments and reclassifications to Net other operating income	—	—	(2)	—
Fair value change in contingent consideration payable (gain)	(3)	—	(37)	—
Finance lease income	(6)	(3)	(17)	(9)
Asset impairment charges	27	20	55	26
Gain on sale of assets and other	(3)	(1)	(2)	(4)
Unrealized foreign exchange (gain) loss ⁽¹⁾	(8)	8	15	5
Calculated tax (expense) recovery on adjustments and reclassifications ⁽²⁾	(16)	(22)	(62)	3
Adjusted net (loss) earnings attributable to common shareholders⁽³⁾	(8)	35	76	233
Weighted average number of common shares outstanding in the period	297	296	297	303
Net (loss) income per common share attributable to common shareholders	(0.20)	(0.12)	(0.43)	0.80
Adjustments and reclassifications (net of tax)	0.18	0.24	0.69	(0.03)
Adjusted net (loss) earnings per common share attributable to common shareholders⁽³⁾	(0.02)	0.12	0.26	0.77

(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 and nine months ended Sept. 30, 2025 (three and nine ended Sept. 30, 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:

(in millions of Canadian dollars except where noted)	3 months ended Sept. 30		9 months ended Sept. 30	
	2025	2024	2025	2024
Cash flow from operating activities ⁽¹⁾	251	229	415	581
Change in non-cash operating working capital balances	(104)	(48)	94	59
Cash flow from operations before changes in working capital	147	181	509	640
Adjustments				
Share of adjusted FFO from joint venture ⁽¹⁾	1	—	4	4
Decrease in finance lease receivable	8	5	23	15
Brazeau penalties payment	—	—	33	—
Acquisition-related transaction and restructuring costs	—	1	8	8
Other ⁽²⁾	—	4	10	14
FFO⁽³⁾	156	191	587	681
Deduct:				
Sustaining capital expenditures ⁽¹⁾	(37)	(35)	(117)	(75)
Dividends paid on preferred shares	(14)	(13)	(40)	(39)
Distributions paid to subsidiaries' non-controlling interests	(1)	(10)	(3)	(34)
Principal payments on lease liabilities	—	(1)	(1)	(3)
Other	1	(1)	(5)	(1)
FCF⁽³⁾	105	131	421	529
Weighted average number of common shares outstanding in the period	297	296	297	303
Cash flow from operating activities per share	0.85	0.77	1.40	1.92
FFO per share⁽³⁾	0.53	0.65	1.98	2.25
FCF per share⁽³⁾	0.35	0.44	1.42	1.75

(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, less distributions from an equity-accounted joint venture.

(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.

Reconciliation of Adjusted EBITDA to FFO and FCF

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

	3 months ended Sept. 30		9 months ended Sept. 30	
	2025	2024	2025	2024
Adjusted EBITDA ⁽¹⁾⁽⁵⁾	238	315	857	973
Provisions	(4)	2	2	8
Net interest expense ⁽²⁾	(66)	(62)	(204)	(167)
Current income tax recovery (expense)	2	(63)	(57)	(123)
Realized foreign exchange (loss) gain ⁽³⁾	(2)	2	—	(7)
Decommissioning and restoration costs settled	(11)	(10)	(31)	(29)
Other non-cash items	(1)	7	20	26
FFO⁽⁴⁾⁽⁵⁾	156	191	587	681
Deduct:				
Sustaining capital expenditures ⁽³⁾⁽⁵⁾	(37)	(35)	(117)	(75)
Dividends paid on preferred shares	(14)	(13)	(40)	(39)
Distributions paid to subsidiaries' non-controlling interests	(1)	(10)	(3)	(34)
Principal payments on lease liabilities	—	(1)	(1)	(3)
Other	1	(1)	(5)	(1)
FCF⁽⁴⁾⁽⁵⁾	105	131	421	529

(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) 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 below for detailed calculation.

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

(4) 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.

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

Net interest expense in the reconciliation of our adjusted EBITDA to our FFO and FCF is calculated as follows:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2025	2024	2025	2024
Interest expense	85	83	266	232
Less: Interest Income	(7)	(4)	(18)	(19)
Less: non-cash items ⁽¹⁾	(12)	(17)	(44)	(46)
Net Interest Expense	66	62	204	167

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

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	Sept. 30, 2025	Dec. 31, 2024
Credit facilities, long-term debt and lease liabilities ⁽¹⁾	3,665	3,808
Exchangeable debentures	350	350
Less: Cash and cash equivalents	(211)	(337)
Add: Bank overdraft	—	1
Add: 50 per cent of issued preferred shares and exchangeable preferred shares ⁽²⁾	671	671
Other ⁽³⁾	(19)	(24)
Adjusted net debt⁽⁴⁾	4,456	4,469
Adjusted EBITDA⁽⁵⁾	1,139	1,255
Adjusted net debt to adjusted EBITDA (times)	3.9	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 Sept. 30, 2025 and \$17 million as at Dec. 31, 2024) and fair value of hedging instruments on debt (included in risk management assets and/or liabilities on the Condensed 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 for Sept. 30, 2025 was higher compared to Dec. 31, 2024, due to lower trailing twelve months adjusted EBITDA as at Sept. 30, 2025 as compared to Dec. 31, 2024.

Material Accounting Policies and Critical Accounting Estimates

The preparation of unaudited interim condensed consolidated 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 these 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.

During the nine months ended Sept. 30, 2025, revisions to the fair values of Assets held for sale and Contingent consideration payable were made based on new information obtained during the period. For details refer to Note 5 of the Company's unaudited interim condensed consolidated financial statements as at and for the nine months ended Sept. 30, 2025.

Valuation 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 three and nine months ended Sept. 30, 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 three and nine months ended Sept. 30, 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 which 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.

During the three months ended Sept. 30, 2025, 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 2086. The resulting fair value measurements are categorized within Level III of the fair value hierarchy. No impairment of goodwill arose for any segment.

During three and nine months ended Sept. 30, 2025, there were no significant changes in estimates, however, significant estimation uncertainty and judgment is applied in determining the recoverable amount of the Hydro, Wind and Solar, Gas and Energy Marketing segments, 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.

Refer to Note 2(Q)(II) of the Company's 2024 audited annual consolidated financial statements for further details on the significant accounting judgments and key sources of estimation uncertainty.

Accounting Changes

The accounting policies adopted in the preparation of the unaudited interim condensed consolidated financial statements are consistent with those followed in the preparation of the Company's annual consolidated financial statements for the year ended Dec. 31, 2024.

Future Accounting Changes

Amendments to IFRS 7 and IFRS 9 – 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. The Company is currently evaluating the impacts to the financial statements and such impacts cannot be reasonably estimated at this time.

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. The Company is currently evaluating the impacts to the financial statements and such impacts cannot be reasonably estimated at this time.

IFRS 18 – Presentation and Disclosure in Financial Statements

On Apr. 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 and such impacts cannot be reasonably estimated at this time.

Governance and 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.

Please refer to the Governance and Risk Management section of our 2024 Annual MD&A and Note 12 of our unaudited interim condensed consolidated financial statements for details on our risks and how we manage them. Our risk management profile and practices have not changed materially from Dec. 31, 2024.

Regulatory Updates

Refer to the Policy and Legal Risks discussion in our 2024 Annual MD&A for further details that supplement the recent developments as discussed below:

Canada

Federal

The Government of Canada has set objectives for carbon emissions reductions, including a 45 to 50 per cent national emissions reduction over 2005 levels by 2035, a net-zero electricity grid by 2035 and a net-zero national economy by 2050. The government has utilized several policy tools to achieve its emissions objectives, including but not limited to, carbon pricing, emissions performance regulations, funding for industrial energy transition, and incentives for consumers. The federal requirement for a consumer carbon price was removed on April 1, 2025; however, the requirement for industrial carbon pricing remains in place.

Canada's provinces have jurisdiction over their respective electricity sectors and play an important role in setting industrial carbon pricing policy and emissions performance standards, subject to equivalency requirements with the federal government's carbon pricing regime, pursuant to its authority to set national carbon pricing standards. Jurisdictional responsibilities between the federal and provincial governments enable both levels of government to implement policies that impact our sector. Leadership changes at either level of government can influence policy direction.

A federal election occurred on April 28, 2025, resulting in a minority government for the Liberal Party of Canada. TransAlta continues to monitor policy developments related to our business, including but not limited to the Clean Electricity Regulations, Investment Tax Credits, industrial carbon pricing, as well as funding for net-zero technologies.

Alberta

During the first quarter of 2025, the Government of Alberta commenced consultation on the Technology Innovation and Emissions Reduction Regulation (TIER) in advance of the scheduled program review in 2026. The TIER program has been in place since 2007 and is expected to be maintained going forward.

In the second quarter of 2025, the provincial government announced its intention to indefinitely freeze the industrial carbon price at \$95 per tonne, rather than proceed with annual increases as set out in a previous Ministerial Order. This change is scheduled to be implemented in 2026, in alignment with the federal carbon pricing regime. TransAlta continues to monitor this development.

In the third quarter of 2025, the Government of Alberta introduced proposed amendments to the Technology Innovation and Emissions Reduction (TIER) regulation. Key elements of the proposal include the recognition of on-site emissions reduction investments as an additional compliance pathway under the TIER system, and the option for smaller facilities currently participating in the program to opt out for the 2025 compliance year, with the stated intent of reducing administrative burden and costs. The Government of Alberta has indicated that formal amendments to the regulation will be drafted and incorporated in 2025. Further details are expected to be released upon finalization of the regulatory changes.

During 2025, the Government has carried out legislative changes to implement the Restructured Energy Market (REM), which has included amendments to the Electric Utilities Act and Transmission Regulation. During the third quarter of 2025, the AESO finalized the REM design and issued a draft of the detailed market rules to implement the REM.

On July 10, 2025, the Minister of Affordability and Utilities (Minister) issued a letter to the AESO that directed the AESO to implement locational marginal pricing in Alberta and allocate financial transmission rights to in-service generating units and those that have made a financial investment decision on or before July 9, 2025 (Incumbent Generators). Financial transmission rights will provide mitigation to Incumbent Generators that could be exposed to lower pricing due to the adoption of locational marginal pricing, allowing those generators to be paid at the system-wide price. The financial transmission rights will be allocated to Incumbent Generators for fixed volume and for a period of eight years unless the asset retires before the eight year period expires. The Minister has directed the AESO to collect stakeholder feedback and provide advice to the Minister regarding these items.

On Aug. 27, 2025, the AESO published the Restructured Energy Market (REM) Final Design, outlining key market reforms including an increase in the price cap, phased changes to the energy offer cap and floor, introduction of a new 30-minute real-time ramping product, adoption of locational marginal pricing, a revised secondary offer cap, a new local market power mechanism, a reliability unit commitment process for long lead time assets, and changes to the procurement of day-ahead operating reserves market.

The AESO is engaging with industry stakeholders on the REM market rules over the remainder of 2025 and it is expected that Ministerial approval of those rules will be required by the first quarter of 2026. TransAlta continues to be actively involved in all AESO consultation processes regarding the REM and associated initiatives. At this time,

the AESO plans to carry out information technology system development work over 2026 and 2027 with the intent to implement REM in 2027 or 2028.

On June 4, 2025, the AESO advised that 1,200 MW of large load hosting capacity will be made available for Phase I data centre development with in-service dates in 2027 and 2028. The AESO will complete the finalization of the allocation process during the fourth quarter of 2025. In tandem, the Government of Alberta and AESO are proceeding with the design requirements for Phase II of data centre developments; this will apply to data centre projects that have in-service dates in 2028 and beyond. Finalization of the Phase II design is expected to occur in 2025. TransAlta is actively engaged with the AESO and stakeholders on large load connection and data centre development in the province.

Ontario

On Aug. 14, 2025, the Ontario Ministry of the Environment, Conservation and Parks finalized amendments to the Emissions Performance Standard regulation under the Environmental Protection Act, R.S.O. 1990. The amendments, introduced in response to federal changes, provide increased flexibility for voluntary participants to exit the Emissions Performance Standard program.

United States

During the nine months ended Sept. 30, 2025, President Trump signed a number of executive orders seeking to enable or continue the development and operation of thermal generation in the country, as well as limiting the development of renewable electricity generation. Related to existing thermal generation, the U.S. Department of Energy has issued emergency orders requiring a number of thermal generating facilities to stay online, citing reliability concerns. In terms of renewable energy development, federal agency actions have continued. In the first quarter of 2025, the Department of the Interior took action related to delaying wind permits for both offshore and land-based developments. Starting in the third quarter of 2025, actions have expanded to include both solar and wind energy permits and approvals, involving orders or directives from multiple federal agencies, including the U.S. Departments of Interior, Transportation and Treasury and U.S. Army Corps of Engineers.

On July 4, 2025, President Trump signed into law a budget reconciliation bill, the "One Big Beautiful Bill" Act (Bill), which significantly reduced the availability of federal tax credits for renewable technologies established under the Inflation Reduction Act (IRA) of 2022. IRA tax credits for wind and solar were substantially rolled back as part of the Bill. The Bill retained the 100 per cent value tax credits for wind and solar through 2027, provided that the projects are placed in service by Dec. 31, 2027. An exception applies for wind and solar projects that start construction by July 3, 2026 and complete construction by 2030. On Aug. 15, 2025, the Internal Revenue Service (IRS) revised its guidance for "begin of construction" rules for wind and solar tax credits. The guidance removed the five per cent safe harbor method and left intact the physical work test to begin construction. The four-year construction continuity safe harbor remains in place; it allows projects to qualify for tax credits if placed in service up to four full calendar years after construction begins.

The Bill also introduces supply chain limitations on project components from foreign entities of concern which may receive additional guidance from the IRS. The Bill retains the IRA's favourable transferability provisions, preserving the ability to sell or transfer credits for the full duration of the credit. Additionally, the Bill provides favourable treatment for energy storage with full tax credits available for projects starting construction before 2033.

In addition to federal actions, state and regional renewable and climate policies continue to have a significant impact on the pace of energy transition in the country. The Company continues to assess actions at all levels of government as they emerge.

Australia

On March 8, 2025, a state election occurred in Western Australia. The Labor government, led by Premier Roger Cook won a third consecutive four-year term. The re-election of the Labor government is expected to provide continued stability in the state.

The Australian federal election was held on May 3, 2025. The Labor Party secured a majority government and a second term. The results are not expected to have a significant impact on TransAlta.

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). During the three and nine months ended Sept. 30, 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.

In accordance with the provisions of National Instrument (NI) 52-109 and consistent with U.S. Securities and Exchange Commission guidance, the scope of the evaluation did not include internal controls over financial reporting of Heartland, which the Company acquired on Dec. 4, 2024. Heartland was excluded from management's evaluation of the effectiveness of the Company's internal control over financial reporting as at Dec. 31, 2024, due to the proximity of the acquisition to year-end. Further details related to the acquisition are disclosed in Note 4 to the Company's Consolidated Financial Statements for the year ended Dec. 31, 2024.

Consistent with the evaluation at Dec. 31, 2024, the scope of the evaluation as at Sept. 30, 2025 does not include controls over financial reporting of the assets acquired through the Heartland acquisition on Dec. 4, 2024. Heartland's total and net assets represented approximately seven and 20 per cent of the Company's total and net assets, respectively, as at Sept. 30, 2025 and 14 and 35 per cent of the Company's revenues and net loss, respectively, for the nine months ended Sept. 30, 2025.

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 Sept. 30, 2025, the end of the period covered by this MD&A, our ICFR and DC&P were effective.

Glossary of Key Terms

Alberta Electric System Operator (AESO)

The independent system operator and regulatory authority for the Alberta Interconnected Electric System. authority for the Alberta Interconnected Electric System.

Alberta Hydro Assets

The Company's hydroelectric assets, owned through a wholly owned subsidiary, TransAlta Renewables Inc. These assets are located in Alberta and consist of the Barrier, Bearspaw, Cascade, Ghost, Horseshoe, Interlakes, Kananaskis, Pocaterra, Rundle, Spray, Three Sisters, Bighorn and Brazeau hydro facilities.

Ancillary Services

As defined by the Electric Utilities Act (Alberta), Ancillary Services are those 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.

Availability

A measure of time, expressed as a percentage of continuous operation 24 hours a day, 365 days a year, that a generating unit is capable of generating electricity, regardless of whether or not it is actually generating electricity.

Capacity

The rated continuous load-carrying ability, expressed in megawatts, of generation equipment.

Cogeneration

A generating facility that produces electricity and another form of useful thermal energy (such as heat or steam) used for industrial, commercial, heating or cooling purposes.

Derate

To lower the rated electrical capability of a power generating facility or unit.

Disclosure Controls and Procedures (DC&P)

Refers to controls and other procedures designed to ensure that information required to be disclosed in the reports filed by the Company or submitted 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 the Company in its reports that it files or submits under applicable securities legislation is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Dispatch optimization

Power is not produced during periods of low market price, but if required, is purchased in the market to fulfil contract obligations.

Exchangeable Debentures

On May 1, 2019, Brookfield Renewable Partners or its affiliates (collectively, Brookfield) invested \$350 million in exchange for seven per cent unsecured subordinated debentures due May 1, 2039.

Exchangeable Preferred Shares

On Oct. 30, 2020, Brookfield invested \$400 million in the Company in exchange for redeemable, retractable first preferred shares (Series I). The Series I Preferred Shares are accounted for as current debt and the exchangeable preferred share dividends are reported as interest expense.

Exchangeable Securities

The Exchangeable Debentures and the Exchangeable Preferred Shares which are exchangeable into an equity ownership interest in TransAlta's Alberta hydro assets in the future at a value based on a multiple of the Alberta Hydro Assets' future-adjusted EBITDA (Option to Exchange).

Free Cash Flow (FCF)

Represents the amount of cash that is available to invest in growth initiatives, make scheduled debt principal repayments on debt, repay maturing debt, pay common share dividends or repurchase common shares and provides the ability to evaluate cash flow trends in comparison with the results from prior periods. Refer to the Non-IFRS and Supplementary Financial Measures section for additional information.

Funds from Operations (FFO)

Represents 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. Refer to the Non-IFRS and Supplementary Financial Measures section for additional information.

Gigajoule (GJ)

A metric unit of energy commonly used in the energy industry. One GJ equals 947,817 British Thermal Units (Btu). One GJ is also equal to 277.8 kilowatt hours (kWh).

Gigawatt (GW)

A measure of electric power equal to 1,000 megawatts.

Gigawatt hour (GWh)

A measure of electricity consumption equivalent to the use of 1,000 megawatts of power over a period of one hour.

Greenhouse Gas (GHG)

A gas that has the potential to retain heat in the atmosphere, including water vapour, carbon dioxide, methane, nitrous oxide, hydrofluorocarbons and perfluorocarbons.

Heartland Credit Facilities

As part of the Heartland acquisition on Dec. 4, 2024, the Company assumed a \$232 million drawn term facility and a \$25 million revolving facility with a syndicate of banks, (collectively, the Heartland Credit Facilities).

ICFR

Internal control over financial reporting.

IFRS

International Financial Reporting Standards.

Megawatt (MW)

A measure of electric power equal to 1,000,000 watts.

Megawatt Hour (MWh)

A measure of electricity consumption equivalent to the use of 1,000,000 watts of power over a period of one hour.

Merchant

A term used to describe assets that are not contracted and are exposed to market pricing.

NCIB

Normal Course Issuer Bid.

OM&A

Operations, maintenance and administration costs.

Other Hydro Assets

The Company's hydroelectric assets located in British Columbia, Ontario which include the Taylor, Belly River, Waterton, St. Mary, Upper Mamquam, Pingston, Bone Creek, Akolkolex, Ragged Chute, Misema, Galetta, and Moose Rapids facilities.

Planned outage

Periodic planned shutdown of a generating unit for major maintenance and repairs. Duration is normally in weeks. The time is measured from unit shutdown to putting the unit back on line.

Power Purchase Agreement (PPA)

A long-term commercial agreement for the sale of electric energy to PPA buyers.

PP&E

Property, plant and equipment.

Renewable Energy Credits (REC)

All right, title, interest and benefit in and to any credit, reduction right, offset, allocated pollution right, emission reduction allowance, renewable attribute or other proprietary or contractual right, whether or not tradable, resulting from the actual or assumed displacement or reduction of emissions, or other environmental characteristic, from the production of one MWh of electrical energy from a facility utilizing certified renewable energy technology.

Required Divestitures

To meet the requirements of the federal Competition Bureau related to the Heartland Generation acquisition, the Company entered into a consent agreement with the Commissioner of Competition, pursuant to which TransAlta agreed to divest Heartland's Poplar Hill and Rainbow Lake facilities (the Required Divestitures) following closing of the acquisition of Heartland Generation.

TA Cogen

The Company owns 50.01 per cent in TransAlta Cogeneration, L.P. (TA Cogen), which owns, operates or has an interest in a portfolio of cogeneration facilities, including three natural-gas-fired cogeneration facilities (Ottawa, Windsor and Fort Saskatchewan) and a natural-gas-fired facility (Sheerness).

Term Facility

The former \$400 million term facility with our banking syndicate and original maturity on Sept. 7, 2025, bearing floating interest rates that varied depending on the option selected (e.g., Canadian prime and bankers' acceptances). On March 25, 2025, the Company repaid the term facility in advance of the scheduled maturity date with the proceeds received from the \$450 million senior notes offering.

Turbine

A machine for generating rotary mechanical power from the energy of a stream of fluid (such as water, steam or hot gas). Turbines convert the kinetic energy of fluids to mechanical energy through the principles of impulse and reaction or a mixture of the two.

Unplanned outage

The shutdown of a generating unit due to an unanticipated breakdown.

Value at Risk (VaR)

A measure used to manage exposure to market risk from commodity risk management activities.

Condensed Consolidated Statements of (Loss) Earnings

(in millions of Canadian dollars except where noted)

Unaudited	3 months ended Sept. 30		9 months ended Sept. 30	
	2025	2024	2025	2024
Revenues (Note 3)	615	638	1,806	2,167
Fuel and purchased power (Note 4)	227	213	677	690
Carbon compliance costs (Note 4)	35	41	10	73
Gross margin	353	384	1,119	1,404
Operations, maintenance and administration (Note 4)	179	143	525	421
Depreciation and amortization	135	133	431	388
Asset impairment charges (Note 5)	27	20	55	26
Taxes, other than income taxes	12	10	36	27
Net other operating income	(11)	(13)	(37)	(37)
Operating income	11	91	109	579
Equity (loss) income	(1)	(1)	2	3
Fair value change in contingent consideration payable (Note 5)	3	—	37	—
Finance lease income	6	3	17	9
Interest income	7	4	18	19
Interest expense (Note 6)	(85)	(83)	(266)	(232)
Foreign exchange gain (loss)	3	(6)	(18)	(12)
Gain on sale of assets and other	3	1	2	4
(Loss) earnings before income taxes	(53)	9	(99)	370
Income tax expense (Note 7)	1	31	19	88
Net (loss) earnings	(54)	(22)	(118)	282
Net (loss) earnings attributable to:				
Common shareholders	(49)	(23)	(102)	268
Non-controlling interests (Note 8)	(5)	1	(16)	14
	(54)	(22)	(118)	282
Net (loss) earnings attributable to TransAlta shareholders	(49)	(23)	(102)	268
Preferred share dividends (Note 18)	13	13	26	26
Net (loss) earnings attributable to common shareholders	(62)	(36)	(128)	242
Weighted average number of common shares outstanding in the period (millions)	297	296	297	303
Net (loss) earnings per share attributable to common shareholders, basic and diluted (Note 17)	(0.20)	(0.12)	(0.43)	0.80

See accompanying notes.

Condensed Consolidated Statements of Comprehensive (Loss) Income

(in millions of Canadian dollars)

Unaudited	3 months ended Sept. 30		9 months ended Sept. 30	
	2025	2024	2025	2024
Net (loss) earnings	(54)	(22)	(118)	282
Other comprehensive income (loss)				
Net actuarial (losses) gains on defined benefit plans, net of tax ⁽¹⁾	—	(3)	2	8
Total items that will not be reclassified subsequently to net (loss) earnings	—	(3)	2	8
Gains (losses) on translating net assets of foreign operations, net of tax	8	(5)	(10)	9
(Losses) gains on financial instruments designated as hedges of foreign operations, net of tax ⁽²⁾	(3)	6	11	(7)
Gains on derivatives designated as cash flow hedges, net of tax ⁽³⁾	37	81	9	147
Reclassification of gains on derivatives designated as cash flow hedges to net (loss) earnings, net of tax ⁽⁴⁾	(13)	(10)	(41)	—
Total items that will be reclassified subsequently to net (loss) earnings	29	72	(31)	149
Other comprehensive income (loss)	29	69	(29)	157
Total comprehensive (loss) income	(25)	47	(147)	439
Total comprehensive (loss) income attributable to:				
TransAlta shareholders	(20)	46	(131)	425
Non-controlling interests (Note 8)	(5)	1	(16)	14
	(25)	47	(147)	439

(1) Net of income tax expense of nil million and \$1 million for the three and nine months ended Sept. 30, 2025 (Sept. 30, 2024 — \$1 million recovery and \$2 million expense).

(2) Net of income tax recovery of \$1 million and expense of \$1 million for the three and nine months ended Sept. 30, 2025 (Sept. 30, 2024 — \$1 million expense and \$1 million recovery).

(3) Net of income tax expense of \$8 million and \$2 million for the three and nine months ended Sept. 30, 2025 (Sept. 30, 2024 — \$22 million expense and \$38 million expense).

(4) Net of reclassification of income tax recovery of nil and \$10 million for the three and nine months ended Sept. 30, 2025 (Sept. 30, 2024 — \$2 million recovery and \$1 million expense).

See accompanying notes.

Condensed Consolidated Statements of Financial Position

(in millions of Canadian dollars)

Unaudited	Sept. 30, 2025	Dec. 31, 2024
Current assets		
Cash and cash equivalents	211	337
Restricted cash (Note 16)	70	69
Trade and other receivables (Note 9)	768	767
Prepaid expenses and other	66	68
Risk management assets (Note 11 and 12)	159	318
Inventory	139	134
Assets held for sale (Note 5 and 14)	45	80
	1,458	1,773
Non-current assets		
Investments	144	159
Long-term portion of finance lease receivables	283	305
Risk management assets (Note 11 and 12)	38	93
Property, plant and equipment (Note 13)	5,748	6,020
Right-of-use assets	114	120
Intangible assets	254	281
Goodwill	517	517
Deferred income tax assets	47	52
Long-term financial assets (Note 10)	125	—
Other assets	164	179
Total assets	8,892	9,499
Current liabilities		
Bank overdraft	—	1
Accounts payable, accrued liabilities and other current liabilities (Note 9)	637	756
Current portion of decommissioning and other provisions (Note 15)	110	83
Risk management liabilities (Note 11 and 12)	150	277
Dividends payable (Note 17 and 18)	19	49
Exchangeable securities	750	750
Contingent consideration payable (Note 5 and 14)	15	81
Current portion of credit facilities, long-term debt and lease liabilities (Note 16)	169	572
	1,850	2,569
Non-current liabilities		
Credit facilities, long-term debt and lease liabilities (Note 16)	3,496	3,236
Decommissioning and other provisions (Note 15)	871	850
Deferred income tax liabilities	423	470
Risk management liabilities (Note 11 and 12)	441	305
Contract liabilities	26	24
Defined benefit obligation and other long-term liabilities	173	202
Total liabilities	7,280	7,656
Equity		
Common shares (Note 17)	3,169	3,179
Preferred shares (Note 18)	942	942
Contributed surplus	40	42
Deficit	(2,629)	(2,458)
Accumulated other comprehensive income	12	41
Equity attributable to shareholders	1,534	1,746
Non-controlling interests (Note 8)	78	97
Total equity	1,612	1,843
Total liabilities and equity	8,892	9,499

Commitments and contingencies (Note 19)

See accompanying notes.

Condensed Consolidated Statements of Changes in Equity

(in millions of Canadian dollars)

Unaudited	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income (loss)	Attributable to shareholders	Attributable to non-controlling interests	Total
9 months ended Sept. 30, 2025								
Balance, Dec. 31, 2024	3,179	942	42	(2,458)	41	1,746	97	1,843
Net loss	—	—	—	(102)	—	(102)	(16)	(118)
Other comprehensive loss:								
Net gains 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	—	—	—	—	(32)	(32)	—	(32)
Net actuarial gains on defined benefits plans, net of tax	—	—	—	—	2	2	—	2
Total comprehensive loss	—	—	—	(102)	(29)	(131)	(16)	(147)
Common share dividends (Note 17)	—	—	—	(39)	—	(39)	—	(39)
Preferred share dividends (Note 18)	—	—	—	(26)	—	(26)	—	(26)
Shares purchased under normal course issuer bid (NCIB) (Note 17)	(20)	—	—	(4)	—	(24)	—	(24)
Share-based payment plans and stock options exercised	10	—	(2)	—	—	8	—	8
Distributions declared to non-controlling interests (Note 8)	—	—	—	—	—	—	(3)	(3)
Balance, Sept. 30, 2025	3,169	942	40	(2,629)	12	1,534	78	1,612

	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income (loss)	Attributable to shareholders	Attributable to non-controlling interests	Total
9 months ended Sept. 30, 2024								
Balance, Dec. 31, 2023	3,285	942	41	(2,567)	(164)	1,537	127	1,664
Net earnings	—	—	—	268	—	268	14	282
Other comprehensive income:								
Net gains on translating net assets of foreign operations, net of hedges and tax	—	—	—	—	2	2	—	2
Net gains on derivatives designated as cash flow hedges, net of tax	—	—	—	—	147	147	—	147
Net actuarial gains on defined benefits plans, net of tax	—	—	—	—	8	8	—	8
Total comprehensive income	—	—	—	268	157	425	14	439
Common share dividends (Note 17)	—	—	—	(35)	—	(35)	—	(35)
Preferred share dividends (Note 18)	—	—	—	(26)	—	(26)	—	(26)
Shares purchased under NCIB (Note 17)	(128)	—	—	14	—	(114)	—	(114)
Provision for repurchase of shares under Automatic Securities Purchase Plan (ASPP) (Note 17)	19	—	—	—	—	19	—	19
Share-based payment plans and stock options exercised	15	—	(7)	—	—	8	—	8
Distributions declared to non-controlling interests (Note 8)	—	—	—	—	—	—	(34)	(34)
Balance, Sept. 30, 2024	3,191	942	34	(2,346)	(7)	1,814	107	1,921

See accompanying notes.

Condensed Consolidated Statements of Cash Flows

(in millions of Canadian dollars)

Unaudited	3 months ended Sept. 30		9 months ended Sept. 30	
	2025	2024	2025	2024
Operating activities				
Net (loss) earnings	(54)	(22)	(118)	282
Depreciation and amortization	135	133	431	388
Gain on sale of assets and other	(3)	—	(3)	(1)
Accretion of provisions (Note 6)	13	12	42	36
Decommissioning and restoration costs settled (Note 15)	(11)	(10)	(31)	(29)
Deferred income tax expense (recovery) (Note 7)	3	(32)	(38)	(35)
Unrealized loss (gain) from risk management activities	42	59	199	(60)
Unrealized foreign exchange (gain) loss	(5)	7	15	3
Provisions and contract liabilities	1	—	(33)	2
Asset impairment charges (Note 5)	27	20	55	26
Equity loss, net of distributions from investments	2	2	2	1
Other non-cash items	(3)	12	(12)	27
Cash flow from operations before changes in working capital	147	181	509	640
Change in non-cash operating working capital balances	104	48	(94)	(59)
Cash flow from operating activities	251	229	415	581
Investing activities				
Additions to property, plant and equipment (Note 13)	(53)	(74)	(158)	(200)
Additions to intangible assets	(2)	(3)	(7)	(7)
Restricted cash (Note 16)	(20)	(23)	(1)	4
Loan advances	(1)	—	(5)	—
Acquisitions, net of cash acquired	—	—	(2)	—
Increase in Long-term financial assets (Note 10)	(21)	—	(128)	—
Investments	—	(1)	—	(1)
Proceeds on sale of property, plant and equipment	4	1	4	3
Realized loss on financial instruments	—	(1)	(2)	—
Decrease in finance lease receivable	8	5	23	15
Development expenditures	1	—	(3)	(4)
Other	2	4	2	22
Change in non-cash investing working capital balances	(19)	(1)	(25)	(30)
Cash flow used in investing activities	(101)	(93)	(302)	(198)
Financing activities				
Net decrease in borrowings under credit facilities (Note 16)	(101)	(1)	(444)	(3)
Repayment of long-term debt (Note 16)	(28)	(22)	(118)	(87)
Issuance of long-term debt (Note 16)	—	—	450	—
Dividends paid on common shares (Note 17)	(19)	(19)	(55)	(54)
Dividends paid on preferred shares (Note 18)	(14)	(13)	(40)	(39)
Repurchase of common shares under NCIB (Note 17)	—	(24)	(24)	(114)
Proceeds on issuance of common shares (Note 17)	2	1	2	5
Distributions paid to subsidiaries' non-controlling interests (Note 8)	(1)	(10)	(3)	(34)
Decrease in lease liabilities	—	(1)	(1)	(3)
Financing fees and other	(3)	—	(7)	(1)
Change in non-cash financing working capital balances	—	1	(1)	(5)
Cash flow used in financing activities	(164)	(88)	(241)	(335)
Cash flow (used in) from operating, investing and financing activities	(14)	48	(128)	48
Effect of translation on foreign currency cash	3	2	2	5
(Decrease) increase in cash and cash equivalents	(11)	50	(126)	53
Cash and cash equivalents, beginning of period	222	351	337	348
Cash and cash equivalents, end of period	211	401	211	401
Cash taxes (received) paid	(14)	19	80	56
Cash interest paid	67	54	205	187
Cash interest received	6	3	16	16

See accompanying notes.

Notes to the Condensed Consolidated Financial Statements

(Unaudited)

(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.

B. Basis of Preparation

These unaudited interim condensed consolidated financial statements have been prepared in compliance with International Financial Reporting Standard (IFRS) and International Accounting Standard (IAS) 34 Interim Financial Reporting using the same accounting policies as those used in the Company's most recent audited annual consolidated financial statements. These unaudited interim condensed consolidated financial statements do not include all of the disclosures included in the Company's audited annual consolidated financial statements. Accordingly, they should be read in conjunction with the Company's most recent audited annual consolidated financial statements which are available on SEDAR+ at www.sedarplus.ca and on EDGAR at www.sec.gov.

The unaudited interim condensed consolidated financial statements include the accounts of the Company and the subsidiaries that it controls.

The unaudited interim condensed consolidated financial statements have been prepared on a historical cost basis except for certain financial instruments, which are stated at fair value.

These unaudited interim condensed consolidated financial statements reflect all adjustments which consist of normal recurring adjustments and accruals that are, in the opinion of management, necessary for a fair presentation of results. Interim results will fluctuate due to plant maintenance schedules, the seasonal demands for electricity and changes in energy prices. Consequently, interim condensed results are not necessarily indicative of annual results. TransAlta's results are partly seasonal due

to the nature of the electricity market and related fuel costs.

These unaudited interim condensed consolidated financial statements were authorized for issue by the Audit, Finance and Risk Committee on behalf of TransAlta's Board of Directors (the Board) on Nov. 5, 2025.

C. Significant Accounting Judgments and Key Sources of Estimation Uncertainty

The preparation of these unaudited interim condensed consolidated financial statements in accordance with IAS 34 requires management to use judgment and make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and disclosures of contingent assets and liabilities. These estimates are subject to uncertainty. Actual results could differ from these 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 estimates are made and that could significantly affect the amounts recognized in the unaudited interim condensed 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.

During the nine months ended Sept. 30, 2025, revisions to the fair values of Assets held for sale and Contingent consideration payable were made based on new information obtained during the period. Refer to Note 5.

During the three months ended Sept. 30, 2025, 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 2086. The resulting fair value measurements are categorized within Level III of the fair value hierarchy. No impairment of goodwill arose for any segment.

During three and nine months ended Sept. 30, 2025, there were no significant changes in estimates, however, significant estimation uncertainty and judgment is applied

in determining the recoverable amount of the Hydro, Wind and Solar, Gas and Energy Marketing segments, 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.

Refer to Note 2(Q)(II) of the Company's 2024 audited annual consolidated financial statements for further details on the significant accounting judgments and key sources of estimation uncertainty.

2. Accounting Changes

The accounting policies adopted in the preparation of the unaudited interim condensed consolidated financial statements are consistent with those followed in the preparation of the Company's annual consolidated financial statements for the year ended Dec. 31, 2024.

A. Future Accounting Changes

The Company closely monitors both new accounting standards and amendments to existing accounting standards issued by the International Accounting Standards Board (IASB). The following standards have been issued but are not yet in effect.

Amendments to IFRS 7 and IFRS 9 – 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. The Company is currently evaluating the impacts to the financial statements and such impacts cannot be reasonably estimated at this time.

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. The Company is currently evaluating the impacts to the financial statements and such impacts cannot be reasonably estimated at this time.

IFRS 18 – Presentation and Disclosure in Financial Statements

On Apr. 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 and such impacts cannot be reasonably estimated at this time.

B. 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.

3. Revenue

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 for the purpose of determining how economic factors affect the recognition of revenue.

3 months ended Sept. 30, 2025	Hydro	Wind & Solar	Gas	Energy Transition	Energy Marketing	Corporate⁽¹⁾	Total
Revenues from contracts with customers							
Power and other	15	40	134	4	—	(2)	191
Environmental and tax attributes ⁽²⁾	—	18	(4)	—	—	—	14
Revenue from contracts with customers	15	58	130	4	—	(2)	205
Revenue from derivatives and other trading activities ⁽³⁾	23	(76)	88	78	37	2	152
Revenue from merchant sales	47	15	102	76	—	—	240
Other ⁽⁴⁾	10	2	6	—	—	—	18
Total revenue	95	(1)	326	158	37	—	615
Revenues from contracts with customers							
Timing of revenue recognition							
At a point in time	—	6	(4)	4	—	—	6
Over time	15	52	134	—	—	(2)	199
Total revenue from contracts with customers	15	58	130	4	—	(2)	205

(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.

3 months ended Sept. 30, 2024	Hydro	Wind & Solar	Gas	Energy Transition	Energy Marketing	Total
Revenues from contracts with customers						
Power and other	7	38	116	4	—	165
Environmental and tax attributes ⁽¹⁾	8	13	—	—	—	21
Revenue from contracts with customers	15	51	116	4	—	186
Revenue from derivatives and other trading activities ⁽²⁾	5	(73)	61	81	55	129
Revenue from merchant sales	83	17	132	80	—	312
Other ⁽³⁾	2	4	5	—	—	11
Total revenue	105	(1)	314	165	55	638
Revenues from contracts with customers						
Timing of revenue recognition						
At a point in time	8	13	—	3	—	24
Over time	7	38	116	1	—	162
Total revenue from contracts with customers	15	51	116	4	—	186

(1) The environmental and tax attributes represent environmental attributes and production tax transfer sales not bundled with power and other sales.

(2) 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.

(3) 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.

9 months ended Sept. 30, 2025	Hydro	Wind & Solar	Gas	Energy Transition	Energy Marketing	Corporate ⁽¹⁾	Total
Revenues from contracts with customers							
Power and other	33	184	494	9	9	—	729
Environmental and tax attributes ⁽²⁾	70	83	7	—	—	(68)	92
Revenue from contracts with customers	103	267	501	9	9	(68)	821
Revenue from derivatives and other trading activities ⁽³⁾	29	(171)	124	197	93	2	274
Revenue from merchant sales	163	48	282	178	—	—	671
Other ⁽⁴⁾	15	11	13	1	—	—	40
Total revenue	310	155	920	385	102	(66)	1,806
Revenues from contracts with customers							
Timing of revenue recognition							
At a point in time	70	38	7	9	—	(68)	56
Over time	33	229	494	—	9	—	765
Total revenue from contracts with customers	103	267	501	9	9	(68)	821

(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.

9 months ended Sept. 30, 2024	Hydro	Wind & Solar	Gas	Energy Transition	Energy Marketing	Corporate⁽¹⁾	Total
Revenues from contracts with customers							
Power and other	23	168	353	10	—	—	554
Environmental and tax attributes ⁽²⁾	61	61	—	—	—	(34)	88
Revenue from contracts with customers	84	229	353	10	—	(34)	642
Revenue from derivatives and other trading activities ⁽³⁾	15	(53)	218	226	154	—	560
Revenue from merchant sales	210	52	441	225	—	—	928
Other ⁽⁴⁾	7	11	19	—	—	—	37
Total revenue	316	239	1,031	461	154	(34)	2,167
Revenues from contracts with customers							
Timing of revenue recognition							
At a point in time	61	61	—	9	—	(34)	97
Over time	23	168	353	1	—	—	545
Total revenue from contracts with customers	84	229	353	10	—	(34)	642

(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.

4. 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:

	3 months ended Sept. 30				9 months ended Sept. 30			
	2025		2024		2025		2024	
	Fuel and purchased power	OM&A	Fuel and purchased power	OM&A	Fuel and purchased power	OM&A	Fuel and purchased power	OM&A
Gas fuel costs	91	—	81	—	321	—	264	—
Coal fuel costs	42	—	41	—	96	—	78	—
Royalty, land lease, other direct costs	6	—	5	—	22	—	23	—
Purchased power	88	—	86	—	238	—	325	—
Salaries and benefits	—	81	—	67	—	234	—	201
Other operating expenses	—	98	—	76	—	291	—	220
Total	227	179	213	143	677	525	690	421

OM&A

OM&A expenses for the three and nine months ended Sept. 30, 2025 were \$179 million and \$525 million, respectively (Sept. 30, 2024 — \$143 million and \$421 million) and included costs to support strategic and growth initiatives, expenses related to operations of the Heartland Generation (Heartland) facilities and associated corporate costs and spending related to the planning, design and implementation of an upgrade to the Company's enterprise resource planning (ERP) system.

Carbon Compliance

As at Sept. 30, 2025, the Company holds 443,067 emission credits in inventory that were purchased externally with a recorded book value of \$21 million (Dec. 31, 2024 — 460,585 emission credits with a recorded book value of \$18 million). The Company also has 1,555,309 (Dec. 31, 2024 — 2,109,491) of internally generated eligible emission credits from the Company's Wind and Solar and Hydro segments which have no recorded book value.

During the nine months ended Sept. 30, 2025, the Company utilized 1,498,447 emission credits (Sept. 30, 2024 — 978,894 emissions credits) with a carrying value of \$17 million (Sept. 30, 2024 — \$22 million), to settle a portion of the 2024 carbon compliance obligation (Sept. 30, 2024 — 2023 carbon compliance obligation). During the nine months ended Sept. 30, 2025, \$103 million was recognized as a reduction in the Company's carbon compliance costs (Sept. 30, 2024 — \$42 million).

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. The compliance price of carbon for the 2024 obligation was \$80 per tonne rising to \$95 per tonne in 2025.

5. Asset Impairment Charges

The Company recognized the following asset impairment charges (reversals):

	3 months ended Sept. 30		9 months ended Sept. 30	
	2025	2024	2025	2024
Impairment charge, net of impairment reversals related to the Wind and Solar facilities	20	—	20	—
Changes in decommissioning and restoration provisions on retired assets ⁽¹⁾	4	17	22	14
Project development costs ⁽²⁾	—	3	7	12
Impairment reversal related to the Energy Transition Equipment	—	—	(31)	—
Impairment charge related to the Required Divestitures	3	—	37	—
Asset impairment charges	27	20	55	26

(1) During the three and nine months ended Sept. 30, 2025 and 2024, the Company recorded asset impairment charges driven by changes in discount rates.

(2) During the nine months ended Sept. 30, 2025 and Sept. 30, 2024, the Company recognized an impairment charge in the Corporate segment related to projects that are no longer proceeding.

Wind and Solar Facilities

During the three and nine months ended Sept. 30, 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 three and nine months ended Sept. 30, 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 which 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.

Energy Transition Equipment Sale

On March 20, 2025, the Company entered into an

agreement to sell generation equipment that had previously been impaired in the Energy Transition segment with closing of the sale expected during the fourth quarter of 2025. During the nine months ended Sept. 30, 2025, the Company recorded an asset impairment reversal of \$31 million, for a previously recognized impairment loss and transferred the respective generation equipment and associated decommissioning liabilities to Assets held for sale and Liabilities held for sale.

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, pursuant to which the Company agreed to divest Heartland's Poplar Hill and Rainbow Lake facilities (the Required Divestitures) following closing of the acquisition on Dec. 4, 2024.

During the nine months ended Sept. 30, 2025, the Company recognized an impairment loss in the amount of \$37 million related to the Required Divestitures held for sale in the Gas segment based on updated expectations of the fair value less costs to sell. A corresponding reduction in the contingent consideration payable was also recognized. The contingent consideration payable as at Sept. 30, 2025 of \$15 million (Dec. 31, 2024 — \$81 million) was determined based on expected sale proceeds and net cash flows from operations pertaining to the Required Divestitures up until the date of sale.

6. Interest Expense

The components of interest expense are as follows:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2025	2024	2025	2024
Interest on debt	53	49	156	148
Interest on exchangeable debentures ⁽¹⁾	6	7	18	22
Interest on exchangeable preferred shares ⁽²⁾	7	7	21	21
Capitalized interest (Note 13)	—	—	—	(16)
Interest on lease liabilities	1	2	8	7
Credit facility fees, bank charges and other interest	5	6	21	14
Accretion of provisions (Note 15)	13	12	42	36
Interest expense	85	83	266	232

(1) On May 1, 2019, Brookfield invested \$350 million in exchange for seven per cent unsecured subordinated debentures due May 1, 2039.

(2) On Oct. 30, 2020, Brookfield invested \$400 million in the Company in exchange for redeemable, retractable first preferred shares (Series I). The Series I Preferred Shares are accounted for as current debt and the exchangeable preferred share dividends are reported as interest expense. On Oct. 22, 2025, the Company declared a dividend of \$7 million in aggregate on the Series I Preferred Shares at the fixed rate of 1.764 per cent, per share, payable on Dec. 1, 2025.

7. Income Taxes

The components of income tax expense are as follows:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2025	2024	2025	2024
Current income tax (recovery) expense	(2)	63	57	123
Deferred income tax (recovery) expense related to the origination and reversal of temporary differences	(15)	(28)	(77)	(9)
Write-down (reversal) of unrecognized deferred income tax assets ⁽¹⁾	18	(4)	39	(26)
Income tax expense	1	31	19	88
Current income tax (recovery) expense	(2)	63	57	123
Deferred income tax expense (recovery)	3	(32)	(38)	(35)
Income tax expense	1	31	19	88

(1) During the three and nine months ended Sept. 30, 2025, the Company recorded a \$18 million and \$39 million write-down of deferred tax assets, respectively (Sept. 30, 2024 — \$4 million and \$26 million reversal of write-down, respectively). The deferred income tax assets primarily pertain to the tax benefits arising from tax losses incurred by the Company's directly owned U.S. operations, as well as other deductible differences.

8. Non-Controlling Interests

The Company's subsidiaries and operations that have non-controlling interests are as follows:

Subsidiary/Operation	Non-controlling interest owner	NCI as at Sept. 30, 2025	NCI as at Dec. 31, 2024	NCI as at Sept. 30, 2024
TransAlta Cogeneration LP	Canadian Power Holdings Inc.	49.99%	49.99%	49.99%
Kent Hills Wind LP	Natural Forces Technologies Inc.	17.00%	17.00%	17.00%

TransAlta Cogeneration, LP (TA Cogen) operates a portfolio of cogeneration facilities in Canada and owns 50 per cent of Sheerness, 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:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2025	2024	2025	2024
Net (loss) earnings attributable to non-controlling interests				
TransAlta Cogeneration L.P.	(3)	2	(16)	14
Kent Hills Wind LP	(2)	(1)	—	—
	(5)	1	(16)	14
Total comprehensive (loss) income attributable to non-controlling interests				
TransAlta Cogeneration L.P.	(3)	2	(16)	14
Kent Hills Wind LP	(2)	(1)	—	—
	(5)	1	(16)	14
Distributions paid to non-controlling interests				
TransAlta Cogeneration L.P.	1	10	3	34
Kent Hills Wind LP	—	—	—	—
	1	10	3	34

As at	Sept. 30, 2025	Dec. 31, 2024
Equity attributable to non-controlling interests		
TransAlta Cogeneration L.P.	(27)	(46)
Kent Hills Wind LP	(51)	(51)
	(78)	(97)

9. Trade and Other Receivables and Accounts Payable, Accrued Liabilities and Other Current Liabilities

	Sept. 30, 2025	Dec. 31, 2024
Trade accounts receivable	601	570
Collateral provided (Note 12)	88	124
Current portion of finance lease receivables	30	30
Current portion of loan receivable	—	1
Income taxes receivable	49	42
Trade and other receivables	768	767

	Sept. 30, 2025	Dec. 31, 2024
Accounts payable and accrued liabilities	568	694
Income taxes payable	10	23
Interest payable	21	17
Current portion of contract liabilities	31	12
Liabilities held for sale (Note 14)	7	1
Collateral held (Note 12)	—	9
Accounts payable, accrued liabilities and other current liabilities	637	756

10. Long-Term Financial Assets

Nova Clean Energy, LLC

During the nine months ended Sept. 30, 2025, the Company made available a US\$75 million term loan and a US\$100 million revolving facility to Nova Clean Energy, LLC (Nova), a developer of renewable energy projects. As at Sept. 30, 2025, US\$26 million and US\$64 million have been drawn from the term loan and revolving facility, respectively. These facilities are classified as financial assets measured at Fair Value Through Profit and Loss (FVTPL). 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.

11. 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.

B. Fair Value of Financial Instruments

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

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.

b. 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 insufficient trading volume or lack of recent trades exists, the Company relies on similar interest or currency rate inputs and other third-party information such as credit spreads.

c. Level III

Fair values are determined using inputs for the assets or liabilities that are not readily observable.

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. Refer to Note 14 of the 2024 audited annual consolidated financial statements for further details.

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 Sept. 30, 2025, are as follows: Level I — \$5 million net asset (Dec. 31, 2024 — \$12 million net liability), Level II — \$32 million net liability (Dec. 31, 2024 — \$2 million net liability) and Level III — \$375 million net liability (Dec. 31, 2024 — \$153 million net liability).

Significant changes in commodity net risk management assets (liabilities) during the nine months ended Sept. 30, 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 nine months ended Sept. 30, 2025 and 2024, respectively:

	9 months ended Sept. 30, 2025			9 months ended Sept. 30, 2024		
	Hedge	Non-hedge	Total	Hedge	Non-hedge	Total
Opening balance	—	(153)	(153)	—	(147)	(147)
Changes attributable to:						
Market price changes on existing contracts	—	(184)	(184)	—	(21)	(21)
Market price changes on new contracts	—	4	4	—	8	8
Contracts settled	—	(46)	(46)	—	24	24
Change in foreign exchange rates	—	4	4	—	(6)	(6)
Net risk management liabilities at end of period	—	(375)	(375)	—	(142)	(142)
Additional Level III information:						
Total losses included in earnings before income taxes	—	(176)	(176)	—	(19)	(19)
Unrealized (losses) gains included in earnings before income taxes relating to net liabilities held at period end	—	(222)	(222)	—	5	5

As at Sept. 30, 2025, the total Level III risk management asset balance was \$56 million (Dec. 31, 2024 – \$110 million) and the Level III risk management liability balance was \$431 million (Dec. 31, 2024 – \$263 million). The net risk management liabilities increased mainly due to unfavourable market price changes and settled contracts.

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; however, the potential offsetting effects of Level II positions are not considered. 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		Sept. 30, 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 or increase of US\$6	+26 / -44
		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 \$32 or increase of \$10	+68 / -20
		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\$11 or increase of US\$3	+78 / -48
		Wind discounts	2% decrease or 5% 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.

b. Long-Term Wind Energy Sale – Canada

In Alberta, 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 customers pay the Company the difference and if the pool price is higher than the fixed contract price, the Company refunds the difference to the customers. 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 until the third quarter of 2041 and the third quarter of 2035, respectively.

The energy components of these contracts are accounted for as derivatives, with changes in fair value presented in revenue.

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, achieve 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 second quarter of 2024 and extend until the second quarter of 2039 and the fourth quarter of 2038, respectively.

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 facility. 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 and extends until the second quarter of 2044.

The energy components of these contracts are accounted for as derivatives, with changes in fair value presented in revenue.

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 \$8 million as at Sept. 30, 2025 (Dec. 31, 2024 — \$4 million net liability) are classified as Level II fair value measurements.

IV. Other Financial Assets and Liabilities

	Fair value ⁽¹⁾			Total carrying value ⁽¹⁾
	Level II	Level III	Total	
Exchangeable securities — Sept. 30, 2025	752	—	752	750
Long-term debt — Sept. 30, 2025	3,358	—	3,358	3,517
Long-term financial assets — Sept. 30, 2025 ⁽²⁾	—	125	125	125
Loan receivable — Sept. 30, 2025 ⁽³⁾	29	—	29	29
Exchangeable securities — Dec. 31, 2024	739	—	739	750
Long-term debt — Dec. 31, 2024	3,447	—	3,447	3,657
Loan receivable — Dec. 31, 2024 ⁽³⁾	25	—	25	25

(1) Includes current portion.

(2) Refer to Note 10 for further details.

(3) Included within Other assets.

During the nine months ended Sept. 30, 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. Refer to Note 10 for more details. 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 share price for which observable market data is not available. The Nova facilities are valued at the exchange amount, which represents the amounts drawn. There have been no material movements in the fair value to the end of the reporting period.

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 long-term financial assets and finance lease receivables approximate the carrying amounts as the amounts receivable represent cash flows from repayments of principal and interest.

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 11 above for 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 (loss) earnings 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 condensed consolidated statements of financial position in risk management assets or liabilities and is recognized in net (loss) earnings 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:

9 months ended Sept. 30	2025	2024
Unamortized net gain at beginning of period	11	3
New inception gains	—	18
Change resulting from amended contract	—	2
Change in foreign exchange rates	1	(1)
Amortization recorded in net (loss) earnings during the period	(25)	(13)
Unamortized net (loss) gain at end of period	(13)	9

12. Risk Management Activities

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. Refer to Note 15 of the 2024 audited annual consolidated financial statements for further details of the Company's risk management activities.

B. Net Risk Management Assets and Liabilities

Aggregate net risk management assets (liabilities) are as follows:

As at Sept. 30, 2025

	Cash flow hedges	Not designated as a hedge	Total
Commodity risk management			
Current	10	(3)	7
Long-term	—	(409)	(409)
Net commodity risk management liabilities	10	(412)	(402)
Other			
Current	—	2	2
Long-term	—	6	6
Net other risk management assets	—	8	8
Total net risk management assets (liabilities)	10	(404)	(394)

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)

C. Nature and Extent of Risks Arising from Financial Instruments

I. Market Risk

i. Commodity Price Risk – 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.

A value at risk (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. Changes in market prices associated with proprietary trading activities affect net (loss) earnings in the period that the price changes occur. VaR at Sept. 30, 2025, associated with the Company's proprietary trading activities was \$1 million (Dec. 31, 2024 — \$3 million).

ii. Commodity Price Risk – Generation

The generation segments utilize 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 is prepared and approved annually, which 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 (loss) earnings.

VaR at Sept. 30, 2025, associated with the Company's commodity derivative instruments used in generation hedging activities was \$2 million (Dec. 31, 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 (loss) earnings in the period in which the price change occurs. VaR at Sept. 30, 2025, associated with these transactions was \$8 million (Dec. 31, 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 11(B)(II).

II. Credit Risk

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 Sept. 30, 2025:

	Investment grade (per cent)	Non-investment grade (per cent)	Total (per cent)	Total amount
Trade and other receivables ⁽¹⁾	85	15	100	768
Long-term finance lease receivable	100	—	100	283
Risk management assets ⁽¹⁾	61	39	100	197
Long-term financial assets ⁽²⁾	—	100	100	125
Loans receivable ⁽³⁾	—	100	100	29
Total				1,402

(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 10 for further details.

(3) Includes \$29 million loans receivable included within other assets with counterparties that have no external credit rating.

The Company did not have material expected credit losses as at Sept. 30, 2025. The Company's maximum exposure to credit risk at Sept. 30, 2025, without taking into account collateral held or right of set-off, is represented by the current carrying amounts of receivables, risk management assets, loans receivable and long-term financial assets as per the condensed consolidated statements of financial position. Letters of credit, cash,

and first priority liens on assets 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 Sept. 30, 2025, was \$50 million (Dec. 31, 2024 — \$77 million).

III. Liquidity Risk

The Company has sufficient existing liquidity available to meet its upcoming debt maturities. The next major debt repayment is scheduled for the fourth quarter of 2029. Our highly diversified asset portfolio, by both fuel type and operating region, and our long-term contracted asset base provide stability in our cash flows.

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.

A maturity analysis of the Company's financial liabilities is as follows:

	2025	2026	2027	2028	2029	2030 and thereafter	Total
Accounts payable, accrued liabilities and other current liabilities	637	—	—	—	—	—	637
Credit facilities and long-term debt ⁽¹⁾	46	169	329	164	909	1,936	3,553
Exchangeable securities ⁽²⁾	—	—	—	—	—	750	750
Commodity risk management (assets) liabilities ⁽³⁾	(17)	6	13	18	19	363	402
Other risk management assets ⁽³⁾	(1)	(1)	—	1	—	(7)	(8)
Lease liabilities	2	5	5	5	5	126	148
Interest on credit facilities, long-term debt and lease liabilities ⁽⁴⁾	56	205	197	178	161	704	1,501
Interest on exchangeable securities ⁽²⁾⁽⁴⁾	14	53	53	52	12	—	184
Dividends payable	19	—	—	—	—	—	19
Total	756	437	597	418	1,106	3,872	7,186

(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.

(3) Negative amount represents a receivable position or cash inflow.

(4) Not recognized as a financial liability on the condensed consolidated statements of financial position and excludes the impact of interest rate swaps.

D. Collateral

I. Financial Assets Provided as Collateral

At Sept. 30, 2025, the Company provided \$88 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 condensed consolidated statements of financial position. At Sept. 30, 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 Sept. 30, 2025, the Company held \$305 thousand (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 condensed 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 Sept. 30, 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 \$108 million (Dec. 31, 2024 — \$128 million) of collateral to its counterparties.

13. Property, Plant and Equipment

During the three and nine months ended Sept. 30, 2025, the Company had additions to property, plant, and equipment (PP&E) of \$53 million and \$158 million, respectively, mainly related to major maintenance for our Canadian facilities in the Gas segment due to timing of spend, the addition of maintenance for the gas facilities acquired from Heartland and spend to support dam safety at Hydro facilities in Alberta. Additions also included a network upgrade project in Australia and major maintenance in the Wind and Solar segment.

During the three and nine months ended Sept. 30, 2024, the Company had additions to PP&E of \$74 million and

\$200 million, respectively, mainly related to assets under construction for the White Rock and the Horizon Hill wind projects, which were commissioned in the first and second quarters of 2024, and planned major maintenance.

During the three and nine months ended Sept. 30, 2025, the Company did not capitalize any interest to PP&E. During the three and nine months ended Sept. 30, 2024, the Company capitalized interest of nil and \$16 million, respectively, to PP&E at a weighted average rate of 6.5 per cent.

14. Assets and Liabilities Held for Sale

On Aug. 1, 2025, the Company completed the sale of its 100 per cent interest in the 48 MW Poplar Hill facility and the assets and liabilities were removed from Assets and Liabilities Held for Sale.

Subsequent to quarter end, on Oct. 2, 2025, the Company completed the sale of its 50 per cent interest in the 97 MW Rainbow Lake facility.

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. Energy Capital Partners is entitled to receive the proceeds from the sale of both facilities, net of certain adjustments, following completion of the divestitures.

15. Decommissioning and Other Provisions

The change in decommissioning and other provision balances is as follows:

	Decommissioning and restoration	Other provisions	Total
Balance, Dec. 31, 2024	848	85	933
Liabilities incurred	—	18	18
Liabilities settled	(31)	(16)	(47)
Accretion (Note 6)	40	2	42
Transfer to liabilities held for sale	(6)	—	(6)
Revisions in estimated cash flows	(10)	7	(3)
Revisions in discount rates	53	1	54
Change in foreign exchange rates	(10)	—	(10)
Balance, Sept. 30, 2025	884	97	981

Included in the condensed consolidated statements of financial position as:

As at	Sept. 30, 2025	Dec. 31, 2024
Current portion	110	83
Non-current portion	871	850
Total decommissioning and other provisions	981	933

A. Decommissioning and Restoration

During the nine months ended Sept. 30, 2025, revisions in discount rates increased the decommissioning and restoration provision by \$53 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 4.6 to 7.6 per cent as at Sept. 30, 2025. This has resulted in a corresponding increase in PP&E of \$31 million on operating assets and the recognition of \$22 million of impairment charges in net (loss) earnings related to retired assets.

During the nine months ended Sept. 30, 2025, the decommissioning and restoration provision decreased by \$10 million primarily due to revisions in estimated cash

flows for certain Hydro assets. Operating assets included in PP&E decreased by \$10 million with no impact on retired assets.

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. Information about the expected timing of settlement and uncertainties that could impact the amount or timing of settlement has not been provided as this may impact the Company's ability to settle the provisions in the most favourable manner.

16. Credit Facilities, Long-Term Debt and Lease Liabilities

A. Amounts Outstanding

The Company's credit facilities are summarized in the table below:

As at Sept. 30, 2025	Utilized				
	Facility size	Outstanding letters of credit ⁽¹⁾	Cash drawings	Available capacity	Maturity date
Credit facilities					
Committed					
Syndicated credit facility	1,900	392	102	1,406	Q2 2029
Bilateral credit facilities	240	152	—	88	Q2 2027
Heartland credit facilities	256	8	204	44	Q4 2027
Heartland EDC letter of credit facility	30	14	—	16	Q4 2025
Total committed	2,426	566	306	1,554	
Non-committed					
Demand facilities	400	212	—	188	N/A
Total Non-committed	400	212	—	188	

(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 Sept. 30, 2025, TransAlta had provided cash collateral of \$93 million.

During the third quarter of 2025, the size of 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 third quarter of 2025, the maturity of the Bilateral credit facilities in the aggregate amount of \$240 million was extended by one year to June 30, 2027.

Credit facilities are the primary source of short-term liquidity after internally generated cash flow. The Company is in compliance with the terms of its credit facilities and all undrawn amounts are fully available.

Letters of credit in the amount of \$212 million were issued from non-committed demand facilities which are fully backstopped, thereby reducing the available capacity on the committed credit facilities. In addition to the net \$1.3 billion of committed capacity available under the credit facilities, the Company had \$211 million of available cash and cash equivalents as at Sept. 30, 2025.

TransAlta's debt has terms and conditions, including financial covenants, that are considered ordinary and customary. As at Sept. 30, 2025, the Company was in compliance with all of its debt covenants.

B. 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 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 having been made on Sept. 24, 2025.

C. 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.

D. Heartland Credit Facilities

As part of the Heartland acquisition on Dec. 4, 2024, the Company assumed a term facility and revolving facility with a syndicate of banks. As at Sept. 30, 2025 the drawn term facility was \$204 million. Scheduled repayments totalling \$20 million made under the term facility during the nine months ended Sept. 30, 2025 have resulted in a corresponding reduction in the borrowing capacity of the facility.

E. Restrictions Related to Non-Recourse Debt and Other Debt

The Melancthon Wolfe Wind LP, Pingston Power Inc., TAPC Holdings LP, New Richmond Wind LP, Kent Hills Wind LP, TEC Hedland Pty Ltd. and Windrise Wind LP non-recourse bonds, the TransAlta OCP LP bond, and Heartland credit facilities, with a total carrying value of \$1.7 billion as at Sept. 30, 2025 (Dec. 31, 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 third quarter of 2025, with the exception of Windrise Wind LP. The funds in the entities will remain there until the next debt service coverage ratio can be performed in the fourth

quarter of 2025. At Sept. 30, 2025, \$70 million (Dec. 31, 2024 — \$117 million) of cash was subject to these financial restrictions.

At Sept. 30, 2025, \$6 million (AU\$6 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, for the purpose of paying 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.

F. Restricted Cash

As at Sept. 30, 2025, the Company had \$17 million (Dec. 31, 2024 — \$17 million) of restricted cash related to the TransAlta OCP bonds, which is required to be held in a debt service reserve account in the third and fourth quarters of the year to fund scheduled future debt repayments. As at Sept. 30, 2025, the Company also had \$52 million (Dec. 31, 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. Finally, the Company also had \$1 million (Dec. 31, 2024 — nil) of restricted cash related to deposits received for assets held for sale.

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 \$33 million as at Sept. 30, 2025 (Sept. 30, 2024 — increased \$20 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 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 \$11 million as at Sept. 30, 2025 (Sept. 30, 2024 — increased \$16 million due to strengthening of the Australian dollar). As this debt is issued by an Australian subsidiary, the foreign currency translation impacts are recognized within other comprehensive (loss) income.

17. 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	
	Common shares (millions)	Amount	Common shares (millions)	Amount
9 months ended Sept. 30				
Issued and outstanding, beginning of period	297.5	3,179	306.9	3,285
Reversal of provision for repurchase of common shares under Automatic Securities Purchase Plan	—	—	1.7	19
Purchased and cancelled under the NCIB ⁽¹⁾⁽²⁾	(1.9)	(20)	(11.8)	(128)
Share-based payment plans	0.8	7	0.8	9
Stock options exercised	0.3	3	0.9	6
Issued and outstanding, end of period	296.7	3,169	298.5	3,191

(1) The nine months ended Sept. 30, 2025 includes nil tax on share buybacks (Sept. 30, 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 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:

9 months ended Sept. 30	2025	2024
Total shares purchased ⁽¹⁾	1,932,800	11,814,700
Average purchase price per share	12.42	9.65
Total cost (\$ millions)	24	114
Book value of shares cancelled	20	128
Amount recorded in deficit	(4)	14

(1) The nine months ended Sept. 30, 2025 includes nil tax on share buybacks (Sept. 30, 2024 — \$2 million) on the fair value of the shares repurchased.

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. Dividends

On Oct. 22, 2025, the Company declared a quarterly dividend of \$0.065 per common share, payable on Jan. 1, 2026. There have been no other transactions involving common shares between the reporting date and the date of completion of these condensed consolidated financial statements.

18. Preferred Shares

Issued and Outstanding

All preferred shares issued and outstanding are non-voting cumulative redeemable fixed or floating rate first preferred shares.

Series ⁽¹⁾	Sept. 30, 2025		Dec. 31, 2024	
	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 period	38.6	942	38.6	942

(1) The Series I Preferred Shares are accounted for as long-term debt.

On Oct. 22, 2025, the Company declared a quarterly dividend of \$0.17981 per share on the Series A preferred shares, \$0.29560 per share on the Series B preferred shares, \$0.36588 per share on the Series C preferred

shares, \$0.36302 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 Dec. 31, 2025.

19. Commitments and Contingencies

While the Company has not incurred any additional material contractual commitments in the nine months ended Sept. 30, 2025, either directly or through its interests in joint operations and joint ventures, there were

reductions to the expected future payments under the Company's long-term service agreements in the nine months ended Sept. 30, 2025.

Total revised approximate future payments under the long-term service agreements are as follows:

	2025	2026	2027	2028	2029	2030 and thereafter	Total
Long-term service agreements	12	51	44	29	17	118	271

Refer to the commitments disclosed in Note 37 of the 2024 audited annual consolidated financial statements.

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 the excess 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 and turbines at various wind facilities.

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. The Company 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. Refer to Note 37 of the 2024 audited annual consolidated financial statements for the current material outstanding contingencies. There were no material changes to the contingencies in the nine months ended Sept. 30, 2025.

20. Segment Disclosures

A. Description of Reportable Segments

The Company has six reportable segments as described in Note 1 of the Company's 2024 audited annual consolidated financial statements. The Gas reportable segment includes Heartland, which was acquired on Dec. 4, 2024. Refer to Note 4 of the 2024 audited annual consolidated financial statements for further details of the Heartland business acquisition and preliminary purchase price allocation. There were no adjustments made to the preliminary purchase price allocation as at Sept. 30, 2025.

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 tables

below show the reconciliation of the total segmented results and adjusted EBITDA to the statement of (loss) earnings reported under IFRS.

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.

B. Reported Adjusted Segment Earnings and Segment Assets

I. Reconciliation of Adjusted EBITDA to (Loss) Earnings before Income Tax

3 Months Ended Sept. 30, 2025	Hydro	Wind & Solar ⁽¹⁾	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments ⁽¹⁾	Reclass adjustments	IFRS financials
Revenues	95	3	326	158	37	—	619	(4)	—	615
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	(3)	78	(12)	(10)	(8)	—	45	—	(45)	—
Decrease in finance lease receivable	—	1	7	—	—	—	8	—	(8)	—
Finance lease income	—	1	5	—	—	—	6	—	(6)	—
Revenues from Required Divestitures	—	—	(4)	—	—	—	(4)	—	4	—
Unrealized foreign exchange (gain) loss on commodity	—	—	(1)	—	1	—	—	—	—	—
Adjusted revenue	92	83	321	148	30	—	674	(4)	(55)	615
Fuel and purchased power	5	5	119	98	—	—	227	—	—	227
Reclassifications and adjustments:										
Fuel and purchased power related to Required Divestitures	—	—	1	—	—	—	1	—	(1)	—
Adjusted fuel and purchased power	5	5	120	98	—	—	228	—	(1)	227
Carbon compliance costs	—	—	35	—	—	—	35	—	—	35
Adjusted gross margin	87	78	166	50	30	—	411	(4)	(54)	353
OM&A	14	28	64	20	13	41	180	(1)	—	179
Reclassifications and adjustments:										
OM&A related to Required Divestitures	—	—	(2)	—	—	—	(2)	—	2	—
ERP integration costs	—	—	—	—	—	(6)	(6)	—	6	—
Acquisition-related transaction and restructuring costs	—	—	—	—	—	(1)	(1)	—	1	—
Adjusted OM&A	14	28	62	20	13	34	171	(1)	9	179
Taxes, other than income taxes	—	5	5	2	—	1	13	(1)	—	12
Net other operating income	—	—	(11)	—	—	—	(11)	—	—	(11)
Adjusted EBITDA⁽²⁾	73	45	110	28	17	(35)	238			
Depreciation and amortization										(135)
Equity loss										(1)
Interest income										7
Interest expense										(85)
Foreign exchange gain										3
Finance lease income										6
Fair value change in contingent consideration										3
Asset impairment charges										(27)
Gain on sale of assets and other										3
Loss before income taxes										(53)

(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 months ended Sept. 30, 2024	Hydro	Wind & Solar ⁽¹⁾	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments ⁽¹⁾	Reclass adjustments	IFRS financials
Revenues	105	2	314	165	55	—	641	(3)	—	638
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	1	74	(5)	(8)	(3)	—	59	—	(59)	—
Decrease in finance lease receivable	—	—	5	—	—	—	5	—	(5)	—
Finance lease income	—	1	2	—	—	—	3	—	(3)	—
Unrealized foreign exchange loss on commodity	—	—	1	—	—	—	1	—	(1)	—
Adjusted revenues	106	77	317	157	52	—	709	(3)	(68)	638
Fuel and purchased power	4	5	100	104	—	—	213	—	—	213
Carbon compliance costs	—	—	40	1	—	—	41	—	—	41
Adjusted gross margin	102	72	177	52	52	—	455	(3)	(68)	384
OM&A	13	26	43	17	10	35	144	(1)	—	143
Reclassifications and adjustments:										
Acquisition-related transaction and restructuring costs	—	—	—	—	—	(1)	(1)	—	1	—
Adjusted OM&A	13	26	43	17	10	34	143	(1)	1	143
Taxes, other than income taxes	—	5	3	1	—	1	10	—	—	10
Net other operating income	—	(3)	(10)	—	—	—	(13)	—	—	(13)
Adjusted EBITDA ⁽²⁾⁽³⁾	89	44	141	34	42	(35)	315			
Depreciation and amortization										(133)
Equity loss										(1)
Interest income										4
Interest expense										(83)
Foreign exchange loss										(6)
Finance lease income										3
Asset impairment charges										(20)
Gain on sale of assets and other										1
Earnings before income taxes										9

(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.

9 months ended Sept. 30, 2025	Hydro	Wind & Solar ⁽¹⁾	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments ⁽¹⁾	Reclass adjustments	IFRS financials
Revenues	310	169	920	385	102	(66)	1,820	(14)	—	1,806
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	(6)	182	27	4	(9)	—	198	—	(198)	—
Decrease in finance lease receivable	—	2	21	—	—	—	23	—	(23)	—
Finance lease income	—	4	13	—	—	—	17	—	(17)	—
Revenues from Required Divestitures	—	—	(11)	—	—	—	(11)	—	11	—
Unrealized foreign exchange gain on commodity	—	—	(1)	—	(1)	—	(2)	—	2	—
Adjusted revenue	304	357	969	389	92	(66)	2,045	(14)	(225)	1,806
Fuel and purchased power	16	24	388	247	—	2	677	—	—	677
Reclassifications and adjustments:										
Fuel and purchased power related to Required Divestitures	—	—	(2)	—	—	—	(2)	—	2	—
Adjusted fuel and purchased power	16	24	386	247	—	2	675	—	2	677
Carbon compliance costs (recovery)	—	2	76	—	—	(68)	10	—	—	10
Adjusted gross margin	288	331	507	142	92	—	1,360	(14)	(227)	1,119
OM&A	40	82	188	55	28	135	528	(3)	—	525
Reclassifications and adjustments:										
OM&A related to Required Divestitures	—	—	(5)	—	—	—	(5)	—	5	—
ERP integration costs	—	—	—	—	—	(16)	(16)	—	16	—
Acquisition-related transaction and restructuring costs	—	—	—	—	—	(6)	(6)	—	6	—
Adjusted OM&A	40	82	183	55	28	113	501	(3)	27	525
Taxes, other than income taxes	2	15	15	3	—	2	37	(1)	—	36
Net other operating income	—	(4)	(33)	—	—	—	(37)	—	—	(37)
Reclassifications and adjustments:										
Insurance recovery	—	2	—	—	—	—	2	—	(2)	—
Adjusted net other operating income	—	(2)	(33)	—	—	—	(35)	—	(2)	(37)
Adjusted EBITDA⁽²⁾	246	236	342	84	64	(115)	857			
Depreciation and amortization										(431)
Equity income										2
Interest income										18
Interest expense										(266)
Foreign exchange loss										(18)
Finance lease income										17
Fair value change in contingent consideration										37
Asset impairment charges										(55)
Gain on sale of assets and other										2
Loss before income taxes										(99)

(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.

9 months ended Sept. 30, 2024	Hydro	Wind & Solar ⁽¹⁾	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments ⁽¹⁾	Reclass adjustments	IFRS financials
Revenues	316	253	1,031	461	154	(34)	2,181	(14)	—	2,167
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	(3)	61	(86)	(28)	(5)	—	(61)	—	61	—
Decrease in finance lease receivable	—	1	14	—	—	—	15	—	(15)	—
Finance lease income	—	4	5	—	—	—	9	—	(9)	—
Unrealized foreign exchange gain on commodity	—	—	(1)	—	—	—	(1)	—	1	—
Adjusted revenues	313	319	963	433	149	(34)	2,143	(14)	38	2,167
Fuel and purchased power	13	22	339	316	—	—	690	—	—	690
Carbon compliance costs (recovery)	—	—	106	1	—	(34)	73	—	—	73
Adjusted gross margin	300	297	518	116	149	—	1,380	(14)	38	1,404
OM&A	39	70	131	50	29	105	424	(3)	—	421
Reclassifications and adjustments:										
Acquisition-related transaction and restructuring costs	—	—	—	—	—	(8)	(8)	—	8	—
Adjusted OM&A	39	70	131	50	29	97	416	(3)	8	421
Taxes, other than income taxes	2	13	9	3	—	1	28	(1)	—	27
Net other operating income	—	(7)	(30)	—	—	—	(37)	—	—	(37)
Adjusted EBITDA ⁽²⁾⁽³⁾	259	221	408	63	120	(98)	973			
Depreciation and amortization										(388)
Equity income										3
Interest income										19
Interest expense										(232)
Foreign exchange loss										(12)
Finance lease income										9
Asset impairment charges										(26)
Gain on sale of assets and other										4
Earnings before income taxes										370

(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.

21. Related-Party Transactions

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.

The Company may, in the normal course of operations, enter into transactions on market terms with associates

Transactions with Brookfield include the following:

that have been measured at exchange value and recognized in the condensed 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. Refer to Note 26 and 36 of the 2024 audited annual consolidated financial statements.

	3 months ended Sept. 30		9 months ended Sept. 30	
	2025	2024	2025	2024
Power sales	27	18	76	49