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 months ended March 31, 2026 and 2025, and should be read in conjunction with the audited annual consolidated financial statements and MD&A (2025 Annual MD&A) contained within our 2025 Annual 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 March 31, 2026. 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 May 5, 2026. Additional information with respect to TransAlta, including our Annual Information form (AIF) for the year ended Dec. 31, 2025, is available on SEDAR+ at ***www.sedarplus.ca****, on EDGAR at* ***www.sec.gov*** *and on our website at* ***www.transalta.com****. Information on or connected to our website is not incorporated by reference herein. For the Glossary of Key Terms used in this MD&A refer to the 2025 Annual Report.*

Forward-Looking Statements

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

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

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

- Our 2026 Outlook and the targets contained therein;
- Our hedging assumptions;
- Our estimated spot price sensitivity and the associated impacts on our Adjusted EBITDA target;
- Our expectation that cash flow from our operating activities will be sufficient to meet our short and long-term financial obligations;
- Our expectations about strategies for growth and expansion;
- Expected costs and schedules for planned projects, including the Centralia planned coal-to-gas conversion project;
- The power generation industry generally and the supply of, and demand for, electricity;
- The cyclicality of our business;
- The expected impact of future tax and accounting changes; and
- Expected industry, market and economic conditions.

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

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

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

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

- Fluctuations in power prices;
- Changes in supply and demand for electricity;
- Our ability to contract our electricity generation for prices that will provide expected returns;
- Our ability to replace contracts as they expire;
- Risks associated with development projects and acquisitions;
- Our ability to develop, access or implement, on a timely basis and on reasonable terms, the technology necessary to efficiently and effectively operate our assets and achieve expected future results;
- Any difficulty raising needed capital in the future on reasonable terms;
- Long-term commitments on gas transportation capacity that may not be fully utilized over time;
- Changes to legislative, regulatory and political environments, including changes to carbon pricing, renewable energy policies and emissions regulations in Canada, the United States and Australia;
- Environmental requirements and changes in, or liabilities under, these requirements;
- Operational risks involving our facilities, including unplanned outages and equipment failure;
- Disruptions in the transmission and distribution of electricity;
- Grid reliability;

- Reductions in production;
- Impairments and/or writedowns of assets;
- Adverse impacts on our information technology systems and our internal control systems, including increased cybersecurity threats;
- Commodity risk management and energy-trading risks;
- Reduced labour availability, ability to continue to staff our operations and facilities and other labour relations matters;
- Disruptions to our supply chains;
- Weather conditions and their impact on electricity generation and demand;
- Climate change-related risks, including the increased frequency and severity of extreme weather events;
- Reductions to our generating units' relative efficiency or capacity factors;
- General economic risks, including deterioration of equity markets, increasing interest rates, changes to foreign exchange rates or rising inflation;
- General domestic and international economic and political developments, including potential trade tariffs;
- Industry risk and competition, including from emerging technologies affecting the demand, generation, distribution or storage of electricity;
- Counterparty credit risks;
- Inadequacy or unavailability of insurance coverage;
- Increases in the Company's income taxes and any risk of reassessments;
- Legal, regulatory and contractual disputes and proceedings involving the Company;
- Reputational and stakeholder-related risks; and
- Reliance on key personnel.

The foregoing risk factors, among others, are described in further detail in the "Risk Management" section of the 2025 Annual Report.

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

Description of the Business

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

Our diversified portfolio consists of both high-quality contracted assets and merchant assets. Our contracted assets provide stable long-term cash flow and earnings, balancing our merchant fleet. Our merchant assets include our unique hydro portfolio, legacy and peaking thermal assets and wind assets. Our merchant exposure is primarily in Alberta, where 61 per cent of our generating capacity is located and 77 per cent exposed to the merchant market.

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

The following table provides our consolidated ownership by segment of our facilities across Alberta and other regions in which we operate as at March 31, 2026:

As at March 31, 2026		Hydro	Wind & Solar	Gas(4)(5)	Total
Alberta	Gross installed capacity (MW)(2)	834	764	3,650	5,248
	Number of facilities	17	14	15	46
	Weighted average contract life (years)	—	16	8	10
	Contracted capacity (MW)	—	336	887	1,223
	Contracted capacity as a % of total capacity (%)	—	44	24	23
Other regions(1)	Gross installed capacity (MW)(2)	88	1,823	1,464	3,375
	Number of facilities	7	22	14	43
	Weighted average contract life (years)	14	10	8	10
	Contracted capacity (MW)	88	1,823	1,155	3,066
	Contracted capacity as a % of total capacity (%)	100	100	79	91
Total	Gross installed capacity (MW)(2)	**922**	**2,587**	**5,114**	**8,623**
	Number of facilities	**24**	**36**	**29**	**89**
	Weighted average contract life (years)	**14**	**11**	**8**	**10**
	Contracted capacity (MW)	**88**	**2,159**	**2,042**	**4,289**
	Contracted capacity as a % of total capacity (%)(3)	**10**	**83**	**40**	**50**

(1) Other regions include the U.S., Western Australia and Canada, excluding Alberta. Gross installed capacity across all segments for the U.S., Western Australia and Canada, excluding Alberta, totaled 1,024 MW, 498 MW and 1,853 MW, respectively, with the number of facilities across all segments totaling 10, 9 and 24, respectively. Refer to 2025 Annual Report for details.

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

(3) Approximately 50 per cent of our total installed capacity is contracted with creditworthy counterparties.

(4) Gas segment includes gross installed capacity of 310 MW from four facilities in Ontario attributable to the acquisition of Far North. The contracted capacity of these facilities as at March 31, 2026 was nil and increased to 100 per cent effective May 1, 2026. Refer to the "Significant and Subsequent events" section.

(5) Gas segment excludes Ada Cogeneration facility in the U.S, with a fully contracted gross installed capacity of 29 MW, due to its retirement on Jan. 5, 2026.

Following Centralia's cessation of coal-fired operations at the end of 2025 in the normal course, the Energy Transition segment is no longer considered a reportable segment. The segment has therefore been excluded from the table above. Refer to Note 19 of our unaudited interim condensed consolidated financial statements for details. The facility currently remains available for power generation in accordance with and for the duration of the order received from the U.S. Department of Energy. Refer to Significant and Subsequent Events for detail.

Highlights

	3 months ended March 31,	
(in millions of Canadian dollars except where noted)	**2026**	**2025**
Operational information[1]		
Availability (%)	**93.8**	94.9
Production (GWh)	**5,444**	6,832
Select financial information[1]		
Revenues	**565**	758
Adjusted EBITDA[2]	**204**	270
Adjusted Earnings before income taxes[2]	**30**	28
Earnings before income taxes	**23**	49
Adjusted Net Earnings Attributable to Common Shareholders[2]	**18**	30
Net earnings attributable to common shareholders	**13**	46
Cash flows[1]		
Cash flow from operating activities	**123**	7
Funds from operations[2]	**137**	179
Free cash flow[2]	**102**	139
Per share[1]		
Weighted average number of common shares outstanding (in millions)	**297**	298
Adjusted Net Earnings Attributable to Common Shareholders per share[2][3]	**0.06**	0.10
Net earnings per share attributable to common shareholders, basic and diluted	**0.04**	0.15
Dividends declared per common share	**0.07**	0.07
Cash flow from operating activities per share[4]	**0.41**	0.02
Funds from operations per share[2][3]	**0.46**	0.60
Free cash flow per share[2][3]	**0.34**	0.47

(1) IFRS financial statements for the three months ended March 31, 2025 include the results attributable to Poplar Hill and Rainbow Lake facilities (collectively, the Required Divestitures), which the Company divested in accordance with a consent agreement entered into with the Commissioner of Competition for Canada. Our non-IFRS measures and operational Key Performance Indicators exclude the results of the Required Divestitures.

(2) These are non-IFRS measures and ratios, which are not defined and have no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the "Segmented Financial Performance and Operating Results by Geographical Location" 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 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	March 31, 2026	Dec. 31, 2025
Liquidity and capital resources		
Available liquidity(1)	**1,542**	1,500
Adjusted Net Debt to Adjusted EBITDA (times)(2)(3)	**4.3**	4.0
Total Consolidated Net Debt(2)(4)	**3,785**	3,725
Assets and liabilities		
Total assets	**8,787**	8,661
Total long-term liabilities(5)	**5,494**	5,366
Total liabilities	**7,311**	7,196

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

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

(3) The most directly comparable IFRS ratio to Adjusted Net Debt to Adjusted EBITDA (times) is calculated as credit facilities, long-term debt and lease liabilities of $3,706 million (Dec. 31, 2025 — $3,593 million) divided by loss before income taxes for the last four quarters of $167 million (Dec. 31, 2025 — loss before income taxes $141 million) and is equal to (22) times (Dec. 31, 2025 — (25) times). Refer to the "Key Non-IFRS Financial Ratios" section of this MD&A for details of the calculation.

(4) The most directly comparable IFRS measure to Total Consolidated Net Debt is total credit facilities, long-term debt and lease liabilities, which is equal to $3,706 million (Dec. 31, 2025 — $3,593 million). Refer to the table in the "Financial Condition" section of this MD&A for more details on the composition of Total Consolidated Net Debt.

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

Significant and Subsequent Events

Appointment of New Chief Financial Officer (CFO) and Chief Commercial Officer

Mike Politeski was appointed Executive Vice President, Finance and CFO, effective May 1, 2026 and Grant Arnold has been appointed Executive Vice President, Growth and Chief Commercial Officer, effective May 6, 2026.

Chief Executive Officer Succession

John Kousinioris, President and Chief Executive Officer and a Director of TransAlta retired on April 30, 2026. Joel Hunter, TransAlta’s Executive Vice President, Finance and CFO, succeeded Mr. Kousinioris as President and Chief Executive Officer 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.

Annual Shareholder Meeting

Joel Hunter was elected to the Board of Directors following the annual shareholder meeting on April 30, 2026. At the annual shareholder meeting, the Company received strong support on all items of business, including the election of the nominated directors, the reappointment of auditors, the Company's approach to executive compensation and the increase in shares available under the Company's share unit plan.

Centralia Unit 2 Mandated to Remain Available for additional 90 days

On March 16, 2026, the Company received another order from the U.S. Department of Energy (the Order) requiring that our 700 MW Centralia Unit 2 facility (Facility) remain available for operation for an additional period of 90 days, until June 14, 2026. As previously communicated, the first order from the U.S. Department of Energy dated Dec. 16, 2025 required that our Facility remain available if called upon to operate for a period of 90 days, until March 16, 2026. The Company is currently compliant with the Order and continues to work with the state and federal governments in relation thereto.

Memorandum of Understanding for Data Centre Development at Keephills Site Signed

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

Declared Increase in Common Share Dividend

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

Acquisition of Far North

On Feb. 2, 2026, the Company closed the acquisition of Far North Power Corporation (Far North), including 310 MW of capacity from four natural gas-fired facilities, for a purchase price of $95 million from an affiliate of Hut 8 Corporation, subject to working capital and other adjustments. The net cash payment for the transaction was funded through a combination of cash on hand and borrowings under TransAlta's credit facilities.

Mothballing of Sheerness Unit 1

On Apr. 1, 2026, the Company mothballed Sheerness Unit 1. The Company initially provided notice to the Alberta Electric System Operator (AESO) on Dec. 18, 2025, that Sheerness Unit 1 would be mothballed on April 1, 2026, for a period of up to two years. The Company maintains the flexibility to return the mothballed unit to service when market fundamentals improve or contracting opportunities are secured.

Operating and Financial Performance

Operating Performance

Availability

The following table provides availability (%) by segment:

3 months ended March 31	2026	2025
Hydro	**95.4**	93.6
Wind and Solar	**92.9**	94.0
Gas	**94.0**	95.5
Energy Transition[(1)]	**100.0**	97.1
Availability[(1)] (%)	**93.8**	94.9

(1) Centralia Unit 2 facility ceased coal-fired operations at the end of 2025 in the normal course and therefore, the facility is excluded from total availability. The facility remains available for power generation as mandated by the United States Department of Energy.

Availability measures the percentage of time a facility is able to produce electricity and is a key indicator of fleet performance. It is affected by planned and unplanned outages and derates. Planned outages are scheduled to minimize operational impacts, and in strong price environments may be adjusted to accelerate a unit's return to service.

Availability for the three months ended March 31, 2026, was 93.8 per cent compared to 94.9 per cent for the same period in 2025, primarily due to:

- Higher unplanned maintenance outages in the Wind and Solar and Gas segments; partially offset by
- Lower planned maintenance outages in the Hydro segment.

Production and Long-Term Average Generation

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

	2026			2025		
As at March 31	Actual production (GWh)	LTA generation (GWh)	Production as a % of LTA	Actual production (GWh)	LTA generation (GWh)	Production as a % of LTA
Hydro	**360**	**373**	**97%**	383	402	95%
Wind and Solar	**1,938**	**1,921**	**101%**	1,905	2,056	93%
Gas	**3,146**			3,504		
Energy Transition	**—**			1,040		
Total	**5,444**			6,832		

In addition to availability, the Company uses long-term average (LTA) generation as a key performance indicator for its renewable facilities, comparing actual production to expected long-term output. While Hydro and Wind and Solar production can vary period to period, over longer durations, facilities are expected to perform in-line with their LTA, which represents an annualized energy output expected from our facilities based on historical resource data, observed operating performance and forward-looking assumptions about future conditions. LTA generation is not applicable to the Gas segment, as these dispatchable facilities operate based on market conditions, and merchant and customer demand.

Total production for the three months ended March 31, 2026, decreased by 1,388 GWh, or 20 per cent, compared to the same period in 2025, primarily due to:

- No production at Centralia Unit 2 in the Energy Transition segment. Refer to the "Description of the Business" section of this MD&A; and
- Higher dispatch optimization in Alberta in the Gas segment due to lower market prices.

Financial Performance Review of Consolidated Information

3 months ended March 31	2026	2025
Revenues	**565**	758
Gross Margin	**361**	432
Operations, maintenance and administration	**(181)**	(173)
Depreciation and amortization	**(105)**	(146)
Interest expense	**(82)**	(93)
Earnings before income taxes	**23**	49
Income tax expense	**(6)**	(7)
Net earnings attributable to common shareholders	**13**	46
Adjusted earnings before income taxes[(1)]	**30**	28
Adjusted net earnings attributable to common shareholders[(1)]	**18**	30
Adjusted EBITDA[(1)]	**204**	270
Free Cash Flow[(1)]	**102**	139
Cash flow from Operating activities	**123**	7

(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 non-IFRS measures, including, where applicable, reconciliations to measures calculated in accordance with IFRS.

First Quarter Variance Analysis (2026 versus 2025)

Revenues for the three months ended March 31, 2026, decreased by $193 million, or 25 per cent, compared to the same period in 2025, primarily due to:

- No production at Centralia Unit 2;
- Lower spot and hedged power prices in the Alberta market; and
- Higher dispatch optimization in the Gas segment driven by lower power prices in Alberta.

Gross Margin for the three months ended March 31, 2026, decreased by $71 million, or 16 per cent, compared to the same period in 2025, primarily due to:

- Lower revenues as explained above; partially offset by
- Lower fuel and purchased power costs at Centralia due to no production as stated above; and
- Lower fuel and purchase power and carbon compliance costs in the Gas segment due to lower production and lower natural gas prices.

OM&A expenses for the three months ended March 31, 2026 increased by $8 million, or five per cent, compared to the same period in 2025, primarily due to:

- Higher termination, restructuring and facility shutdown costs;
- Higher legal costs arising from cost determinations made after the conclusion of arbitration proceedings; partially offset by
- Lower spending on early stage growth and development projects; and
- Expected cost recoveries as a result of complying with the Order related to Centralia

Depreciation and amortization for the three months ended March 31, 2026, decreased by $41 million, or 28 per cent, compared to the same period in 2025, primarily due to:

- Lower depreciation in the Gas segment in the current period due to a change in the useful life assumptions in 2025 for the Sheerness facilities; and
- Lower depreciation for Centralia Unit 2 due to the cessation of coal-fired operations in the normal course.

Interest expense for the three months ended March 31, 2026, decreased by $11 million, or 12 per cent, compared to 2025, primarily due to:

- Lower interest on certain senior notes following their refinancing at lower interest rates during 2025;
- Lower interest on lease liabilities; and
- Lower accretion and other interest on provisions.

Earnings before income taxes for the three months ended March 31, 2026, decreased by $26 million, or 53 per cent, compared to the same period in 2025, due to:

- The items noted above; and
- Fair value gain on contingent consideration payable totalling $34 million related to the Required Divestitures recognized in the first quarter of 2025; partially offset by
- Higher asset impairment reversals in the current period primarily related to a change in discount rates on decommissioning and restoration provisions on retired assets; and
- Higher other operating income due to legal settlement recoveries.

Income tax expense for the three months ended March 31, 2026, decreased by $1 million, or 14 per cent, compared to the same period in 2025 due to a decrease in earnings before income taxes, partially offset by other non-taxable differences.

Net earnings attributable to common shareholders for the three months ended March 31, 2026, decreased by $33 million, or 72 per cent, compared to the same period of 2025 due to:

- The items noted above; and
- Net earnings attributable to non-controlling interests compared to net loss in the comparative period due to higher net earnings for TransAlta Cogeneration, LP (TA Cogen) resulting from higher revenues in Ontario and lower depreciation for the Sheerness facilities, partially offset by lower revenues at the Sheerness facilities due to weaker merchant pricing in Alberta.

Adjusted Earnings before income taxes for the three months ended March 31, 2026, increased by $2 million, or seven per cent, compared to the same period in 2025, primarily due to:

- Lower depreciation and amortization, and lower interest expense as explained above; partially offset by
- The factors causing lower Adjusted EBITDA described in the "Adjusted EBITDA" section of this MD&A.

Adjusted Net Earnings attributable to common shareholders for the three months ended March 31, 2026, decreased by $12 million, or 40 per cent compared to the same period in 2025, primarily due to:

- Net earnings attributable to non-controlling interests compared to net loss in the comparative period due to higher net earnings for TA Cogen resulting from higher revenues in Ontario and lower depreciation for Sheerness facilities, partially offset by lower revenues at Sheerness facilities due to weaker merchant pricing in Alberta; partially offset by
- The factors causing higher Adjusted Earnings before Income Taxes explained above.

For FCF variance commentary refer to the "Free Cash Flow" section of this MD&A.

For Cash flow from operating activities variance commentary, refer to the "Cash Flows" section of this MD&A.

For reconciliation Cash flow from operating activities to FCF refer to the "Reconciliation of Cash Flow from Operations to FFO and FCF" section of this MD&A.

Adjusted EBITDA

For the three months ended March 31, 2026, the Company's Adjusted EBITDA was $204 million compared to $270 million for the same period in 2025, a decrease of $66 million, or 24 per cent.

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

	3 months ended March 31
Adjusted EBITDA(1) for the three months ended March 31, 2025	270
Hydro: Lower due to lower environmental and tax attributes sales to third parties and lower spot power prices in the Alberta market, partially offset by higher ancillary services volumes.	(12)
Wind and Solar: Lower due to lower contract revenue driven by reduced availability and lower wind resource in Eastern Canada.	(7)
Gas: Lower primarily due to higher natural gas cost in Eastern Canada, the retirement of the Ada Cogeneration facility and lower hedge and spot power prices in the Alberta market, which led to higher dispatch optimization.	(11)
Energy Marketing: Lower primarily due to higher OM&A due to higher incentive costs driven by higher unrealized mark-to-market gains included in the incentive calculation.	(4)
Corporate: Comparable to the same period in 2025.	4
Energy Transition: Lower due to no production at Centralia Unit 2.	(36)
Adjusted EBITDA(1) for the three months ended March 31, 2026	**204**

(1) Adjusted EBITDA is a non-IFRS measure. Refer to the "Non-IFRS and Supplementary Financial Measures" section of this MD&A. The most directly comparable IFRS measure is earnings before income taxes of $23 million ($49 million for the three months ended March 31, 2025). Refer to the "Reconciliation of Non-IFRS Measures on a Consolidated Basis by Segments" section of this MD&A.

Free Cash Flow

For the three months ended March 31, 2026, the Company's FCF decreased by $37 million, or 27 per cent, compared to the same period in 2025.

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

	3 months ended March 31
FCF[1] for the three months ended March 31, 2025	139
Lower Adjusted EBITDA due to the items noted above.	(66)
Lower net interest expense[2] primarily due to lower interest on certain senior notes following their refinancing at lower interest rates during 2025 and lower interest on lease liabilities.	11
Higher realized foreign exchange gains from operating activities.	17
Other[3]	1
FCF[1] for the three months ended March 31, 2026	**102**

(1) FCF is a non-IFRS measure, is not defined and has no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers. Refer to the "Non-IFRS and Supplementary Financial Measures" section of this MD&A for more information regarding this measure. The most directly comparable IFRS measure is cash flow from operating activities, which was $123 million and $7 million for the three months ended March 31, 2026 and 2025, respectively. Refer to the "Cash Flows" section of this MD&A.

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

(3) Other consists primarily of lower decommissioning and restoration costs settled, lower sustaining capital and lower loan advances by the Company's subsidiary, Kent Hills Wind LP to its 17 per cent partner. Other also includes changes in deferred payments, contract assets and liabilities, onerous contracts and long-term incentive accruals.

2026 Outlook

For 2026, the Company reaffirms Adjusted EBITDA to be in the range of $950 million to $1,050 million and FCF to be in the range of $350 million to $450 million. The assumptions disclosed in the "2026 Outlook" of the 2025 Annual MD&A remain the same. For details, please refer to the "2026 Outlook" section of the 2025 Annual Report.

The following table outlines our expectations on key financial targets and related assumptions for 2026 and should be read in conjunction with the narrative discussion that follows and the "Risk Management" section of the 2025 Annual Report:

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

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

(2) Represents forward-looking information.

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

The Company's 2026 outlook may be impacted by a number of factors, including hedging assumptions detailed further below.

Alberta Hedging

Range of hedging assumptions	Q2 2026	Q3 2026	Q4 2026	2027
Hedged production (GWh)	2,253	2,399	2,199	5,495
Hedge price ($/MWh)	$64	$63	$65	$65
Hedged gas amounts (GJ)	8.3 million	8.9 million	7.2 million	27.2 million
Hedge gas prices ($/GJ)	$3.05	$3.07	$3.39	$2.81

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

Segmented Financial Performance and Operating Results by Geographical Location

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 Adjusted EBITDA by segment across the regions we operate in for the three months ended March 31, 2026 and 2025:

3 months ended March 31, 2026	Hydro	Wind & Solar[2]	Gas	Energy Marketing	Corporate	Energy Transition	Total
Alberta	35	12	47	17	(37)	(1)	73
Canada, excluding Alberta	—	33	19	—	—	—	52
U.S.	—	48	—	—	—	2	50
Western Australia	—	2	27	—	—	—	29
Adjusted EBITDA[1]	**35**	**95**	**93**	**17**	**(37)**	**1**	**204**
Adjusted Earnings (Loss) before Income Taxes[1]	**26**	**45**	**51**	**17**	**(110)**	**1**	**30**
Earnings (loss) before income taxes	**29**	**46**	**63**	**28**	**(143)**	**—**	**23**

3 months ended March 31, 2025	Hydro	Wind & Solar[2]	Gas	Energy Marketing	Corporate	Energy Transition	Total
Alberta	47	10	50	21	(41)	(2)	85
Canada, excluding Alberta	—	48	27	—	—	—	75
U.S.	—	42	3	—	—	39	84
Western Australia	—	2	24	—	—	—	26
Adjusted EBITDA[1]	47	102	104	21	(41)	37	270
Adjusted Earnings (Loss) before Income Taxes[1]	38	49	40	19	(140)	22	28
Earnings (loss) before income taxes	59	11	65	18	(151)	47	49

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

Hydro

3 months ended March 31	2026	2025	Change	
Gross installed capacity (MW)	922	922	—	— %
LTA generation (GWh)	373	402	(29)	(7)%
Availability (%)	95.4	93.6	1.8	2 %
Production				
Contract production (GWh)	52	38	14	37 %
Merchant production (GWh)	308	345	(37)	(11)%
Total energy production (GWh)	360	383	(23)	(6)%
Ancillary service volumes (GWh)(1)	826	713	113	16 %
Alberta Hydro Assets ancillary services revenues(1)	23	20	3	15 %
Alberta Hydro Assets revenues(2)	22	26	(4)	(15)%
Other Hydro Assets revenues and other Hydro revenues(3)	8	9	(1)	(11)%
Environmental and tax attributes revenues	1	10	(9)	(90)%
Adjusted Revenues(4)	54	65	(11)	(17)%
Fuel and purchased power	(4)	(4)	—	— %
Adjusted Gross Margin(4)	50	61	(11)	(18)%
OM&A	(14)	(13)	(1)	8 %
Taxes, other than income taxes	(1)	(1)	—	— %
Adjusted EBITDA(4)	35	47	(12)	(26)%
Earnings before income taxes	29	59	(30)	(51)%
Supplementary Information: Gross revenues per MWh				
Alberta Hydro Assets revenues ($/MWh)(2)	71	75	(4)	(5)%
Alberta Hydro Assets ancillary services revenues ($/MWh)(1)	28	28	—	— %

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

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

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

(4) Adjusted Revenues, Adjusted Gross Margin and Adjusted EBITDA 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 $57 million (March 31, 2025 — $86 million), to Adjusted Gross Margin — gross margin of $53 million (March 31, 2025 — $82 million), to Adjusted EBITDA — earnings before income taxes of $29 million (March 31, 2025 — $59 million).

Adjusted Revenues for the three months ended March 31, 2026 decreased compared to the same period in 2025, primarily due to:

- Lower environmental and tax attributes revenues due to lower sales of emission credits to third parties; and
- Lower spot and hedged power prices in the Alberta market; partially offset by
- Higher ancillary services volumes due to production optimization between the Gas and Hydro segments.

Adjusted EBITDA for the three months ended March 31, 2026, decreased compared to the same period in 2025, primarily due to lower Adjusted Revenues as explained by the factors above.

Earnings before income taxes for the three months ended March 31, 2026 decreased compared to the same period in 2025, primarily due to:

- Lower Adjusted EBITDA as explained above; and
- Lower unrealized mark-to-market gains due to unfavourable changes in forward prices in the current period.

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 March 31	2026	2025	Change	
Gross installed capacity (MW)	2,587	2,587	—	— %
LTA generation (GWh)	1,921	2,056	(135)	(7)%
Availability (%)	92.9	94.0	(1.1)	(1)%
Production				
Contract production (GWh)	1,570	1,610	(40)	(2)%
Merchant production (GWh)	368	295	73	25 %
Total production (GWh)	1,938	1,905	33	2 %
Adjusted Revenues(1)(3)	109	119	(10)	(8)%
Environmental and tax attributes revenues(1)	24	26	(2)	(8)%
Adjusted Revenues(2)(3)	133	145	(12)	(8)%
Fuel and purchased power	(7)	(10)	3	(30)%
Carbon compliance costs	—	(1)	1	(100)%
Adjusted Gross Margin(2)(3)	126	134	(8)	(6)%
OM&A	(25)	(29)	4	(14)%
Taxes, other than income taxes	(7)	(5)	(2)	40 %
Adjusted Net Other Operating Income(3)	1	2	(1)	(50)%
Adjusted EBITDA(2)(3)	95	102	(7)	(7)%
Earnings before income taxes(4)	46	11	35	318 %

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

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

(3) Adjusted Revenues, Adjusted Gross Margin, Adjusted Net Other Operating Income, Adjusted EBITDA 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 $118 million (March 31, 2025 — $100 million), to Adjusted Gross Margin — gross margin of $111 million (March 31, 2025 — $89 million), to Adjusted Net Other Operating Income — net other operating income of $13 million (March 31, 2025 — $4 million), to Adjusted EBITDA — earnings before income taxes of $46 million (March 31, 2025 — $11 million).

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

Adjusted Revenues for the three months ended March 31, 2026 decreased compared to the same period in 2025, primarily due to lower contract revenue driven by lower availability and wind resource in Eastern Canada.

Adjusted EBITDA for the three months ended March 31, 2026 decreased compared to the same period in 2025, primarily due to lower Adjusted Revenues as explained by the factors above.

Earnings before income taxes for the three months ended March 31, 2026 increased compared to the same period in 2025, primarily due to:

- Lower unrealized mark-to-market losses in the current period mainly due to the adoption of IFRS 9 hedge accounting. Effective Jan. 1, 2026, certain Virtual Power Purchase Agreement (VPPA) contracts were designated as cash flow hedges. As a result, the effective portion of unrealized gains and losses due to changes in fair value is recognized in other comprehensive income, while the ineffective portion is recognized in revenue; and
- Higher legal settlement recoveries compared to the same period in 2025; partially offset by
- Lower Adjusted EBITDA as explained above.

Gas

3 months ended March 31	2026	2025	Change	
Gross installed capacity(1) (MW)	5,114	4,834	280	6 %
Availability (%)	94.0	95.5	(1.5)	(2)%
Production				
Contract sales volume (GWh)	2,394	2,550	(156)	(6)%
Merchant sales volume (GWh)	1,000	1,292	(292)	(23)%
Purchased power (GWh)(2)	(248)	(338)	90	(27)%
Total production (GWh)	3,146	3,504	(358)	(10)%
Adjusted Revenues(3)	342	366	(24)	(7)%
Adjusted Fuel and Purchased Power(3)	(154)	(161)	7	(4)%
Carbon compliance costs	(39)	(49)	10	(20)%
Adjusted Gross Margin(3)	149	156	(7)	(4)%
Adjusted OM&A(3)	(62)	(57)	(5)	9 %
Taxes, other than income taxes	(5)	(5)	—	— %
Net other operating income	11	10	1	10 %
Adjusted EBITDA(3)	93	104	(11)	(11)%
Earnings before income taxes	63	65	(2)	(3)%

(1) Includes gross installed capacity of 310 MW from four facilities in Ontario attributable to the acquisition of Far North. Refer to the "Significant and Subsequent events" section. Gas segment excludes the Ada Cogeneration facility in the U.S, with a gross installed capacity of 29 MW, due to its retirement on Jan. 5, 2026.

(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 and Adjusted EBITDA 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 $348 million (March 31, 2025 — $390 million), to Adjusted Fuel and Purchased Power — fuel and purchased power of $154 million (March 31, 2025 — $163 million), to Adjusted Gross Margin — gross margin of $155 million (March 31, 2025 — $178 million), to Adjusted OM&A — OM&A of $62 million (March 31, 2025 — $59 million) and to Adjusted EBITDA — earnings before income taxes of $63 million (March 31, 2025 — $65 million).

Adjusted Revenues for the three months ended March 31, 2026 decreased compared to the same period in 2025, primarily due to:

- Lower hedge and spot power prices in the Alberta market compared to the same period in 2025, which led to higher dispatch optimization in the current period;
- Lower contract revenue from the Ada Cogeneration facility due to its retirement in the first quarter of 2026; partially offset by
- Positive contribution from higher realized pricing in Ontario and the acquisition of the Far North facilities.

Adjusted EBITDA for the three months ended March 31, 2026 decreased compared to the same period in 2025, primarily due to:

- Lower Adjusted Revenues as explained above;
- Higher natural gas costs in Eastern Canada; partially offset by
- Lower fuel and carbon compliance costs due to higher dispatch optimization.

Earnings before income taxes for the three months ended March 31, 2026 were comparable to the same period in 2025, primarily due to:

- Lower Adjusted EBITDA as explained above; and
- Lower unrealized mark-to-market gains in the current period due to less favourable hedge prices in the current period; partially offset by
- Lower depreciation driven by a change in the useful life assumptions in 2025 for the Sheerness facilities.

Energy Marketing

3 months ended March 31	2026	2025	Change	
Adjusted Revenues(1)	28	28	—	— %
OM&A	(11)	(7)	(4)	57 %
Adjusted EBITDA(1)	17	21	(4)	(19)%
Earnings before income taxes	28	18	10	56 %

(1) Adjusted Revenues and Adjusted EBITDA 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 $39 million (March 31, 2025 — $27 million) and to Adjusted EBITDA — earnings before income taxes of $28 million (March 31, 2025 — $18 million).

Adjusted Revenues for the three months ended March 31, 2026 were comparable to the same period in 2025.

Adjusted EBITDA for the three months ended March 31, 2026 was lower compared to the same period in 2025 primarily driven by higher OM&A due to higher accrued incentive costs driven by higher unrealized mark-to-market gains.

Earnings before income taxes for the three months ended March 31, 2026 increased compared to the same period in 2025 due to:

- Higher unrealized mark-to-market gains due to more favourable trading positions; partially offset by
- Lower Adjusted EBITDA as explained above.

Corporate

3 months ended March 31	2026	2025	Change	
Adjusted OM&A(1)	(38)	(41)	3	(7)%
Adjusted EBITDA(1)	(37)	(41)	4	(10)%
Loss before income taxes	(143)	(151)	8	(5)%

(1) Adjusted OM&A and Adjusted EBITDA 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 is OM&A of $62 million (March 31, 2025 — $49 million). The most directly comparable IFRS measure to Adjusted EBITDA is loss before income taxes of $143 million (March 31, 2025 — $151 million).

Adjusted EBITDA for the three months ended March 31, 2026 was comparable to the same period in 2025.

Loss before income taxes for the three months ended March 31, 2026 decreased compared to the same period in 2025 due to:

- Comparable Adjusted EBITDA as stated above;
- Lower interest expense driven by lower interest on certain senior notes, following their refinancing at lower interest rates during 2025, lower interest on lease liabilities and lower accretion and other interest on provisions; and
- Lower spending on early stage growth and development projects; partially offset by
- Higher unrealized foreign exchange losses driven by unfavourable changes in foreign currency rates;
- Higher termination and restructuring costs as part of strategic decisions; and
- Higher legal costs arising from cost determinations made after the conclusion of arbitration proceedings in the current period.

Energy Transition[1]

3 months ended March 31	2026	2025	Change	
Gross installed capacity (MW)	671	671	—	— %
Availability[2] (%)	100.0	97.1	2.9	3 %
Total production (GWh)	—	1,040	(1,040)	(100)%
Adjusted Revenues[3]	2	153	(151)	(99)%
Fuel and purchased power	—	(98)	98	(100)%
Adjusted Gross Margin[3]	2	55	(53)	(96)%
Adjusted OM&A[3]	(1)	(17)	16	(94)%
Taxes, other than income taxes	—	(1)	1	(100)%
Adjusted EBITDA[3]	1	37	(36)	(97)%
Earnings before income taxes	—	47	(47)	(100)%
Supplementary information:				
Highvale mine reclamation spend[4]	3	3	—	— %
Centralia mine reclamation spend[4]	3	4	(1)	(25)%

(1) The Energy Transition segment is a non-reportable segment as at March 31, 2026. Refer to Note 19 of the condensed consolidated financial statements the three months ended March 31, 2026.

(2) Centralia Unit 2 facility ceased coal-fired operations at the end of 2025 in the normal course. The facility remains available for power generation as mandated by the United States Department of Energy.

(3) Adjusted Revenues, Adjusted Gross Margin, Adjusted OM&A, Adjusted EBITDA 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 $2 million (March 31, 2025 — $154 million), to Adjusted Gross Margin — gross margin of $2 million (March 31, 2025 — $56 million), to Adjusted OM&A — OM&A of $8 million (March 31, 2025 — $17 million), to Adjusted EBITDA — earnings before income taxes of $— million (March 31, 2025 — $47 million).

(4) Highvale and Centralia mine reclamation spending, 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 condensed consolidated statements of financial position under IFRS.

Adjusted Revenues and Adjusted EBITDA for the three months ended March 31, 2026 decreased compared to the same period in 2025, primarily due to no production at Centralia.

Adjusted OM&A has been reduced by the expected recoveries as a result of complying with the Order. Refer to the "Regulatory Updates" section of this MD&A.

Earnings before income taxes for the three months ended March 31, 2026 decreased compared to the same period in 2025, due to:

- Lower Adjusted EBITDA as explained above;
- Lower impairment reversal due to the reversal in the comparative period related to the generation equipment classified as held for sale; and
- Community fund expense related to the retirement of coal operations at Centralia; partially offset by
- Lower depreciation due to the cessation of coal-fired operations at Centralia in the normal course; and
- Higher asset impairment reversals in the current period due to a decrease in decommissioning and restoration provisions on retired assets primarily driven by changes in discount rates.

Mine reclamation spending for the three months ended March 31, 2026 was consistent with the same period in 2025.

Optimization of the Alberta Portfolio

The Alberta electricity portfolio metrics disclosed below are supplementary financial measures used to provide additional insight into the segment performance in the Alberta market.

Approximately 61 per cent of our generating capacity is located in Alberta, with 77 per cent exposed to merchant market. Our portfolio of assets consists of hydro, wind, battery storage and natural gas generation facilities.

Our hydro and gas fleets provide ancillary services, with hydro assets also supporting grid reliability, including black start capability and contributing to drought mitigation through regulated river flows. Our Alberta wind and hydro assets generate environmental credits sold to third parties and our Gas segment.

Portfolio performance is supported by fuel and asset diversity, enabling optimization between energy production and ancillary services. A significant portion of our Alberta capacity is hedged through commercial and industrial customer contracts and financial instruments to enhance cash-flow stability.

During periods of low market prices, we may elect not to dispatch gas generation and instead monetize contracted or hedged positions. In the first quarter of 2026, this strategy resulted in contracted and hedged gas volumes exceeding actual merchant production.

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

	2026				2025			
3 months ended March 31	**Hydro**	**Wind & Solar**	**Gas**	**Total**	**Hydro**	**Wind & Solar**	**Gas**	**Total**
Gross installed capacity (MW)	**834**	**764**	**3,650**	**5,248**	834	764	3,650	5,248
Total production[1] (GWh)	**308**	**659**	**2,004**	**2,971**	345	557	2,293	3,195
Contract production (GWh)	**—**	**291**	**1,318**	**1,609**	—	262	1,370	1,632
Merchant production (GWh)	**308**	**368**	**686**	**1,362**	345	295	923	1,563
Ancillary services volumes (GWh)	**826**	**15**	**144**	**985**	714	19	268	1,001
Hedged volumes (GWh)	**243**	**23**	**2,088**	**2,354**	276	38	1,959	2,273
Production contracted or hedged (%)	**79%**	**48%**	**170%**	**133%**	80%	54%	145%	122%
Hedged volumes as a percentage of gross installed capacity (%)	**13%**	**1%**	**26%**	**21%**	15%	2%	25%	20%
Adjusted Revenues[2][3] ($)	**49**	**26**	**199**	**274**	62	28	226	316
Fuel ($)	**(1)**	**(3)**	**(85)**	**(89)**	(1)	(4)	(99)	(104)
Purchased power ($)	**(2)**	**(1)**	**(8)**	**(11)**	(3)	(1)	(11)	(15)
Carbon compliance costs[3] ($)	**—**	**—**	**(30)**	**(30)**	—	(1)	(36)	(37)
Adjusted Gross Margin ($)	**46**	**22**	**76**	**144**	58	22	80	160

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

(2) Revenues have been adjusted to exclude the impact of unrealized mark-to-market gains or losses. The Energy Transition segment is a non-reportable segment as at March 31, 2026 and is no longer included in the table above. Refer to Note 19 of the condensed consolidated financial statements the three months ended March 31, 2026.

(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.

Total production for the Alberta portfolio for the three months ended March 31, 2026, was 2,971 GWh, compared to 3,195 GWh for the same period in 2025. The decrease of 224 GWh, or seven per cent, was primarily due to:

- Lower merchant production in the Gas segment due to dispatch optimization driven by lower market prices;
- Lower production from the Hydro segment due to lower storage levels in the beginning of the year; partially offset by
- Higher production volumes in the Wind and Solar segment due to higher wind resource.

Ancillary services volumes for the three months ended March 31, 2026 were comparable to the the same period of 2025, due to production optimization between the Gas and Hydro segments.

Hedged volumes for the Alberta portfolio for the three months ended March 31, 2026, increased compared to the same period in 2025. In anticipation of the risk of lower prices in 2026, the Company deployed a defensive strategy to increase financial hedges for the merchant portfolio at attractive margins. 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 March 31, 2026, was $144 million, compared to $160 million in the same period of 2025. The decrease of $16 million, or 10 per cent, was primarily due to:

- Lower gross margin for the Hydro segment due to lower environmental and tax attributes revenue due to lower sales of emission credits to third parties and lower spot power prices; and
- Lower gross margin for the Gas segment due to the impact of lower Alberta spot and hedge power prices, resulting in higher dispatch optimization and lower contributions from hedging.

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

3 months ended March 31	2026	2025
Alberta Market		
Spot power price average per MWh	**32**	40
Natural gas price (AECO) per GJ	**1.93**	2.03
Carbon compliance price per tonne(1)	**110**	95
Alberta Portfolio Results		
Realized merchant power price per MWh(2)	**101**	122
Ancillary services price per MWh(3)	**29**	26
Hydro energy spot power price per MWh	**46**	70
Hydro ancillary services price per MWh	**28**	28
Wind energy spot power price per MWh	**20**	20
Gas spot power price per MWh	**48**	56
Hedged power price average per MWh(4)	**66**	71
Hedged volume (GWh)	**2,354**	2,273
Fuel cost per MWh(5)	**44**	45
Carbon compliance cost per MWh(6)	**15**	16

(1) The Government of Alberta froze the carbon price per tonne at $95 under the Technology Innovation and Emissions Reduction regulation. During the three months ended March 31, 2026, the carbon compliance obligation has been accrued at a price of $110 per tonne in consideration of the federal Output-Based Pricing System backstop, which, if imposed on the province of Alberta, would result in a carbon pricing obligation of $110 per tonne.

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

(3) Ancillary services price per MWh for the Alberta electricity portfolio is a supplementary financial measure and represents the average ancillary services price across Hydro, Gas and Wind and Solar segments.

(4) 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.

(5) 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 segment.

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

The average spot power price per MWh in Alberta for the three months ended March 31, 2026, decreased by $8 per MWh, compared to the same period in 2025, primarily due to the impact of milder weather during the current period.

The realized merchant power price per MWh of production for Alberta for the three months ended March 31, 2026, decreased by $21 per MWh, compared to the same period in 2025, primarily due to:

- Lower average spot power prices as explained above and lower hedge power prices compared to the same period in 2025; partially offset by
- Favourable hedge positions settling and production optimization, which generated positive contributions over settled spot prices in Alberta.

Fuel cost per MWh for the three months ended March 31, 2026, was comparable to the same period in 2025.

Carbon compliance cost per MWh of production for the Alberta portfolio for the three months ended March 31, 2026 was comparable to the same period in 2025, primarily due to:

- A favourable impact on carbon compliance cost per MWh due to a higher proportion of production from lower-carbon-emitting cogeneration facilities; partially offset by
- An increase in the carbon price per tonne from $95 in 2025 to $110 in 2026.

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. 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.

	Q2 2025	Q3 2025	Q4 2025	Q1 2026
Revenues	433	615	599	**565**
Gross margin	334	353	301	**361**
OM&A	173	179	186	**181**
Depreciation and amortization	150	135	148	**105**
(Loss) earnings before income taxes	(95)	(53)	(42)	**23**
Net (loss) earnings attributable to common shareholders	(112)	(62)	(62)	**13**
Net (loss) earnings per share attributable to common shareholders, basic and diluted[(1)]	(0.38)	(0.20)	(0.21)	**0.04**

	Q2 2024	Q3 2024	Q4 2024	Q1 2025
Revenues	582	638	678	758
Gross margin	436	384	390	432
OM&A	144	143	234	173
Depreciation and amortization	131	133	143	146
Earnings (loss) before income taxes	94	9	(51)	49
Net earnings (loss) attributable to common shareholders	56	(36)	(65)	46
Net earnings (loss) per share attributable to common shareholders, basic and diluted[(1)]	0.18	(0.12)	(0.22)	0.15

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

Operating results have been impacted by the following events:

- The acquisition of Far North on Feb. 2, 2026;
- The acquisition of Heartland on Dec. 4, 2024; and
- No production at Centralia starting the first quarter of 2026 due to the cessation of coal-fired operations in the normal course.

Refer to the "Description of the Business" section of this MD&A.

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

- Alberta spot and hedged power prices;
- Mid-Columbia power prices until the fourth quarter of 2025;
- Ontario spot power prices;
- The effects of unrealized mark-to-market gains and losses from hedging and derivative positions due to favourable and unfavourable changes in forward rates; and
- The effects of realized mark-to-market gains and losses on settled trades.

Effective Jan. 1, 2026, certain VPPA contracts were designated as cash flow hedges. As a result, the effective portion of unrealized gains and losses due to changes in fair value is recognized in other comprehensive income, while the ineffective portion is recognized in revenue.

Gross Margin has been impacted by:

- Factors impacting revenues as described above;
- Natural gas prices;
- Purchased power costs;
- Carbon price per tonne, which increased from $80 in 2024 to $95 in 2025 and $110 in 2026; and
- Utilization of internally generated and externally purchased emission credits to settle a portion of our 2024 and 2023 GHG obligation, which reduced the carbon compliance obligation in the second quarters of 2025 and 2024, respectively.

OM&A has been impacted by:

- Strategic and growth initiatives;
- Legal costs arising from cost determinations made after the conclusion of arbitration proceedings in the first quarter of 2026;
- The planning, design and implementation of an upgrade to our ERP system;
- Expected recoveries for Centralia as a result of complying with the Order in the first quarter of 2026; and
- Acquisition-related transaction and restructuring costs related to Heartland and Far North acquisitions.

Depreciation has been impacted by:

- Lower depreciation in the Gas segment in the current period due to a change in the useful life assumptions in 2025 for the Sheerness facilities;
- Lower depreciation for Centralia Unit 2 facility due to the cessation of coal-fired operations in the normal course; and
- The revision to the useful lives of certain facilities in the third quarter of 2024.

(Loss) earnings before income taxes have been impacted by:

- The factors explained above;
- Net other operating income, which includes insurance recoveries and legal settlement recoveries;
- Interest expense and foreign exchange gains and losses; and
- Asset impairment charges and reversals on operating and retired assets primarily driven by changes in decommissioning liabilities and impairment, net of reversals, related to certain Wind and Solar facilities in the third quarter of 2025.

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

- The factors explained above;
- Changes in net earnings (losses) attributable to non-controlling interests primarily due to changes in net earnings for TA Cogen resulting from weaker merchant pricing in the Alberta market and depreciation impacts from changes in the useful life assumptions of the Sheerness facilities.

Financial Condition

Balance Sheet Analysis

The following table highlights significant changes in the Condensed Consolidated Statements of Financial Position from Dec. 31, 2025 to March 31, 2026:

As at	March 31, 2026	Dec. 31, 2025	Increase/ (decrease)
Total current assets	**1,385**	1,336	49
Total non-current assets	**7,402**	7,325	77
Total assets	**8,787**	8,661	126
Total current liabilities	**1,817**	1,830	(13)
Total non-current liabilities	**5,494**	5,366	128
Total liabilities	**7,311**	7,196	115

Working Capital

The deficit of current assets relative to current liabilities, including the current portion of long-term debt and lease liabilities, was $432 million as at March 31, 2026 (Dec. 31, 2025 – $494 million).

The working capital deficit was primarily caused by the classification of exchangeable securities totaling $750 million as current liabilities as a result of Brookfield's conversion option that can be exercised at any time after Dec. 31, 2024, although there is no obligation to deliver cash equivalent resources and Brookfield cannot call for repayment. Refer to Note 26 of the 2025 consolidated financial statements for details.

The deficit as at March 31, 2026, decreased from Dec. 31, 2025 primarily as a result of lower accounts receivable and collateral provided, partially offset by lower accounts payable and accrued liabilities and higher income taxes receivable. For the working capital management discussion, refer to the "Financial Capital" section below.

Non-Current Assets

Non-current assets as at March 31, 2026, were $7,402 million, an increase of $77 million from $7,325 million as at Dec. 31, 2025, primarily due to higher property, plant and equipment (PP&E) resulting from the acquisition of Far North totaling $101 million, capital additions of $27 million and higher foreign exchange gains on translation of the balances denominated in foreign currency to the presentation currency, partially offset by depreciation of $97 million for the three months ended March 31, 2026.

In addition, during the three months ended March 31, 2026, the Company completed Mount Keith West Network Upgrade project and accordingly derecognized $39 million from the assets under construction and recognized a finance lease receivable.

Non-Current Liabilities

Non-current liabilities as at March 31, 2026, were $5,494 million, an increase of $128 million from $5,366 million as at Dec. 31, 2025, mainly due to an increase in credit facilities, long-term debt and lease liabilities driven by cash drawings on the syndicated credit facility to finance the Far North acquisition.

Contractual Obligations

There were no material changes to the Company's contractual obligations during the quarter. The Company's significant contractual commitments are described in Note 36 Commitments and Contingencies of the consolidated financial statements for the year ended Dec. 31, 2025.

Financial Capital

The Company is focused on maintaining a strong balance sheet and financial position to ensure access to sufficient financial capital. The Company expects cash flow from operating activities to be sufficient to meet its obligations, support sustaining capital expenditures and fund dividends over both the short- and long-term. Given its financing track record in recent years, the Company has robust access to capital markets for future funding needs. The Company has a total of $2.2 billion committed capacity under its credit facilities as at March 31, 2026, of which $1.3 billion remains available for short-term borrowings. Refer to the "Credit Facilities" section below for further details.

The Company manages working capital deficits primarily through cash generated from operating activities and the availability of credit facilities. Management regularly monitors liquidity and funding requirements, and evaluates the Company's capital structure in light of prevailing market conditions. Current leverage levels are considered manageable, they reflect management's ongoing assessment of the risk profile and cash flow characteristics associated with the Company's assets.

For information on Company's credit ratings, refer to "Financial Condition" section of the 2025 Annual Report. Risks associated with our credit ratings are discussed in the "Risk Management" section of the 2025 Annual Report.

Capital Structure

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

As at	March 31, 2026		Dec. 31, 2025	
	$	% of total	$	% of total
Senior unsecured debt	**1,852**	**33**	1,734	31
Non-recourse debt	**1,481**	**26**	1,471	26
Recourse debt - OCP Bond	**153**	**3**	166	3
Tax equity financing	**72**	**1**	76	1
Lease liabilities	**148**	**3**	146	3
Credit facilities, long-term debt and lease liabilities[1]	**3,706**	**66**	3,593	64
Add: Exchangeable debentures	**350**	**6**	350	6
Add: Bank overdraft	**7**	**—**	—	—
Less: Cash and cash equivalents	**(274)**	**(5)**	(205)	(3)
Less: TransAlta OCP LP restricted cash[2]	**—**	**—**	(17)	—
Less: Fair value of foreign exchange forward contracts on foreign-currency denominated debt	**(4)**	**—**	4	—
Total Consolidated Net Debt[3][4][5]	**3,785**	**67**	3,725	67
Exchangeable preferred securities[5]	**400**	**7**	400	7
Total equity	**1,476**	**26**	1,465	26
Total capital	**5,661**	**100**	5,590	100

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

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

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

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

Credit Facilities

The Company's credit facilities are summarized in Note 14 of the Condensed Consolidated Financial Statements.

The Company maintains a strong financial position, with $1.5 billion in liquidity as at March 31, 2026. Credit facilities are the primary source of short-term liquidity after internally generated cash flow.

As at March 31, 2026, the Company had total committed capacity of $2.2 billion, against which $526 million of letters of credit were issued and $200 million was drawn in cash. Under the $400 million non-committed capacity, the Company issued $221 million of fully backstopped letters of credit, which reduced the available capacity on the committed credit facilities.

The Company is in compliance with all covenants under its credit facilities and all undrawn amounts are fully available.

In addition to the net $1.3 billion of remaining committed capacity, the Company held $274 million in cash and cash equivalents, resulting in total available liquidity of $1.5 billion as at March 31, 2026.

TransAlta's debt has terms and conditions, including financial covenants, that are considered ordinary and customary. As at March 31, 2026, the Company was in compliance with all of its debt covenants.

Non-Recourse Debt and Other

All non-recourse debt, the TransAlta OCP LP bond, and the Heartland credit facilities are subject to customary financing conditions and covenants that may restrict the Company's ability to access funds generated by the facilities' operations. Upon meeting certain distribution tests, typically performed once per quarter, the funds can be distributed by the subsidiary entities to their respective parent entity. These conditions include meeting a debt-service coverage ratio prior to distribution, which was met by these entities in the first quarter of 2026, with the exception of Windrise Wind LP. The funds in Windrise that have accumulated will remain there until the debt-service coverage ratio distribution threshold is met. At March 31, 2026, $133 million (Dec. 31, 2025 – $101 million) of cash was subject to these financial restrictions.

At March 31, 2026, $9 million (AU$9 million) of funds held by TEC Hedland Pty Ltd. are not accessible by other corporate entities as the funds must be solely used by the project entities to pay major maintenance costs.

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

The $750 million of exchangeable securities are exchangeable into an equity ownership interest in TransAlta's Alberta Hydro Assets between Dec. 31, 2024 and Dec. 31, 2028.

Returns to Providers of Capital

Interest Income and Interest Expense

The components of interest expense are disclosed in Note 7 of the Condensed Consolidated Financial Statements. Net Interest Expense in the reconciliation of our Adjusted EBITDA to our FFO and FCF is calculated as follows:

3 months ended March 31	2026	2025
Interest expense	**82**	93
Less: Interest Income	**(7)**	(5)
Less: non-cash items(1)	**(14)**	(16)
Net Interest Expense(2)	**61**	72

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

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

Interest expense for the three months ended March 31, 2026 was lower compared to the same period in 2025, primarily due to lower interest on certain senior notes, following their refinancing at lower interest rates during 2025, lower interest on lease liabilities and lower accretion and other interest on provisions.

Interest income for the three months ended March 31, 2026 was comparable to the same period in 2025.

Series B Preferred Shares conversion

On March 31, 2026, holders of Series B preferred shares converted 1,148,549 of the 2,370,087 outstanding Series B shares into Series A shares on a one-for-one basis. As a result of the conversion, on March 31, 2026, the Company had 10,778,462 Series A Shares and 1,221,538 Series B Shares issued and outstanding.

Other Series Preferred Shares

Other Series preferred shares outstanding for the three months ended March 31, 2026 remained unchanged.

Share Capital

For details on common and preferred shares issued and outstanding refer to Notes 15 and 16 of the Condensed Consolidated Financial Statements.

As at May 5, 2026, the outstanding number of common shares was 297.8 million. The outstanding number of preferred shares was as follows: Series A 10.8 million, Series B 1.2 million, Series C 10.0 million, Series D 1.0 million, Series E 9.0 million and Series G 6.6 million.

Cash Flows

The following table highlights significant changes in the Condensed Consolidated Statements of Cash Flows for the three months ended March 31, 2026 and March 31, 2025:

3 months ended March 31	2026	2025	Increase/ (decrease)
Cash and cash equivalents, beginning of period	**205**	337	(132)
Provided by (used in):			
Operating activities	**123**	7	116
Investing activities	**(93)**	(144)	51
Financing activities	**38**	38	—
Effect of translation on foreign currency cash	**1**	—	1
Cash and cash equivalents, end of period	**274**	238	36

Cash Flow from Operating Activities

Cash from operating activities increased in the three months ended March 31, 2026, primarily due to favourable working capital movements driven by lower accounts receivable and collateral provided, partially offset by lower accounts payable and accrued liabilities. Gross margin was lower primarily due to lower revenues, partially offset by lower fuel and purchased power costs. Cash taxes decreased during the three months ended March 31, 2026, attributed to a lower tax obligation as at Dec. 31, 2025, resulting from lower earnings before income taxes for the year ended Dec. 31, 2025 compared to 2024.

Cash Flow used in Investing Activities

Cash used in investing activities for the three months ended March 31, 2026, decreased compared to the same period in 2025, primarily due to Nova facilities issued during the first quarter of 2025, partially offset by the cash paid to acquire Far North facilities in the current period and favourable change in non-cash investing working capital balances due to lower capital accruals.

Cash Flow from Financing Activities

Cash from financing activities for the three months ended March 31, 2026, was consistent compared to the same period in 2025, primarily due to higher cash drawings under the syndicated credit facility to finance the Far North acquisition in the current period and a repayment of the $400 million variable rate term loan facility and the issuance of $450 million senior notes during the first quarter of 2025.

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.

Total sustaining capital expenditures for the three months ended March 31, 2026 were comparable to the same period in 2025.

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

3 months ended March 31	2026	2025
Hydro	**1**	4
Wind and Solar	**4**	4
Gas	**14**	11
Corporate	**2**	4
Sustaining capital expenditures	**21**	23

Growth and Development Capital Expenditures

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

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

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

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

3 months ended March 31	2026	2025
Hydro	**1**	—
Gas	**4**	11
Energy Transition	**3**	—
Growth and development expenditures	**8**	11

Growth and development expenditures for the three months ended March 31, 2026 were lower compared to the same period in 2025, primarily due to:

- Lower spend in the Gas segment primarily due to a completion of the capital maintenance at Sarnia during the first quarter of 2025 caused by the plant outage in the fourth quarter of 2024; partially offset by
- Higher spending in the Energy Transition segment related to the Centralia conversion from coal to natural gas, which extends the operating life of the existing plant.

Refer to the "Strategic Priorities" section of the 2025 Annual Report for more details.

Growth

Over the course of 2025 and 2024, we refined our development pipeline to align with evolving regulatory and interconnection dynamics, while progressing opportunities at our legacy assets. The pipeline now includes 860 MW of mid-stage projects and 2,890 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	Wind	Solar	Storage	Total
Various	1,890	465	190	345	2,890

Mid-Stage Development

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

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

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

Projects under Construction

The Mount Keith West network upgrade transmission project was completed during the three months ended March 31, 2026. Accordingly, the Company derecognized $39 million from the assets under construction and recognized a finance lease receivable.

Other Consolidated Analysis

Commitments

The Company has not incurred any additional material contractual commitments in the three months ended March 31, 2026, either directly or through its interests in joint operations and joint ventures. For the current material outstanding commitments, please refer to Note 18 Commitments and Contingencies in the condensed consolidated financial statements and Note 36 of the 2025 audited annual consolidated financial statements.

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 excess capacity.

Contingencies

For the current material outstanding contingencies, please refer to Note 36 of the 2025 audited annual consolidated financial statements. There were no material changes to the contingencies during the three months ended March 31, 2026.

Financial Instruments

For details on Financial instruments refer to Note 14 of the notes to the audited annual 2025 consolidated financial statements and Note 10 of our unaudited interim condensed consolidated financial statements as at and for the three months ended March 31, 2026.

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 March 31, 2026, Level III instruments had a net liabilities carrying value of $319 million (2025 – net liabilities $312 million). The Level III liabilities increased during the three months ended March 31, 2026 due to volatility in market prices across multiple markets on existing contracts and contract settlements, and a decrease in the the carrying value of Nova facilities. Our risk management profile and practices have not changed materially from Dec. 31, 2025.

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 condensed consolidated financial statements prepared in accordance with IFRS. We believe that these non-IFRS amounts, measures and ratios, read together with our IFRS amounts, provide readers with a better understanding of how management assesses results.

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

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

Non-IFRS Financial Measures

This section provides additional information on these non-IFRS measures, including their reconciliation to the most comparable IFRS measure.

Adjusted EBITDA

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

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

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

Adjusted Revenue

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

- The impact of unrealized mark-to-market gains or losses and unrealized foreign exchange gains or losses on commodity transactions.
- Certain assets that we own in Canada and Western Australia are fully contracted and recorded as finance leases under IFRS. We believe that it is more appropriate to reflect the payments we receive under the contracts as a capacity payment in our revenues instead of as finance lease income and a decrease in finance lease receivables.
- Revenues from the Required Divestitures as they do not reflect ongoing business performance.

Adjusted Fuel and Purchased Power

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

Adjusted OM&A

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

- Termination, restructuring and facility shutdown costs mainly for costs incurred as part of strategic decisions and facility shutdowns, and that do not represent ongoing business performance and are not reflective of the Company's ability to generate cash flows in the future. Termination, restructuring and facility shutdown costs mainly include termination, severance, inventory write downs and related costs.
- Legal costs arising from cost determinations made after the conclusion of arbitration proceedings that are not reflective of ongoing business performance.
- The expenses related to the Centralia community fund (Fund), which was established under the Company''s obligations in the Energy Transition Bill related to the retirement of coal operations at Centralia, with a total commitment of US$55 million over the 2015–2026 period. With the facility reaching end of life on Dec. 31, 2025, and all commercial operations now ceased, expenditures associated with the Fund in 2026 no longer relate to a revenue-generating facility and are not reflective of 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 business performance.
- Acquisition-related transaction and restructuring costs, mainly comprising severance, legal and consultant fees as these do not reflect ongoing business 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; and
- Legal settlement recoveries related to investing activities and not reflective of operating performance.

Additional Adjustments

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

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

Adjustments for Equity-Accounted Investments

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

Adjusted Earnings (Loss) before Income Taxes

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

Adjusted Net Earnings (Loss) Attributable to Common Shareholders

Adjusted Net Earnings (Loss) Attributable to Common Shareholders represents net earnings (loss) 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 earnings (loss) attributable to common shareholders (the most directly comparable IFRS measure), please refer to the reconciliation of net earnings attributable to common shareholders to Adjusted Net Earnings attributable to common shareholders of this section of MD&A.

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

Adjusted Net Earnings (Loss) per Common Share Attributable to Common Shareholders is calculated as Adjusted Net Earnings (Loss) 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 Earnings (Loss) Attributable per Common Share is a non-IFRS ratio and the most directly comparable IFRS measure is net income (loss) per common share attributable to common shareholders. Refer to the reconciliation of net earnings attributable to common shareholders to Adjusted Net Earnings Attributable to Common Shareholders of this section of 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.
- We adjust for legal costs related to arbitration proceedings that are not reflective of ongoing business performance.
- 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.
- 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 paid during the first quarter of 2025 and have been excluded from FFO composition.
- Other adjustments include payments/receipts for production tax credits, which are reductions to tax equity debt and include distributions from equity-accounted joint ventures.

Free Cash Flow (FCF)

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

Adjusted Net Debt

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

Total Consolidated Net Debt

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

Net Interest Expense

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

Adjusted Gross Margin

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

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
- Ancillary services price per MWh
- Hedged power price average per MWh
- Fuel cost per MWh
- Carbon compliance per MWh

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

The following table reflects Adjusted EBITDA and Adjusted Earnings (Loss) before income taxes by segment and provides reconciliation to earnings (loss) before income taxes for the three months ended March 31, 2026:

	Hydro	Wind & Solar[1]	Gas	Energy Marketing	Corporate	Energy Transition	Total	Equity-accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	57	125	348	39	1	2	572	(7)	—	565
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	(3)	6	(18)	(11)	—	—	(26)	—	26	—
Decrease in finance lease receivable	—	1	7	—	—	—	8	—	(8)	—
Finance lease income	—	1	6	—	—	—	7	—	(7)	—
Unrealized foreign exchange gain on commodity	—	—	(1)	—	—	—	(1)	—	1	—
Adjusted Revenue	54	133	342	28	1	2	560	(7)	12	565
Fuel and purchased power	(4)	(7)	(154)	—	—	—	(165)	—	—	(165)
Carbon compliance	—	—	(39)	—	—	—	(39)	—	—	(39)
Adjusted Gross Margin	50	126	149	28	1	2	356	(7)	12	361
OM&A	(14)	(25)	(62)	(11)	(62)	(8)	(182)	1	—	(181)
Reclassifications and adjustments:										
Termination, restructuring and facility shutdown costs	—	—	—	—	11	—	11	—	(11)	—
Legal costs related to arbitration proceedings	—	—	—	—	9	—	9	—	(9)	—
Centralia community fund expenses	—	—	—	—	—	7	7	—	(7)	—
ERP integration costs	—	—	—	—	3	—	3	—	(3)	—
Acquisition-related transaction and restructuring costs	—	—	—	—	1	—	1	—	(1)	—
Adjusted OM&A	(14)	(25)	(62)	(11)	(38)	(1)	(151)	1	(31)	(181)
Taxes, other than income taxes	(1)	(7)	(5)	—	—	—	(13)	—	—	(13)
Net other operating income	—	13	11	—	—	—	24	—	—	24
Reclassifications and adjustments:										
Legal settlement recoveries	—	(12)	—	—	—	—	(12)	—	12	—
Adjusted Net other operating income	—	1	11	—	—	—	12	—	12	24
Adjusted EBITDA[2]	35	95	93	17	(37)	1	204			
Depreciation and amortization	(9)	(50)	(42)	—	(4)	—	(105)	—	—	(105)
Equity income	—	—	—	—	(1)	—	(1)	—	4	3
Interest income	—	—	—	—	7	—	7	—	—	7
Interest expense	—	—	—	—	(84)	—	(84)	2	—	(82)
Realized foreign exchange gain[3]	—	—	—	—	9	—	9	—	—	9
Adjusted Earnings (Loss) before income taxes[2]	26	45	51	17	(110)	1	30			
Reclassifications and adjustments above	3	4	6	11	(24)	(7)	(7)			
Finance lease income	—	1	6	—	—	—	7	—	—	7
Skookumchuk earnings reclass to Equity income[1]	—	(4)	—	—	4	—	—	—	—	—
Asset impairment reversals	—	—	—	—	—	6	6	—	—	6
Loss on sale of assets and other	—	—	—	—	(2)	—	(2)	—	—	(2)
Unrealized foreign exchange loss[3]	—	—	—	—	(11)	—	(11)	—	—	(11)
Earnings (loss) before income taxes	29	46	63	28	(143)	—	23	—	—	23

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

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

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

The following table reflects Adjusted EBITDA and Adjusted Earnings (Loss) before income taxes by segment and provides reconciliation to earnings (loss) before income taxes for the three months ended March 31, 2025:

	Hydro	Wind & Solar[1]	Gas	Energy Marketing	Corporate	Energy Transition	Total	Equity-accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	86	107	390	27	1	154	765	(7)	—	758
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	(21)	36	(32)	1	—	(1)	(17)	—	17	—
Decrease in finance lease receivable	—	1	7	—	—	—	8	—	(8)	—
Finance lease income	—	1	5	—	—	—	6	—	(6)	—
Revenues from Required Divestitures	—	—	(4)	—	—	—	(4)	—	4	—
Adjusted Revenues	65	145	366	28	1	153	758	(7)	7	758
Fuel and purchased power	(4)	(10)	(163)	—	(2)	(98)	(277)	—	—	(277)
Reclassifications and adjustments:										
Fuel and purchased power related to Required Divestitures	—	—	(2)	—	—	—	(2)	—	(2)	—
Adjusted Fuel and Purchased Power	(4)	(10)	(161)	—	(2)	(98)	(275)	—	(2)	(277)
Carbon compliance	—	(1)	(49)	—	1	—	(49)	—	—	(49)
Gross margin	61	134	156	28	—	55	434	(7)	5	432
OM&A	(13)	(29)	(59)	(7)	(49)	(17)	(174)	1	—	(173)
Reclassifications and adjustments:										
OM&A related to Planned Divestitures	—	—	2	—	—	—	2	—	(2)	—
ERP integration costs	—	—	—	—	4	—	4	—	(4)	—
Acquisition-related transaction and restructuring costs	—	—	—	—	4	—	4	—	(4)	—
Adjusted OM&A	(13)	(29)	(57)	(7)	(41)	(17)	(164)	1	(10)	(173)
Taxes, other than income taxes	(1)	(5)	(5)	—	—	(1)	(12)	—	—	(12)
Net other operating income	—	4	10	—	—	—	14	—	—	14
Reclassifications and adjustments:										
Insurance recovery	—	(2)	—	—	—	—	(2)	—	2	—
Adjusted Net Other Operating Income	—	2	10	—	—	—	12	—	2	14
Adjusted EBITDA[2]	47	102	104	21	(41)	37	270			
Depreciation and amortization	(9)	(53)	(64)	(2)	(5)	(15)	(148)	2	—	(146)
Equity income	—	—	—	—	(1)	—	(1)	—	3	2
Interest income	—	—	—	—	5	—	5	—	—	5
Interest expense	—	—	—	—	(94)	—	(94)	1	—	(93)
Realized foreign exchange loss[3]	—	—	—	—	(4)	—	(4)	—	—	(4)
Adjusted Earnings (Loss) before income taxes[2]	38	49	40	19	(140)	22	28			
Reclassifications and adjustments above	21	(36)	20	(1)	(8)	1	(3)			
Finance lease income	—	1	5	—	—	—	6	—	—	6
Skookumchuk earnings reclass to equity income[1]	—	(3)	—	—	3	—	—	—	—	—
Fair value change in contingent consideration payable	—	—	34	—	—	—	34	—	—	34
Asset impairment (charges) reversals	—	—	(34)	—	(5)	24	(15)	—	—	(15)
Loss on sale of assets and other	—	—	—	—	(1)	—	(1)	—	—	(1)
Earnings (loss) before income taxes	59	11	65	18	(151)	47	49	—	—	49

(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.

Reconciliation of Net Earnings Attributable to Common Shareholders to Adjusted Net Earnings Attributable to Common Shareholders

The following table reflects reconciliation of net earnings attributable to common shareholders to Adjusted Net Earnings Attributable to Common Shareholders for the three months ended March 31, 2026 and 2025:

	3 months ended March 31	
(in millions of Canadian dollars except where noted)	**2026**	**2025**
Net earnings attributable to common shareholders	**13**	46
Adjustments and reclassifications (pre-tax):		
Adjustments and reclassifications to revenues	**(12)**	(7)
Adjustments and reclassifications to fuel and purchased power	**—**	2
Adjustments and reclassifications to OM&A	**31**	10
Adjustments and reclassifications to net other operating income	**(12)**	(2)
Fair value change in contingent consideration payable (gain)	**—**	(34)
Finance lease income	**(7)**	(6)
Asset impairment (reversals) charges	**(6)**	15
Loss on sale of assets and other	**2**	1
Unrealized foreign exchange loss(1)	**11**	—
Calculated tax expense on adjustments and reclassifications(2)	**(2)**	5
Adjusted Net Earnings Attributable to Common Shareholders(3)	**18**	30
Weighted average number of common shares outstanding in the period (in millions)	**297**	298
Net earnings per common share attributable to common shareholders	**0.04**	0.15
Adjustments and reclassifications (net of tax)	**0.02**	(0.05)
Adjusted Net Earnings per Common Share Attributable to Common Shareholders(3)	**0.06**	0.10

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

(2) Represents a theoretical tax calculated by applying the Company's consolidated effective tax rate of 23.3 per cent for the three months ended March 31, 2026 (three months ended March 31, 2025 — 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 Earnings Attributable to Common Shareholders and Adjusted Net 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 earnings attributable to common shareholders and net earnings per share attributable to common shareholders, basic and diluted. Refer to the "Non-IFRS and Supplementary Financial Measures" section of this MD&A for more details.

Reconciliation of Cash Flow from Operations to FFO and FCF

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

	3 months ended March 31	
(in millions of Canadian dollars except where noted)	**2026**	**2025**
Cash flow from operating activities[1]	**123**	7
Change in non-cash operating working capital balances	**(19)**	117
Cash flow from operations before changes in working capital	**104**	124
Adjustments		
Share of adjusted FFO from joint venture[1]	**3**	2
Decrease in finance lease receivable	**8**	8
Brazeau penalties payment	**—**	33
Other[2]	**22**	12
FFO[3]	**137**	179
Deduct:		
Sustaining capital expenditures[1]	**(21)**	(23)
Dividends paid on preferred shares	**(13)**	(13)
Distributions paid to subsidiaries' non-controlling interests	**(1)**	—
Other[3]	**—**	(4)
FCF[4]	**102**	139
Weighted average number of common shares outstanding in the period	**297**	298
Cash flow from operating activities per share	**0.41**	0.02
FFO per share[4]	**0.46**	0.60
FCF per share[4]	**0.34**	0.47

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

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

(3) Other consists of principal payments on lease liabilities and unsecured loan advances by the Company's subsidiary, Kent Hills Wind LP to its 17 per cent partner.

(4) 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. 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 March 31	2026	2025
Adjusted EBITDA(1)(2)	**204**	270
Provisions	**7**	8
Net Interest Expense(3)	**(61)**	(72)
Current income tax expense	**(12)**	(13)
Realized foreign exchange gain (loss)(4)	**15**	(2)
Decommissioning and restoration costs settled	**(6)**	(9)
Other non-cash items(5)	**(10)**	(3)
FFO(2)(6)	**137**	179
Deduct:		
Sustaining capital(2)(4)	**(21)**	(23)
Dividends paid on preferred shares	**(13)**	(13)
Distributions paid to subsidiaries' non-controlling interests	**(1)**	—
Other(7)	**—**	(4)
FCF(2)(6)	**102**	139

(1) Adjusted EBITDA is defined in the "Non-IFRS and Supplementary Financial Measures" section of this MD&A and reconciled to earnings before income taxes above.

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

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

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

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

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

(7) Other consists of principal payments on lease liabilities and unsecured loan advances by the Company's subsidiary, Kent Hills Wind LP to its 17 per cent partner.

Key Non-IFRS Financial Ratios

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

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

Adjusted Net Debt to Adjusted EBITDA

(in millions of Canadian dollars except where noted)

As at	March 31, 2026	Dec. 31, 2025
Credit facilities, long-term debt and lease liabilities(1)	**3,706**	3,593
Exchangeable debentures	**350**	350
Less: Cash and cash equivalents	**(274)**	(205)
Add: Bank overdraft	**7**	—
Add: 50 per cent of issued preferred shares and exchangeable preferred shares(2)	**671**	671
Other(3)	**(4)**	(13)
Adjusted Net Debt(4)	**4,456**	4,396
Adjusted EBITDA(5)	**1,038**	1,104
Adjusted Net Debt to Adjusted EBITDA (times)	**4.3**	4.0

(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 condensed 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 nil restricted cash as at March 31, 2026 (Dec. 31, 2025 - $17 million) 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 long-term target for Adjusted Net Debt to Adjusted EBITDA is 3.0 to 4.0 times.

Our Adjusted Net Debt to Adjusted EBITDA ratio at March 31, 2026 was higher compared to Dec. 31, 2025, due to lower trailing twelve months Adjusted EBITDA and higher debt to finance Far North acquisition as at March 31, 2026, as compared to Dec. 31, 2025.

Refer to Financial Capital section of this MD&A for further discussion on liquidity and capital management.

Material Accounting Policies, Accounting Changes and Critical Accounting Estimates

Material Accounting Policies and Accounting Changes

Our material accounting policies are described in Note 2 of the consolidated financial statements for the year ended Dec. 31, 2025.

In accordance with the amendments to IFRS 9 Financial Instruments and IFRS 7 Financial Instruments, effective Jan. 1, 2026, the Company has prospectively designated certain pre-existing VPPAs within the Wind and Solar segment as held for hedging and has applied hedge accounting. As a result, the effective portion of changes in the fair value of these hedging derivatives, arising on or after Jan. 1, 2026, will be recognised in OCI while any ineffective portion will be recognized in net earnings. The transitional provisions did not permit retrospective designation.

For a description of current and future accounting changes impacting our business, refer to Note 2 of the condensed consolidated financial statements the three months ended March 31, 2026.

Critical Accounting Judgments and Estimates

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

Management reviews these judgments and estimates on a continuous basis. Any revisions are recognized in the period in which they are identified and in any subsequent periods impacted by the change. Refer to Note 2 of the consolidated financial statements for the year ended Dec. 31, 2025 for a description of our significant accounting judgments and key sources of estimation uncertainty.

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 "Risk Management" section of our 2025 Annual MD&A and Note 11 of our unaudited interim condensed consolidated financial statements the three months ended March 31, 2026 for details on our risks and how we manage them. Our risk management profile and practices have not changed materially from Dec. 31, 2025.

Regulatory Updates

Refer to the Significant and Subsequent Events and Risk Management discussions in our 2025 Annual MD&A for further details on the corporation's assessment and management of policy and regulatory risks that supplement the recent developments as discussed below:

Canada

Federal

The current Liberal government in Canada was elected on April 28, 2025, as a minority government. Through by-election results and floor crossings, the Liberal party now holds a majority of the seats in the House of Commons.

On Nov. 27, 2025, the Canadian and Alberta governments signed a memorandum of understanding that among other items, agreed to place the Canadian Electricity Regulations in abeyance, upon completion of a new carbon pricing agreement administered through Alberta's TIER program. The governments did not achieve the April 1, 2026 goal for completion of this work; however, have stated they remain committed. TransAlta continues to monitor these and other policy developments related to our business, including but not limited to the release of industrial strategies related to electricity and AI, Investment Tax Credits, and funding for net-zero technologies.

Alberta

On March 12, 2026, the Minister of Affordability and Utilities approved the AESO's Restructured Energy Market (REM) ISO rules. This action provides the details for the finalized REM design. The AESO also updated the implementation schedule for REM, with implementation now expected to occur in early 2028.

The AESO and Government of Alberta continue to develop the Phase 2 policy framework for incremental data center integration in the province. In 2025, the AESO released the Phase 1 design, through the allocation of 1,200 MW of large load hosting capacity with in-service dates in 2027 and 2028. The Phase 2 process 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 2026.

United States

On March 13, 2026, the U.S. Department of Energy (U.S. DOE) issued an amendment to the Dec. 16, 2025 202(c) order for the Centralia facility, amending the identified Balancing Authority and Reliability Coordinator. On March 16, 2026, the U.S. DOE issued a second 90-day order for the period of March 17 to June 14, 2026. At the state level, on March 11, 2026, Washington Governor Ferguson signed HB 2367 into law, which ended exemptions at the Centralia facility related to GHG emission performance standards and limitations after Dec. 31, 2025.

On April 30, 2026, TransAlta filed a petition for cost recovery for the first 90-day 202(c) order. The Company continues to work with the state and federal governments in relation to the order and filing.

At the federal level, TransAlta continues to monitor policies and agency developments related to our business, including but not limited to: wind, solar and battery tax credits; permit issuance for land-based wind and solar projects; electricity infrastructure permitting reform legislation; large load integration; and regulatory reforms for thermal power generation.

Australia

In 2025, the federal and Western Australian governments both held elections, resulting in majority, renewed terms for both incumbent governments. TransAlta continues to monitor policy developments in Australia.

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 months ended March 31, 2026, 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 condensed 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 Jan. 2026, the Company implemented an upgrade to our Enterprise Resource Planning (ERP) system across the organization resulting in the modification to a number of its internal controls. No other changes to the internal control over financial reporting occurred during the period ended March 31, 2026 that materially affected, or reasonably likely to materially affect, the Company's internal control over financial reporting. Management will continue to evaluate the Company's disclosure controls, procedures and internal control over financial reporting to make modifications as deemed necessary.

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 Far North, which the Company acquired on Feb. 2, 2026. Far North was excluded from management's evaluation of the effectiveness of the Company's internal control over financial reporting as at March 31, 2026, due to the proximity of the acquisition to the end of the reporting period. Further details related to the acquisition are disclosed in Note 3 of the Condensed Consolidated Financial statements for the three months ended March 31, 2026. Far North's total and net assets represented approximately one and seven per cent of the Company's total and net assets, respectively, as at March 31, 2026 and one and eight per cent of the Company's revenues and net earnings, respectively, for the three months ended March 31, 2026.

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 March 31, 2026, the end of the period covered by this MD&A, our ICFR and DC&P were effective.

Condensed Consolidated Statements of Earnings

(in millions of Canadian dollars except where noted)

	3 months ended March 31	
Unaudited	**2026**	**2025**
Revenues (Note 4)	**565**	758
Fuel and purchased power (Note 5)	**165**	277
Carbon compliance costs	**39**	49
Gross margin	**361**	432
Operations, maintenance and administration (Note 5)	**181**	173
Depreciation and amortization (Note 13)	**105**	146
Asset impairment (reversals) charges (Note 6)	**(6)**	15
Taxes, other than income taxes	**13**	12
Net other operating income	**(24)**	(14)
Operating income	**92**	100
Equity income	**3**	2
Fair value change in contingent consideration payable (Note 6)	**—**	34
Finance lease income	**7**	6
Interest income	**7**	5
Interest expense (Note 7)	**(82)**	(93)
Foreign exchange loss	**(2)**	(4)
Loss on sale of assets and other	**(2)**	(1)
Earnings before income taxes	**23**	49
Income tax expense (Note 8)	**6**	7
Net earnings	**17**	42
Net earnings attributable to:		
Common shareholders	**13**	46
Non-controlling interests	**4**	(4)
	17	42
Weighted average number of common shares outstanding in the period (*millions*)	**297**	298
Net earnings per share attributable to common shareholders, basic and diluted (Note 15)	**0.04**	0.15

See accompanying notes.

Condensed Consolidated Statements of Comprehensive Income

(in millions of Canadian dollars)

	3 months ended March 31	
Unaudited	**2026**	**2025**
Net earnings	**17**	42
Other comprehensive income (loss)		
Gains (losses) on translating net assets of foreign operations	**12**	(1)
(Losses) gains on financial instruments designated as hedges of foreign operations, net of tax(1)	**(3)**	1
Gains (losses) on derivatives designated as cash flow hedges, net of tax(2)	**22**	(1)
Reclassification of gains on derivatives designated as cash flow hedges to net earnings, net of tax(3)	**(5)**	(9)
Total items that will be reclassified subsequently to net earnings	**26**	(10)
Other comprehensive income (loss)	**26**	(10)
Total comprehensive income	**43**	32
Total comprehensive income attributable to:		
TransAlta shareholders	**39**	36
Non-controlling interests	**4**	(4)
	43	32

(1) Net of income tax of nil for the three months ended March 31, 2026 (March 31, 2025 – nil).

(2) Net of income tax expense of $7 million for the three months ended March 31, 2026 (March 31, 2025 – nil).

(3) Net of reclassification of income tax recovery of $1 million for the three months ended March 31, 2026 (March 31, 2025 – $2 million).

See accompanying notes.

Condensed Consolidated Statements of Financial Position

(in millions of Canadian dollars) (Unaudited)

As at	March 31, 2026	Dec. 31, 2025
Current assets		
Cash and cash equivalents	**274**	205
Restricted cash (Note 14)	**60**	78
Trade and other receivables (Note 9)	**655**	699
Prepaid expenses and other	**70**	51
Risk management assets (Note 10 and 11)	**178**	162
Inventory	**118**	111
Assets held for sale	**30**	30
	1,385	1,336
Non-current assets		
Investments	**149**	144
Long-term portion of finance lease receivables (Note 12)	**316**	277
Risk management assets (Note 10 and 11)	**43**	32
Property, plant and equipment (Note 3 and 13)	**5,680**	5,665
Right-of-use assets	**111**	111
Intangible assets	**237**	243
Goodwill (Note 3)	**524**	516
Deferred income tax assets	**52**	41
Long-term financial assets (Note 10)	**133**	140
Other assets	**157**	156
Total assets	**8,787**	8,661
Current liabilities		
Bank overdraft	**7**	—
Accounts payable, accrued liabilities and other current liabilities (Note 9)	**593**	613
Current portion of decommissioning and other provisions	**95**	84
Risk management liabilities (Note 10 and 11)	**154**	156
Dividends payable (Note 15 and 16)	**40**	52
Exchangeable securities	**750**	750
Current portion of long-term debt and lease liabilities (Note 14)	**178**	175
	1,817	1,830
Non-current liabilities		
Credit facilities, long-term debt and lease liabilities (Note 14)	**3,528**	3,418
Decommissioning and other provisions (Note 3)	**810**	807
Deferred income tax liabilities	**442**	423
Risk management liabilities (Note 10 and 11)	**517**	519
Contract liabilities	**29**	26
Defined benefit obligation and other long-term liabilities	**168**	173
Total liabilities	**7,311**	7,196
Equity		
Common shares (Note 15)	**3,174**	3,169
Preferred shares (Note 16)	**942**	942
Contributed surplus	**27**	42
Deficit	**(2,738)**	(2,730)
Accumulated other comprehensive (loss) income	**2**	(24)
Equity attributable to shareholders	**1,407**	1,399
Non-controlling interests	**69**	66
Total equity	**1,476**	1,465
Total liabilities and equity	**8,787**	8,661

Commitments and contingencies (Note 18)

See accompanying notes.

Condensed Consolidated Statements of Changes in Equity

(in millions of Canadian dollars)

Unaudited 3 months ended March 31, 2026	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income (loss)	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec. 31, 2025	3,169	942	42	(2,730)	(24)	1,399	66	1,465
Net earnings	—	—	—	**13**	—	**13**	**4**	**17**
Other comprehensive income:								
Net gains on translating net assets of foreign operations, net of hedges and tax	—	—	—	—	**9**	**9**	—	**9**
Net gains on derivatives designated as cash flow hedges, net of tax	—	—	—	—	**17**	**17**	—	**17**
Total comprehensive earnings	—	—	—	**13**	**26**	**39**	**4**	**43**
Common share dividends (Note 15)	—	—	—	**(21)**	—	**(21)**	—	**(21)**
Share-based payment plans and stock options exercised	**5**	—	**(15)**	—	—	**(10)**	—	**(10)**
Distributions declared to non-controlling interests	—	—	—	—	—	—	**(1)**	**(1)**
Balance, March 31, 2026	**3,174**	**942**	**27**	**(2,738)**	**2**	**1,407**	**69**	**1,476**

3 months ended March 31, 2025	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income (loss)	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec. 31, 2024	3,179	942	42	(2,458)	41	1,746	97	1,843
Net earnings	—	—	—	46	—	46	(4)	42
Other comprehensive loss:								
Net losses on derivatives designated as cash flow hedges, net of tax	—	—	—	—	(10)	(10)	—	(10)
Total comprehensive income	—	—	—	46	(10)	36	(4)	32
Common share dividends (Note 15)	—	—	—	(20)	—	(20)	—	(20)
Shares purchased under normal course issuer bid (NCIB) (Note 15)	(3)	—	—	(1)	—	(4)	—	(4)
Provision for repurchase of shares under the automatic securities purchase plan (ASPP) (Note 15)	(20)	—	—	—	—	(20)	—	(20)
Share-based payment plans and stock options exercised	7	—	(13)	—	—	(6)	—	(6)
Balance, March 31, 2025	3,163	942	29	(2,433)	31	1,732	93	1,825

See accompanying notes.

Condensed Consolidated Statements of Cash Flows

(in millions of Canadian dollars)

	3 months ended March 31	
Unaudited	**2026**	**2025**
Operating activities		
Net earnings	**17**	42
Depreciation and amortization	**105**	146
Accretion of provisions (Note 7)	**13**	15
Decommissioning and restoration costs settled	**(6)**	(9)
Deferred income tax recovery (Note 8)	**(6)**	(6)
Unrealized gain from risk management activities	**(25)**	(12)
Unrealized foreign exchange loss	**11**	—
Provisions and contract liabilities	**7**	(32)
Asset impairment (reversals) charges (Note 6)	**(6)**	15
Equity income, net of distributions from investments	**(2)**	—
Other non-cash items	**(4)**	(35)
Cash flow from operations before changes in working capital	**104**	124
Change in non-cash operating working capital balances (Note 17)	**19**	(117)
Cash flow from operating activities	**123**	7
Investing activities		
Additions to property, plant and equipment (Note 13)	**(27)**	(32)
Additions to intangible assets	**(2)**	(2)
Restricted cash (Note 14)	**20**	18
Acquisitions, net of cash acquired (Note 3)	**(106)**	(2)
Decrease (increase) in long-term financial assets (Note 10)	**9**	(106)
Decrease in finance lease receivable	**8**	8
Long-term prepaids and other	**13**	(7)
Change in non-cash investing working capital balances	**(8)**	(21)
Cash flow used in investing activities	**(93)**	(144)
Financing activities		
Net increase (decrease) under credit facilities and other borrowings (Note 14)	**109**	(347)
Repayment of long-term debt (Note 14)	**(35)**	(26)
Issuance of long-term debt (Note 14)	**—**	450
Dividends paid on common shares (Note 15)	**(19)**	(18)
Dividends paid on preferred shares (Note 16)	**(13)**	(13)
Repurchase of common shares under NCIB (Note 15)	**—**	(3)
Distributions paid to subsidiaries' non-controlling interests	**(1)**	—
Financing fees and other	**(3)**	(5)
Cash flow from financing activities	**38**	38
Cash flow from (used in) operating, investing and financing activities	**68**	(99)
Effect of translation on foreign currency cash	**1**	—
Increase (decrease) in cash and cash equivalents	**69**	(99)
Cash and cash equivalents, beginning of period	**205**	337
Cash and cash equivalents, end of period	**274**	238
Cash taxes paid	**39**	67
Cash interest paid	**66**	64
Cash interest received	**7**	4

See accompanying notes.

Notes to the Condensed Consolidated Financial Statements

(Tabular amounts in millions of Canadian dollars, except as otherwise noted)

1. Corporate Information

A. Description of the Business

TransAlta Corporation (TransAlta or the Company) was incorporated under the *Canada Business Corporations Act* in March 1985 and became a public company in December 1992. The Company's head office is located in Calgary, Alberta.

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 May 5, 2026.

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.

Refer to Note 2(Q) of the Company's 2025 audited annual consolidated financial statements for further details on the significant accounting judgments and key sources of estimation uncertainty.

Business Combinations

The fair value of assets acquired and liabilities assumed in a business combination, is estimated based on information available at the date of acquisition. While management uses best estimates and assumptions to accurately value assets acquired and liabilities assumed at the date of acquisition, estimates are inherently uncertain and subject to refinement.

Accounting for business combinations requires significant judgment, estimates and assumptions at the acquisition date. In developing estimates of fair values at the acquisition date, management uses a variety of factors including market data, market prices, capacity, historical and future expected cash flows, growth rates and discount rates. Information regarding a business business combination that occurred during the three months ended March 31, 2026 has been included in Note 3.

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, 2025, except for the adoption of new standards effective as of Jan. 1, 2026.

A. Current Accounting Changes

Amendments to IFRS 9 and IFRS 7 — Nature-Dependent Electricity Contracts

On Dec. 18, 2024, the IASB issued amendments to IFRS 9 Financial Instruments and IFRS 7 Financial Instruments: Disclosure to improve reporting of the financial effects of nature-dependent electricity (e.g., wind and solar) contracts, which are often structured as power purchase agreements. Under these contracts, the amount of electricity generated can vary based on uncontrollable factors such as weather conditions.

The amendments clarify the application of own-use requirements, permit hedge accounting if these contracts are used as hedging instruments and add new disclosure requirements about the effect of these contracts on a company's financial performance and cash flows. Specifically, the amendments will now allow for hedge accounting to be applied in instances where there is variability in the underlying amount of electricity because the source of electricity generation depends on uncontrollable natural conditions.

The amendments are effective for annual reporting periods beginning on or after Jan. 1, 2026.

In accordance with the permitted transitional provisions, effective Jan. 1, 2026, the Company has prospectively designated certain pre-existing VPPAs within the Wind and Solar segment as held for hedging and has applied hedge accounting. As a result, the effective portion of changes in the fair value of these hedging derivatives, arising on or after Jan. 1, 2026, will be recognised in OCI while any ineffective portion will be recognized in net earnings. The transitional provisions did not permit retrospective designation. Refer to Note 11 Risk Management for details.

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 amendments clarified the date of recognition and derecognition of financial assets and liabilities, including an exception for certain financial liabilities settled through an electronic payment system. The amendments also clarified the requirements for assessing contractual cash flow characteristics of financial assets, including those with ESG-linked features. The amendments did not have a material impact on the consolidated financial statements.

B. Future Accounting Changes

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

IFRS 18 — Presentation and Disclosure in Financial Statements

On April 9, 2024, the IASB issued a new standard, IFRS 18 *Presentation and Disclosure in Financial Statements*, which introduced new requirements for improved comparability in the statement of profit or loss, enhanced transparency of management-defined performance measures and more useful grouping of information in the financial statements. The standard is effective for annual reporting periods beginning on or after Jan. 1, 2027. The Company is currently evaluating the impacts to the financial statements.

C. Comparative Figures

Certain comparative figures have been reclassified to conform to the current period's presentation. These reclassifications did not impact previously reported net earnings.

3. Business Acquisitions

On Feb. 2, 2026, the Company acquired all issued and outstanding common shares of Far North Corporation (Far North) from an affiliate of Hut 8 Corp. (the Far North Acquisition). The Far North Acquisition, which includes Far North and its subsidiaries' entire business operations in Ontario consisting of four natural gas-fired generation facilities totaling 310 MW, was completed for an aggregate purchase price of $107 million including working capital adjustments of $12 million. The Far North Acquisition was funded through a combination of cash on hand and draws on the Company's credit facilities.

The acquired tangible assets and assumed liabilities are recorded at their estimated fair values at the date of the Acquisition. The total consideration was allocated to the tangible acquired and liabilities assumed, with any excess recorded to goodwill. Goodwill of $7 million recognized on the transaction is a result of net deferred tax liabilities recognized on the transaction, which are recorded at the Company's effective tax rate without discounting. None of the goodwill is expected to be deductible for tax purposes.

The preliminary purchase price allocation reflects management's best estimate of the fair value of the acquired assets and liabilities based on the analysis of information obtained to date. Management is continuing to obtain specific information to support the valuation of the decommissioning provision, inventory, property, plant and equipment, and deferred taxes. Any adjustments to the purchase price allocation will be made as soon as practicable but no later than one year from the date of acquisition.

The following table summarizes the preliminary fair values that were assigned to the net assets acquired as at the Acquisition Date.

	Feb. 2, 2026
Current Assets and Non-Current Assets	
Cash and cash equivalents	1
Trade and other receivables	9
Prepaid expenses and other	6
Inventory	3
Property, plant and equipment	101
Deferred income tax assets	4
Current Liabilities and Non-Current Liabilities	
Accounts payable and accrued liabilities	4
Decommissioning provision non-current portion	9
Deferred income tax liabilities	11
Total identifiable net assets at fair value	100
Goodwill arising on acquisition	7
Net assets acquired	107
Total cash consideration	107
Total purchase consideration transferred	107

Revenue generated by the Far North Acquisition for the period Feb. 2, 2026 to March 31, 2026 was $4 million. Net loss before taxes for the same period was $2 million.

Had Far North been acquired at the beginning of the year, the assets would have contributed $7 million to revenues and a $3 million loss to net earnings before taxes on a proforma basis.

4. 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 to determine how economic factors affect the recognition of revenue.

3 months ended March 31, 2026	Hydro	Wind and Solar	Gas	Energy Marketing	Corporate[2]	Energy Transition	Total
	Reportable Segments[1]						
Revenues from contracts with customers							
Power and other	7	69	159	4	—	2	241
Environmental and tax attributes[3]	—	24	4	—	—	—	28
Revenue from contracts with customers	7	93	163	4	—	2	269
Revenue from derivatives and other trading activities[4]	10	(5)	89	35	1	—	130
Revenue from merchant sales	37	25	95	—	—	—	157
Other[5]	3	5	1	—	—	—	9
Total revenue	57	118	348	39	1	2	565
Revenues from contracts with customers							
Timing of revenue recognition							
At a point in time	—	6	4	—	—	2	12
Over time	7	87	159	4	—	—	257
Total revenue from contracts with customers	7	93	163	4	—	2	269

(1) Refer to Note 19 Segment disclosures for details.

(2) The elimination of intercompany sales is reflected in the Corporate segment.

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

(4) 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. Effective Jan. 1, 2026, the Company applied hedge accounting to certain Virtual Power Purchase Agreements (VPPAs) within the Wind and Solar segment prospectively. Accordingly, the effective portion of unrealized gains or losses on the hedging instruments was recognized through OCI. Refer to Note 11 for details.

(5) 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 March 31, 2025	Reportable Segments(1) Hydro	Wind and Solar	Gas	Energy Marketing	Corporate(2)	Energy Transition	Total
Revenues from contracts with customers							
Power and other	5	82	162	4	2	3	258
Environmental and tax attributes(3)	10	26	7	—	(1)	—	42
Revenue from contracts with customers	15	108	169	4	1	3	300
Revenue from derivatives and other trading activities(4)	22	(33)	103	23	—	63	178
Revenue from merchant sales	47	20	115	—	—	88	270
Other(5)	2	5	3	—	—	—	10
Total revenue	86	100	390	27	1	154	758
Revenues from contracts with customers							
Timing of revenue recognition							
At a point in time	10	9	7	—	(1)	3	28
Over time	5	99	162	4	2	—	272
Total revenue from contracts with customers	15	108	169	4	1	3	300

(1) Refer to Note 19 Segment disclosures for details.

(2) The elimination of intercompany sales is reflected in the Corporate segment.

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

(4) 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.

(5) 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.

5. 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:

	2026		2025	
3 months ended March 31	Fuel and purchased power	OM&A	Fuel and purchased power	OM&A
Gas fuel costs	**139**	**—**	142	—
Coal fuel costs	**—**	**—**	44	—
Royalty, land lease, other direct costs	**6**	**—**	6	—
Purchased power	**20**	**—**	85	—
Salaries and benefits	**—**	**99**	—	76
Other operating expenses[(1)]	**—**	**82**	—	97
Total	**165**	**181**	277	173

(1) Other operating expenses include contracted manpower, materials, insurance, office costs and other administrative and overhead costs.

6. Asset Impairment (Reversals) Charges

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

3 months ended March 31	Segment	2026	2025
Impairment charge related to the Required Divestitures[(1)]	Gas	**—**	34
Impairment reversal related to generation equipment	Energy Transition	**—**	(31)
Changes in decommissioning and restoration provisions related to retired assets[(2)]	Energy Transition	**(6)**	7
Project development costs[(3)]	Corporate	**—**	5
Asset impairment (reversals) charges		**(6)**	15

(1) To meet the requirements of the federal Competition Bureau related to the acquisition of Heartland, the Company entered into a consent agreement with the Commissioner of Competition, under which the Company divested Heartland's Poplar Hill and Rainbow Lake facilities following the closing of the acquisition on Dec. 4, 2024.

(2) Changes relate to changes in discount rates, revisions in estimated cash flows and timing of cash flows.

(3) The Company recognized an impairment charge in the Corporate segment related to projects that are no longer proceeding.

7. Interest Expense

The components of interest expense are as follows:

3 months ended March 31	2026	2025
Interest on debt	48	51
Interest on exchangeable debentures[1]	6	6
Interest on exchangeable preferred shares[2]	7	7
Interest on lease liabilities	2	5
Credit facility fees, bank charges and other interest	6	9
Accretion of provisions	13	15
Interest expense	82	93

(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 April 29, 2026, the Company declared a dividend of $7 million in aggregate on the Series I Preferred Shares at the fixed rate of 1.726 per cent, per share, payable on June 30, 2026.

8. Income Taxes

The components of income tax expense are as follows:

3 months ended March 31	2026	2025
Current income tax expense	12	13
Deferred income tax recovery related to the origination and reversal of temporary differences	(12)	(12)
Writedown of unrecognized deferred income tax assets[1]	6	6
Income tax expense	6	7
Current income tax expense	12	13
Deferred income tax recovery	(6)	(6)
Income tax expense	6	7

(1) The deferred income tax assets mainly relate to the tax benefits associated with tax losses related to the Company's directly owned U.S. operations and other deductible differences.

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

	March 31, 2026	Dec. 31, 2025
Trade accounts receivable	**457**	507
Collateral provided (Note 11)	**74**	92
Current portion of finance lease receivables	**32**	30
Current portion of loan receivable	**—**	1
Income taxes receivable	**92**	69
Trade and other receivables	**655**	699

	March 31, 2026	Dec. 31, 2025
Accounts payable and accrued liabilities	**500**	548
Income taxes payable	**6**	11
Interest payable	**21**	23
Current portion of contract liabilities	**28**	17
Liabilities held for sale	**6**	6
Collateral held (Note 11)	**27**	3
Contingent consideration payable	**5**	5
Accounts payable, accrued liabilities and other current liabilities	**593**	613

10. 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

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

Level II fair values are determined, directly or indirectly, using inputs that are observable for the asset or liability.

Fair values falling within the Level II category are determined through the use of quoted prices in active markets, which in some cases are adjusted for factors specific to the asset or liability, such as basis, credit valuation and location differentials.

The Company's commodity risk management Level II financial instruments include over-the-counter derivatives with values based on observable commodity futures curves and derivatives with inputs validated by broker quotes or other publicly available market data providers. Level II fair values are also determined using valuation techniques, such as option pricing models and interpolation formulas, where the inputs are readily observable.

In determining Level II fair values of other risk management assets and liabilities, the Company uses observable inputs other than unadjusted quoted prices that are observable for the asset or liability, such as interest rate yield curves and currency rates. For certain financial instruments where there is insufficient trading volume or a lack of recent trades, the Company relies on similar interest or currency rate inputs and other third-party information such as credit spreads.

c. Level III

Level III fair values are determined using inputs for the assets or liabilities that are not readily observable.

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.

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 2025 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 March 31, 2026, are as follows: Level I – $5 million net liability (Dec. 31, 2025 – $10 million net liability), Level II – $9 million net asset (Dec. 31, 2025 – $33 million net liability) and Level III – $452 million net liability (Dec. 31, 2025 – $447 million net liability).

Significant changes in commodity net risk management assets and liabilities during the three months ended March 31, 2026, are primarily attributable to volatility in market prices across multiple markets on existing 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 three months ended March 31, 2026 and 2025, respectively:

	3 months ended March 31, 2026			3 months ended March 31, 2025		
	Hedge	Non-hedge	Total	Hedge	Non-hedge	Total
Opening balance	—	(447)	(447)	—	(153)	(153)
Changes attributable to:						
Change in hedge designation due to IFRS 9 amendment	(442)	442	—	—	—	—
Market price changes on existing contracts	25	—	25	—	(43)	(43)
Market price changes on new contracts	—	(1)	(1)	—	1	1
Contracts settled	(5)	(18)	(23)	—	(13)	(13)
Change in foreign exchange rates	(6)	—	(6)	—	1	1
Net risk management liabilities at end of period	(428)	(24)	(452)	—	(207)	(207)
Additional Level III information:						
Gains recognized in other comprehensive earnings	19	—	19	—	—	—
Total gains (losses) included in earnings before income taxes	(9)	(1)	(10)	—	(41)	(41)
Unrealized losses included in earnings before income taxes relating to net assets (liabilities) held at period end	—	(19)	(19)	—	(54)	(54)

As at March 31, 2026, the total Level III risk management asset balance was $52 million (Dec. 31, 2025 – $65 million) and the Level III risk management liability balance was $504 million (Dec. 31, 2025 – $512 million). The net risk management liabilities increased mainly due to volatility in market prices across multiple markets on existing contracts and contract settlements.

The information on risk management contracts or groups of risk management contracts that are included in Level III measurements and the related unobservable inputs and sensitivities are outlined in the following table.

These include the effects on fair value of discounting, liquidity and credit value adjustments; 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 VPPAs, that are recognized as derivatives for accounting purposes. Effective Jan. 1, 2026, the Company has prospectively designated certain pre-existing VPPAs within the Wind and Solar segment as held for hedging and has applied hedge accounting.

The sensitivity tables below reflect the potential impacts of unobservable inputs on the fair value of the long-term wind energy sales agreements for both derivatives designated as hedges and derivatives without hedge designation. These agreements are backed by physical assets to effectively reduce our market risk.

As at		March 31, 2026		
Description	**Valuation technique**	**Unobservable input**	**Reasonably possible change**	**Potential change in fair value[1]**
Long-term wind energy sale — Eastern U.S.	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of US$6 or increase of US$6	
		Illiquid future REC[2] prices (per unit)	Price decrease of US$4 or increase of US$17	**+25 -43**
		Wind discounts	0% decrease or 5% increase	
Long-term wind energy sale — Canada	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of $21 or increase of $10	**+57 -23**
		Wind discounts	5% decrease or 6% increase	
Long-term wind energy sale — Central U.S.	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of US$6 or increase of US$3	**+47 -53**
		Wind discounts	2% decrease or 6% increase	

(1) Potential change in fair value represents the total increase or decrease in recognized fair value that could arise from the use of the reasonably possible changes of all unobservable inputs.

(2) Renewable energy credits

As at		Dec. 31, 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	
		Illiquid future REC[2] prices (per unit)	Price decrease of US$4 or increase of US$17	+26 -43
		Wind discounts	0% decrease or 5% increase	
Long-term wind energy sale — Canada	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of $21 or increase of $10	+55 -22
		Wind discounts	5% decrease or increase	
Long-term wind energy sale — Central U.S.	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of US$7 or increase of US$3	+47 -52
		Wind discounts	2% decrease or 6% increase	

(1) Potential change in fair value represents the total increase or decrease in recognized fair value that would arise from the use of the reasonably possible changes of all unobservable inputs.

(2) Renewable energy credits

a. Long-Term Wind Energy Sale – Eastern U.S.

The Company is party to a long-term contract for differences (CFD) for the offtake of 100 per cent of the generation from its 90 MW Big Level wind facility. The CFD, together with the sale of electricity generated into the PJM Interconnection at the prevailing real-time energy market price, achieve the fixed contract price per MWh on proxy generation.

Under the CFD, if the market price is lower than the fixed contract price, the customer pays the Company the difference and if the market price is higher than the fixed contract price, the Company refunds the difference to the customer. The customer is also entitled to the physical delivery of environmental attributes. The contract expires in December 2034. The contract is accounted for as a derivative with changes in fair value presented in revenue.

The key unobservable inputs used in the valuation of the contract are expected proxy generation volumes and non-liquid forward prices for power, renewable energy credits and wind discounts.

b. Long-Term Wind Energy Sale – Canada

In Alberta, the Company is party to two VPPAs for the offtake of 100 per cent of the generation from its 130 MW Garden Plain wind facility. The VPPAs, together with the sale of electricity generated into the Alberta power market at the pool price, achieve the fixed contract prices per MWh. Under the VPPAs, if the pool price is lower than the fixed contract price, the customer pays the Company the difference and if the pool price is higher than the fixed contract price, the Company refunds the difference to the customer. Customers are also entitled to the physical delivery of environmental attributes. Both VPPAs commenced on commercial operation of the facility in August 2023 and extend for a weighted average period of approximately 17 years.

The energy components of these contracts are accounted for as derivatives and have been designated as cash flow hedges effective Jan. 1, 2026. The effective portion of unrealized gains and losses due to changes in fair value is recognized in other comprehensive income, while the ineffective portion is recognized in revenue. Realized gains and losses are reclassified to revenue when the hedged transactions impact earnings.

c. Long-Term Wind Energy Sale – Central U.S.

The Company is party to two long-term VPPAs for the offtake of 100 per cent of the generation from its 302 MW White Rock East and White Rock West wind power facilities. The VPPAs, together with the sale of electricity generated into the U.S. Southwest Power Pool (SPP) market at the relevant price nodes, achieves the fixed contract prices per MWh. Under the VPPAs, if the SPP pricing is lower than the fixed contract price the customer pays the Company the difference, and if the SPP pricing is higher than the fixed contract price, the Company refunds the difference to the customer. The customer is also entitled to the physical delivery of environmental attributes. The VPPAs commenced on commercial operation of the facilities in the first quarter of 2024.

The Company is also party to a VPPA for the offtake of 100 per cent of the generation from its 202 MW Horizon Hill wind power project. The VPPA, together with the sale of electricity generated into the SPP market at the relevant price node, achieve the fixed contract price per MWh. Under the VPPA, if the SPP pricing is lower than the fixed contract price, the customer pays the Company the difference and if the SPP pricing is higher than the fixed contract price, the Company refunds the difference to the customer. The customer is also entitled to the physical delivery of environmental attributes. The VPPA commenced on commercial operation of the facility in the second quarter of 2024.

The energy components of these contracts are accounted for as derivatives and have been designated as cash flow hedges effective Jan. 1, 2026. The effective portion of unrealized gains and losses due to changes in fair value is recognized in other comprehensive income, while the ineffective portion is recognized in revenue. Realized gains and losses are reclassified to revenue when the hedged transactions impact earnings.

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 liabilities with a net fair value of $2 million as at March 31, 2026 (Dec. 31, 2025 – $9 million net assets) are classified as Level II fair value measurements.

IV. Other Financial Assets and Liabilities

The fair value of financial assets and liabilities measured at other than fair value is as follows:

	Fair value(2)				Total carrying value(2)
	Level I	Level II	Level III	Total	
Long-term debt — March 31, 2026	**—**	**3,326**	**—**	**3,326**	**3,558**
Exchangeable securities — March 31, 2026	**—**	**752**	**—**	**752**	**750**
Long-term financial asset — March 31, 2026	**—**	**—**	**133**	**133**	**133**
Loan receivable — March 31, 2026(1)	**—**	**30**	**—**	**30**	**30**
Long-term debt — Dec. 31, 2025	—	3,255	—	3,255	3,447
Exchangeable securities — Dec. 31, 2025	—	752	—	752	750
Long-term financial asset — Dec. 31, 2025	—	—	140	140	140
Loan receivable — Dec. 31, 2025(1)	—	31	—	31	31

(1) Included within Other assets.

(2) Includes current and non-current portions.

The fair values of the Company's debentures, senior notes and exchangeable securities are determined using prices observed in secondary markets. Non-recourse and other long-term debt fair values are determined by calculating an implied price based on a current assessment of the yield to maturity.

The carrying amount of other short-term financial assets and liabilities (cash and cash equivalents, restricted cash, trade accounts receivable, collateral provided, bank overdraft, accounts payable and accrued liabilities, collateral held and dividends payable) approximates fair value due to the liquid nature of the asset or liability. The fair values of the finance lease receivables approximate the carrying amounts as the amounts receivable represent cash flows from repayments of principal and interest.

Long-term Financial Asset

During the year ended Dec. 31, 2025, the Company made available a US$75 million term loan, which is convertible to equity at any time, and a US$100 million revolving facility (collectively, the Nova facilities) to Nova Clean Energy, LLC (Nova), a developer of renewable energy projects.

As at March 31, 2026 the carrying amount of Nova facilities totalled $133 million, which approximates fair value. A net decrease of $7 million against the carrying amount as at Dec. 31, 2025 is mainly due to the repayments of $9 million, partially offset by foreign exchange gain, change in fair value and accrued interest totaling $2 million during the three months ended March 31, 2026. Nova facilities are classified as Level 3 within fair value hierarchy.

Refer to Note 14, Section IV of the 2025 consolidated financial statements for the year ended Dec. 31, 2025 for details.

11. Risk Management

A. Risk Management Strategy

The Company is exposed to market risk from changes in commodity prices, foreign exchange rates, interest rates, credit risk and liquidity risk. These risks affect the Company's earnings and the value of associated financial instruments that the Company holds. In certain cases, the Company seeks to minimize the effects of these risks by using derivatives to hedge its risk exposures. The Company's risk management strategy, policies and controls are designed to ensure that the risks it assumes comply with the Company's internal objectives and risk tolerance. Refer to Note 15 of the 2025 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 March 31, 2026

	Cash flow hedges[(1)]	Not designated as a hedge	Total
Commodity risk management			
Current	**14**	**16**	**30**
Long-term	**(442)**	**(36)**	**(478)**
Net commodity risk management liabilities	**(428)**	**(20)**	**(448)**
Other			
Current	**—**	**(6)**	**(6)**
Long-term	**—**	**4**	**4**
Net other risk management liabilities	**—**	**(2)**	**(2)**
Total net risk management liabilities	**(428)**	**(22)**	**(450)**

(1) Effective Jan. 1, 2026, the Company has prospectively designated certain pre-existing VPPAs within the Wind and Solar segment as held for hedging and has applied hedge accounting. Refer to Note 15, section A of the annual consolidated financial statements for the year ended Dec. 31, 2025 for additional disclosure related to the designation of hedges.

As at Dec. 31, 2025

	Cash flow hedges	Not designated as a hedge	Total
Commodity risk management			
Current	—	4	4
Long-term	—	(494)	(494)
Net commodity risk management liabilities	—	(490)	(490)
Other			
Current	—	2	2
Long-term	—	7	7
Net other risk management assets	—	9	9
Total net risk management liabilities	—	(481)	(481)

C. Nature and Extent of Risks Arising from Financial Instruments

I. Market Risk

i. Commodity Price Risk Management – Proprietary Trading

The Company's Energy Marketing segment conducts proprietary trading activities and uses a variety of instruments to manage risk, earn trading revenue and gain market information.

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 earnings in the period that the price changes occur. VaR at March 31, 2026, associated with the Company's proprietary trading activities was $1 million (Dec. 31, 2025 – $1 million).

ii. Commodity Price Risk Management – Generation

The generation segments use various commodity contracts to manage the commodity price risk associated with electricity generation, fuel purchases, emissions and byproducts, as considered appropriate. A Commodity Exposure Management Policy, prepared and approved annually, outlines the intended hedging strategies associated with the Company's generation assets and related commodity price risks. Controls also include restrictions on authorized instruments, management reviews on individual portfolios and approval of asset transactions that could add potential volatility to the Company's reported net earnings.

VaR at March 31, 2026, associated with the Company's commodity derivative instruments used in generation hedging activities was nil (Dec. 31, 2025 – nil). For positions and economic hedges that do not meet hedge accounting requirements or for short-term optimization transactions such as buybacks entered into to offset existing hedge positions, these transactions are marked to the market value with changes in market prices associated with these transactions affecting net earnings in the period in which the price change occurs. VaR at March 31, 2026, associated with these transactions was $9 million (Dec. 31, 2025 – $9 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 10(B)(II).

iii. Commodity Price Risk Management – Hedges

Effective Jan. 1, 2026, the Company has prospectively designated certain pre-existing VPPAs within the Wind and Solar segment as held for hedging and has applied hedge accounting. Any ineffectiveness, such as locational price basis differences, is recognized in net earnings. Refer to Note 2 for details.

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 March 31, 2026:

	Investment grade (per cent)	Non-investment grade (per cent)	Total (per cent)	Total amount
Trade and other receivables(1)	79	21	100	**655**
Long-term finance lease receivable	100	—	100	**316**
Risk management assets(1)	60	40	100	**221**
Long-term financial assets(2)	—	100	100	**133**
Loans receivable(3)	—	100	100	**30**
Total				**1,355**

(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 $30 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 March 31, 2026. The Company's maximum exposure to credit risk at March 31, 2026, without taking into account collateral held or right of set-off, is represented by the current carrying amounts of receivables and risk management assets as per the 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 March 31, 2026, was $55 million (Dec. 31, 2025 – $51 million). The Company has counterparty credit insurance programs that mitigate our exposure to credit risk.

III. Liquidity Risk

The Company has sufficient existing liquidity available to meet its upcoming debt maturities. Between 2026 and 2028, the Company has a total of $632 million of scheduled debt and tax equity repayments. 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:

	2026	2027	2028	2029	2030	2031 and thereafter	Total
Bank overdraft	7	—	—	—	—	—	7
Accounts payable, accrued liabilities and other current liabilities	593	—	—	—	—	—	593
Long-term debt(1)	136	332	164	454	282	2,237	3,605
Exchangeable securities(2)	—	—	—	—	—	750	750
Commodity risk management (assets) liabilities(3)	(27)	(1)	16	28	25	407	448
Other risk management (assets) liabilities	10	(4)	2	1	1	(8)	2
Lease liabilities	4	6	6	5	5	122	148
Interest on long-term debt and lease liabilities(4)	137	191	173	160	141	719	1,521
Interest on exchangeable securities(2)(4)	40	53	53	53	53	456	708
Dividends payable	40	—	—	—	—	—	40
Total	**940**	**577**	**414**	**701**	**507**	**4,683**	**7,822**

(1) Excludes impact of hedge accounting and derivatives.

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

(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 March 31, 2026, the Company provided $74 million (Dec. 31, 2025 – $92 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 March 31, 2026, the Company provided $20 million (Dec. 31, 2025 – $20 million) in surety bonds as security for commodity trading activities.

II. Financial Assets Held as Collateral

At March 31, 2026, the Company held $27 million (Dec. 31, 2025 – $3 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 March 31, 2026, the Company had posted collateral of $236 million (Dec. 31, 2025 – $338 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 $98 million (Dec. 31, 2025 – $92 million) of collateral to its counterparties.

12. Finance Lease Receivables

During the three months ended March 31, 2026, the Mount Keith West Network Upgrade project was completed. As a result, the Company derecognized assets under construction and recognized a finance lease receivable of $39 million.

Amounts receivable under the Company's finance leases relating to the Mount Keith West Network Upgrade, Mount Keith 132kV expansion, Northern Goldfields solar facilities, the Poplar Creek cogeneration facility, the Muskeg River and the Primrose cogeneration plants are as follows:

	March 31, 2026		Dec. 31, 2025	
	Minimum lease receipts	Present value of minimum lease receipts	Minimum lease receipts	Present value of minimum lease receipts
Within one year	**56**	**54**	48	47
Second to fifth years inclusive	**209**	**173**	183	156
More than five years	**261**	**121**	206	104
	526	**348**	437	307
Less: unearned finance lease income	**179**	**—**	131	—
Add: unguaranteed residual value	**1**	**—**	1	—
Total finance lease receivables	**348**	**348**	307	307

	March 31, 2026	Dec. 31, 2025
Included in the Condensed Consolidated Statements of Financial Position as:		
Current portion of finance lease receivables	**32**	30
Long-term portion of finance lease receivables	**316**	277
Total finance lease receivables	**348**	307

13. Property, Plant and Equipment

During the three months ended March 31, 2026, the Company had additions of $101 million from the acquisition of Far North, and $27 million related to major maintenance in the Gas and Wind and Solar segments.

As outlined in Note 12, $39 million related to the Mount Keith West Network Upgrade project was derecognized from assets under construction and recognized as a finance lease receivable.

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

A. Amounts Outstanding

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

As at March 31, 2026		Utilized			
Credit facilities	**Facility size**	**Outstanding letters of credit[1]**	**Cash drawings**	**Available capacity**	**Maturity date**
Committed					
Syndicated credit facility	1,900	348	200	1,352	Q2 2029
Bilateral credit facilities	240	146	—	94	Q2 2027
Heartland EDC letter of credit facility	30	12	—	18	Q4 2026
Heartland DSR letter of credit facility	27	20	—	7	Q4 2027
Heartland revolving facility	25	—	—	25	Q4 2027
Total committed	**2,222**	**526**	**200**	**1,496**	
Non-committed					
Demand facility	400	221	—	179	N/A
Total Non-committed	**400**	**221**	**—**	**179**	

(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 March 31, 2026, TransAlta provided cash collateral of $74 million.

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

TransAlta's debt has terms and conditions, including financial covenants, that are considered ordinary and customary. As at March 31, 2026, the Company was in compliance with all of its debt covenants.

Letters of credit in the amount of $221 million were issued from non-committed demand facilities as at March 31, 2026. In addition to the net $1.3 billion of committed capacity available under the credit facilities, the Company had $267 million of available cash and cash equivalents as at March 31, 2026.

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

All non-recourse debt, the TransAlta OCP LP bond, and the Heartland credit facilities, with a total carrying value of $1.6 billion as at March 31, 2026 (Dec. 31, 2025 – $1.6 billion), are subject to customary financing conditions and covenants that may restrict the Company’s ability to access funds generated by the facilities’ operations. At March 31, 2026, $133 million (Dec. 31, 2025 – $101 million) of cash was subject to these financial restrictions.

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 first quarter of 2026, with the exception of Windrise Wind LP. The funds in Windrise that have accumulated will remain there until the debt-service coverage ratio distribution threshold is met.

At March 31, 2026, $9 million (AU$9 million) of funds held by TEC Hedland Pty Ltd. cannot be accessed by other corporate entities as the funds must be solely used by the project entities and to pay major maintenance costs. Additionally, certain non-recourse bonds require that certain reserve accounts be established and funded through cash held on deposit and/or by providing letters of credit.

C. Restricted Cash

As at March 31, 2026, the Company had nil (Dec. 31, 2025 – $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. The Company also had $4 million (Dec. 31, 2025 – $4 million) of restricted cash related to holdbacks associated with the Required Divestitures and $56 million (Dec. 31, 2025 – $57 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.

D. Currency Impacts

The strengthening of the U.S. dollar has increased the U.S. dollar-denominated long-term debt balances, mainly the senior notes and tax equity financings, by $14 million as at March 31, 2026 (Dec. 31, 2025 – decreased $28 million due to the weakening of the U.S. dollar). Almost all of the U.S.-dollar-denominated debt is hedged either through financial contracts or a hedge of net investments in U.S. operations.

Additionally, the strengthening of the Australian dollar has increased the Australian-dollar-denominated non-recourse senior secured notes balance by approximately $27 million as at March 31, 2026 (Dec. 31, 2025 – increased $16 million due to strengthening of the Australia dollar). As this debt is issued by an Australian subsidiary, the foreign currency translation impacts are recognized within other comprehensive income (loss).

15. Common Shares

A. Issued and Outstanding

TransAlta is authorized to issue an unlimited number of voting common shares without nominal or par value.

	2026		2025	
3 months ended March 31	**Common shares (millions)**	**Amount**	**Common shares (millions)**	**Amount**
Issued and outstanding, beginning of period	**296.7**	**3,169**	297.5	3,179
Purchased and cancelled under the NCIB[1]	**—**	**—**	(0.3)	(3)
Share-based payment plans	**0.9**	**4**	0.9	7
Stock options exercised	**0.1**	**1**	—	—
Issued and outstanding, end of period, prior to ASPP	**297.7**	**3,174**	298.1	3,183
Provision for repurchase of common shares under ASPP	**—**	**—**	(1.5)	(20)
Issued and outstanding, end of period	**297.7**	**3,174**	296.6	3,163

(1) Shares purchased by the Company under the NCIB (as defined below) are recognized as a reduction to share capital equal to the average carrying value of the common shares. Any difference between the aggregate purchase price and the average carrying value of the common shares is recorded in retained earnings (deficit).

B. Normal Course Issuer Bid (NCIB) Program

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 Feb. 25, 2026, the Company declared a quarterly dividend of $0.070 per common share, payable on July 1, 2026. There have been no transactions involving common shares between the reporting date and the date of completion of these Condensed Consolidated Financial Statements.

16. Preferred Shares

A. Issued and Outstanding

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

As at March 31	2026		2025	
Series[(1)]	Number of shares (millions)	Amount	Number of shares (millions)	Amount
Series A	**10.8**	**263**	9.6	235
Series B	**1.2**	**30**	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.

Series A Cumulative Redeemable Rate Reset First Series A Preferred Shares conversion

On March 31, 2026, none of the Company's 9,629,913 Series A preferred shares currently outstanding were converted into Series B preferred shares. As a result, the next conversion date was reset to March 31, 2031.

Series B Cumulative Redeemable Floating Rate First Series B Preferred Shares conversion

On March 31, 2026, holders of Series B preferred shares converted 1,148,549 of the 2,370,087 outstanding Series B shares into Series A shares on a one-for-one basis.

As a result, on March 31, 2026, the Company had 10,778,462 Series A preferred shares issued and outstanding and 1,221,538 Series B preferred shares issued and outstanding.

B. Dividends

On April 29, 2026, the Company declared quarterly preferred share dividends, payable on June 30, 2026, as follows: $0.29888 per Series A share, $0.26309 per Series B share, $0.36588 per Series C share, $0.32978 per Series D share, $0.43088 per Series E share and $0.42331 per Series G share.

17. Cash Flow Information

Change in Non-Cash Operating Working Capital

3 months ended March 31	2026	2025
Source (use):		
Accounts receivable	**98**	(71)
Prepaid expenses	**(14)**	(19)
Income taxes receivable	**(21)**	(36)
Inventory	**(4)**	1
Accounts payable, accrued liabilities and provisions	**(32)**	25
Income taxes payable	**(8)**	(17)
Change in non-cash operating working capital	**19**	(117)

18. Commitments and Contingencies

The Company has not incurred any additional material contractual commitments in the three months ended March 31, 2026, either directly or through its interests in joint operations and joint ventures. Refer to the commitments disclosed in Note 36 of the 2025 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 excess capacity.

Contingencies

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

Refer to Note 36 of the 2025 audited annual consolidated financial statements for the current material outstanding contingencies. There were no material changes to the contingencies during the three months ended March 31, 2026.

19. Segment Disclosures

A. Description of Reportable Segments

The Company is comprised of four generation segments: Hydro, Wind and Solar, Gas and Energy Transition and two non-generation segments: Energy Marketing and Corporate.

During the first quarter of 2026, the Company updated its assessment of reportable segments to reflect changes in how the Chief Operating Decision Maker (CODM) makes operating decisions, assesses performance and allocates resources. As a result of the reassessment, the Company concluded that the Energy Transition segment no longer meets the quantitative thresholds under IFRS 8 to be presented as a reportable segment, primarily due to Centralia Unit 2 ceasing coal-fired operations, as scheduled at the end of 2025 in the normal course, however the unit remains available to operate in accordance with and for the duration of the order received from the United States Department of Energy.

Accordingly, as at March 31, 2026 the Company has five reportable segments, reflecting the revised assessment for the Energy Transition segment compared to six reportable segments as at Dec. 31, 2025.

The segment results are presented using Adjusted EBITDA, consistent with the measure reviewed by the President and CODM when assessing performance and making operating decisions across the Company's segments.

For internal reporting purposes, the Company presents its share of Skookumchuck's results within the Wind and Solar segment on a proportionate, line-by-line basis. This proportionate information is not prepared in accordance with IFRS. Under IFRS, the investment in Skookumchuck is accounted for as a joint venture using the equity method.

The tables below show the reconciliation of the total segment results and Adjusted EBITDA (non-IFRS measure) to the statement of earnings reported under IFRS.

B. Reported Adjusted Segment Earnings and Segment Assets

I. Reconciliation of Adjusted EBITDA to Earnings before Income Tax

	Reportable Segments									
3 months ended March 31, 2026	Hydro	Wind & Solar[1]	Gas	Energy Marketing	Corporate	Energy Transition[2]	Total	Equity-accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	57	125	348	39	1	2	572	(7)	—	565
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	(3)	6	(18)	(11)	—	—	(26)	—	26	—
Decrease in finance lease receivable	—	1	7	—	—	—	8	—	(8)	—
Finance lease income	—	1	6	—	—	—	7	—	(7)	—
Unrealized foreign exchange gain on commodity	—	—	(1)	—	—	—	(1)	—	1	—
Adjusted Revenue	54	133	342	28	1	2	560	(7)	12	565
Fuel and purchased power	(4)	(7)	(154)	—	—	—	(165)	—	—	(165)
Carbon compliance costs	—	—	(39)	—	—	—	(39)	—	—	(39)
Adjusted Gross Margin	50	126	149	28	1	2	356	(7)	12	361
OM&A	(14)	(25)	(62)	(11)	(62)	(8)	(182)	1	—	(181)
Reclassifications and adjustments:										
Termination, restructuring and facility shutdown costs	—	—	—	—	11	—	11	—	(11)	—
Legal costs related to arbitration proceedings	—	—	—	—	9	—	9	—	(9)	—
Centralia community fund expense	—	—	—	—	—	7	7	—	(7)	—
ERP integration costs	—	—	—	—	3	—	3	—	(3)	—
Acquisition-related transaction and restructuring costs	—	—	—	—	1	—	1		(1)	—
Adjusted OM&A	(14)	(25)	(62)	(11)	(38)	(1)	(151)	1	(31)	(181)
Taxes, other than income taxes	(1)	(7)	(5)	—	—	—	(13)	—	—	(13)
Net other operating income	—	13	11	—	—	—	24	—	—	24
Reclassifications and adjustments:										
Legal settlement recoveries	—	(12)	—	—	—	—	(12)	—	12	—
Adjusted Net Other Operating Income	—	1	11	—	—	—	12	—	12	24
Adjusted EBITDA[3]	35	95	93	17	(37)	1	204			
Equity income										3
Finance lease income										7
Depreciation and amortization										(105)
Asset impairment reversals										6
Interest income										7
Interest expense										(82)
Foreign exchange loss										(2)
Loss on sale of assets and other										(2)
Earnings before income taxes										23

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

(2) The Energy Transition segment no longer meets the quantitative thresholds under IFRS 8 to be presented as a reportable segment as at March 31, 2026.

(3) Adjusted EBITDA is not defined, has no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers.

	Reportable Segments									
3 months ended March 31, 2025	**Hydro**	**Wind & Solar[1]**	**Gas**	**Energy Marketing**	**Corporate**	**Energy Transition[2]**	**Total**	**Equity-accounted investments[1]**	**Reclass adjustments**	**IFRS financials**
Revenues	86	107	390	27	1	154	765	(7)	—	758
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	(21)	36	(32)	1	—	(1)	(17)	—	17	—
Decrease in finance lease receivable	—	1	7	—	—	—	8	—	(8)	—
Finance lease income	—	1	5	—	—	—	6	—	(6)	—
Revenues from Required Divestitures	—	—	(4)	—	—	—	(4)	—	4	—
Adjusted Revenues	65	145	366	28	1	153	758	(7)	7	758
Fuel and purchased power	(4)	(10)	(163)	—	(2)	(98)	(277)	—	—	(277)
Reclassifications and adjustments:										
Fuel and purchased power related to the Required Divestitures	—	—	(2)	—	—	—	(2)	—	(2)	—
Adjusted Fuel and Purchased Power	(4)	(10)	(161)	—	(2)	(98)	(275)	—	(2)	(277)
Carbon compliance costs	—	(1)	(49)	—	1	—	(49)	—	—	(49)
Adjusted Gross Margin	61	134	156	28	—	55	434	(7)	5	432
OM&A	(13)	(29)	(59)	(7)	(49)	(17)	(174)	1	—	(173)
Reclassifications and adjustments:										
OM&A related to the Planned Divestitures	—	—	2	—	—	—	2	—	(2)	—
ERP integration costs	—	—	—	—	4	—	4	—	(4)	—
Acquisition-related transaction and restructuring costs	—	—	—	—	4	—	4	—	(4)	—
Adjusted OM&A	(13)	(29)	(57)	(7)	(41)	(17)	(164)	1	(10)	(173)
Taxes, other than income taxes	(1)	(5)	(5)	—	—	(1)	(12)	—	—	(12)
Net other operating income	—	4	10	—	—	—	14	—	—	14
Reclassifications and adjustments:										
Insurance recovery	—	(2)	—	—	—	—	(2)	—	2	—
Adjusted Net Other Operating Income	—	2	10	—	—	—	12	—	2	14
Adjusted EBITDA[3]	47	102	104	21	(41)	37	270			
Equity income										2
Finance lease income										6
Depreciation and amortization										(146)
Asset impairment charges										(15)
Interest income										5
Interest expense										(93)
Foreign exchange loss										(4)
Fair value change in contingent consideration										34
Loss on sale of assets and other										(1)
Earnings before income taxes										49

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

(2) The Energy Transition segment no longer meets the quantitative thresholds under IFRS 8 to be presented as a reportable segment as at March 31, 2026.

(3) Adjusted EBITDA is not defined, has no standardized meaning under IFRS and may not be comparable to similar measures presented by other issuers.

20. 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 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 35 of the 2025 audited annual consolidated financial statements.

Transactions with Brookfield include the following:

3 months ended March 31	2026	2025
Power sales	**9**	28