

# Consolidated Financial Statements

## Management's Report

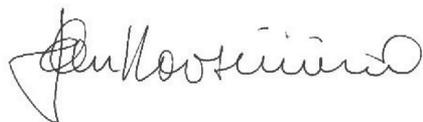
### To the Shareholders of TransAlta Corporation

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

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

Management also believes that TransAlta's operations are conducted in conformity with the law and with a high standard of business conduct.

The Board of Directors (the Board) is responsible for ensuring that management fulfils its responsibilities for financial reporting and internal controls. The Board carries out its responsibilities principally through its Audit, Finance and Risk Committee (the Committee). The Committee, which consists solely of independent directors, reviews the financial statements and annual report and recommends them to the Board for approval. The Committee meets with management and internal and external auditors to discuss internal controls, auditing matters and financial reporting issues. Internal and external auditors have full and unrestricted access to the Committee. The Committee also recommends the firm of external auditors to be appointed by shareholders.



**John Kousiniotis**

President and Chief Executive Officer



**Joel Hunter**

Executive Vice President, Finance and  
Chief Financial Officer

February 26, 2026

# Management's Annual Report on Internal Control Over Financial Reporting

## To the Shareholders of TransAlta Corporation

The following report is provided by management in respect of TransAlta Corporation's (TransAlta or the Company) internal control over financial reporting (as defined in Rules 13a-15f and 15d-15f under the United States Securities Exchange Act of 1934 and National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings (NI 51-109)).

TransAlta's management is responsible for establishing and maintaining adequate internal control over financial reporting for the Company.

Management uses the Committee of Sponsoring Organizations of the Treadway Commission (COSO) 2013 framework to evaluate the effectiveness of TransAlta's internal control over financial reporting. Management believes that the COSO 2013 framework is appropriate for its evaluation of TransAlta's internal control over financial reporting because it is free from bias, permits reasonably consistent qualitative and quantitative measurements of internal controls, is sufficiently complete so any relevant factors that would alter a conclusion about the effectiveness of the Company's internal controls are not omitted, and is relevant to an evaluation of internal control over financial reporting.

Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives due to its inherent limitations. Internal control over financial reporting includes processes that involve human diligence and compliance that are subject to lapses in judgment and breakdowns resulting from human failures.

Internal control over financial reporting can also be circumvented by collusion or improper overrides. As a result of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis. These inherent limitations are known features of the financial reporting process and it is possible to design safeguards into the process to reduce, though not eliminate, this risk.

TransAlta equity accounts for our investment in the SP Skookumchuck Investment, LLC (Skookumchuck) in accordance with International Financial Reporting Standards. Management does not have the contractual ability to assess the internal controls of this equity investment. Once the financial information is obtained from Skookumchuck, it falls within the scope of TransAlta's internal controls framework. Management's conclusion regarding the effectiveness of internal controls does not extend to the internal controls at the transactional level of this associate.

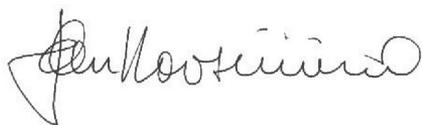
Included in the 2025 Consolidated Financial Statements of TransAlta for equity-accounted investments are one per cent and eight per cent of the Company's total and net assets, respectively, as at Dec. 31, 2025, and zero per cent and (5) per cent of the Company's revenues and net loss, respectively, for the year ended Dec. 31, 2025.

## Changes in Internal Control over Financial Reporting

There has been no change in the Company's internal control over financial reporting that occurred during the year covered by the Annual Report that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

Management has assessed the effectiveness of TransAlta's internal control over financial reporting as at Dec. 31, 2025, and has concluded that such internal control over financial reporting was effective.

Ernst & Young LLP, who has audited the Consolidated Financial Statements of TransAlta for the year ended Dec. 31, 2025, has also issued a report on internal control over financial reporting under the standards of the Public Company Accounting Oversight Board. This report is located on the following page of the Annual Report.



**John Kousinioris**

President and Chief Executive Officer



**Joel Hunter**

Executive Vice President, Finance and  
Chief Financial Officer

February 26, 2026

# Report of Independent Registered Public Accounting Firm

## To the Shareholders and Board of Directors of TransAlta Corporation

### Opinion on Internal Control Over Financial Reporting

We have audited TransAlta Corporation's internal control over financial reporting as of December 31, 2025, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the "COSO criteria"). In our opinion, TransAlta Corporation (the "Company") maintained, in all material respects, effective internal control over financial reporting as of December 31, 2025, based on the COSO criteria.

As indicated in the accompanying Management's Annual Report on Internal Control over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of the equity accounted joint venture of SP Skookumchuck Investment, LLC which is included in the 2025 consolidated financial statements of the Company and constituted 1% and 8% of total and net assets, respectively, as of December 31, 2025, and 0% and (5)% of revenues and net earnings, respectively, for the year then ended. Our audit of internal control over financial reporting of the Company also did not include an evaluation of the internal control over financial reporting of the equity accounted joint venture of SP Skookumchuck Investment, LLC.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated statements of financial position of TransAlta Corporation as of December 31, 2025 and 2024, the related consolidated statements of (loss) earnings, comprehensive (loss) income, changes in equity and cash flows for the years then ended, and the related notes and our report dated February 26, 2026 expressed an unqualified opinion thereon.

### Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

## Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/Ernst & Young LLP

Chartered Professional Accountants

Calgary, Canada

February 26, 2026

# Report of Independent Registered Public Accounting Firm

## To the Shareholders and Board of Directors of TransAlta Corporation

### Opinion on the Financial Statements

We have audited the accompanying consolidated statements of financial position of TransAlta Corporation (the "Company") as of December 31, 2025 and 2024, the related consolidated statements of (loss) earnings, comprehensive (loss) income, changes in equity and cash flows for the years then ended, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2025 and 2024, and its financial performance and its cash flows for the years then ended, in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2025, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("2013 framework"), and our report dated February 26, 2026 expressed an unqualified opinion thereon.

### Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

## Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

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### Valuation of Long-Lived Assets related to certain cash generating units ("CGU"s) and Goodwill related to the Wind & Solar segment

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**Description of the Matter** As disclosed in notes 2(G), 2(H), 2(Q)(II), 7, 19, and 22 of the consolidated financial statements, the Company owns significant Wind & Solar generation assets and has recognized goodwill from historical acquisitions which must be tested for impairment at least annually or when indicators of impairment are present. The carrying value of Goodwill related to the Wind & Solar segment as at December 31, 2025 was \$177 million and the recoverable amount of long-lived assets in the Wind & Solar segment that had indicators of impairment or impairment reversal during the year was \$596 million.

Determining the recoverable amounts for the Wind & Solar segment for the purposes of the goodwill impairment test and of certain CGUs in the Wind & Solar segment with indicators of impairment or impairment reversal ("Wind & Solar CGUs") for the asset impairment test was identified as a critical audit matter due to the significant estimation uncertainty and judgment applied by management in determining the recoverable amount, primarily due to the sensitivity of the significant assumptions to the future cash flows and the effect that changes in these assumptions would have on the recoverable amount. The estimates with a high degree of subjectivity include electricity production, sales prices, cost inputs, and determining the appropriate discount rate.

**How We Addressed the Matter in Our Audit** We obtained an understanding of management's process for estimating the recoverable amount of the Wind & Solar segment and the Wind & Solar CGUs. We evaluated the design and tested the operating effectiveness of controls over the Company's processes to determine the recoverable amount. Our audit procedures to test the Company's recoverable amount of the Wind & Solar segment and the Wind & Solar CGUs with indicators of impairment or impairment reversal included, among others, comparing the significant assumptions used to estimate cash flows to current contracts with external parties and historical trends and obtaining historical electricity generation data to evaluate future electricity production forecasts. We assessed the historical accuracy of management's forecasts by comparing them with actual results and performed a sensitivity analysis to evaluate the assumptions that were most significant to the determination of the recoverable amount. We evaluated the Company's determination of future sales prices by comparing them to externally available third-party future electricity price estimates. We also involved our internal valuation specialist to assist in our evaluation of the discount rates, which involved benchmarking the inputs against available market data.

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**Valuation of Level III Derivative Instruments**


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Description of the Matter As disclosed in notes 2(B), 2(Q)(V) and 14 of the consolidated financial statements, the Company enters into transactions that are accounted for as derivative financial instruments and are recorded at fair value. The valuation of derivative instruments classified as level III are determined using assumptions that are not readily observable. As at December 31, 2025 the fair value of the Company's derivative financial instruments classified as level III was a \$65 million risk management asset and a \$512 million risk management liability.

Auditing the determination of fair value of level III derivative instruments that rely on significant unobservable inputs can be complex and relies on judgments and estimates concerning future prices, discount rates, credit value adjustments, liquidity and delivery volumes, and can fluctuate significantly depending on market conditions. Therefore, such determination of fair value was identified as a critical audit matter.

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How We Addressed the Matter in Our Audit We obtained an understanding of the Company's processes and we evaluated and tested the design and operating effectiveness of internal controls addressing the determination and review of inputs used in establishing level III fair values. Our audit procedures included, among others, testing a sample of level III derivative instrument internal models used by management and evaluating the significant assumptions utilized. We also compared management's future pricing assumptions, credit value adjustments, and liquidity assumptions to third-party data as well as comparing terms such as delivery volumes and timing to executed commodity contracts. We compared the delivery volume assumptions to historical information. We performed a sensitivity analysis to evaluate assumptions including future commodity prices, delivery volumes and discount rates. For a sample of level III derivative instruments, we involved our internal valuation specialist to assist in our evaluation of the appropriateness of the fair value by evaluating the key assumptions and methodologies.

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/s/Ernst & Young LLP

Chartered Professional Accountants

We have served as auditors of TransAlta Corporation and its predecessor entities since 1947.

Calgary, Canada

February 26, 2026

## Consolidated Statements of (Loss) Earnings

(in millions of Canadian dollars except where noted)

<b>Year ended Dec. 31</b>	<b>2025</b>	<b>2024</b>
Revenues (Note 5)	2,405	2,845
Fuel and purchased power (Note 6)	935	939
Carbon compliance costs (Note 16)	50	112
<b>Gross margin</b>	<b>1,420</b>	<b>1,794</b>
Operations, maintenance and administration (Note 6)	711	655
Depreciation and amortization (Note 19, 20, 21 and 27)	579	531
Asset impairment (reversals) charges (Note 7)	(13)	46
Taxes, other than income taxes	50	36
Net other operating income (Note 8)	(47)	(59)
<b>Operating income</b>	<b>140</b>	<b>585</b>
Equity income (Note 9)	6	5
Fair value change in contingent consideration payable (Note 7)	37	—
Finance lease income (Note 17)	23	14
Interest income	28	30
Interest expense (Note 10)	(347)	(324)
Foreign exchange (loss) gain	(21)	5
(Loss) gain on sale of assets and other	(7)	4
<b>(Loss) earnings before income taxes</b>	<b>(141)</b>	<b>319</b>
Income tax expense (Note 11)	17	80
<b>Net (loss) earnings</b>	<b>(158)</b>	<b>239</b>
<b>Net (loss) earnings attributable to:</b>		
Common shareholders	(138)	229
Non-controlling interests (Note 12)	(20)	10
	(158)	239
Net (loss) earnings attributable to TransAlta shareholders	(138)	229
Preferred share dividends (Note 29)	52	52
<b>Net (loss) earnings attributable to common shareholders</b>	<b>(190)</b>	<b>177</b>
<b>Weighted average number of common shares outstanding in the year (millions)</b>	<b>297</b>	<b>302</b>
<b>Net (loss) earnings per share attributable to common shareholders, basic and diluted (Note 28)</b>	<b>(0.64)</b>	<b>0.59</b>

See accompanying notes.

# Consolidated Statements of Comprehensive (Loss) Income

(in millions of Canadian dollars)

Year ended Dec. 31	2025	2024
<b>Net (loss) earnings</b>	<b>(158)</b>	239
<b>Other comprehensive (loss) income</b>		
Net actuarial gains on defined benefit plans, net of tax <sup>(1)</sup>	5	9
<b>Total items that will not be reclassified subsequently to net (loss) earnings</b>	<b>5</b>	9
(Losses) gains on translating net assets of foreign operations	<b>(12)</b>	30
Gains (losses) on financial instruments designated as hedges of foreign operations, net of tax <sup>(2)</sup>	<b>11</b>	(28)
(Losses) gains on derivatives designated as cash flow hedges, net of tax <sup>(3)</sup>	<b>(1)</b>	213
Reclassification of gains on derivatives designated as cash flow hedges to net (loss) earnings, net of tax <sup>(4)</sup>	<b>(68)</b>	(19)
<b>Total items that will be reclassified subsequently to net (loss) earnings</b>	<b>(70)</b>	196
<b>Other comprehensive (loss) income</b>	<b>(65)</b>	205
<b>Total comprehensive (loss) income</b>	<b>(223)</b>	444
<b>Total comprehensive (loss) income attributable to:</b>		
TransAlta shareholders	<b>(203)</b>	434
Non-controlling interests (Note 12)	<b>(20)</b>	10
	<b>(223)</b>	444

(1) Net of income tax expense of \$1 million for the year ended Dec. 31, 2025 (2024 – \$3 million expense).

(2) Net of income tax expense of \$1 million for the year ended Dec. 31, 2025 (2024 – \$4 million recovery).

(3) Net of income tax expense of nil million for the year ended Dec. 31, 2025 (2024 – \$57 million expense).

(4) Net of reclassification of income tax recovery of \$14 million for the year ended Dec. 31, 2025 (2024 – \$4 million recovery).

See accompanying notes.

# Consolidated Statements of Financial Position

(in millions of Canadian dollars)

As at Dec. 31	2025	2024
Current assets		
Cash and cash equivalents	205	337
Restricted cash (Note 25)	78	69
Trade and other receivables (Note 13)	699	767
Prepaid expenses and other	51	68
Risk management assets (Note 14 and 15)	162	318
Inventory (Note 16)	111	134
Assets held for sale (Note 4 and 18)	30	80
	<b>1,336</b>	<b>1,773</b>
Non-current assets		
Investments (Note 9)	144	159
Long-term portion of finance lease receivables (Note 17)	277	305
Risk management assets (Note 14 and 15)	32	93
Property, plant and equipment (Note 19)	5,665	6,020
Right-of-use assets (Note 20)	111	120
Intangible assets (Note 21)	243	281
Goodwill (Note 22)	516	517
Deferred income tax assets (Note 11)	41	52
Long-term financial assets (Note 14)	140	—
Other assets (Note 23)	156	179
<b>Total assets</b>	<b>8,661</b>	<b>9,499</b>
Current liabilities		
Bank overdraft	—	1
Accounts payable, accrued liabilities and other current liabilities (Note 13)	613	756
Current portion of decommissioning and other provisions (Note 24)	84	83
Risk management liabilities (Note 14 and 15)	156	277
Dividends payable (Note 28 and 29)	52	49
Exchangeable securities (Note 26)	750	750
Contingent consideration payable (Note 4 and 7)	—	81
Current portion of long-term debt and lease liabilities (Note 25)	175	572
	<b>1,830</b>	<b>2,569</b>
Non-current liabilities		
Credit facilities, long-term debt and lease liabilities (Note 25)	3,418	3,236
Decommissioning and other provisions (Note 24)	807	850
Deferred income tax liabilities (Note 11)	423	470
Risk management liabilities (Note 14 and 15)	519	305
Contract liabilities (Note 5)	26	24
Defined benefit obligation and other long-term liabilities (Note 27)	173	202
<b>Total liabilities</b>	<b>7,196</b>	<b>7,656</b>
Equity		
Common shares (Note 28)	3,169	3,179
Preferred shares (Note 29)	942	942
Contributed surplus	42	42
Deficit	(2,730)	(2,458)
Accumulated other comprehensive (loss) income (Note 30)	(24)	41
<b>Equity attributable to shareholders</b>	<b>1,399</b>	<b>1,746</b>
Non-controlling interests (Note 12)	66	97
<b>Total equity</b>	<b>1,465</b>	<b>1,843</b>
<b>Total liabilities and equity</b>	<b>8,661</b>	<b>9,499</b>

Commitments and contingencies (Note 36)  
Subsequent events (Note 38)

See accompanying notes.



John P. Dielwart  
Director

On behalf of the Board:



Thomas M. O'Flynn  
Chair of Audit, Finance and Risk Committee

# Consolidated Statements of Changes in Equity

(in millions of Canadian dollars)

	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income (loss) <sup>(1)</sup>	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec. 31, 2023	3,285	942	41	(2,567)	(164)	1,537	127	1,664
Net earnings	—	—	—	229	—	229	10	239
Other comprehensive income:								
Net gains on translating net assets of foreign operations, net of hedges and of tax	—	—	—	—	2	2	—	2
Net gains on derivatives designated as cash flow hedges, net of tax	—	—	—	—	194	194	—	194
Net actuarial gains on defined benefits plans, net of tax	—	—	—	—	9	9	—	9
<b>Total comprehensive income</b>	—	—	—	229	205	434	10	444
Common share dividends (Note 28)	—	—	—	(71)	—	(71)	—	(71)
Preferred share dividends (Note 29)	—	—	—	(52)	—	(52)	—	(52)
Shares purchased under normal course issuer bid (NCIB) (Note 28)	(146)	—	—	3	—	(143)	—	(143)
Reversal of provision for repurchase of shares under the automatic share purchase plan (Note 28)	19	—	—	—	—	19	—	19
Share-based payment plans and stock options exercised (Note 31)	21	—	1	—	—	22	—	22
Distributions declared to non-controlling interests (Note 12)	—	—	—	—	—	—	(40)	(40)
<b>Balance, Dec. 31, 2024</b>	<b>3,179</b>	<b>942</b>	<b>42</b>	<b>(2,458)</b>	<b>41</b>	<b>1,746</b>	<b>97</b>	<b>1,843</b>
Net loss	—	—	—	<b>(138)</b>	—	<b>(138)</b>	<b>(20)</b>	<b>(158)</b>
Other comprehensive loss:								
Net loss on translating net assets of foreign operations, net of hedges and tax	—	—	—	—	<b>(1)</b>	<b>(1)</b>	—	<b>(1)</b>
Net losses on derivatives designated as cash flow hedges, net of tax	—	—	—	—	<b>(69)</b>	<b>(69)</b>	—	<b>(69)</b>
Net actuarial gains on defined benefits plans, net of tax	—	—	—	—	<b>5</b>	<b>5</b>	—	<b>5</b>
<b>Total comprehensive loss</b>	—	—	—	<b>(138)</b>	<b>(65)</b>	<b>(203)</b>	<b>(20)</b>	<b>(223)</b>
Common share dividends (Note 28)	—	—	—	<b>(78)</b>	—	<b>(78)</b>	—	<b>(78)</b>
Preferred share dividends (Note 29)	—	—	—	<b>(52)</b>	—	<b>(52)</b>	—	<b>(52)</b>
Shares purchased under NCIB (Note 28)	<b>(20)</b>	—	—	<b>(4)</b>	—	<b>(24)</b>	—	<b>(24)</b>
Share-based payment plans and stock options exercised (Note 31)	<b>10</b>	—	—	—	—	<b>10</b>	—	<b>10</b>
Distributions declared to non-controlling interests (Note 12)	—	—	—	—	—	—	<b>(11)</b>	<b>(11)</b>
<b>Balance, Dec. 31, 2025</b>	<b>3,169</b>	<b>942</b>	<b>42</b>	<b>(2,730)</b>	<b>(24)</b>	<b>1,399</b>	<b>66</b>	<b>1,465</b>

(1) Refer to Note 30 for details on components of and changes in accumulated other comprehensive income (loss).

See accompanying notes.

# Consolidated Statements of Cash Flows

(in millions of Canadian dollars)

Year ended Dec. 31	2025	2024
<b>Operating activities</b>		
Net (loss) income	(158)	239
Depreciation and amortization (Note 19, 20, 21 and 27)	579	531
Gain on sale of assets and other	(1)	(1)
Accretion of provisions (Note 10 and 24)	57	50
Decommissioning and restoration costs settled (Note 24)	(39)	(41)
Deferred income tax recovery (Note 11)	(32)	(63)
Unrealized loss from risk management activities	289	2
Unrealized foreign exchange loss (gain)	6	(29)
Provisions and contract liabilities	(32)	23
Asset impairment (reversals) charges (Note 7)	(13)	46
Equity income, net of distributions from investments (Note 9)	(1)	—
Other non-cash items	(12)	1
Cash flow from operations before changes in working capital	643	758
Change in non-cash operating working capital balances (Note 33)	3	38
<b>Cash flow from operating activities</b>	<b>646</b>	<b>796</b>
<b>Investing activities</b>		
Additions to property, plant and equipment (Note 19 and 37)	(249)	(311)
Additions to intangible assets (Note 21 and 37)	(11)	(10)
Restricted cash (Note 25)	(7)	(1)
Loan advances (Note 23)	(6)	(1)
Acquisitions, net of cash acquired (Note 4)	—	(217)
Increase in long-term financial assets (Note 14)	(145)	—
Investments (Note 9)	(7)	(5)
Proceeds on sale of property, plant and equipment	8	4
Realized (loss) gain on financial instruments	(2)	1
Decrease in finance lease receivable (Note 17)	30	21
Development expenditures	(2)	(6)
Other	(4)	25
Change in non-cash investing working capital balances	(23)	(20)
<b>Cash flow used in investing activities</b>	<b>(418)</b>	<b>(520)</b>
<b>Financing activities</b>		
Net (decrease) increase in borrowings under credit facilities (Note 25 and 33)	(448)	143
Repayment of long-term debt (Note 25 and 33)	(736)	(131)
Issuance of long-term debt (Note 25 and 33)	991	—
Dividends paid on common shares (Note 28)	(74)	(71)
Dividends paid on preferred shares (Note 29)	(52)	(52)
Repurchase of common shares under NCIB (Note 28)	(24)	(143)
Proceeds on issuance of common shares	3	12
Realized gain on financial instruments	2	4
Distributions paid to subsidiaries' non-controlling interests (Note 12)	(11)	(40)
Decrease in lease liabilities (Note 25 and 33)	(4)	(6)
Financing fees and other	(8)	(1)
Change in non-cash financing working capital balances	(1)	(6)
<b>Cash flow used in financing activities</b>	<b>(362)</b>	<b>(291)</b>
<b>Cash flow used in operating, investing and financing activities</b>	<b>(134)</b>	<b>(15)</b>
<b>Effect of translation on foreign currency cash</b>	<b>2</b>	<b>4</b>
<b>Decrease in cash and cash equivalents</b>	<b>(132)</b>	<b>(11)</b>
<b>Cash and cash equivalents, beginning of year</b>	<b>337</b>	<b>348</b>
<b>Cash and cash equivalents, end of year</b>	<b>205</b>	<b>337</b>
Cash taxes paid	85	104
Cash interest paid	282	269
Cash interest received	28	30

See accompanying notes.

# Notes to the Consolidated Financial Statements

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

## 1. Corporate Information

### A. Description of the Business

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

### Operating Segments

#### Generation Segments

The Company is comprised of four generation segments: Hydro, Wind and Solar, Gas, and Energy Transition. The Company directly or indirectly owns and operates hydro, wind and solar, and natural gas-fired facilities, along with a coal-fired facility and natural gas pipeline operations in Canada, the United States (U.S.) and Western Australia. Transmission in Canada and Western Australia is included within the Hydro and Gas segments in Canada and Western Australia, respectively. The Wind and Solar segment includes the financial results, on a proportionate basis, of our investment in SP Skookumchuck Investment, LLC (Skookumchuck). Segment revenues are derived from the availability and production of electricity and steam as well as ancillary services.

#### Energy Marketing Segment

The Energy Marketing segment derives revenue and earnings from the trading of electricity, natural gas and environmental products across a variety of North American markets, excluding Alberta.

The Energy Marketing segment also performs services on behalf of certain assets outside of Alberta for the marketing of available generating capacity as well as the procurement of the fuel and transmission needs for the fleet. Contracts of various durations for the forward sales of electricity and for the purchase of natural gas and transmission capacity are used and these activities are included in the gross margin of the related generation segment.

### Corporate Segment

The Corporate segment includes the Company's central finance, legal, administrative, corporate development, and investor relations functions. Activities and charges directly or reasonably attributable to other segments are allocated to them.

### B. Basis of Preparation

These Consolidated Financial Statements have been prepared by management in compliance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB).

The Consolidated Financial Statements have been prepared on a historical cost basis except for financial instruments, which are measured at fair value, as explained in the following accounting policies.

These Consolidated Financial Statements were authorized for issue by TransAlta's Board of Directors (the Board) on Feb. 26, 2026.

### C. Basis of Consolidation

The Consolidated Financial Statements include the accounts of the Company and the subsidiaries that it controls. Control exists when the Company is exposed, or has rights, to variable returns from its involvement with the subsidiary and has the ability to affect the returns through its power over the subsidiary. The financial statements of the subsidiaries are prepared for the same reporting period and apply consistent accounting policies as the parent company.

## 2. Material Accounting Policies

The Company has reviewed its material accounting policies. The definition of material that management has used to judgmentally determine disclosure is that information is deemed material if omitting or misstating it could influence decisions users make on the basis of financial information.

### A. Revenue Recognition

#### I. Revenue from Contracts with Customers

The majority of the Company's revenues from contracts with customers are derived from the sale of generation capacity, electricity, thermal energy, environmental attributes and byproducts of power generation. The Company evaluates whether the contracts it enters into meet the definition of a contract with a customer at the inception of the contract and on an ongoing basis if there is an indication of significant changes in facts and circumstances. Contract modifications are accounted for as separate contracts when the consideration for the additional promised goods reflects a stand-alone selling price. Otherwise, contract modifications are accounted for as part of the existing contract. If the additional goods are not considered distinct the transaction price can be affected and adjustments to previously recognized revenue can occur. If the additional goods are distinct, the existing and modified contracts are treated together as a new contract, with impacts reflected prospectively from the modification date, which can include the blending of contract prices. Revenue is measured based on the transaction price specified in a contract with a customer. Revenue is recognized when the control of the goods or services is transferred to the customer. For certain contracts, revenue may be recognized at the invoiced amount, as permitted using the invoice practical expedient, if such amount corresponds directly with the Company's performance to date. The Company excludes amounts collected on behalf of third parties from revenue.

#### Performance Obligations

Each promised good or service is accounted for separately as a performance obligation if it is distinct. The Company's contracts may contain more than one performance obligation.

#### Transaction Price

The Company allocates the transaction price in the contract to each performance obligation. The transaction price allocated to performance obligations may include variable consideration. Variable consideration is included in the transaction price for each performance obligation when it is highly probable that a significant reversal of the cumulative variable revenue will not occur. Variable consideration that has previously been constrained is assessed at each reporting period to determine whether the constraint is lifted. The consideration contained in some of the Company's contracts with customers is primarily variable and may include both variability in quantity and pricing, such as: revenues can be dependent upon future production volumes that are driven by customer or market demand or by the operational ability of a plant; revenues can be dependent upon the variable cost of producing energy; revenues can be dependent upon market prices; and revenues can be subject to various indices and escalators.

When multiple performance obligations are present in a contract, the transaction price is allocated to each performance obligation in an amount that depicts the consideration the Company expects to be entitled to in exchange for transferring the good or service. The Company estimates the amount of the transaction price to allocate to individual performance obligations based on their relative stand-alone selling prices, which is primarily estimated based on the amounts that would be charged to customers under similar market conditions.

## Recognition

The nature, timing of recognition of satisfied performance obligations and payment terms for the Company's goods and services are described below:

<b>Good or service</b>	<b>Description</b>
<b>Capacity</b>	Capacity refers to the availability of an asset to deliver goods or services. Customers typically pay for capacity for each defined time period (e.g., monthly) in an amount representative of the availability of the asset for the defined time period. Obligations to deliver capacity are satisfied over time and revenue is recognized using a time-based measure. Contracts for capacity are typically long-term in nature and payments are typically received on a monthly basis.
<b>Contract power</b>	The sale of contract power refers to the delivery of units of electricity to a customer under the terms of a contract. Customers pay a contractually specified price for the output at the end of predefined contractual periods (e.g., monthly). Obligations to deliver electricity are satisfied over time and revenue is recognized using a units-based output measure (i.e., megawatt hours). Contracts for power are typically long-term in nature and payments are typically received on a monthly basis.
<b>Thermal energy</b>	Thermal energy refers to the delivery of units of steam to a customer under the terms of a contract. Customers pay a contractually specified price for the output at the end of predefined contractual periods (e.g., monthly). Obligations to deliver steam are satisfied over time and revenue is recognized using a units-based output measure (i.e., gigajoules). Contracts for thermal energy are typically long-term in nature and payments are typically received on a monthly basis.
<b>Environmental attributes</b>	Environmental attributes refers to the delivery of renewable energy certificates, green attributes and other similar items. Customers may contract for environmental attributes in conjunction with the purchase of power, in which case the customer pays for the attributes in the month subsequent to the delivery of the power. Alternatively, customers pay upon delivery of the environmental attributes. Obligations to deliver environmental attributes are satisfied at a point in time, generally upon delivery of the item.
<b>Generation byproducts</b>	Generation byproducts refers to the sale of byproducts from the use of coal in the Company's current U.S. and previous Canadian coal operations. Obligations to deliver byproducts are satisfied at a point in time, generally upon delivery of the item. Payments are received upon satisfaction of delivery of the byproducts.

A contract liability is recorded when the Company receives consideration before the performance obligations have been satisfied. A contract asset is recorded when the Company has rights to consideration for the completion of a performance obligation before it has invoiced the customer. The Company recognizes unconditional rights to consideration separately as a receivable. Contract assets and receivables are evaluated at each reporting period to determine whether there is any objective evidence that they are impaired.

## II. Revenue from Other Sources

### Merchant Revenue

Revenues from non-contracted capacity (i.e., merchant) include energy payments, at market price, for each MWh produced and are recognized upon delivery.

### Lease Revenue

In certain situations, a long-term electricity or thermal sales contract may contain, or be considered, a lease. Revenues associated with non-lease elements are recognized as goods or services revenues as outlined above. Where the terms and conditions of the contract result in the customer assuming the principal risks and rewards of ownership of the underlying asset, the contractual arrangement is considered a finance lease, which results in the recognition of finance lease income. Where the Company retains the principal risks and rewards, the contractual arrangement is an operating lease. Rental income, including contingent rents where applicable, is recognized over the term of the contract.

## Revenue from derivatives and other trading activities

Commodity risk management activities involve the use of derivatives such as physical and financial swaps, forward sales contracts, futures contracts and options, which are used to earn revenues and gain market information. The Company also enters into contracts for differences and Virtual Power Purchase Agreements (VPPA). Contracts for differences are financial contracts whereby the Company receives a fixed price per MWh and pays the prevailing real-time energy market price per MWh. With a VPPA, the Company receives the difference between the fixed contract price per MWh and the settled market price. These arrangements meet the definition of a derivative and judgment is applied to determine if the contract meets the "own use" exemption or if derivative treatment is required.

These derivatives are accounted for using fair value accounting. The initial recognition and subsequent changes in fair value affect reported net earnings in the period the change occurs and are presented on a net basis in revenue. The fair values of instruments that remain open at the end of the reporting period represent unrealized gains or losses and are presented on the Consolidated Statements of Financial Position as risk management assets or liabilities. Some of the derivatives used by the Company in trading activities are not traded on an active exchange or have terms that extend beyond the time period for which exchange-based quotes are available. The fair values of these derivatives are determined using internal valuation techniques or models.

## B. Financial Instruments and Hedges

### I. Financial Instruments

#### Classification and Measurement

IFRS 9 introduced the requirement to classify and measure financial assets based on their contractual cash flow characteristics and the Company's business model for the financial asset. All financial assets and liabilities, including derivatives, are recognized at fair value on the Consolidated Statements of Financial Position when the Company becomes party to the contractual provisions of a financial instrument or non-financial derivative contract. Financial assets must be classified and measured at either amortized cost, at fair value through profit or loss (FVTPL), or at fair value through other comprehensive income (loss) (FVTOCI).

Financial assets with contractual cash flows arising on specified dates, consisting solely of principal and interest, and that are held within a business model whose objective is to collect the contractual cash flows, are subsequently measured at amortized cost. Financial assets measured at FVTOCI are those that have contractual cash flows, arising on specific dates, consisting solely of principal and interest, and that are held within a business model whose objective is to collect the contractual cash flows and to sell the financial asset and investments in equity instruments. All other financial assets are subsequently measured at FVTPL.

Financial liabilities are classified as FVTPL when the financial liability is held for trading. All other financial liabilities are subsequently measured at amortized cost.

Funds received under tax equity investment arrangements are classified as long-term debt. These arrangements are used in the U.S. when project investors acquire an equity investment in a project entity, and in return for their investment, are allocated substantially all of the earnings, cash flows and tax benefits (such as production tax credits, investment tax credits, accelerated tax depreciation, as applicable) until they have achieved the agreed upon target rate of return. Once achieved, the arrangements flip, with the Company then receiving the majority of earnings, cash flows and tax benefits. At that time, the tax equity investor's investment is subsequently considered residual equity ownership, with distributions classified as non-controlling interest. In applying the effective interest method to tax equity financings, the Company has made an accounting policy choice to recognize the impacts of the tax attributes in net interest expense.

The Company enters into a variety of derivative financial instruments to manage its exposure to commodity price risk, interest rate risk and foreign currency exchange risk, including fixed price financial swaps, long-term physical power sale contracts, foreign exchange forward contracts, interest rate swap contracts, and designating foreign currency debt as a hedge of net investments in foreign operations.

Derivatives are initially recognized at fair value at the date the derivative contracts are entered into and are subsequently remeasured to their fair value at the end of each reporting period. The resulting gain or loss is recognized in net earnings immediately, unless the derivative is designated and effective as a hedging instrument, in which case the timing of the recognition in net earnings is dependent on the nature of the hedging relationship.

Derivatives embedded in non-derivative host contracts that are not financial assets within the scope of IFRS 9 (e.g., financial liabilities) are treated as separate derivatives when they meet the definition of a derivative, their risks and characteristics are not closely related to those of the host contracts and the host contracts are not measured at FVTPL. Derivatives embedded in hybrid contracts that contain financial asset hosts within the scope of IFRS 9 are not separated, and the entire contract is measured at either FVTPL or amortized cost, as appropriate.

Financial assets are derecognized when the contractual rights to receive cash flows expire. Financial liabilities are derecognized when the obligation is discharged, cancelled or expired.

Financial assets are also derecognized when the Company has transferred its rights to receive cash flows from the asset or has assumed an obligation to pay the received

cash flows to a third party under a "pass-through" arrangement and either transferred substantially all the risks and rewards of the asset, or transferred control of the asset. TransAlta will continue to recognize the asset and any associated liability if it retains substantially all of the risks and rewards of the asset, or retains control of the asset. Continuing involvement that takes the form of a guarantee over the transferred asset is measured at the lower of the original carrying amount of the asset and the maximum amount of consideration that TransAlta could be required to repay.

Financial assets and liabilities are offset and the net amount is reported in the Consolidated Statements of Financial Position if there is a currently enforceable legal right to offset the recognized amounts and there is an intention to settle on a net basis or realize the assets and settle the liabilities simultaneously.

Transaction costs are expensed as incurred for financial instruments classified or designated as FVTPL. For other financial instruments, such as debt instruments, transaction costs are recognized as part of the carrying amount of the financial instrument. The Company uses the effective interest method of amortization for any transaction costs or fees, premiums or discounts earned or incurred for financial instruments measured at amortized cost.

### Impairment of Financial Assets

TransAlta recognizes an allowance for expected credit losses for financial assets measured at amortized cost as well as certain other instruments. The loss allowance for a financial asset is measured at an amount equal to the lifetime expected credit loss if its credit risk has increased significantly since initial recognition or if the financial asset is a purchased or originated credit-impaired financial asset. If the credit risk on a financial asset has not increased significantly since initial recognition, its loss allowance is measured at an amount equal to the 12-month expected credit loss.

For trade receivables, lease receivables and contract assets recognized under IFRS 15, TransAlta applies a simplified approach for measuring the loss allowance. Therefore, the Company does not track changes in credit risk but instead recognizes a loss allowance at an amount equal to the lifetime expected credit losses at each reporting date.

The assessment of the expected credit loss is based on historical data and adjusted by forward-looking information that includes third-party default rates over time, dependent on credit ratings.

## II. Hedges

Where hedge accounting can be applied and the Company chooses to seek hedge accounting treatment, a hedge relationship is designated as a fair value hedge, a cash flow hedge or a hedge of foreign currency exposures of a net investment in a foreign operation.

A relationship qualifies for hedge accounting if, at inception, it is formally designated and documented as a hedge and the hedging instrument and the hedged item have values that generally move in opposite direction because of the hedged risk. The documentation includes identification of the hedging instrument and hedged item or transaction, the nature of the risk being hedged, the Company's risk management objectives and strategy for undertaking the hedge and how hedge effectiveness will be assessed. The process of hedge accounting includes linking derivatives to specific recognized assets and liabilities or to specific firm commitments or highly probable anticipated transactions.

The Company formally assesses, both at the hedge's inception and on an ongoing basis, whether the derivatives used are highly effective in offsetting changes in fair values or cash flows of hedged items. If hedge criteria are not met or the Company does not apply hedge accounting, the derivative is recognized at fair value on the Consolidated Statements of Financial Position, with subsequent changes in fair value recorded in net earnings in the period of change.

### Fair Value Hedges

In a fair value hedging relationship, the carrying amount of the hedged item is adjusted for changes in fair value attributable to the hedged risk, with the changes being recognized in net earnings. Changes in the fair value of the hedged item, to the extent that the hedging relationship is effective, are offset by changes in the fair value of the hedging derivative, which is also recorded in net earnings.

For fair value hedges relating to items carried at amortized cost, any adjustment to carrying value is amortized through profit or loss over the remaining term of the hedge using the effective interest rate (EIR) method. The EIR amortization may begin as soon as an adjustment exists and no later than when the hedged item ceases to be adjusted for changes in its fair value attributable to the risk being hedged.

If the hedged item is derecognized, the unamortized fair value is recognized immediately in net earnings.

### Cash Flow Hedges

In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in other comprehensive income (loss) (OCI) while any ineffective portion is recognized in net earnings. The cash flow hedge reserve is adjusted to the lower of the cumulative gain or loss on the hedging instrument and the cumulative change in fair value of the hedged item.

If cash flow hedge accounting is discontinued, the amounts previously recognized in accumulated other comprehensive income (loss) (AOCI) must remain in AOCI if the hedged future cash flows are still expected to occur. Otherwise, the amount will be immediately reclassified to net earnings as a reclassification adjustment. After discontinuation, once the hedged cash flow occurs, any amount remaining in AOCI

must be accounted for depending on the nature of the underlying transaction.

### Hedges of Foreign Currency Exposures of a Net Investment in a Foreign Operation

When hedging the foreign currency exposure of a net investment in a foreign operation, the effective portion of foreign exchange gains and losses on the hedging instrument is recognized in OCI and the ineffective portion is recognized in net earnings. The related fair values are recorded in risk management assets or liabilities, as appropriate. The amounts previously recognized in AOCI are recognized in net earnings when there is a reduction in the hedged net investment as a result of a disposal, partial disposal or loss of control.

## C. Cash and Cash Equivalents

Cash and cash equivalents comprises cash and highly liquid investments with original maturities of three months or less.

## D. Inventory

### I. Fuel

The Company's inventory balance is composed of coal and natural gas used as fuel, which is measured at the lower of weighted average cost and net realizable value. The cost of natural gas and purchased coal inventory includes all applicable expenditures and charges incurred in bringing the inventory to its existing condition and location.

### II. Energy Marketing

Commodity inventories held in the Energy Marketing segment for trading purposes are measured at fair value less costs to sell. Changes in fair value less costs to sell are recognized in net earnings in the period of change.

### III. Parts, Materials and Supplies

Parts, materials and supplies are recorded at the lower of cost and measured at moving average costs and net realizable value.

## IV. Emission Credits and Allowances

Emission credits and allowances are recorded as inventory at cost. Those purchased for use by the Company are recorded at cost and are carried at the lower of weighted average cost and net realizable value. For emission credits that are not ordinarily interchangeable, the Company records the credits using the specific identification method. Credits granted to or internally generated by TransAlta are recorded at nil. Emission liabilities are recorded at the estimated compliance cost required by the Company to settle its obligation in excess of government-established caps and targets. Compliance costs that are recoverable under the terms of the contracts with third parties are recognized as revenue from contracts with customers.

Emission credits and allowances that are held for trading and that meet the definition of a derivative are accounted for using the fair value method of accounting. Emission credits and allowances that do not satisfy the criteria of a derivative are accounted for using the accrual method.

## E. Property, Plant and Equipment

The Company's investment in property, plant and equipment (PP&E) is initially measured at the original cost of each component at the time of construction, purchase or acquisition. A component is a tangible portion of an asset that can be separately identified and depreciated over its own expected useful life and is expected to provide a benefit for a period in excess of one year. Original cost includes items such as materials, labour, borrowing costs and other directly attributable costs, including the initial estimate of the cost of decommissioning and restoration. Costs are recognized as PP&E if it is probable that future economic benefits will be realized and the cost of the item can be measured reliably. The cost of major spare parts is capitalized and classified as PP&E, as these items can only be used in connection with an item of PP&E.

Planned maintenance is performed at regular intervals. Planned major maintenance includes inspection, repair and maintenance of existing components and the replacement of existing components. Costs incurred for planned major maintenance activities are capitalized in the period maintenance activities occur and are amortized on a straight-line basis over the term until the next major maintenance event. Expenditures incurred for the replacement of components during major maintenance are capitalized and amortized over the estimated useful life of such components.

The cost of routine repairs and maintenance and the replacement of minor parts is charged to net earnings as incurred. Subsequent to initial recognition and measurement at cost, all classes of PP&E continue to be measured using the cost model and are reported at cost less accumulated depreciation and impairment losses, if any. An item of PP&E or a component is derecognized upon disposal or when no future economic benefits are expected from its use or disposal. Any gain or loss arising on derecognition is included in net earnings when the asset is derecognized. The estimate of the useful life of each component of PP&E is based on current facts and past experience and takes into consideration existing long-term sales agreements and contracts, current and forecasted demand and the potential for technological obsolescence. The useful life is used to estimate the rate at which the component of PP&E is depreciated. PP&E assets are subject to depreciation when the asset is considered to be available for use, which is typically at the start of commercial operations. Insurance spares that are designated as critical for uninterrupted operation in a particular facility are depreciated over the life of that facility, even if the item is not in service. Capital

spares begin to be depreciated when the item is put into service. Each significant component of an item of PP&E is depreciated to its residual value over its estimated useful life, generally using straight-line or unit-of-production methods. Estimated useful lives, residual values and depreciation methods are reviewed annually and are subject to revision based on new or additional information. The effect of a change in useful life, residual value or depreciation method is accounted for prospectively.

Estimated remaining useful lives of the components of depreciable assets, categorized by asset class, are as follows:

Hydro generation	1-47 years
Wind and Solar generation	1-29 years
Gas generation	1-32 years
Energy Transition	1-8 years
Capital spares and other	1-47 years

TransAlta capitalizes borrowing costs on capital invested in projects under construction. Upon commencement of commercial operations, capitalized borrowing costs, as a portion of the total cost of the asset, are depreciated over the estimated useful life of the related asset.

## F. Intangible Assets

Intangible assets acquired in a business combination are recognized separately from goodwill at their fair value at the date of acquisition. Intangible assets acquired separately are recognized at cost. Internally generated intangible assets arising from development projects are recognized when certain criteria related to the feasibility of internal use or sale and probable future economic benefits of the intangible asset, are demonstrated.

Intangible assets are initially recognized at cost, which is composed of all directly attributable costs necessary to create, produce and prepare the intangible asset to be capable of operating in the manner intended by management.

Software-as-a-service, such as cloud-based software, that do not meet the criteria of an intangible asset are expensed as incurred, including implementation costs.

Subsequent to initial recognition, intangible assets continue to be measured using the cost model and are reported at cost less accumulated amortization and impairment losses, if any. Amortization is included in depreciation and amortization in the Consolidated Statements of Earnings.

Amortization commences when the intangible asset is available for use and is computed on a straight-line basis over the intangible asset's estimated useful life. Estimated useful lives of intangible assets may be determined, for example, with reference to the term of the related contract or licence agreement. The estimated useful lives and

amortization methods are reviewed annually with the effect of any changes being accounted for prospectively.

Intangible assets consist of power sale contracts with fixed prices higher than market prices at the date of acquisition, software and intangibles under development. Estimated remaining useful lives of intangible assets are as follows:

Software	1-6 years
Power sale contracts	1-16 years

## G. Impairment of Tangible and Intangible Assets Excluding Goodwill

At the end of each reporting period, the Company assesses whether there is any indication that PP&E and finite life intangible assets are impaired.

Factors that could indicate that an impairment exists include: significant underperformance relative to historical or projected operating results; significant changes in the manner in which an asset is used, or in the Company's overall business strategy; or significant negative industry or economic trends. In some cases, these events are clear. However, in many cases, a clearly identifiable event indicating possible impairment does not occur. Instead, a series of individually insignificant events occur over a period of time leading to an indication that an asset may be impaired. This can be further complicated in situations where the Company is not the operator of the facility. Events can occur in these situations that may not be known until a date subsequent to their occurrence.

The Company's operations, the market and business environment are routinely monitored and judgments and assessments are made to determine whether an event has occurred that indicates a possible impairment. If such an event has occurred, an estimate is made of the recoverable amount of the asset or cash-generating unit (CGU) to which the asset belongs. The recoverable amount is the higher of an asset's fair value less costs of disposal and its value in use. Fair value is the price that would be received if the asset was sold in an orderly transaction between market participants at the measurement date. In determining fair value, recent market transactions are taken into account. If no such transactions can be identified, an appropriate valuation model such as discounted cash flow is used. Value in use is the present value of the estimated future cash flows expected to be derived from the asset from its continued use and ultimate disposal by the Company. If the recoverable amount is less than the carrying amount of the asset or CGU, an asset impairment charge is recognized in net earnings and the asset's carrying amount is reduced to its recoverable amount.

At each reporting date, an assessment is made whether there is any indication that an impairment charge previously recognized may no longer exist or may have decreased. If

such indication exists, the recoverable amount of the asset or CGU to which the asset belongs is estimated and, if there has been an increase in the recoverable amount, the impairment charge previously recognized is reversed. If an impairment charge is subsequently reversed, the carrying amount of the asset is increased to the lesser of the revised estimate of its recoverable amount or the carrying amount that would have been determined (net of depreciation) had no impairment charge been recognized previously. A reversal of an impairment charge is recognized in net earnings.

## H. Goodwill

Goodwill arising in a business combination is recognized as an asset at the date control is acquired. Goodwill is measured as the cost of an acquisition plus the amount of any non-controlling interest in the acquiree (if applicable) less the fair value of the related identifiable assets acquired and liabilities assumed.

Goodwill is not subject to amortization, but is tested for impairment at least annually, or more frequently, if an analysis of events and circumstances indicates that a possible impairment may exist. These events could include a significant change in financial position of the CGUs or groups of CGUs to which the goodwill relates or significant negative industry or economic trends. For impairment purposes, goodwill is allocated to each of the Company's CGUs or groups of CGUs that are expected to benefit from the synergies of the business combination in which the goodwill arose. Accordingly, the Company performs its test for impairment, where the recoverable amount of the CGUs or groups of CGUs to which the goodwill relates is compared to its carrying amount for each operating segment. If the recoverable amount is less than the carrying amount, an impairment charge is immediately recognized in net earnings, by first reducing the carrying amount of the goodwill and then by reducing the carrying amount of the other assets in the unit. An impairment charge recognized for goodwill is not reversed in subsequent periods.

## I. Income Taxes

The Company uses the liability method of accounting for income taxes. Under the liability method, deferred income tax assets and liabilities are recognized on the differences between the carrying amounts of assets and liabilities and their respective income tax basis (temporary differences). A deferred income tax asset may also be recognized for the benefit expected from unused tax credits and losses available for carryforward, to the extent that it is probable that future taxable earnings will be available against which the tax credits and losses can be applied. Deferred income tax assets and liabilities are measured based on income tax rates and tax laws that are enacted or substantively enacted by the end of the reporting period and that are

expected to apply in the years in which temporary differences are expected to be realized or settled. Deferred income tax is charged or credited to net earnings, except when related to items charged or credited to either OCI or directly to equity. The carrying amount of deferred income tax assets is evaluated at the end of each reporting period and is reduced to the extent that it is no longer probable that sufficient taxable income will be available to allow all or part of the asset to be realized. Unrecognized deferred tax assets are reassessed at each reporting date and are recognized to the extent that it has become probable that future taxable income will allow the deferred income tax asset to be recovered.

Deferred income tax liabilities are recognized for taxable temporary differences arising on investments in subsidiaries, except where the Company is able to control the reversal of the temporary difference and it is probable that the temporary difference will not reverse in the foreseeable future.

Cash taxes paid disclosed on the Consolidated Statements of Cash Flows includes income taxes and taxes paid related to the Part VI.1 tax in Canada for the period.

## J. Employee Future Benefits

The Company has defined benefit pension and other post-employment benefit plans. The current service cost of providing benefits under the defined benefit plans is determined using the projected unit credit method prorated based on service. The net interest cost is determined by applying the discount rate to the net defined benefit liability. The discount rate used to determine the present value of the defined benefit obligation and the net interest cost, is determined by reference to market yields at the end of the reporting period on high-quality corporate bonds with terms and currencies that match the estimated terms and currencies of the benefit obligations. Remeasurements, which include actuarial gains and losses and the return on plan assets (excluding net interest), are recognized through OCI in the period in which they occur. Actuarial gains and losses arise from experience adjustments and changes in actuarial assumptions. Remeasurements are not reclassified to profit or loss, from OCI, in subsequent periods.

Gains or losses arising from either a curtailment or settlement of a defined benefit plan are recognized when the curtailment or settlement occurs. When the restructuring of a benefit plan gives rise to a curtailment and a settlement of obligations, the curtailment is accounted for before the settlement.

In determining whether statutory minimum funding requirements of the Company's defined benefit pension plans give rise to recording an additional liability, letters of credit provided by the Company as security are considered to alleviate the funding requirements. No additional liability results in these circumstances.

Contributions payable under defined contribution pension plans are recognized as a liability and an expense in the period in which the services are rendered.

## K. Provisions

Provisions are recognized when the Company has a present obligation (legal or constructive) as a result of a past event, it is probable that the Company will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. A legal obligation can arise through a contract, legislation or other operation of law. A constructive obligation arises from an entity's actions whereby through an established pattern of past practice, published policies or a sufficiently specific current statement, the entity has indicated it will accept certain responsibilities and has thus created a valid expectation that it will discharge those responsibilities. The amount recognized as a provision is the best estimate, remeasured at each period-end, of the expenditures required to settle the present obligation, considering the risks and uncertainties associated with the obligation. Where expenditures are expected to be incurred in the future, the obligation is measured at its present value using a current market-based, risk-adjusted discount rate.

The Company records a decommissioning and restoration provision for all generating facilities and mine sites for which it is legally or constructively required to remove the facilities at the end of their useful lives and restore the plant or mine sites. For some hydro facilities, the Company is required to remove the generating equipment, but is not required to remove the structures.

Initial decommissioning provisions are recognized at their present value when incurred. Each reporting date, the Company determines the present value of the provision using the current discount rates that reflect the time value of money and associated risks. The Company recognizes the initial decommissioning and restoration provisions, as well as changes resulting from revisions to cost estimates and period-end revisions to the market-based, risk-adjusted discount rate, as a cost of the related PP&E (see Note 2(E)) to the extent the related PP&E asset is still in use. Where the related PP&E asset has reached the end of its useful life, changes in the decommissioning and restoration provision are recognized in net earnings. Where the Company expects to receive reimbursement from a third party for a portion of future decommissioning costs, the reimbursement is recognized as a separate asset when it is virtually certain that the reimbursement will be received.

Changes in other provisions resulting from revisions to estimates of expenditures required to settle the obligation or period-end revisions to the market-based, risk-adjusted discount rate are recognized in net earnings.

The accretion of the net present value discount for both the decommissioning and restoration provision and other

provisions are charged to net earnings each period and is included in interest expense.

## L. Leases

Under IFRS 16, a contract contains a lease when the customer obtains the right to control the use of an identified asset for a period of time in exchange for consideration.

### I. Lessee

The Company enters into lease arrangements with respect to land, building and office space, vehicles and site machinery and equipment. For all contracts that meet the definition of a lease under IFRS 16 in which the Company is the lessee and which are not exempt as short-term or low-value leases, the Company:

- Recognizes right-of-use assets and lease liabilities in the Consolidated Statements of Financial Position;
- Recognizes depreciation of the right-of-use assets and interest expense on lease liabilities in the Consolidated Statements of Earnings; and
- Recognizes the principal repayments on lease liabilities as financing activities and interest payments on lease liabilities as operating activities in the Consolidated Statements of Cash Flows.

For short-term and low-value leases, the Company recognizes the lease payments as operating expenses.

Variable lease payments that do not depend on an index or a rate are not included in the measurement of the lease liability and the right-of-use asset and are recognized as an expense in the period in which the event or condition that triggers the payments occurs.

Right-of-use assets are initially measured at an amount equal to the lease liability and adjusted for any payments made at or before the commencement date, plus any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset, or to restore the underlying asset or the site on which it is located, less any lease incentives received.

Lease liabilities are initially measured at the present value of the lease payments that are not paid at commencement and discounted using the Company's incremental borrowing rate or the rate implicit in the lease. The lease liability is remeasured when there is a change in future lease payments arising from a change in an index or rate, or if there is a change in the Company's estimate or assessment of whether it will exercise an extension, termination or purchase option. A corresponding adjustment is made to the carrying amount of the right-of-use asset, or is recorded in profit or loss if the carrying amount of the right-of-use asset has been reduced to zero.

The lease term includes periods covered by an option to extend if the Company is reasonably certain to exercise that

option and periods covered by an option to terminate if the Company is reasonably certain not to exercise that option.

Right-of-use assets are depreciated over the shorter period of either the lease term or the useful life of the underlying asset. If a lease transfers ownership of the underlying asset or the cost of the right-of-use asset reflects that the Company expects to exercise the purchase option, the related right-of-use asset is depreciated over the useful life of the underlying asset.

The Company has elected to apply the practical expedient that permits a lessee not to separate non-lease components and instead account for any lease and associated non-lease components as a single arrangement.

## II. Lessor

Power Purchase Agreements (PPAs) and other long-term contracts may contain, or may be considered, leases where the fulfillment of the arrangement is dependent on the use of a specific asset (e.g., a generating unit) and the arrangement conveys to the customer the right to control the use of that asset.

If the Company determines that the contractual provisions of a contract contain, or are, a lease and result in the customer assuming the principal risks and rewards of ownership of the asset, the arrangement is a finance lease. Assets subject to finance leases are not reflected as PP&E and the net investment in the lease, represented by the present value of the amounts due from the lessee, is recorded in the Consolidated Statements of Financial Position as a financial asset, classified as a finance lease receivable. The payments considered to be part of the leasing arrangement are apportioned between a reduction in the lease receivable and finance lease income. The finance lease income element of the payments is recognized using a method that results in a constant rate of return on the net investment in each period and is reflected in finance lease income on the Consolidated Statements of Earnings.

Where the Company determines that the contractual provisions of a contract contain, or are, a lease and result in the Company retaining the principal risks and rewards of ownership of the asset, the arrangement is an operating lease. For operating leases, the asset is, or continues to be, capitalized as PP&E and depreciated over its useful life.

## M. Non-Controlling Interests

Non-controlling interests arise from business combinations in which the Company acquires less than a 100 per cent interest. Non-controlling interests are initially measured at either fair value or at the non-controlling interest's proportionate share of the acquiree's identifiable net assets. The Company determines which measurement is used on a transaction-by-transaction basis. Non-controlling interests also arise from other contractual arrangements between the Company and other parties, whereby the other party has

acquired an equity interest in a subsidiary and the Company retains control.

Subsequent to acquisition, the carrying amount of non-controlling interests is increased or decreased by the non-controlling interest's share of subsequent changes in equity and payments to the non-controlling interest. Total comprehensive income (loss) is attributed to the non-controlling interests even if this results in the non-controlling interests having a negative balance.

When the proportion of the equity held by non-controlling interests changes, the carrying amounts of the controlling and non-controlling interests are adjusted to reflect the changes in their relative interests in the subsidiary. Any difference between the amount by which the non-controlling interests are adjusted and the fair value of the consideration paid or received, is recognized directly in equity and attributed to shareholders.

## N. Joint Arrangements

A joint arrangement is a contractual arrangement that establishes the terms by which two or more parties agree to undertake and jointly control an economic activity. The Company's joint arrangements are generally classified as two types: joint operations and joint ventures.

A joint operation arises when the parties that have joint control have rights to the assets and obligations for the liabilities relating to the arrangement. Generally, each party takes a share of the output from the asset and each bears an agreed upon share of the costs incurred in respect of the joint operation. The Company reports its interests in joint operations in its Consolidated Financial Statements using the proportionate consolidation method by recognizing its share of the assets, liabilities, revenues and expenses in respect of its interest in the joint operation.

In a joint venture, the venturers do not have rights to individual assets or obligations of the venture. Rather, each venturer has rights to the net assets of the arrangement. The Company reports its interests in joint ventures using the equity method. Under the equity method, the investment is initially recognized at cost and the carrying amount is increased or decreased to recognize the Company's share of the joint venture's net earnings or loss after the date of acquisition. The impact of transactions between the Company and joint ventures is eliminated based on the Company's ownership interest. Distributions received from joint ventures reduce the carrying amount of the investment. Any excess of the cost of an acquisition less the fair value of the recognized identifiable assets, liabilities and contingent liabilities of an acquired joint venture is recognized as goodwill and is included in the carrying amount of the investment and is assessed for impairment as part of the investment.

Investments in joint ventures are evaluated for impairment at each reporting date by first assessing whether there is

objective evidence that the investment is impaired. If such objective evidence is present, an impairment charge is recognized if the investment's recoverable amount is less than its carrying amount. The investment's recoverable amount is determined as the higher of value in use and fair value less costs of disposal.

## O. Assets Held for Sale

Assets and disposal groups (assets and liabilities disposed of together) are classified as held for sale if their carrying amount will be recovered primarily through a sale as opposed to continued use by the Corporation. Assets and disposal groups classified as held for sale are measured at the lower of their carrying amount and fair value less costs of disposal. Any impairment is recognized in net earnings. Depreciation and equity accounting ceases when an asset or equity investment, respectively, is classified as held for sale. Assets and disposal groups classified as held for sale are reported as current assets and current liabilities in the Consolidated Statements of Financial Position.

## P. Business Combinations

Transactions in which the acquisition constitutes a business are accounted for using the acquisition method. Identifiable assets acquired and liabilities assumed, including contingent consideration, are measured at their acquisition date fair values. A business consists of inputs and processes applied to those inputs that have the ability to contribute to the creation of outputs. Goodwill is measured as the excess of the fair value of consideration transferred less the fair value of the net assets acquired. Acquisition-related costs to effect the business combination, with the exception of costs to issue debt or equity securities, are recognized in net earnings as incurred.

The optional fair value concentration test is applied on a transaction-by-transaction basis to permit a simplified assessment of whether an acquired set of activities and assets is not a business. Where substantially all of the fair value of the gross assets acquired is concentrated in a single identifiable asset or group of similar identifiable assets, the Company may elect to treat the acquisition as an asset acquisition and not as a business combination.

## Q. Significant Accounting Judgments and Key Sources of Estimation Uncertainty

The preparation of financial statements requires management to make judgments, estimates and assumptions that could affect the reported amounts of assets, liabilities, revenues, expenses and disclosures of contingent assets and liabilities during the period. These estimates are subject to uncertainty. Actual results could differ from those estimates due to factors such as fluctuations in interest rates, foreign exchange rates,

inflation and commodity prices and changes in economic conditions, legislation and regulations.

In the process of applying the Company's accounting policies, management has to make judgments and estimates about matters that are highly uncertain at the time the estimate is made and that could significantly affect the amounts recognized in the Consolidated Financial Statements. Different estimates with respect to key variables used in the calculations, or changes to estimates, could potentially have a material impact on the Company's financial position or performance. The key judgments and sources of estimation uncertainty are described below:

### I. Fair Value of Assets Acquired and Liabilities Assumed in Business Combination

The fair value of assets acquired and liabilities assumed, including contingent consideration, is estimated based on information available at the date of acquisition. While management uses best estimates and assumptions to accurately value assets acquired and liabilities assumed at the date of acquisition, as well as any contingent consideration, estimates are inherently uncertain and subject to refinement.

Accounting for business combinations requires significant judgment, estimates and assumptions at the acquisition date. In developing estimates of fair values at the acquisition date, management uses a variety of factors including market data, market prices, capacity, historical and future expected cash flows, growth rates and discount rates. Information regarding business combinations has been included in Note 4.

### II. Impairment of PP&E and Goodwill

Impairment exists when the carrying amount of an asset, CGU or group of CGUs to which goodwill relates exceeds its recoverable amount, which is the higher of its fair value less costs of disposal and its value in use. An assessment is made at each reporting date as to whether there is any indication that an impairment charge may exist or that a previously recognized impairment charge may no longer exist or may have decreased. In determining fair value less costs of disposal, information about third-party transactions for similar assets is used and if this information is not available, other valuation techniques, such as discounted cash flows, are used. Value in use is computed using the present value of management's best estimates of future cash flows based on the current use and present condition of the asset.

In estimating either fair value less costs of disposal or value in use using discounted cash flow methods, estimates and assumptions must be made about sales prices, cost of sales, production, fuel consumed, capital expenditures, retirement costs and other related cash inflows and outflows over the life of the facilities. In developing these assumptions, management uses estimates of contracted

and future market prices based on expected market supply and demand in the region in which the plant operates, anticipated production levels, planned and unplanned outages, changes to regulations and transmission capacity or constraints for the remaining life of the facilities.

Discount rates are determined by employing a weighted average cost of capital methodology that is based on capital structure, cost of equity and cost of debt assumptions based on comparable companies with similar risk characteristics and market data as the asset, CGU or group of CGUs subject to the test. These estimates and assumptions are susceptible to change from period to period and actual results can and often do, differ from the estimates and can have either a positive or negative impact on the estimate of the impairment charge and may be material.

The impairment outcome can also be impacted by the determination of CGUs or groups of CGUs for asset and goodwill impairment testing. A CGU is the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets and goodwill is allocated to each CGU or group of CGUs that is expected to benefit from the synergies of the acquisition from which the goodwill arose. The allocation of goodwill is reassessed upon changes in the composition of segments, CGUs or groups of CGUs. To determine CGUs, significant judgment is required to determine what constitutes independent cash flows between power plants that are connected to the same system. The Company evaluates the market design, transmission constraints and the contractual profile of each facility, as well as the Company's own commodity price risk management plans and practices, in order to inform this determination.

With regard to the allocation or reallocation of goodwill, significant judgment is required to evaluate synergies and their impacts. The Company evaluates synergies with regard to opportunities from combined talent and technology, functional organization and future growth potential and considers its own performance measurement processes to make this determination. Information regarding significant judgments and estimates in respect of impairment during 2024 to 2025 is disclosed in Notes 7, 19 and 22.

### III. Leases

To determine whether the Company's contracts contain, or are, leases, management must use judgment in assessing whether the contract provides the customer with the right to substantially all of the economic benefits from the use of the asset during the lease term and whether the customer obtains the right to direct the use of the asset during the lease term. For those agreements considered to contain, or be, leases, further judgment is required to determine the lease term by assessing whether termination or extension options are reasonably certain to be exercised. Judgment is

also applied in identifying in-substance fixed payments (included) and variable payments that are based on usage or performance factors (excluded) and in identifying lease and non-lease components (services that the supplier performs) of contracts and in allocating contract payments to lease and non-lease components.

For leases where the Company is a lessor, judgment is required to determine if substantially all of the significant risks and rewards of ownership are transferred to the customer or remain with the Company to appropriately account for the agreement as either a finance or operating lease. These judgments can be significant and impact how the Company classifies amounts related to the arrangement as either PP&E or as a finance lease receivable on the Consolidated Statements of Financial Position and therefore the amount of certain items of revenue and expense is dependent upon such classifications. In 2025 and 2024, finance lease receivables were recognized, when it was determined that the significant risks and rewards of ownership of the facilities were transferred to the customer. Information regarding finance leases is disclosed in Note 17.

### IV. Income Taxes

Preparation of the Consolidated Financial Statements involves determining an estimate of, or provision for, income taxes in each of the jurisdictions in which the Company operates. The process also involves making an estimate of income taxes currently payable and income taxes expected to be payable or recoverable in future periods, referred to as deferred income taxes. Deferred income taxes result from the effects of temporary differences due to items that are treated differently for tax and accounting purposes. The tax effects of these differences are reflected in the Consolidated Statements of Financial Position as deferred income tax assets and liabilities. An assessment must also be made to determine the likelihood that the Company's future taxable income will be sufficient to permit the recovery of deferred income tax assets. To the extent that such recovery is not probable, deferred income tax assets must be reduced. Management uses the Company's long-range forecasts as a basis for evaluation of recovery of deferred income tax assets. Management must exercise judgment in its assessment of continually changing tax interpretations, regulations and legislation to ensure deferred income tax assets and liabilities are complete and fairly presented. Differing assessments and applications than the Company's estimates could materially impact the amounts recognized for deferred income tax assets and liabilities. Information regarding the impacts of the Company's tax policies is disclosed in Note 11.

### V. Financial Instruments and Derivatives

The Company's financial instruments and derivatives are accounted for at fair value, with the initial and subsequent changes in fair value affecting earnings in the period the change occurs. The fair values of financial instruments and derivatives are classified within three levels, with Level III

fair values determined using inputs for the asset or liability that are not readily observable. Transfers between levels of the fair value hierarchy are deemed to have occurred at the end of the reporting period in which the event or change in circumstances that caused the transfer occurred. These fair value levels are outlined and discussed in more detail in Note 14. Some of the Company's fair values are included in Level III because they are not traded on an active exchange or have terms that extend beyond the time period for which exchange-based quotes are available and require the use of internal valuation techniques or models to determine fair value.

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

When the Company enters into contracts to buy or sell non-financial items, such as certain commodities, and the contracts can be settled net in cash, the Company must use judgment to evaluate whether such contracts were entered into and continue to be held for the purposes of the receipt or delivery of the commodity in accordance with the Company's expected purchase, sale or usage requirements (i.e., normal purchase and sale). If this assertion cannot be supported, initially at contract inception and on an ongoing basis, the contracts must be accounted for as derivatives and measured at fair value, with changes in fair value recognized in net earnings. In supporting the normal purchase and sale assertion, the Company considers the nature of the contracts, the forecasted demand and supply requirements to which the contracts relate and its past practice of net settling other similar contracts, which may taint the normal purchase and sale assertion. The Company also enters into PPAs and contracts for differences and judgment is applied to determine if the contract meets the "own use" exemption or if derivative treatment is required.

## VI. Provisions for Decommissioning and Restoration Activities

TransAlta recognizes provisions for decommissioning and restoration obligations as outlined in Note 2(K). Initial decommissioning provisions and subsequent changes thereto are determined using the Company's best estimate of the required cash expenditures, adjusted to reflect the risks and uncertainties inherent in the timing and amount of settlement. The estimated cash expenditures are present valued using a current, risk-adjusted, market-based, pre-tax

discount rate. A change in estimated cash flows, market interest rates or timing could have a material impact on the carrying amount of the provision. Information regarding significant judgments and estimates made during 2024 to 2025 regarding decommissioning and restoration provisions is disclosed in Notes 7, 19 and 24.

## VII. Useful Life of PP&E

Each significant component of an item of PP&E is depreciated over its estimated useful life. Estimated useful lives are determined based on current facts and past experience and take into consideration the anticipated physical life of the asset, existing long-term sales agreements and contracts, current and forecasted demand, the potential for technological obsolescence and regulations. The useful lives of PP&E are reviewed at least annually to ensure they continue to be appropriate. Information on changes in useful lives of facilities is disclosed in Note 19.

## VIII. Employee Future Benefits

The Company provides pension and other post-employment benefits, such as health and dental benefits, to employees. The cost of providing these benefits is dependent upon many factors, including actual plan experience and estimates and assumptions about future experience.

The liability for pension and post-employment benefits and associated costs included in annual compensation expenses are impacted by estimates related to:

- Employee demographics, including age, compensation levels, employment periods, the level of contributions made to the plans and earnings on plan assets;
- The effects of changes to the provisions of the plans; and
- Changes in key actuarial assumptions, including rates of compensation and health-care cost increases and discount rates.

Due to the complexity of the valuation of pension and post-employment benefits, a change in the estimate of any one of these factors could have a material effect on the carrying amount of the liability for pension and other post-employment benefits or the related expense. These assumptions are reviewed annually to ensure they continue to be appropriate. Disclosures on employee future benefits are disclosed in Note 32.

## IX. Other Provisions

Where necessary, the Company recognizes provisions arising from ongoing business activities, such as interpretation and application of contract terms, ongoing litigation and force majeure claims. These provisions and subsequent changes thereto, are determined using the Company's best estimate of the outcome of the underlying event and can also be impacted by determinations made by third parties, in compliance with contractual requirements. The actual amount of the provisions that may be required could differ materially from the amount recognized. More

information is disclosed in Note 24 with respect to other provisions.

## X. Revenue from Contracts with Customers

Where contracts contain multiple promises for goods or services, management exercises judgment in determining whether goods or services constitute distinct goods or services or a series of distinct goods that are substantially the same and that have the same pattern of transfer to the customer. The determination of a performance obligation affects whether the transaction price is recognized at a point in time or over time. Management considers both the mechanics of the contract and the economic and operating environment of the contract to determine whether the goods or services in a contract are distinct.

In determining the transaction price and estimates of variable consideration, management considers the past history of customer usage in estimating the goods and services to be provided to the customer. The Company also considers the historical production levels and operating conditions for its variable generating assets. The Company's contracts generally outline a specific amount to be invoiced to a customer associated with each performance obligation in the contract. Where contracts do not specify amounts for individual performance obligations, the Company estimates the amount of the transaction price to allocate to individual performance obligations based on their stand-alone selling price, which is primarily estimated based on the amounts that would be charged to customers under similar market conditions.

The satisfaction of performance obligations requires management to make judgments as to when control of the underlying good or service transfers to the customer. Determining when a performance obligation is satisfied affects the timing of revenue recognition. Management considers both customer acceptance of the good or service and the impact of laws and regulations such as certification requirements, to determine when this transfer occurs.

When contracts are modified, management must exercise judgment to determine, depending upon the facts and circumstances of the changes to the contract, whether the modification is accounted for as a new contract or as part of the existing contract. If it is required to be accounted for as part of the existing contract the transaction price can be affected and adjustments to previously recognized revenue can occur, or the impacts can be reflected prospectively from the modification date.

Management also applies judgment in determining whether the invoice practical expedient permits recognition of revenue at the invoiced amount if that invoiced amount corresponds directly with the entity's performance to date.

## XI. Classification of Joint Arrangements

Upon entering into, or acquiring an interest in, a joint arrangement, the Company must classify it as either a joint operation or joint venture, and this classification affects the accounting for the joint arrangement. In making this classification, the Company exercises judgment in evaluating the terms and conditions of the arrangement to determine whether the parties have rights to the assets and obligations or rights to the net assets. Factors such as the legal structure, contractual arrangements and other facts and circumstances, such as where the purpose of the arrangement is primarily for the provision of the output to the parties and when the parties are substantially the only source of cash flows for the arrangement, must be evaluated to understand the rights of the parties to the arrangement.

## XII. Significant Influence

Upon entering into an investment, the Company must classify it as either an investment in an associate or an investment under IFRS 9. In making this classification, the Company exercises judgment in evaluating whether it has significant influence over the investee. Significant influence is the power to participate in the financial and operating policy decisions of the investee, but is not control or joint control over those policies. If the Company holds 20 per cent or more of the voting rights in the investee, it is presumed that the entity has significant influence, unless it can be clearly demonstrated that this is not the case. Other factors such as representation on the Board, participation in policy-making processes, material transactions between the Company and investee, interchange of managerial personnel or providing essential technical information are considered when assessing if the Company has significant influence over an investee.

## XIII. Change in Estimates

During the year ended Dec. 31, 2025, there were changes in estimates relating to asset impairment (reversals) charges (Note 7), decommissioning and other provisions (Note 24) and defined benefit obligation (Note 27). During the year ended Dec. 31, 2024, there were changes in estimates relating to asset impairment (reversals) charges (Note 7), useful lives (Note 19), decommissioning and other provisions (Note 24) and defined benefit obligation (Note 27).

## 3. Accounting Changes

### A. Current Accounting Changes

There were no changes in accounting policies during the year ended December 31, 2025.

### B. Future Accounting Changes

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

#### Amendments to IFRS 9 and IFRS 7 – Nature-Dependent Electricity Contracts

On Dec. 18, 2024, the IASB issued amendments to IFRS 9 Financial Instruments and IFRS 7 Financial Instruments: Disclosure to improve reporting of the financial effects of nature-dependent electricity (e.g., wind and solar) contracts, which are often structured as power purchase agreements. Under these contracts, the amount of electricity generated can vary based on uncontrollable factors such as weather conditions. The amendments clarify the application of own-use requirements, permit hedge accounting if these contracts are used as hedging instruments and add new disclosure requirements about the effect of these contracts on a company's financial performance and cash flows. The amendments are effective for annual reporting periods beginning on or after Jan. 1, 2026.

Starting in the first quarter of 2026, the Company has designated certain pre-existing VPPAs within the Wind and Solar segment as held for hedging and has applied hedge accounting. As a result, the effective portion of changes in the fair value of these hedging derivatives, arising on or after Jan. 1, 2026, will be recognised in OCI while any ineffective portion will be recognized in net (loss) earnings. Retrospective designation is not permitted.

#### Amendments to IFRS 7 and IFRS 9 – Classification and Measurement of Financial Instruments

On May 29, 2024, the IASB issued Amendments to the Classification and Measurement of Financial Instruments effective Jan. 1, 2026 impacting IFRS 7 and 9. The IASB amended the requirements related to settling financial liabilities using an electronic payment system and assessing contractual cash flow characteristics of financial assets, including those with ESG-linked features. This amendment is not expected to have a material impact on the consolidated financial statements.

#### IFRS 18 – Presentation and Disclosure in Financial Statements

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

### C. Comparative Figures

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

## 4. Business Acquisitions

### Acquisition of Heartland Generation

On Dec. 4, 2024, the Company acquired all issued and outstanding common shares of Heartland Generation Ltd. and Alberta Power (2000) Ltd. (collectively, Heartland) from Energy Capital Partners (ECP) (the Acquisition). The Acquisition, which includes Heartland's entire business operations in Alberta and British Columbia, was completed for an aggregate purchase price of \$493 million, including the assumption of long-term debt of \$232 million. The Acquisition was funded through a combination of cash on hand and borrowings under the Company's credit facilities.

On Aug. 1, 2025 and Oct. 2, 2025, the Company completed the sale of its 100 per cent interest in the 48 MW Poplar Hill facility and 50 per cent interest in the 97 MW Rainbow Lake facility, respectively, pursuant to the requirements of the federal Competition Bureau, which required the Company to enter into a consent agreement with the Commissioner of Competition to divest Heartland's Poplar Hill and Rainbow Lake assets (the Required Divestitures). Refer to Notes 7 and 18 for details.

The purchase price allocation was completed before the end of the measurement period and reflects management's best estimate of the fair value of the acquired assets and liabilities. There were no subsequent adjustments made to the original purchase price allocation and goodwill on acquisition was attributable to the Gas segment. The \$51 million of goodwill recognized on the transaction is a result of deferred tax liabilities recognized on the transaction, which are recorded at the Company's effective tax rate without discounting, and from value attributed to the assembled workforce. None of the goodwill is expected to be deductible for tax purposes.

The following table summarizes the purchase price allocation representing the consideration paid and the estimated fair value of the net assets acquired as at Dec. 4, 2024.

	<b>Dec. 4, 2024</b>
Current and Non-Current Assets	
Cash and cash equivalents	276
Trade and other receivables	126
Risk management assets	16
Prepaid expenses and other assets	106
Assets held for sale (Note 18)	80
Long-term portion of finance lease receivables (Note 17)	107
Property, plant and equipment and Right-of-use assets (Note 19 and 20)	413
Intangible assets (Note 21)	57
Deferred income tax assets (Note 11)	41
Current and Non-Current Liabilities	
Accounts payable and accrued liabilities	193
Risk management liabilities	4
Credit facilities, long-term debt and lease liabilities (Note 25)	232
Decommissioning and other provisions (Note 24)	156
Deferred income tax liabilities (Note 11)	108
Contract liabilities	6
Total identifiable net assets at fair value	523
Goodwill arising on acquisition (Note 22)	51
<b>Net assets acquired</b>	<b>574</b>
Cash consideration	493
Contingent consideration payable	81
<b>Total purchase consideration transferred</b>	<b>574</b>

## 5. Revenue

### A. Disaggregation of Revenue

The majority of the Company's revenues are derived from the sale of power, capacity and environmental and tax attributes, and from asset optimization activities, which the Company disaggregates into the following groups to determine how economic factors affect the recognition of revenue.

<b>Year ended Dec. 31, 2025</b>	<b>Hydro</b>	<b>Wind and Solar</b>	<b>Gas</b>	<b>Energy Transition</b>	<b>Energy Marketing</b>	<b>Corporate<sup>(1)</sup></b>	<b>Total</b>
Revenues from contracts with customers							
Power and other	42	264	671	13	9	—	999
Environmental and tax attributes <sup>(2)</sup>	70	106	11	—	—	(68)	119
Revenue from contracts with customers	112	370	682	13	9	(68)	1,118
Revenue from derivatives and other trading activities <sup>(3)</sup>	34	(251)	172	248	121	7	331
Revenue from merchant sales	203	71	393	233	—	—	900
Other <sup>(4)</sup>	19	16	20	1	—	—	56
<b>Total revenue</b>	<b>368</b>	<b>206</b>	<b>1,267</b>	<b>495</b>	<b>130</b>	<b>(61)</b>	<b>2,405</b>
Revenues from contracts with customers							
Timing of revenue recognition							
At a point in time	70	42	11	13	—	(68)	68
Over time	42	328	671	—	9	—	1,050
<b>Total revenue from contracts with customers</b>	<b>112</b>	<b>370</b>	<b>682</b>	<b>13</b>	<b>9</b>	<b>(68)</b>	<b>1,118</b>

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

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

(3) Represents realized and unrealized gains or losses from hedging and derivative positions. Volatility and pricing in commodity markets can vary significantly from period to period and impact movements in derivative positions.

(4) Other revenue includes production tax credits related to U.S. wind facilities subject to tax equity financing arrangements, total lease income from long-term contracts that meet the criteria of operating leases and other miscellaneous revenues.

## Notes to the Consolidated Financial Statements

<b>Year ended Dec. 31, 2024</b>	<b>Hydro</b>	<b>Wind and Solar</b>	<b>Gas</b>	<b>Energy Transition</b>	<b>Energy Marketing</b>	<b>Corporate<sup>(1)</sup></b>	<b>Total</b>
Revenues from contracts with customers							
Power and other	36	242	494	12	—	—	784
Environmental and tax attributes <sup>(2)</sup>	61	77	2	—	—	(34)	106
Revenue from contracts with customers	97	319	496	12	—	(34)	890
Revenue from derivatives and other trading activities <sup>(3)</sup>	16	(69)	282	311	168	—	708
Revenue from merchant sales	287	71	546	291	—	—	1,195
Other <sup>(4)</sup>	9	15	26	2	—	—	52
<b>Total revenue</b>	<b>409</b>	<b>336</b>	<b>1,350</b>	<b>616</b>	<b>168</b>	<b>(34)</b>	<b>2,845</b>
Revenues from contracts with customers							
Timing of revenue recognition							
At a point in time	61	28	—	12	—	(34)	67
Over time	36	291	496	—	—	—	823
<b>Total revenue from contracts with customers</b>	<b>97</b>	<b>319</b>	<b>496</b>	<b>12</b>	<b>—</b>	<b>(34)</b>	<b>890</b>

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

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

(3) Represents realized and unrealized gains or losses from hedging and derivative positions. Volatility and pricing in commodity markets can vary significantly from period to period and impact movements in derivative positions.

(4) Other revenue includes production tax credits related to U.S. wind facilities subject to tax equity financing arrangements, total lease income from long-term contracts that meet the criteria of operating leases and other miscellaneous revenues.

## B. Performance Obligations

The performance obligations in the Company's contracts with its customers include the provision of electricity and steam capacity; the delivery of electricity, thermal energy and environmental attributes; the provision of operation and maintenance services and water management services; and the supply of byproducts from coal generation.

The aggregate amount of transaction prices allocated to remaining performance obligations (contract revenues that have not yet been recognized) as at Dec. 31, 2025, is approximately \$2,524 million, with approximately \$566 million expected to be recognized during the period 2026-2028; \$493 million during the period of 2029-2031; \$745 million during the period of 2032-2036; and \$720 million for 2037 and thereafter.

These amounts exclude future revenues that are related to constrained variable consideration. In many of the Company's contracts, elements of the transaction price are considered constrained, such as for variable revenues dependent upon future production volumes that are driven

by customer or market demand or market prices that are subject to factors outside the Company's influence. As a result, the amounts of future revenues disclosed above represent only a portion of future revenues that are expected to be realized by the Company from its contractual portfolio.

Contract liabilities of \$43 million as at Dec. 31, 2025 represent the consideration received from customers in advance of satisfying the related performance obligation by supplying the related goods or services. Revenue is recognized when the performance obligation is satisfied.

## C. Significant Customer

For the year ended Dec. 31, 2025, sales to the Alberta Electric System Operator represented 20 per cent of the Company's total revenue (2024 – 24 per cent). There were no other companies that accounted for more than 10 per cent of the Company's total revenue.

## 6. Expenses by Nature

### Fuel, Purchased Power and Operations, Maintenance and Administration (OM&A)

Fuel and purchased power and OM&A expenses classified by nature are as follows:

Year ended Dec. 31	2025		2024	
	Fuel and purchased power	OM&A	Fuel and purchased power	OM&A
Gas fuel costs	464	—	369	—
Coal fuel costs	134	—	123	—
Royalty, land lease, other direct costs	28	—	28	—
Purchased power	309	—	419	—
Salaries and benefits	—	317	—	296
Other operating expenses <sup>(1)</sup>	—	394	—	359
<b>Total</b>	<b>935</b>	<b>711</b>	939	655

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

## 7. Asset Impairment (Reversals) Charges

As part of the Company's monitoring controls, long-range forecasts are prepared for each CGU. The long-range forecast estimates are used to assess the significance of potential indicators of impairment and provide criteria to evaluate adverse changes in operations. The Company also considers the relationship between its market capitalization and its book value, among other factors, when reviewing for indicators of impairment. When indicators of impairment are present, the Company estimates a recoverable amount (the higher of value in use or fair value less costs of disposal) for

the affected CGUs using discounted cash flow projections. The valuations are subject to measurement uncertainty from assumptions and inputs to the discount rates, power price forecasts, useful lives of the assets (extending to the last planned asset retirement in 2072) and long-range forecasts, which include changes to production, fuel costs, operating costs and capital expenditures. The Company recognized the following asset impairment (reversals) charges:

Year ended Dec. 31	Segment	2025	2024
Impairment charge, net of impairment reversals	Wind and Solar	20	—
Impairment charge related to the Required Divestitures	Gas	37	—
Impairment reversal related to generation equipment (Note 18)	Energy Transition	(30)	—
Changes in decommissioning and restoration provisions <sup>(1)</sup> (Note 24)	Energy Transition	(44)	24
Project development costs <sup>(2)</sup>	Corporate	4	22
<b>Asset impairment (reversals) charges</b>		<b>(13)</b>	46

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

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

### Wind and Solar facilities Impairment Charge

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

During the year ended Dec. 31, 2025, the Company recognized impairment reversals for one wind facility and one solar facility, which had been previously impaired. The impairment reversals of \$17 million were primarily due to changes in power price assumptions that favourably impacted estimated future cash flows. The recoverable amount of \$233 million for these two facilities was

estimated based on fair value less costs of disposal using a discounted cash flow model and was categorized as a Level III fair value measurement. The discount rates used in the fair value measurements were in the range of 6.10 to 7.24 per cent.

### Required Divestitures

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

During the year ended Dec. 31, 2025, the Company recognized an impairment loss in the amount of \$37 million related to the Required Divestitures, with a corresponding fair value change in contingent consideration payable recognized in the statement of (loss) earnings for the period.

## 8. Net Other Operating Income

Net other operating income includes the following:

Year ended Dec. 31	2025	2024
Alberta Off-Coal Agreements	(43)	(40)
Other	(4)	(19)
<b>Net other operating income</b>	<b>(47)</b>	<b>(59)</b>

### Alberta Off-Coal Agreements (OCA)

Under the terms of the OCA, the Company receives annual cash payments of approximately \$43 million from the Government of Alberta if it ceases coal-fired emissions on or before Dec. 31, 2030. The Company achieved the cessation of all coal-fired emissions by Dec. 31, 2021.

The Company receives OCA payments on or before July 31, which are recognized in net other operating income evenly throughout the year. Under the terms of the OCA, the affected facilities may continue to generate electricity using non-coal-fired methods after Dec. 31, 2030.

### Other

The Company receives liquidated damages related to the requirements to be met by the contractors on turbine availability guarantees at our Wind sites.

During the year ended Dec. 31, 2024, the Company also received reimbursement of \$9 million from the Balancing Pool for TransAlta's decommissioning costs for Sundance A.

## 9. Investments

### Investments

The change in investments is as follows:

	Skookumchuck	Other investments <sup>(1)(2)</sup>	Total
Balance, Dec. 31, 2023	104	34	138
Investment	—	8	8
Equity income (loss)	10	(5)	5
Distributions received	(5)	—	(5)
Changes in foreign exchange rates	9	2	11
Net change in fair value recognized in earnings	—	2	2
Balance, Dec. 31, 2024	118	41	159
Investment	—	7	7
Equity income (loss)	8	(2)	6
Distributions received	(5)	—	(5)
Changes in foreign exchange rates	(6)	(2)	(8)
Net change in fair value recognized in loss	—	(1)	(1)
Acquisition of control of previously equity-accounted investment	—	(14)	(14)
<b>Balance, Dec. 31, 2025</b>	<b>115</b>	<b>29</b>	<b>144</b>

(1) Other investments include EMG International, LLC accounted for using the equity method and Energy Impact Partners accounted for at FVTPL.

(2) On Feb. 28, 2025, the Company acquired the remaining 40 per cent interest in Tent Mountain, previously accounted for using the equity method. Tent Mountain became a wholly-owned subsidiary as at Dec. 31, 2025.

## Skookumchuck Wind Project

TransAlta holds a 49 per cent membership interest in SP Skookumchuck Investment, LLC, which is accounted for using the equity method. Skookumchuck is a 136.8 MW wind project located in Lewis and Thurston counties near Centralia in Washington state. The project has a 20-year PPA with Puget Sound Energy that ends in 2040.

## Other Investments

### EMG International, LLC

TransAlta holds a 30 per cent interest in EMG, a wastewater treatment processing company, which is accounted for using the equity method. Earnings are derived from the design and construction of wastewater treatment facilities.

Summarized financial information on the results of operations relating to the Company's pro-rata interests in Skookumchuck is as follows:

<b>Year ended Dec. 31</b>	<b>2025</b>	<b>2024</b>
<b>Results of operations</b>		
Revenues and other operating income	21	21
Expenses	(13)	(12)
<b>Proportionate share of net earnings</b>	<b>8</b>	<b>9</b>

Summarized financial information on the assets and liabilities relating to the Company's pro-rata interests in Skookumchuck is as follows:

<b>As at Dec. 31</b>	<b>2025</b>	<b>2024</b>
Current assets	14	15
Non-current assets	314	342
Current liabilities	(18)	(20)
Non-current liabilities	(74)	(97)
<b>Net assets</b>	<b>236</b>	<b>240</b>

## Energy Impact Partners

On May 6, 2022, the Company entered into a commitment to invest US\$25 million over the next four years in Energy Impact Partners Deep Decarbonization Frontier Fund 1 (the Frontier Fund). The investment in the Frontier Fund provides the Company with a portfolio approach to investing in emerging technologies and the opportunity to identify, pilot, commercialize and bring to market emerging technologies that will facilitate the transition to net-zero emissions. The investment is accounted for at FVTPL.

## 10. Interest Expense

The components of interest expense are as follows:

Year ended Dec. 31	2025	2024
Interest on debt	203	197
Interest on exchangeable debentures (Note 26)	25	31
Interest on exchangeable preferred shares (Note 26)	28	28
Capitalized interest (Note 19)	—	(16)
Net gain on redemption of senior notes <sup>(1)</sup> (Note 25)	(5)	—
Interest on lease liabilities	10	10
Credit facility fees, bank charges and other interest	29	21
Tax shield on tax equity financing (Note 25)	—	3
Accretion of provisions (Note 24)	57	50
<b>Interest expense</b>	<b>347</b>	<b>324</b>

(1) Consists of a \$31 million gain on interest rate derivatives designated as cash flow hedges, partially offset by a \$21 million prepayment premium and \$5 million accelerated amortization of deferred financing costs. Refer to Note 25 for details.

## 11. Income Taxes

### Consolidated Statements of Earnings

#### I. Rate Reconciliation

Year ended Dec. 31	2025	2024
<b>(Loss) earnings before income taxes</b>	<b>(141)</b>	319
Net loss (earnings) attributable to non-controlling interests not subject to tax	20	(10)
<b>Adjusted (Loss) Earnings before income taxes</b>	<b>(121)</b>	309
Statutory Canadian federal and provincial income tax rate (%)	23.3%	23.3%
Expected income tax (recovery) expense	(28)	72
Increase (decrease) in income taxes resulting from:		
Differences in effective foreign tax rates	13	(6)
Non-deductible expense <sup>(1)</sup>	7	46
Non-taxable income	(14)	(10)
Taxable capital (gain) loss	(17)	1
Deferred income tax recovery related to temporary difference on investment in subsidiaries	—	(5)
Writedown (reversal of writedown) of unrecognized deferred income tax assets	54	(13)
Statutory and other rate differences	(1)	(1)
Adjustments in respect of deferred income tax of previous years	(5)	(11)
Other	8	7
<b>Income tax expense</b>	<b>17</b>	80
<b>Effective tax rate (per cent)</b>	<b>(14)</b>	26

(1) This amount is related to current tax adjustments in the U.S. to mitigate cash tax relating to the Base Erosion and Anti-Abuse Tax, Canadian non-deductible penalties, and a tax adjustment relating to dividends on preferred shares, treated as interest for accounting purposes.

## Global Minimum Tax Act

In response to the OECD Pillar Two Model Rules, Canada enacted the *Global Minimum Tax Act* (GMTA) on June 19, 2024. The GMTA provides for a minimum tax of 15 per cent to be applied on a jurisdictional basis. The adoption of the GMTA did not have a material impact on the Company's tax

expense. IAS 12 contains a mandatory temporary exception to recognizing and disclosing information about deferred taxes related to Pillar Two. The Company has applied this exception.

## II. Components of Income Tax Expense

The components of income tax expense are as follows:

Year ended Dec. 31	2025	2024
Current income tax expense	49	143
Deferred income tax recovery related to the origination and reversal of temporary differences	(86)	(45)
Deferred income tax recovery related to temporary difference on investment in subsidiaries	—	(5)
Writedown (reversal of writedown) of unrecognized deferred income tax assets <sup>(1)</sup>	54	(13)
<b>Income tax expense</b>	<b>17</b>	<b>80</b>
Current income tax expense	49	143
Deferred income tax recovery	(32)	(63)
<b>Income tax expense</b>	<b>17</b>	<b>80</b>

(1) During the year ended Dec. 31, 2025, the Company wrote-down deferred tax assets of \$54 million (2024 – \$13 million recovery). The deferred income tax assets mainly relate to the tax benefits associated with tax losses related to the Company's directly owned U.S. operations and other deductible differences. The Company has not recognized \$199 million (2024 – \$152 million) of deferred tax assets on the basis that it is not probable that sufficient future taxable income will be available to utilize them.

## Consolidated Statements of Changes in Equity

The aggregate current and deferred income tax related to items charged or credited to equity are as follows:

Year ended Dec. 31	2025	2024
Income tax (recovery) expense related to:		
Net impact related to cash flow hedges	(14)	53
Net impact related to hedges of foreign operations	1	(4)
Net impact related to net actuarial gains	1	3
<b>Income tax (recovery) expense reported in equity</b>	<b>(12)</b>	<b>52</b>

## Consolidated Statements of Financial Position

Significant components of the Company's deferred income tax assets (liabilities) are as follows:

As at Dec. 31	2025	2024
Loss carryforwards <sup>(1)</sup>	182	149
Future decommissioning and restoration costs	181	184
Property, plant and equipment	(655)	(646)
Investment in subsidiaries	(70)	(60)
Risk management assets and liabilities, net	105	40
Employee future benefits and compensation plans	53	52
Foreign exchange differences	12	16
Other taxable temporary differences	9	(1)
<b>Net deferred income tax liabilities, before unrecognized deferred income tax assets</b>	<b>(183)</b>	<b>(266)</b>
Unrecognized deferred income tax assets	(199)	(152)
<b>Net deferred income tax liabilities</b>	<b>(382)</b>	<b>(418)</b>

(1) U.S. net operating losses generated before 2018 and Canadian non-capital losses have expiry dates ranging from 2031 to 2045. U.S. net operating losses generated from 2018 onward have no expiration.

The net deferred income tax liability is presented in the Consolidated Statements of Financial Position as follows:

As at Dec. 31	2025	2024
Deferred income tax assets <sup>(1)</sup>	41	52
Deferred income tax liabilities	(423)	(470)
<b>Net deferred income tax liabilities</b>	<b>(382)</b>	<b>(418)</b>

(1) The deferred income tax assets presented on the Consolidated Statements of Financial Position are recoverable based on estimated future earnings and tax planning strategies. The assumptions used in the estimate of future earnings are based on the Company's long-range forecasts.

## Contingencies

As of Dec. 31, 2025, the Company had recognized a net liability of nil (2024 – nil) related to uncertain tax positions.

## 12. Non-Controlling Interests

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

Subsidiary/Operation	Non-controlling interest owner	Non-controlling interest as at Dec. 31, 2025	Non-controlling interest as at Dec. 31, 2024
TransAlta Cogeneration LP	Canadian Power Holdings Inc.	49.99%	49.99%
Kent Hills Wind LP	Natural Forces Technologies Inc.	17%	17%

TransAlta Cogeneration, LP (TA Cogen) operates a portfolio of cogeneration facilities in Canada and owns 50 per cent of Sheerness Units 1 and 2, a natural-gas-fired generating facility.

Kent Hills Wind LP, a subsidiary, owns and operates the 167 MW Kent Hills (1, 2 and 3) wind facilities located in New Brunswick.

Summarized financial information relating to subsidiaries with significant non-controlling interests is as follows:

## TA Cogen

<b>Year ended Dec. 31</b>	<b>2025</b>	<b>2024</b>
Revenues	94	167
Net (loss) earnings and total comprehensive (loss) income	(52)	9
Amounts attributable to the non-controlling interest:		
Net (loss) earnings	(20)	9
Total comprehensive (loss) income	(20)	9
Distributions paid to Canadian Power Holdings Inc.	11	40
<b>As at Dec. 31</b>	<b>2025</b>	<b>2024</b>
Current assets	49	47
Long-term assets	56	130
Current liabilities	(35)	(48)
Long-term liabilities	(36)	(32)
Total equity	(34)	(97)
Equity attributable to Canadian Power Holdings Inc.	(15)	(46)
Non-controlling interest share (per cent)	49.99	49.99

## Kent Hills Wind LP

<b>Year ended Dec. 31</b>	<b>2025</b>	<b>2024</b>
Revenues	36	34
Net earnings and total comprehensive income	3	7
Amounts attributable to the non-controlling interest:		
Net earnings and total comprehensive income	—	1
<b>As at Dec. 31</b>	<b>2025</b>	<b>2024</b>
Current assets	12	33
Long-term assets	466	463
Current liabilities	(18)	(26)
Long-term liabilities	(160)	(174)
Total equity	(300)	(296)
Equity attributable to non-controlling interests	(51)	(51)
Non-controlling interest share (per cent)	17	17

## 13. Trade and Other Receivables and Accounts Payable, Accrued Liabilities and Other Current Liabilities

<b>As at Dec. 31</b>	<b>2025</b>	<b>2024</b>
Trade accounts receivable	507	570
Collateral provided (Note 15)	92	124
Current portion of finance lease receivables (Note 17)	30	30
Current portion of loan receivable (Note 23)	1	1
Income taxes receivable	69	42
<b>Trade and other receivables</b>	<b>699</b>	<b>767</b>
<b>As at Dec. 31</b>	<b>2025</b>	<b>2024</b>
Accounts payable and accrued liabilities	548	694
Income taxes payable	11	23
Interest payable	23	17
Current portion of contract liabilities (Note 5)	17	12
Liabilities held for sale (Note 18)	6	1
Collateral held (Note 15)	3	9
Contingent consideration payable	5	—
<b>Accounts payable, accrued liabilities and other current liabilities</b>	<b>613</b>	<b>756</b>

## 14. Financial Instruments

### A. Financial Assets and Liabilities – Classification and Measurement

Financial assets and financial liabilities are measured on an ongoing basis at cost, fair value or amortized cost.

Carrying value as at Dec. 31, 2025	Derivatives used for hedging	Derivatives held for trading (FVTPL)	Amortized cost	Other financial assets and liabilities (FVTPL)	Other financial assets (FVOCI)	Total
<b>Financial assets</b>						
Cash and cash equivalents <sup>(1)</sup>	—	—	205	—	—	205
Restricted cash	—	—	78	—	—	78
Trade and other receivables <sup>(2)</sup>	—	—	630	—	—	630
Long-term financial assets	—	—	—	140	—	140
Long-term portion of finance lease receivables	—	—	277	—	—	277
Long-term portion of loan receivable <sup>(3)</sup>	—	—	30	—	—	30
Other investments <sup>(4)</sup>	—	—	—	25	1	26
Risk management assets						
Current	—	162	—	—	—	162
Long-term	—	32	—	—	—	32
<b>Financial liabilities</b>						
Accounts payable, accrued liabilities and other current liabilities <sup>(5)</sup>	—	—	574	—	—	574
Dividends payable	—	—	52	—	—	52
Risk management liabilities						
Current	—	156	—	—	—	156
Long-term	—	519	—	—	—	519
Credit facilities, long-term debt and lease liabilities <sup>(6)</sup>	—	—	3,593	—	—	3,593
Exchangeable securities	—	—	750	—	—	750

(1) Includes cash equivalents of nil.

(2) Excludes income taxes receivable.

(3) Included in other assets. Refer to Note 23.

(4) Excludes EMG International, LLC and Tent Mountain. Refer to Note 9.

(5) Excludes the current portion of contract liabilities, current income taxes payable, liabilities held for sale and contingent consideration payable.

(6) Includes current portion.

Carrying value as at Dec. 31, 2024	Derivatives used for hedging	Derivatives held for trading (FVTPL)	Amortized cost	Other financial assets (FVTPL)	Other financial assets (FVTOCI)	Total
Financial assets						
Cash and cash equivalents <sup>(1)</sup>	—	—	337	—	—	337
Restricted cash	—	—	69	—	—	69
Trade and other receivables <sup>(2)</sup>	—	—	725	—	—	725
Long-term portion of finance lease receivables	—	—	305	—	—	305
Long-term portion of loan receivable <sup>(3)</sup>	—	—	24	—	—	24
Other investments <sup>(4)</sup>	—	—	—	22	1	23
Risk management assets						
Current	45	273	—	—	—	318
Long-term	—	93	—	—	—	93
Financial liabilities						
Bank overdraft	—	—	1	—	—	1
Accounts payable, accrued liabilities and other current liabilities <sup>(5)</sup>	—	—	720	—	—	720
Contingent consideration	—	—	—	81	—	81
Dividends payable	—	—	49	—	—	49
Risk management liabilities						
Current	—	277	—	—	—	277
Long-term	—	305	—	—	—	305
Credit facilities, long-term debt and lease liabilities <sup>(6)</sup>	—	—	3,808	—	—	3,808
Exchangeable securities	—	—	750	—	—	750

(1) Includes cash equivalents of nil.

(2) Excludes income taxes receivable.

(3) Included in other assets. Refer to Note 23.

(4) Excludes EMG International, LLC and Tent Mountain. Refer to Note 9.

(5) Excludes the current portion of contract liabilities, current income taxes payable and liabilities held for sale.

(6) Includes current portion.

## B. Fair Value of Financial Instruments

The fair value of a financial instrument is the price that would be received when selling the asset or paid to transfer the associated liability in an orderly transaction between market participants at the measurement date. Fair values can be determined by observing quoted prices for the instrument in active markets to which the Company has access. In the absence of an active market, the Company determines fair values based on valuation models or by

reference to other similar products in active markets. Fair values determined using valuation models require the use of assumptions. In determining those assumptions, the Company looks primarily to external readily observable market inputs. However, if these are not available, the Company uses inputs that are not based on observable market data.

## I. Level I, II and III Fair Value Measurements

The Level I, II and III classifications in the fair value hierarchy used by the Company are defined below. The fair value measurement of a financial instrument is included in only one of the three levels, the determination of which is based on the lowest level input that is significant to the derivation of the fair value. The Level III classification is the lowest level classification in the fair value hierarchy.

### a. Level I

Level I fair values are determined using inputs that are quoted prices (unadjusted) in active markets for identical assets or liabilities that the Company has the ability to access at the measurement date. In determining Level I fair values, the Company uses quoted prices for identically traded commodities obtained from active exchanges such as the New York Mercantile Exchange.

### b. Level II

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

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

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

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

### c. Level III

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

The Company may enter into commodity transactions for which market-observable data is not available. In these cases, Level III fair values are determined using valuation techniques such as mark-to-forecast and mark-to-model. For mark-to-model valuations, derivative pricing models, regression-based models and scenario analysis simulation models may be employed.

The model inputs may be based on historical data such as unit availability, transmission congestion, demand profiles for individual non-standard deals and structured products and/or volatility and correlations between products derived from historical price relationships. For assets and liabilities that are recognized at fair value on a recurring basis, the Company determines whether transfers have occurred between levels in the hierarchy by re-assessing categorization (based on the lowest level input that is significant to the fair value measurement as a whole) at the end of each reporting period.

Other than the long-term financial assets discussed in Section IV below, there were no changes in the Company's valuation processes, valuation techniques and types of inputs used in the fair value measurements during the period.

The Company also has various commodity contracts with terms that extend beyond a liquid trading period. As forward market prices are not available for the full period of these contracts, the value of these contracts is derived by reference to a forecast that is based on a combination of external and internal fundamental modelling, including discounting. As a result, these contracts are classified in Level III.

## II. Commodity Risk Management Assets and Liabilities

Commodity risk management assets and liabilities include risk management assets and liabilities that are used in the energy marketing and generation segments in relation to trading activities and certain contracting activities. To the extent applicable, changes in net risk management assets and liabilities for non-hedge positions are reflected within earnings of these businesses.

Commodity risk management assets and liabilities classified by fair value levels as at Dec. 31, 2025, are as follows: Level I – \$10 million net liability (Dec. 31, 2024 – \$12 million net liability), Level II – \$33 million net liability (Dec. 31, 2024 – \$2 million net liability) and Level III – \$447 million net liability (Dec. 31, 2024 – \$153 million net liability).

Significant changes in commodity net risk management assets (liabilities) during the year ended Dec. 31, 2025, are primarily attributable to volatility in market prices across multiple markets on both existing contracts and new contracts and contract settlements.

The following table summarizes the key factors impacting the fair value of the Level III commodity risk management assets and liabilities by classification during the years ended Dec. 31, 2025 and 2024, respectively:

	Year ended Dec. 31, 2025			Year ended Dec. 31, 2024		
	Hedge	Non-hedge	Total	Hedge	Non-hedge	Total
Opening balance	—	(153)	(153)	—	(147)	(147)
Changes attributable to:						
New contracts added	—	—	—	—	3	3
Market price changes on existing contracts	—	(261)	(261)	—	(49)	(49)
Market price changes on new contracts	—	17	17	—	27	27
Contracts settled	—	(48)	(48)	—	23	23
Change in foreign exchange rates	—	(2)	(2)	—	(10)	(10)
<b>Net risk management liabilities at end of year</b>	<b>—</b>	<b>(447)</b>	<b>(447)</b>	<b>—</b>	<b>(153)</b>	<b>(153)</b>
<b>Additional Level III information:</b>						
Total losses included in (loss) earnings before income taxes	—	(246)	(246)	—	(32)	(32)
Unrealized losses included in (loss) earnings before income taxes relating to net assets (liabilities) held at year end	—	(294)	(294)	—	(9)	(9)

The Company's Commodity Exposure Management Policy governs both the commodity transactions undertaken in its proprietary trading business and those undertaken to manage commodity price exposures in its generation business. This policy defines and specifies the controls and management responsibilities associated with commodity trading activities, as well as the nature and frequency of required reporting of such activities.

The Company's risk management department determines methodologies and procedures regarding commodity risk management Level III fair value measurements. Level III fair values are primarily calculated within the Company's energy trading risk management processes. These calculations are based on underlying contractual data as well as observable and non-observable inputs. Development of non-observable inputs requires the use of judgment. To ensure reasonability, the Level III fair value measurements are reviewed and validated by the risk management and finance departments. Review occurs formally on a quarterly basis or more frequently if daily review and monitoring procedures identify unexpected changes to fair value or changes to key parameters.

As at Dec. 31, 2025, the total Level III risk management asset balance was \$65 million (Dec. 31, 2024 – \$110 million) and the Level III risk management liability balance was \$512 million (Dec. 31, 2024 – \$263 million). The net risk management liabilities increased mainly due to volatility in market prices across multiple markets on existing contracts and contract settlements.

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

These include the effects on fair value of discounting, liquidity and credit value adjustments. Sensitivity ranges for the base fair values are determined using reasonably possible alternative assumptions for the key unobservable inputs, which may include forward commodity prices, volatility in commodity prices and correlations, delivery volumes, escalation rates and cost of supply.

Included in the Level III classification are several long-term wind energy sales agreements, including contracts for differences and virtual power purchase agreements, that are recognized as derivatives for accounting purposes. The sensitivity reflects the potential impacts on the fair value of these long-term wind agreements. These long-term wind energy sales are backed by physical assets to effectively reduce our market risk.

Notes to the Consolidated Financial Statements

As at

Dec. 31, 2025

Description	Valuation technique	Unobservable input	Reasonably possible change	Potential change in fair value <sup>(1)</sup>
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 <sup>(2)</sup> 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 5% increase	
Long-term wind energy sale — Central U.S.	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of US\$7 or increase of US\$3	+47 -52
		Wind discounts	2% decrease or 6% increase	

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

(2) Renewable energy credits

As at

Dec. 31, 2024

Description	Valuation technique	Unobservable input	Reasonably possible change	Potential change in fair value <sup>(1)</sup>
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 <sup>(2)</sup> prices (per unit)	Price decrease of US\$12 or increase of US\$8	+42 -30
		Wind discounts	0% decrease or 6% increase	
Long-term wind energy sale — Canada	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of \$57 or increase of \$10	+53 -17
		Wind discounts	15% decrease or 5% increase	
Long-term wind energy sale — Central U.S.	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of US\$4 or increase of US\$3	+84 -77
		Wind discounts	2% decrease or 2% increase	

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

(2) Renewable energy credits

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

The Company is party to a long-term contract for differences (CFD) for the offtake of 100 per cent of the generation from its 90 MW Big Level wind facility. The CFD, together with the sale of electricity generated into the PJM Interconnection at the prevailing real-time energy market price, achieve the fixed contract price per MWh on proxy generation. Under the CFD, if the market price is lower than the fixed contract price, the customer pays the Company the difference and if the market price is higher than the fixed contract price, the Company refunds the difference to the customer. The customer is also entitled to the physical delivery of environmental attributes. The contract expires in December 2034. The contract is accounted for as a derivative with changes in fair value presented in revenue.

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

### b. Long-Term Wind Energy Sale – Canada

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

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

The key unobservable inputs used in the valuations of the contracts are the non-liquid forward prices for power and monthly wind discounts.

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

The Company is party to two long-term VPPAs for the offtake of 100 per cent of the generation from its 302 MW White Rock East and White Rock West wind power facilities. The VPPAs, together with the sale of electricity generated into the U.S. Southwest Power Pool (SPP) market at the

relevant price nodes, achieves the fixed contract prices per MWh. Under the VPPAs, if the SPP pricing is lower than the fixed contract price the customer pays the Company the difference, and if the SPP pricing is higher than the fixed contract price, the Company refunds the difference to the customer. The customer is also entitled to the physical delivery of environmental attributes. The VPPAs commenced on commercial operation of the facilities in the first quarter of 2024.

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

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

The key unobservable inputs used in the valuation of the contracts are the non-liquid forward prices for power and wind discounts.

## III. Other Risk Management Assets and Liabilities

Other risk management assets and liabilities primarily include risk management assets and liabilities that are used to manage exposures on non-energy marketing transactions such as interest rates, the net investment in foreign operations and other foreign currency risks. Hedge accounting is not always applied.

Other risk management assets and liabilities with a total net asset fair value of \$9 million as at Dec. 31, 2025 (Dec. 31, 2024 – \$4 million net liability) are classified as Level II fair value measurements. The changes in other net risk management assets and liabilities during the year ended Dec. 31, 2025, are attributable to contracts settled during 2025.

## IV. Other Financial Assets and Liabilities

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

	Fair value <sup>(2)</sup>				Total carrying value <sup>(2)</sup>
	Level I	Level II	Level III	Total	
Long-term debt — Dec. 31, 2025	—	3,255	—	3,255	3,447
Exchangeable securities — Dec. 31, 2025	—	752	—	752	750
Long-term financial asset — Dec. 31, 2025	—	—	140	140	140
Loan receivable — Dec. 31, 2025 <sup>(1)</sup>	—	31	—	31	31
Long-term debt — Dec. 31, 2024	—	3,447	—	3,447	3,657
Exchangeable securities — Dec. 31, 2024	—	739	—	739	750
Loan receivable — Dec. 31, 2024 <sup>(1)</sup>	—	25	—	25	25

(1) Included within Other assets.

(2) Includes current and non-current portions.

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

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

### Long-term Financial Asset

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

The outstanding principal under the term loan and the revolving facility bear interest of seven per cent per annum with interest paid quarterly. The terms of the term loan and the revolving facility are six and five years, respectively, unless accelerated. The term loan is convertible to equity at any time at the option of the Company and any remaining unused term loan commitments at the time of conversion would be terminated. The term loan and revolving facility are subject to customary financing conditions and covenants that may restrict Nova's ability to access funds. This investment in Nova provides the Company with the exclusive right to purchase Nova's late-stage development projects in the western U.S. The Nova facilities are classified as financial assets measured at FVTPL. The fair value of the Nova facilities are categorized as Level III in the fair value hierarchy as their fair value is determined using a binomial model with multiple inputs such as volatility and equity value for which observable market data is not available. A reasonably possible change in inputs would not result in a material impact in the fair value of the Nova facilities.

The following table summarizes the key factors impacting the fair value of the Level III long-term financial assets by classification during the year ended Dec. 31, 2025:

<b>Year ended Dec. 31, 2025</b>	<b>Total</b>
Opening balance	—
Changes attributable to:	
Draws	170
Repayments	(19)
Fair value changes	(5)
Change in foreign exchange rates	(6)
Transfers out of Level III	—
<b>Balance, Dec. 31, 2025</b>	<b>140</b>
<b>Additional Level III information:</b>	
Losses recognized in other comprehensive loss	—
Total losses included in loss before income taxes	(11)
Unrealized losses included in earnings before income taxes	(11)

### C. Inception Gains and Losses

The majority of derivatives traded by the Company are based on adjusted quoted prices on an active exchange or extend beyond the time period for which exchange-based quotes are available. The fair values of these derivatives are determined using inputs that are not readily observable. Refer to section B of this Note 14 above for a description of the fair value Level III valuation techniques used. In some instances, a difference may arise between the fair value of a financial instrument at initial recognition (the transaction price) and the amount calculated through a valuation model. This unrealized gain or loss at inception is recognized in net earnings (loss) only if the fair value of the instrument is

evidenced by a quoted market price in an active market, observable current market transactions that are substantially the same, or a valuation technique that uses observable market inputs. Where these criteria are not met, the difference is deferred on the Consolidated Statements of Financial Position in risk management assets or liabilities and is recognized in net earnings (loss) over the term of the related contract. Effective Jan. 1, 2025, the difference is calibrated at initial recognition and no inception gains or losses are recognized.

The difference between the transaction price and the fair value determined using a valuation model, yet to be recognized in net (loss) earnings and a reconciliation of changes is as follows:

<b>As at Dec. 31</b>	<b>2025</b>	<b>2024</b>
Unamortized net gain at beginning of year	11	3
New inception gains <sup>(1)</sup>	—	31
Change in foreign exchange rates	1	(3)
Amortization recorded in net (loss) earnings during the year	(33)	(20)
<b>Unamortized net (loss) gain at end of year</b>	<b>(21)</b>	<b>11</b>

(1) During 2024, the Company entered into long-term fixed price power sale contracts with certain of its U.S. customers that resulted in new inception losses due to the difference between the fixed PPA price and future estimated market prices. There are other key factors, such as project economics and incentives, that influence the long-term power price for renewable projects outside of the power price curve, which is not liquid for the majority of the duration of the PPA.

## 15. Risk Management

### A. Risk Management Strategy

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

The Company has two primary streams of risk management activities: (i) financial exposure management; and (ii) commodity exposure management. Within these activities, risks identified for management include commodity risk, interest rate risk, liquidity risk, equity price risk and foreign currency risk.

The Company seeks to minimize the effects of commodity risk, interest rate risk and foreign currency risk by using derivative financial instruments to hedge risk exposures. Of these derivatives, the Company may apply hedge accounting to those hedging commodity price risk, interest rate risk and foreign currency risk.

The use of financial derivatives is governed by the Company's policies approved by the Board, which provide written principles on commodity risk, interest rate risk, liquidity risk, equity price risk and foreign currency risk, as well as the use of financial derivatives and non-derivative financial instruments.

Liquidity risk, credit risk and equity price risk are managed through means other than derivatives or hedge accounting.

The Company enters into various derivative transactions as well as other contracting activities that do not qualify for hedge accounting or where a choice was made not to apply hedge accounting. As a result, the related assets and liabilities are classified as derivatives at fair value through profit and loss. The net realized and unrealized gains or

losses from changes in the fair value of these derivatives are reported in net earnings in the period the change occurs.

The Company designates certain derivatives as hedging instruments to hedge commodity price risk, foreign currency exchange risk in cash flow hedges and hedges of net investments in foreign operations. Hedges of foreign exchange risk on firm commitments are accounted for as cash flow hedges.

At the inception of the hedge relationship, the Company documents the relationship between the hedging instrument and the hedged item, along with its risk management objectives and its strategy for undertaking various hedge transactions. At the inception of the hedge and on an ongoing basis, the Company also documents whether the hedging instrument is effective in offsetting changes in fair values or cash flows of the hedged item attributable to the hedged risk, which is when the hedging relationships meet all of the following hedge effectiveness requirements:

- There is an economic relationship between the hedged item and the hedging instrument;
- The effect of credit risk does not dominate the value changes that result from that economic relationship; and
- The hedge ratio of the hedging relationship is the same as that resulting from the quantity of the hedged item that the Company actually hedges and the quantity of the hedging instrument that the entity actually uses to hedge that quantity of hedged item.

If a hedging relationship ceases to meet the hedge effectiveness requirement relating to the hedge ratio, but the risk management objective for that designated hedging relationship remains the same, the Company adjusts the hedge ratio of the hedging relationship so that it continues to meet the qualifying criteria.

## B. Net Risk Management Assets and Liabilities

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

### As at Dec. 31, 2025

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

### As at Dec. 31, 2024

	Cash flow hedges	Not designated as a hedge	Total
Commodity risk management			
Current	45	8	53
Long-term	—	(220)	(220)
Net commodity risk management assets (liabilities)	45	(212)	(167)
Other			
Current	—	(12)	(12)
Long-term	—	8	8
Net other risk management liabilities	—	(4)	(4)
Total net risk management assets (liabilities)	45	(216)	(171)

## Netting Arrangements

Information about the Company's financial assets and liabilities that are subject to enforceable master netting arrangements or similar agreements is as follows:

<b>As at Dec. 31, 2025</b>	<b>Gross amounts of recognized financial assets (liabilities)</b>	<b>Amounts set off</b>	<b>Net amounts included on the statement of financial position</b>	<b>Master netting arrangements<sup>(1)</sup></b>	<b>Net amount</b>
Current risk management assets	487	(334)	153	(5)	148
Long-term risk management assets	59	(28)	31	(3)	28
Current risk management liabilities	(470)	334	(136)	5	(131)
Long-term risk management liabilities	(45)	28	(17)	3	(14)
Trade and other receivables <sup>(2)</sup>	1,474	(1,338)	136	(18)	118
Accounts payable and accrued liabilities <sup>(2)</sup>	(1,451)	1,338	(113)	18	(95)

<b>As at Dec. 31, 2024</b>	<b>Gross amounts of recognized financial assets (liabilities)</b>	<b>Amounts set off</b>	<b>Net amounts included on the statement of financial position</b>	<b>Master netting arrangements<sup>(1)</sup></b>	<b>Net amount</b>
Current risk management assets	686	(421)	265	(18)	247
Long-term risk management assets	153	(59)	94	(1)	93
Current risk management liabilities	(662)	421	(241)	18	(223)
Long-term risk management liabilities	(128)	59	(69)	1	(68)
Trade and other receivables <sup>(2)</sup>	1,519	(1,273)	246	(7)	239
Accounts payable and accrued liabilities <sup>(2)</sup>	(1,470)	1,273	(197)	7	(190)

(1) Amounts not set off in the Consolidated Statements of Financial Position.

(2) The trade and other receivables and accounts payable and accrued liabilities include amounts related to collateral provided and held. Refer to Note 15(E) below for further details.

## C. Nature and Extent of Risks Arising from Financial Instruments

### I. Market Risk

#### a. Commodity Price Risk Management

The Company has exposure to movements in certain commodity prices in both its electricity generation and proprietary trading businesses, including the market price of electricity and fuels used to produce electricity. Most of the Company's electricity generation and related fuel supply contracts are considered to be contracts for delivery or receipt of a non-financial item in accordance with the Company's expected own use requirements and are not considered to be financial instruments. As such, the discussion related to commodity price risk is limited to the Company's proprietary trading business, VPPAs and other long-term contracts that are derivatives and commodity derivatives used in hedging relationships associated with the Company's electricity generating activities.

To mitigate the risk of adverse commodity price changes, the Company uses three tools:

- A framework of risk controls;
- A predefined hedging plan, including fixed price financial power swaps and long-term physical power sale contracts to hedge commodity price for electricity generation; and
- A committee dedicated to overseeing the risk and compliance program in trading and ensuring the existence of appropriate controls, processes, systems and procedures to monitor adherence to the program.

The Company may, at times, execute hedges for its electricity price exposure in Alberta using fixed price financial swaps or other similar instruments. This hedging strategy falls under the Company's risk management strategy used to hedge commodity price risk.

Market risk exposures are measured using Value at Risk (VaR) supplemented by sensitivity analysis. There has been no change to the Company's exposure to market risks or the manner in which these risks are managed or measured. Position sizes and trade strategies were adjusted to remain within the Company's risk framework.

#### i. Commodity Price Risk Management – Proprietary Trading

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

In compliance with the Company's Commodity Exposure Management Policy, proprietary trading activities are subject to limits and controls, including VaR limits. The Board approves the limit for total VaR from proprietary trading activities. VaR is the most commonly used metric employed to track and manage the market risk associated with trading positions.

A VaR measure gives, for a specific confidence level, an estimated maximum pre-tax loss that could be incurred over a specified period of time. VaR is used to determine the potential change in value of the Company's proprietary trading portfolio, over a three-day period within a 95 per cent confidence level, resulting from normal market fluctuations. VaR is estimated using the historical variance/covariance approach. This measure has inherent limitations. VaR relies on historical data, assuming that past price movements will reflect future market risks. Consequently, it may only be meaningful under normal market conditions and does not account for extreme market events. In addition, the use of a three-day measurement period implies that positions can be unwound or hedged within three days, although this may not be possible if the market becomes illiquid.

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

#### ii. Commodity Price Risk – Generation

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

VaR at Dec. 31, 2025, associated with the Company's commodity derivative instruments used in generation hedging activities was nil (2024 – \$8 million). For positions and economic hedges that do not meet hedge accounting requirements or for short-term optimization transactions such as buybacks entered into to offset existing hedge positions, these transactions are marked to the market value with changes in market prices associated with these transactions affecting net earnings in the period in which the price change occurs. VaR at Dec. 31, 2025, associated with these transactions was \$9 million (2024 – \$13 million).

#### iv. Commodity Price Risk Management – Non-Hedges

The Company's outstanding commodity derivative instruments not designated as hedging instruments are as follows:

As at Dec. 31 Type (thousands)	2025		2024	
	Notional amount sold	Notional amount purchased	Notional amount sold	Notional amount purchased
Electricity (MWh)	46,274	4,244	47,593	8,416
Natural gas (GJ)	13,374	66,414	2,122	79,194
Transmission (MWh)	—	377	—	292
Emissions (MWh)	95	55	167	370
Emissions (tonnes)	3,150	650	1,850	150
Coal (tonnes)	—	—	—	1,728

#### b. Interest Rate Risk Management

Changes in interest rates can impact the Company's borrowing costs and cost of capital. Changes in the cost of capital could affect the feasibility of new growth initiatives. Interest rate risk also arises as the fair value of future cash flows from a financial instrument fluctuates due to changes in market interest rates.

The Company's syndicated credit facility, Heartland term facility and the Poplar Creek non-recourse bond are subject to floating interest rates, which represent 10 per cent of the Company's total long-term debt as at Dec. 31, 2025 (2024 – 23 per cent). Interest rate risk is managed with the use of derivatives.

As at Dec. 31, 2025, 86 per cent of the \$201 million outstanding under the Heartland term facility was hedged at an average rate of 4.4 per cent.

#### c. Currency Rate Risk

The Company has exposure to various currencies, such as the U.S. dollar and the Australian dollar, as a result of investments and operations in foreign jurisdictions, the net earnings from those operations and the acquisition of equipment and services from foreign suppliers.

The Company may enter into the following hedging strategies to mitigate currency rate risk, including:

For the market risk related to long-term power sale and long-term wind energy sales contracts, refer to the Level III measurements table and the related unobservable inputs and sensitivities in Note 14(B)(II).

#### iii. Commodity Price Risk Management – Hedges

At Dec. 31, 2025, the Company had no outstanding commodity derivative instruments designated as hedging instruments, as the long-term power sale contract for Centralia reached its maturity.

- Foreign exchange forward contracts to mitigate adverse changes in foreign exchange rates on project-related expenditures and distributions received in foreign currencies;
- Foreign exchange forward contracts and cross-currency swaps to manage foreign exchange exposure on foreign-denominated debt not designated as a net investment hedge; and
- Designating foreign currency debt as a hedge of the net investment in foreign operations to mitigate the risk due to fluctuating exchange rates related to certain foreign subsidiaries.

The Company's target is to hedge a minimum of 60 per cent of our forecasted foreign operating cash flows over a four-year period. The U.S. exposure is managed with a combination of interest expense on our U.S.-dollar-denominated debt and forward foreign exchange contracts and the Australian exposure is managed with a combination of interest expense on Australian-dollar-denominated debt and forward foreign exchange contracts.

#### i. Net Investment Hedges

When designating foreign currency debt as a hedge of the Company's net investment in foreign subsidiaries, the Company has determined that the hedge is effective if the foreign currency of the net investment is the same as the

currency of the hedge and therefore an economic relationship is present.

The Company's hedges of its net investment in foreign operations were comprised of U.S. dollar denominated long-term debt with a face value of US\$300 million (2024 – US\$300 million).

## ii. Non-Hedges

As at Dec. 31		2025		2024			
Notional amount sold	Notional amount purchased	Fair value (liability) asset	Maturity	Notional amount sold	Notional amount purchased	Fair value (liability) asset	Maturity
Foreign exchange forward contracts – foreign-denominated receipts/expenditures							
AUD12	CAD7	(2)	2026-2029	AUD14	CAD10	(1)	2025-2028
USD277	CAD377	—	2026-2029	USD419	CAD585	(13)	2025-2028
USD99	AUD152	4	2026	USD101	AUD153	(9)	2025
Foreign exchange forward contracts – foreign-denominated debt							
CAD195	USD140	(4)	2026	CAD192	USD140	8	2025

## iii. Impacts of Currency Rate Risk

The possible effect on net earnings and OCI, due to changes in foreign exchange rates associated with financial instruments denominated in currencies other than the Company's functional currency, is outlined below. The sensitivity analysis has been prepared using

management's assessment that an average three cents (2024 – three cents) increase or decrease in these currencies relative to the Canadian dollar is a reasonable potential change over the next quarter.

Year ended Dec. 31	2025		2024	
Currency	Net earnings decrease <sup>(1)</sup>	OCI gain <sup>(1)(2)</sup>	Net earnings decrease <sup>(1)</sup>	OCI gain <sup>(1)(2)</sup>
USD	(14)	—	(17)	—
AUD	(3)	—	(3)	—
<b>Total</b>	<b>(17)</b>	<b>—</b>	<b>(20)</b>	<b>—</b>

(1) These calculations assume an increase in the value of these currencies relative to the Canadian dollar. A decrease would have the opposite effect.

(2) The foreign exchange impact related to financial instruments designated as hedging instruments in net investment hedges has been excluded.

## II. Credit Risk

Credit risk is the risk that customers or counterparties will cause a financial loss for the Company by failing to discharge their obligations and the risk to the Company associated with changes in creditworthiness of entities with which commercial exposures exist. The Company actively manages its exposure to credit risk by assessing the ability of counterparties to fulfil their obligations under the related contracts before entering into such contracts. The Company makes detailed assessments of the credit quality of all counterparties and, where appropriate, obtains corporate guarantees, cash collateral, third-party credit insurance and/

or letters of credit to support the ultimate collection of these receivables. For commodity trading and origination, the Company sets strict credit limits for each counterparty and monitors exposures on a daily basis. TransAlta uses standard agreements that allow for the netting of exposures and often include margining provisions. If credit limits are exceeded, TransAlta will request collateral from the counterparty or halt trading activities with the counterparty.

The Company uses external credit ratings, as well as internal ratings in circumstances where external ratings are not available, to establish credit limits for customers and counterparties.

The following table outlines the Company's maximum exposure to credit risk without taking into account collateral held, including the distribution of credit ratings, as at Dec. 31, 2025:

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

(1) Letters of credit and cash and cash equivalents are the primary types of collateral held as security related to these amounts.

(2) Included within long-term financial assets with counterparties that have no external credit rating. Refer to Note 14 for further details.

(3) Includes \$31 million loans receivable included within other assets with counterparties that have no external credit rating.

An impairment analysis is performed at each reporting date using a provision matrix to measure expected credit losses. The provision rates are based on segment historical rates of default of trade receivables and they incorporate forward-looking credit ratings and forecasted default rates. In addition to calculating expected credit losses, TransAlta monitors key forward-looking information to determine if historical bad debt percentages, forward-looking S&P credit ratings and forecasted default rates continue to be representative of future expected credit losses. The calculation reflects the probability-weighted outcome, the time value of money and reasonable and supportable information that is available at the reporting date about past events, current conditions and forecasts of future economic conditions.

TransAlta evaluates the concentration of risk with respect to trade receivables as low, as its customers are located in

### III. Liquidity Risk

Liquidity risk relates to the Company's ability to access capital to be used for capital projects, debt refinancing, proprietary trading activities, commodity hedging and general corporate purposes. As at Dec. 31, 2025, TransAlta maintains an investment grade rating from one credit rating agency and one notch below investment grade ratings from two credit rating agencies. Between 2026 and 2028, the Company has \$664 million of scheduled non-recourse debt and tax equity principal payments.

Collateral is posted based on negotiated terms with counterparties, which can include the Company's senior unsecured credit rating as determined by certain major credit rating agencies. Some of the Company's derivative instruments contain financial assurance provisions that

several jurisdictions and industries. The Company did not have material expected credit losses as at Dec. 31, 2025.

The Company's maximum exposure to credit risk at Dec. 31, 2025, without taking into account collateral held or right of set-off, is represented by the current carrying amounts of receivables and risk management assets as per the Consolidated Statements of Financial Position. Letters of credit and cash are the primary types of collateral held as security related to these amounts. The maximum credit exposure to any one customer for commodity trading operations and hedging, including the fair value of open trading, net of any collateral held, at Dec. 31, 2025, was \$51 million (Dec. 31, 2024 – \$77 million).

require collateral to be posted only if a material adverse credit-related event occurs.

TransAlta manages liquidity risk by monitoring liquidity on trading positions; preparing and revising longer-term financing plans to reflect changes in business plans and the market availability of capital; reporting liquidity risk exposure for proprietary trading activities on a regular basis to the Risk Management Committee, senior management and the Audit, Finance and Risk Committee (on behalf of the Board); and maintaining sufficient undrawn committed credit lines to support potential liquidity requirements. The Company does not use derivatives to manage liquidity risk.

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

	2026	2027	2028	2029	2030	2031 and thereafter	Total
Accounts payable, accrued liabilities and other current liabilities	613	—	—	—	—	—	613
Long-term debt <sup>(1)</sup>							
Credit facilities <sup>(1)</sup>	—	—	—	98	—	—	98
Debentures	—	—	—	110	141	450	701
Senior notes	—	—	—	—	—	959	959
Non-recourse – Hydro	—	—	—	—	—	39	39
Non-recourse – Wind & Solar	67	70	74	43	45	202	501
Non-recourse and Recourse – Gas	61	65	66	74	95	549	910
Non-recourse Heartland term facility	24	176	—	—	—	—	200
Tax equity financing	18	20	23	18	—	—	79
Exchangeable securities <sup>(2)</sup>	—	—	—	—	—	750	750
Commodity risk management (assets) liabilities <sup>(3)</sup>	(4)	16	23	28	26	401	490
Other risk management (assets) liabilities	(2)	1	1	—	—	(9)	(9)
Lease liabilities	5	5	5	5	5	121	146
Interest on long-term debt and lease liabilities <sup>(4)</sup>	179	184	167	156	138	705	1,529
Interest on exchangeable securities <sup>(2)(4)</sup>	53	53	53	52	53	457	721
Dividends payable	52	—	—	—	—	—	52
<b>Total</b>	<b>1,066</b>	<b>590</b>	<b>412</b>	<b>584</b>	<b>503</b>	<b>4,624</b>	<b>7,779</b>

(1) Excludes impact of hedge accounting and derivatives.

(2) The exchangeable debentures are due May 1, 2039 and the exchangeable preferred shares are perpetual. However, a cash payment could occur after Dec. 31, 2028, at the Company's option, if the exchangeable securities are not exchanged by Brookfield Renewable Partners or its affiliates (collectively Brookfield). At Brookfield's option, the exchangeable securities are currently exchangeable into an equity ownership interest in TransAlta's Alberta Hydro Assets after Dec. 31, 2024. (Note 26).

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

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

## IV. Equity Price Risk

### Total Return Swaps

The Company has certain compensation, deferred and restricted share unit programs, the values of which depend on the common share price of the Company. The Company has fixed a portion of the settlement cost of these programs

by entering into a total return swap for which hedge accounting has not been applied. The total return swap is cash settled every quarter based upon the difference between the fixed price and the market price of the Company's common shares at the end of each quarter.

## D. Effects of Hedge Accounting on Financial Position and Performance

### I. Effect of Hedges

The impact of the hedging instruments on the statement of financial position is as follows:

As at Dec. 31, 2025	Notional amount	Carrying amount	Line item in the statement of financial position	Change in fair value used for measuring ineffectiveness
<b>Commodity price risk</b>				
Cash flow hedges				
Physical power sales <sup>(1)</sup>	—	—	Risk management liabilities	(2)
<b>Foreign currency risk</b>				
Net investment hedges				
Foreign-denominated debt	USD300	CAD411	Credit facilities, long-term debt and lease liabilities	—

(1) In thousands of MWh.

As at Dec. 31, 2024	Notional amount	Carrying amount	Line item in the statement of financial position	Change in fair value used for measuring ineffectiveness
<b>Commodity price risk</b>				
Cash flow hedges				
Physical power sales <sup>(1)</sup>	2,628	45	Risk management assets	114
<b>Foreign currency risk</b>				
Net investment hedges				
Foreign-denominated debt	USD300	CAD431	Credit facilities, long-term debt and lease liabilities	—

(1) In thousands of MWh.

The impact of the hedged items on the statement of financial position is as follows:

As at Dec. 31	2025		2024	
	Change in fair value used for measuring	Cash flow hedge reserve <sup>(1)</sup>	Change in fair value used for measuring	Cash flow hedge reserve <sup>(1)</sup>
<b>Commodity price and interest rate risk</b>				
Cash flow hedges <sup>(2)</sup>	(2)	(4)	114	65
<b>Foreign currency risk</b>				
Net investment hedges				
Net investment in foreign subsidiaries	—	(35)	—	(34)

(1) Included in AOCI, net of tax.

(2) During the fourth quarter of 2025, the Company's commodity price hedges for Centralia, including a long-term physical power sale contract, reached its maturity, and hedge accounting was therefore discontinued.

The hedging gain or loss recognized in OCI before tax is equal to the change in fair value used for measuring effectiveness for the net investment hedge. Ineffectiveness

of nil in after-tax losses was reclassified from OCI to net earnings during the year ended Dec. 31, 2025. (2024 – after-tax losses reclassified of \$4 million)

The impact of designated cash flow hedges on OCI and net earnings is:

Year ended Dec. 31, 2025					
Derivatives in cash flow hedging relationships	Effective portion		Ineffective portion		
	Pre-tax gain recognized in OCI	Location of gain reclassified from OCI	Pre-tax (gain) loss reclassified from OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss recognized in earnings
Commodity contracts	(1)	Revenue	(43)	Revenue	—
Forward starting interest rate swaps	—	Interest expense	(39)	Interest expense	—
<b>OCI impact</b>	<b>(1)</b>	<b>OCI impact</b>	<b>(82)</b>	<b>Net earnings impact</b>	<b>—</b>

Over the next 12 months, the Company estimates that no after-tax losses will be reclassified from AOCI to net earnings.

These estimates assume constant interest rates and exchange rates over time; however, the actual amounts that will be reclassified may vary based on changes in these factors.

Year ended Dec. 31, 2024					
Derivatives in cash flow hedging relationships	Effective portion		Ineffective portion		
	Pre-tax gain (loss) recognized in OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss reclassified from OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss recognized in earnings
Commodity contracts	270	Revenue	(15)	Revenue	—
Forward starting interest rate swaps	—	Interest expense	(8)	Interest expense	—
OCI impact	270	OCI impact	(23)	Net earnings impact	—

## II. Effect of Non-Hedges

For the year ended Dec. 31, 2025, the Company recognized a net unrealized loss of \$289 million (2024 – loss of \$7 million) related to commodity derivatives.

For the year ended Dec. 31, 2025, a loss of \$25 million (2024 – loss of \$63 million) related to foreign exchange

and other derivatives was recognized, which consists of net unrealized losses of \$18 million (2024 – loss of \$36 million) and net realized losses of \$7 million (2024 – loss of \$27 million), respectively.

## E. Collateral

### I. Financial Assets Provided as Collateral

At Dec. 31, 2025, the Company provided \$92 million (Dec. 31, 2024 – \$124 million) in cash and cash equivalents as collateral to regulated clearing agents as security for commodity trading activities. These funds are held in segregated accounts by the clearing agents. Collateral provided is included within trade and other receivables in the Consolidated Statements of Financial Position. At Dec.

31, 2025, the Company provided \$20 million (Dec. 31, 2024 – \$21 million) in surety bonds as security for commodity trading activities.

### II. Financial Assets Held as Collateral

At Dec. 31, 2025, the Company held \$3 million (Dec. 31, 2024 – \$9 million) in cash collateral associated with counterparty obligations. Under the terms of the contracts, the Company may be obligated to pay interest on the

outstanding balances and to return the principal when the counterparties have met their contractual obligations or when the amount of the obligation declines as a result of changes in market value. Interest payable to the counterparties on the collateral received is calculated in accordance with each contract. Collateral held is related to physical and financial derivative transactions in a net asset position and is included in accounts payable and accrued liabilities in the Consolidated Statements of Financial Position.

### III. Contingent Features in Derivative Instruments

Collateral is posted in the normal course of business based on the Company's senior unsecured credit rating as

determined by certain major credit rating agencies. Certain of the Company's derivative instruments contain financial assurance provisions that require collateral to be posted only if a material adverse credit-related event occurs.

At Dec. 31, 2025, the Company had posted collateral of \$338 million (Dec. 31, 2024 – \$424 million) in the form of letters of credit on physical and financial derivative transactions in a net liability position. Certain derivative agreements contain credit-risk-contingent features, which if triggered could result in the Company having to post an additional \$92 million (Dec. 31, 2024 – \$128 million) of collateral to its counterparties.

## 16. Inventory

The components of inventory are as follows:

As at Dec. 31	2025	2024
Parts, materials and supplies	87	85
Coal	6	27
Emission credits	14	18
Natural gas	4	4
<b>Total</b>	<b>111</b>	<b>134</b>

No inventory was pledged as security for liabilities.

As at Dec. 31, 2025, the Company holds 383,192 emission credits in inventory that were purchased externally with a recorded book value of \$14 million (Dec. 31, 2024 – 460,585 emission credits with a recorded book value of \$18 million). The Company also has 1,860,384 (Dec. 31, 2024 – 2,109,491) of internally generated eligible emission credits from the Company's Wind and Solar and Hydro segments that have no recorded book value.

Emission credits can be sold externally or can be used to offset future emission obligations from our gas facilities located in Alberta, where the compliance price of carbon is expected to increase, resulting in a reduced cash cost for carbon compliance in the year of settlement.

During the year ended Dec. 31, 2025 the Company utilized 1,498,447 emission credits (Dec. 31, 2024 – 978,894 emission credits) with a carrying value of \$17 million (Dec. 31, 2024 – \$22 million) to settle a portion of the 2024 carbon compliance obligation (Dec. 31, 2024 – 2023 carbon compliance obligation). During the year ended Dec. 31, 2025, \$103 million was recognized as a reduction in the Company's carbon compliance costs (Dec. 31, 2024 – \$42 million). The compliance price of carbon for the 2024 obligation settled was \$80 per tonne rising to \$95 per tonne in 2025.

## 17. Finance Lease Receivables

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

	2025		2024	
	Minimum lease receipts	Present value of minimum lease receipts	Minimum lease receipts	Present value of minimum lease receipts
<b>As at Dec. 31</b>				
Within one year	48	47	48	47
Second to fifth years inclusive	183	156	185	159
More than five years	206	104	247	129
	<b>437</b>	<b>307</b>	480	335
Less: unearned finance lease income	131	—	146	—
Add: unguaranteed residual value	1	—	1	—
<b>Total finance lease receivables</b>	<b>307</b>	<b>307</b>	335	335

Included in the Consolidated Statements of Financial Position as:

Current portion of finance lease receivables (Note 13)	30	30
Long-term portion of finance lease receivables	277	305
<b>Total finance lease receivables</b>	<b>307</b>	335

## 18. Assets and Liabilities Held for Sale

The change in assets held for sale is as follows:

	2025	2024
As at Jan. 1	80	—
Additions from acquisition of Heartland related to Required Divestitures (Note 4)	—	80
Transfers from property, plant and equipment (Notes 7 and 19)	30	—
Derecognition of Required Divestitures (Notes 7)	(80)	—
<b>Balance, Dec. 31</b>	<b>30</b>	80

The liabilities held for sale as at Dec. 31, 2025 totalling \$6 million are related to the Energy Transition equipment. The amount was transferred from the decommissioning and other provisions and was included within accounts payable, accrued liabilities and other current liabilities.

## 19. Property, Plant and Equipment

A reconciliation of the changes in the carrying amount of PP&E is as follows:

	Assets under construction	Land	Hydro	Wind and Solar	Gas generation	Energy Transition	Capital spares and other <sup>(1)</sup>	Total
<b>Cost</b>								
As at Dec. 31, 2023	1,234	90	884	3,593	4,423	3,914	306	14,444
Additions <sup>(2)</sup>	279	—	—	—	10	—	22	311
Acquisitions (Note 4)	11	—	—	—	401	—	—	412
Disposals	—	(2)	—	—	(1)	(3)	—	(6)
Changes to decommissioning and restoration costs (Note 24)	—	—	16	9	13	—	—	38
Retirement of assets	—	—	(10)	(12)	(16)	—	—	(38)
Change in foreign exchange rates	28	2	—	124	—	146	2	302
Transfer to intangible assets (Note 21)	—	—	—	—	(163)	—	—	(163)
Transfers of assets <sup>(3)</sup>	(1,432)	—	43	1,205	163	14	7	—
Transfers to finance lease receivable (Note 17)	—	—	—	—	(48)	—	—	(48)
As at Dec. 31, 2024	120	90	933	4,919	4,782	4,071	337	15,252
Additions	<b>243</b>	—	—	<b>2</b>	—	—	<b>4</b>	<b>249</b>
Disposals	—	<b>(2)</b>	—	—	—	<b>(2)</b>	—	<b>(4)</b>
Impairment reversals (charges) (Note 7)	<b>31</b>	—	—	<b>(17)</b>	—	—	—	<b>14</b>
Changes to decommissioning and restoration costs (Note 24)	—	—	—	<b>19</b>	<b>16</b>	<b>1</b>	—	<b>36</b>
Retirement of assets	—	—	<b>(8)</b>	<b>(10)</b>	<b>(15)</b>	<b>(8)</b>	—	<b>(41)</b>
Change in foreign exchange rates	<b>2</b>	<b>(1)</b>	—	<b>(93)</b>	<b>13</b>	<b>(86)</b>	—	<b>(165)</b>
Transfers of assets <sup>(3)</sup>	<b>(214)</b>	<b>17</b>	<b>66</b>	<b>30</b>	<b>106</b>	—	<b>(5)</b>	—
Transfers to assets held for sale (Note 18)	<b>(30)</b>	—	—	—	—	—	—	<b>(30)</b>
<b>As at Dec. 31, 2025</b>	<b>152</b>	<b>104</b>	<b>991</b>	<b>4,850</b>	<b>4,902</b>	<b>3,976</b>	<b>336</b>	<b>15,311</b>
<b>Accumulated depreciation</b>								
As at Dec. 31, 2023	—	—	499	1,337	3,049	3,743	102	8,730
Depreciation	—	—	37	170	221	62	28	518
Retirement of assets	—	—	(9)	(9)	(15)	—	—	(33)
Disposals	—	—	—	—	—	(2)	—	(2)
Change in foreign exchange rates	—	—	—	23	1	138	—	162
Transfers to intangible assets (Note 21)	—	—	—	—	(143)	—	—	(143)
As at Dec. 31, 2024	—	—	527	1,521	3,113	3,941	130	9,232
Depreciation	—	—	<b>35</b>	<b>180</b>	<b>269</b>	<b>45</b>	<b>18</b>	<b>547</b>
Retirement of assets	—	—	<b>(7)</b>	<b>(7)</b>	<b>(14)</b>	<b>(8)</b>	—	<b>(36)</b>
Disposals	—	—	—	—	—	<b>(3)</b>	—	<b>(3)</b>
Change in foreign exchange rates	—	—	—	<b>(12)</b>	<b>2</b>	<b>(84)</b>	—	<b>(94)</b>
<b>As at Dec. 31, 2025</b>	—	—	<b>555</b>	<b>1,682</b>	<b>3,370</b>	<b>3,891</b>	<b>148</b>	<b>9,646</b>
<b>Carrying amount</b>								
As at Dec. 31, 2024	120	90	406	3,398	1,669	130	207	6,020
<b>As at Dec. 31, 2025</b>	<b>152</b>	<b>104</b>	<b>436</b>	<b>3,168</b>	<b>1,532</b>	<b>85</b>	<b>188</b>	<b>5,665</b>

(1) Includes major spare parts and standby equipment available, but not in service.

(2) In 2024, the Company capitalized \$16 million of interest to PP&E at a weighted average rate of 6.52 per cent.

(3) Includes transfers of assets upon commissioning to assets in service and other movements.

## Mothballing of Sheerness Unit 1 and Sundance Unit 6

On Dec. 18, 2025, the Company provided notice to the Alberta Electric System Operator that Sheerness Unit 1 will be temporarily mothballed effective April 1, 2026, for a period of up to two years.

On April 1, 2025, the Company mothballed the Sundance Unit 6 facility for a period of up to two years depending on market conditions.

The Company maintains the flexibility to return the mothballed units to service when market fundamentals improve or opportunities to contract are secured.

## Assets under Construction

During the year ended Dec. 31, 2024, the Company achieved commercial operations at the White Rock and Horizon Hill wind facilities. Costs were transferred from assets under construction to the Wind and Solar segment.

## 20. Right-of-Use Assets

The Company leases various properties and types of equipment. Lease contracts are typically made for fixed periods. Leases are negotiated on an individual basis and contain a wide range of terms and conditions.

The lease agreements do not impose covenants, but leased assets may not be used as security for borrowing purposes.

A reconciliation of the changes in the carrying amount of the right-of-use assets is as follows:

	Land	Buildings	Vehicles	Equipment	Total
As at Dec. 31, 2023	97	12	3	5	117
Additions <sup>(1)</sup>	1	3	1	—	5
Depreciation	(5)	(1)	(1)	(1)	(8)
Change in foreign exchange rates	6	—	—	—	6
As at Dec. 31, 2024	99	14	3	4	120
Additions	—	—	1	—	1
Depreciation	(5)	(2)	(1)	(1)	(9)
Change in foreign exchange rates	(1)	—	—	—	(1)
<b>As at Dec. 31, 2025</b>	<b>93</b>	<b>12</b>	<b>3</b>	<b>3</b>	<b>111</b>

(1) Additions to buildings include right-of-use assets of \$1 million acquired from Heartland.

For the year ended Dec. 31, 2025, TransAlta paid \$14 million (2024 – \$16 million) related to recognized lease liabilities, consisting of \$4 million (2024 – \$6 million) of principal repayments and \$10 million (2024 – \$10 million) of interest expense.

Some of the Company's land leases that met the definition of a lease were not recognized as they require variable payments based on production or revenue.

Additionally, certain land leases require payments to be made on the basis of the greater of the minimum fixed payments and variable payments based on production or revenue. For these leases, lease liabilities have been recognized on the basis of the minimum fixed payments. For the year ended Dec. 31, 2025, the Company expensed \$8 million (2024 – \$9 million) in variable land lease payments for these leases.

## 21. Intangible Assets

A reconciliation of the changes in the carrying amount of intangible assets is as follows:

	Power sale and other contracts	Software and other	Intangibles under development	Coal rights	Total
<b>Cost</b>					
As at Dec. 31, 2023	270	446	27	132	875
Additions	—	—	10	—	10
Acquisitions (Note 4)	57	—	—	—	57
Change in foreign exchange rates	5	7	1	—	13
Transfers	20	35	(33)	—	22
As at Dec. 31, 2024	352	488	5	132	977
Additions	—	—	11	—	11
Acquisitions <sup>(1)</sup>	—	—	12	—	12
Retirement of assets	—	(110)	—	—	(110)
Asset impairment charges	(2)	(1)	—	—	(3)
Change in foreign exchange rates	(4)	(5)	—	—	(9)
Transfers	—	6	(6)	—	—
<b>As at Dec. 31, 2025</b>	<b>346</b>	<b>378</b>	<b>22</b>	<b>132</b>	<b>878</b>
<b>Accumulated amortization</b>					
As at Dec. 31, 2023	174	346	—	132	652
Amortization	19	19	—	—	38
Change in foreign exchange rates	4	3	—	—	7
Transfers	—	(1)	—	—	(1)
As at Dec. 31, 2024	197	367	—	132	696
Amortization	28	23	—	—	51
Retirement of assets	—	(110)	—	—	(110)
Change in foreign exchange rates	(1)	(1)	—	—	(2)
<b>As at Dec. 31, 2025</b>	<b>224</b>	<b>279</b>	<b>—</b>	<b>132</b>	<b>635</b>
<b>Carrying amount</b>					
As at Dec. 31, 2024	155	121	5	—	281
<b>As at Dec. 31, 2025</b>	<b>122</b>	<b>99</b>	<b>22</b>	<b>—</b>	<b>243</b>

(1) Relates to the acquisition of the remaining 40 per cent interest in Tent Mountain, which was previously accounted for using the equity method. Refer to Note 9 for further details.

## 22. Goodwill

Goodwill acquired through business combinations has been allocated to groups of CGUs that are expected to benefit from the synergies of the acquisitions. Goodwill by segments is as follows:

<b>As at Dec. 31</b>	<b>2025</b>	<b>2024</b>
Hydro	258	258
Wind and Solar	177	178
Gas (Note 4)	51	51
Energy Marketing	30	30
<b>Total goodwill</b>	<b>516</b>	<b>517</b>

For the purposes of the 2025 goodwill impairment review, the Company determined the recoverable amounts of the Hydro, Wind and Solar, Gas and Energy Marketing segments (2024 goodwill impairment review - Wind and Solar segment) by calculating the fair value less costs of disposal using discounted cash flow projections. The recoverable amounts are based on the Company's long-range forecasts for the periods extending to the last planned asset retirement in 2072. The resulting fair value measurements are categorized within Level III of the fair value hierarchy. No impairment of goodwill arose for any segment in 2025 and 2024.

In 2024, the Company relied on the recoverable amounts determined in 2022 for the Hydro and Energy Marketing segments in performing the 2024 goodwill impairment review.

The significant assumptions impacting the determination of the 2025 fair value for the Hydro, Wind and Solar, Gas and Energy Marketing segments, with a high degree of subjectivity, are the following:

- Forecasts of sales prices for each facility are determined by taking into consideration contract prices for facilities subject to short- or long-term contracts, forward price curves for merchant plants and regional supply-demand balances. Where forward price curves are not available for the duration of the facility's useful life, prices are determined by extrapolation techniques using historical industry and Company-specific data.

- Merchant electricity prices used in the Hydro, Wind and Solar, Gas and Energy Marketing segment models ranged between \$24 per MWh and \$339 per MWh during the forecast period (2024 — merchant electricity prices used in the Wind and Solar segment models ranged between \$40 per MWh and \$225 per MWh).
- Discount rates used for the Hydro, Wind and Solar, Gas and Energy Marketing segments ranged from 5.7 to 7.6 per cent (2024 — discount rates used for the for the Wind and Solar segment ranged from 6.4 to 7.3 per cent). A 0.5 per cent increase in the discount rate would not impact the results of the impairments tests performed.
- The White Rock and the Horizon Hill wind facilities are subject to location-specific price basis, sourced from third-party analysis. This analysis is based on models of the transmission system, including assumptions around potential system upgrades as well as forecasted generation and load in the area.

## 23. Other Assets

The components of other assets are as follows:

<b>As at Dec. 31</b>	<b>2025</b>	<b>2024</b>
South Hedland prepaid transmission access and distribution costs	56	58
TransAlta Energy Transition Bill commitment	19	30
Long-term prepaids and other assets	21	35
Project development costs	14	15
Loans receivable	31	25
Transmission infrastructure	16	17
<b>Total other assets</b>	<b>157</b>	<b>180</b>
Included in the Consolidated Statements of Financial Position as:		
Total current other assets (Note 13)	1	1
Total long-term other assets	156	179
<b>Total other assets</b>	<b>157</b>	<b>180</b>

South Hedland prepaid transmission access and distribution costs are costs that are amortized on a straight-line basis over the South Hedland PPA contract life.

As part of the TransAlta Energy Transition Bill signed into law in the State of Washington, the Company committed to fund US\$55 million in total over the remaining life of the Centralia coal plant to support economic and community development, promote energy efficiency and develop energy technologies related to the improvement of the environment.

Long-term prepaids and other assets include contractually required prepayments and deposits.

Project development costs primarily include the pre-construction project costs, which met the criteria for capitalization.

As at Dec. 31, 2025, \$31 million of the loans receivable (2024 – \$25 million) related to an unsecured loan advanced by the Company's subsidiary, Kent Hills Wind LP, from the net financing proceeds of the Kent Hills Wind Bond, to its 17 per cent partner. The loan bears interest at 4.55 per cent, with interest payable quarterly. No scheduled principal repayments are required until the maturity date of October 2027.

Transmission infrastructure was constructed by the Company and then transferred to a transmission provider upon completion. The balance relates to the Garden Plain and Windrise wind facilities and will be amortized to net earnings over the useful life of the facilities.

## 24. Decommissioning and Other Provisions

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

	Decommissioning and restoration	Other provisions	Total
Dec. 31, 2023	656	33	689
Liabilities acquired (Note 4)	101	55	156
Liabilities incurred	6	12	18
Liabilities settled	(41)	(4)	(45)
Accretion (Note 10)	50	—	50
Transfer to accounts payable	—	(31)	(31)
Transfer to assets held for sale (Note 18)	(1)	—	(1)
Revisions in estimated cash flows	21	20	41
Revisions in discount rates	35	—	35
Change in foreign exchange rates	21	—	21
Balance, Dec. 31, 2024	848	85	933
Liabilities incurred	—	<b>18</b>	<b>18</b>
Liabilities settled	<b>(39)</b>	<b>(51)</b>	<b>(90)</b>
Accretion (Note 10)	<b>53</b>	<b>4</b>	<b>57</b>
Transfer to assets held for sale (Note 18)	<b>(6)</b>	—	<b>(6)</b>
Revisions in estimated cash flows	<b>(71)</b>	<b>19</b>	<b>(52)</b>
Revisions in discount rates	<b>63</b>	<b>1</b>	<b>64</b>
Reversals	—	<b>(17)</b>	<b>(17)</b>
Change in foreign exchange rates	<b>(16)</b>	—	<b>(16)</b>
<b>Balance, Dec. 31, 2025</b>	<b>832</b>	<b>59</b>	<b>891</b>

### Included in the Consolidated Statements of Financial Position as:

As at	Dec. 31, 2025	Dec. 31, 2024
Current portion	84	83
Non-current portion	807	850
<b>Total decommissioning and other provisions</b>	<b>891</b>	933

## A. Decommissioning and Restoration

A provision has been recognized for all generating facilities and mines for which TransAlta is legally, or constructively, required to remove at the end of their useful lives and restore the sites to their original condition. TransAlta estimates that the undiscounted amount of cash flow required to settle these obligations is approximately \$1.8 billion, which will be incurred between 2026 and 2072. The majority of the costs will be incurred between 2026 and 2050.

During the year ended Dec. 31, 2025, the decommissioning and restoration provision decreased by \$71 million primarily due to revisions in estimated cash flows and the timing of cash flows for certain Energy Transition assets, with a corresponding offset recognized in net (loss) earnings.

During the year ended Dec. 31, 2025, the revisions in discount rates increased the decommissioning and restoration provision by \$63 million due to lower discount rates, largely driven by decreases in long-term market benchmark rates. On average, discount rates decreased compared to 2024, with rates ranging from 4.5 to 7.3 per cent as at Dec. 31, 2025. This has resulted in a corresponding increase in PP&E of \$36 million related to operating assets and the recognition of \$27 million of impairment charges in net (loss) earnings related to certain Energy Transition assets.

During the year ended Dec. 31, 2024, the decommissioning and restoration provision increased by \$21 million due to revisions in estimated cash flows and the timing of cash flows for certain Gas and Hydro assets. The timing of cash flows was adjusted to optimize and maximize efficiencies by staging required reclamation work. Operating assets included in PP&E increased by \$14 million and \$7 million was recognized as an impairment charge in net earnings related to retired assets.

During the year ended Dec. 31, 2024, revisions in discount rates increased the decommissioning and restoration provision by \$35 million due to a decrease in discount rates, largely driven by decreases in long-term market benchmark rates. On average, discount rates decreased compared to 2023, with rates ranging from 5.3 to 8.4 per cent as at Dec. 31, 2024. This has resulted in a corresponding increase in PP&E of \$18 million on operating assets and the recognition of a \$17 million impairment charge in net earnings related to retired assets.

At Dec. 31, 2025, the Company has provided a surety bond in the amount of US\$147 million (2024 – US\$147 million) in support of future decommissioning obligations at the Centralia coal mine. At Dec. 31, 2025, the Company had provided a surety bond and letters of credit in the amount of \$193 million (2024 – \$194 million) in support of future decommissioning obligations at the Highvale mine.

## B. Other Provisions

Other provisions include provisions arising from ongoing business activities, amounts related to commercial disputes between the Company and customers or suppliers and onerous contract provisions.

As part of the acquisition of Heartland, the Company recognized an onerous contract provision of \$47 million related to certain natural gas transportation contracts assumed. Payments required under the contracts continue through the first quarter of 2031.

## 25. Credit Facilities, Long-Term Debt and Lease Liabilities

### A. Amounts Outstanding

The amounts outstanding are as follows:

As at Dec. 31	Segment	Maturity	Currency	2025			2024		
				Carrying value	Face value	Interest <sup>(1)</sup>	Carrying value	Face value	Interest
<b>Credit facilities</b>									
Committed syndicated bank facility <sup>(2)</sup>	Corporate	2029	CAD	95	98	4.2%	143	145	5.3%
Term facility	Corporate	2025	CAD	—	—	—%	400	400	5.6%
<b>Debentures</b>									
7.3% Medium term notes	Corporate	2029	CAD	110	110	7.3%	110	110	7.3%
6.9% Medium term notes	Corporate	2030	CAD	141	141	6.9%	141	141	6.9%
5.6% Medium term notes	Corporate	2032	CAD	446	450	5.6%	—	—	—%
<b>Senior notes<sup>(3)</sup></b>									
5.9% Senior notes	Corporate	2034	USD	539	548	5.9%	—	—	—%
7.8% Senior notes	Corporate	2029	USD	—	—	—%	569	575	7.8%
6.5% Senior notes	Corporate	2040	USD	403	411	6.5%	426	431	6.5%
<b>Non-recourse</b>									
Melancthon Wolfe Wind LP bond	Wind & Solar	2028	CAD	98	98	3.8%	133	134	3.8%
New Richmond Wind LP bond	Wind & Solar	2032	CAD	83	84	4.0%	93	94	4.0%
Kent Hills Wind LP bond	Wind & Solar	2033	CAD	164	166	4.5%	179	182	4.5%
Windrise Wind LP bond	Wind & Solar	2041	CAD	150	152	3.4%	157	160	3.4%
Pingston bond	Hydro	2043	CAD	39	39	6.2%	39	39	6.2%
TAPC Holdings LP bond (Poplar Creek)	Gas	2030	CAD	65	66	6.7%	75	76	8.3%
TEC Hedland PTY Ltd bond <sup>(4)</sup>	Gas	2042	AUD	671	677	4.1%	675	683	4.1%
Heartland term facility	Corporate	2027	CAD	201	201	5.3%	224	224	6.6%
<b>Recourse</b>									
TransAlta OCP LP bond	Gas	2030	CAD	166	167	4.5%	192	193	4.5%
<b>Tax equity financing</b>									
Big Level & Antrim <sup>(5)</sup>	Wind & Solar	2029	USD	70	73	6.6%	90	94	6.6%
Lakeswind <sup>(6)</sup>	Wind & Solar	2030	USD	4	4	10.5%	7	7	10.5%
North Carolina Solar <sup>(7)</sup>	Wind & Solar	2030	USD	2	2	7.3%	4	4	7.3%
Total long-term debt				3,447	3,487		3,657	3,692	
Lease liabilities				146			151		
Total credit facilities, long-term debt and lease liabilities				3,593			3,808		
Less: current portion of long-term debt				(170)			(567)		
Less: current portion of lease liabilities				(5)			(5)		
Total current credit facilities, long-term debt and lease liabilities				(175)			(572)		
<b>Total non-current credit facilities, long-term debt and lease liabilities</b>				<b>3,418</b>			<b>3,236</b>		

(1) Interest rate reflects the stipulated rate or the average rate weighted by principal amounts outstanding and is before the effect of hedging.

(2) Composed of swing line loans and other commercial borrowings under long-term committed credit facilities.

(3) US\$700 million face value at Dec. 31, 2025 (2024 – US\$700 million).

(4) AU\$737 million face value at Dec. 31, 2025 (2024 – AU\$761 million).

(5) US\$54 million face value at Dec. 31, 2025 (2024 – US\$65 million).

(6) US\$3 million face value at Dec. 31, 2025 (2024 – US\$5 million).

(7) US\$1 million face value at Dec. 31, 2025 (2024 – US\$3 million).

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

As at Dec. 31, 2025	Utilized					
	Credit facilities	Facility size	Outstanding letters of credit <sup>(1)</sup>	Cash drawings	Available capacity	Maturity date
<b>Committed</b>						
Syndicated credit facility	1,900	438	98	1,364	Q2 2029	
Bilateral credit facilities	240	146	—	94	Q2 2027	
Heartland EDC letter of credit facility	30	14	—	16	Q1 2026	
Heartland DSR letter of credit facility	27	8	—	19	Q4 2027	
Heartland revolving facility	25	—	—	25	Q4 2027	
<b>Total committed</b>	<b>2,222</b>	<b>606</b>	<b>98</b>	<b>1,518</b>		
<b>Non-committed</b>						
Demand facility	400	223	—	177	N/A	
<b>Total Non-committed</b>	<b>400</b>	<b>223</b>	<b>—</b>	<b>177</b>		

(1) TransAlta has obligations to issue letters of credit and cash collateral to secure potential liabilities to certain parties, including those related to potential environmental obligations, commodity risk management and hedging activities, pension plan obligations, construction projects and purchase obligations. Letters of credit drawn against the non-committed facilities reduce the available capacity under the committed syndicated credit facilities. At Dec. 31, 2025, TransAlta provided cash collateral of \$92 million.

## US\$400 million Senior Notes Offering and Early Redemption of the 7.8 per cent Senior Notes

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

On Dec. 22, 2025 the Company redeemed all of its outstanding 7.8 per cent US\$400 million senior notes in advance of the scheduled maturity date of Nov. 15, 2029. The redemption price was \$573 million (US\$416 million) in aggregate, including a \$21 million prepayment premium recognized in interest expense. The Company also recognized \$5 million accelerated amortization of deferred financing costs in interest expense and an offsetting gain of \$31 million on interest rate derivatives designated as cash flow hedges, which were reclassified from other comprehensive income to interest expense upon redemption of the notes. Realized foreign exchange loss on redemption totalled \$19 million and was included under the foreign exchange (loss) gain in the statement of (loss) earnings for the period.

## \$450 million Senior Notes Offering

On March 24, 2025, the Company issued \$450 million of senior notes with a fixed annual coupon of 5.6 per cent, maturing on March 24, 2032. The notes are unsecured and rank equally in right of payment with all existing and future senior indebtedness and senior in right of payment to all future subordinated indebtedness. Interest payments on the notes are made semi-annually, on March 24 and Sept. 24.

## Term Loan Facility Early Repayment

On March 25, 2025, the Company repaid its \$400 million variable rate term loan facility in advance of the scheduled maturity date of Sept. 7, 2025, with the proceeds received from the \$450 million senior notes offering.

## Syndicated and Bilateral Credit Facilities

During the year ended Dec. 31, 2025 the Syndicated credit facility was reduced from \$1.95 billion to \$1.9 billion and the maturity was extended by one year to June 30, 2029.

During the year ended Dec. 31, 2025 the maturity of the Bilateral credit facilities in the aggregate amount of \$240 million was extended by one year to June 30, 2027.

The credit facilities are the primary source of short-term liquidity after the cash flow generated from the Company's business.

## Senior Notes

As at Dec. 31, 2025 a total of US\$300 million (2024 – US\$300 million) of the senior notes has been designated as a hedge of the Company's net investment in U.S. operations.

## Tax Equity

Tax equity financings are typically represented by the initial equity investments made by the project investors at each project (net of financing costs incurred), except for the Lakeswind and North Carolina Solar acquired tax equity financings, which were initially recognized at their fair values. Tax equity financing balances are reduced by the value of tax benefits (production tax credits, tax depreciation and investment tax credits) allocated to the investor and by cash distributions paid to the investor for their share of net earnings and cash flow generated at each project. Tax equity financing balances are increased by interest recognized at the implicit interest rate. The maturity dates of each financing are subject to change and are primarily dependent upon when the project investor achieves the agreed upon targeted return. The Company anticipates the maturity dates of the tax equity financings will be: Lakeswind in March 2030; North Carolina Solar in December 2030; and Big Level and Antrim in December 2029.

## Other

TransAlta's short- and long-term debt has terms and conditions, including financial covenants, that are considered normal and customary. As at Dec. 31, 2025, the Company was in compliance with all debt covenants.

The Heartland credit facilities are not subject to any maintenance or financial covenants but do contain certain covenants that limit Heartland's ability to, among other things, incur additional indebtedness, create or permit liens to exist, make certain acquisitions or dispositions, make distributions and enter into certain hedging agreements.

The Company is in compliance with its terms of the credit facilities and all undrawn amounts are fully available. Letters of credit in the amount of \$223 million were issued from non-committed demand facilities as at Dec. 31, 2025. In addition to the net \$1.5 billion of committed capacity available under the credit facilities, the Company had \$205 million of available cash and cash equivalents as at Dec. 31, 2025.

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

All non-recourse debt, the TransAlta OCP LP bond, and the Heartland credit facilities, with a total carrying value of \$1.6 billion as at Dec. 31, 2025 (2024 – \$1.8 billion), are subject to customary financing conditions and covenants that may restrict the Company's ability to access funds generated by the facilities' operations.

Upon meeting certain distribution tests, typically performed once per quarter, the funds can be distributed by the subsidiary entities to their respective parent entity. These conditions include meeting a debt service coverage ratio prior to distribution, which was met by these entities in the fourth quarter of 2025 with the exception of Windrise Wind LP. The funds in Windrise will remain there until the next debt service coverage ratio can be performed in the first quarter of 2026. At Dec. 31, 2025, \$101 million (2024 – \$117 million) of cash was subject to these financial restrictions.

At Dec. 31, 2025, \$8 million (AU\$9 million) of funds held by TEC Hedland Pty Ltd. cannot be accessed by other corporate entities as the funds must be solely used by the project entities, to pay major maintenance costs. Additionally, certain non-recourse bonds require that certain reserve accounts be established and funded through cash held on deposit and/or by providing letters of credit.

## C. Security

Non-recourse debt totalling \$1.4 billion as at Dec. 31, 2025 (2024 – \$1.5 billion) is secured by a first ranking charge over all of the respective assets of the Company's subsidiaries that issued the debt, which include PP&E with total carrying amounts of \$1.57 billion at Dec. 31, 2025 (2024 – \$1.75 billion) and intangible assets with total carrying amounts of \$55 million (2024 – \$84 million). At Dec. 31, 2025, non-recourse debt of approximately \$65 million (2024 – \$75 million) was secured by a first ranking charge over the equity interests of the issuer that issued the non-recourse debt.

The TransAlta OCP bonds have a carrying value of \$166 million (2024 – \$192 million) and are secured by the assets of TransAlta OCP, including the right to annual capital contributions and OCA payments from the Government of Alberta related to TransAlta's legacy coal facilities (the TransAlta OCA). Under the TransAlta OCA, the Company receives annual cash payments on or before July 31 of approximately \$40 million (approximately \$37 million, net to the Company), commencing on Jan. 1, 2017, and terminating at the end of 2030.

## D. Principal Repayments

	2026	2027	2028	2029	2030	2031 and thereafter	Total
Principal repayments <sup>(1)</sup>	170	331	163	343	281	2,199	3,487
Lease liabilities	5	5	5	5	5	121	146

(1) Excludes impact of hedge accounting and derivatives.

## E. Restricted Cash

As at Dec. 31, 2025, the Company had \$17 million (2024 – \$17 million) of restricted cash related to the TransAlta OCP bonds, which is required to be held in a debt service reserve account to fund scheduled future debt repayments. The Company also had \$4 million of restricted cash related to holdbacks associated with the Required Divestitures and \$57 million (2024 – \$52 million) of restricted cash related to the TEC Hedland Pty Ltd. bond. These cash reserves are required to be held under commercial arrangements and for debt service, which may be replaced by letters of credit in the future.

## F. Letters of Credit

Letters of credit are issued to counterparties as required by various contractual arrangements with the Company and certain subsidiaries of the Company. If the Company or its subsidiary does not perform under such contracts, the counterparty may present its claim for payment to the financial institution through which the letter of credit was issued. All letters of credit expire within one year and are expected to be renewed, as needed, in the normal course of business. The total outstanding letters of credit as at Dec. 31, 2025, was \$829 million (2024 – \$865 million) with nil (2024 – nil) amounts exercised by third parties under these arrangements.

## 26. Exchangeable Securities

On March 22, 2019, the Company entered into an Investment Agreement whereby Brookfield Renewable Partners or its affiliates (collectively Brookfield) agreed to invest \$750 million in TransAlta through the purchase of exchangeable securities, which are exchangeable into an equity ownership interest in TransAlta's Alberta Hydro Assets after Dec. 31, 2024 at a value based on a multiple of the Alberta Hydro Assets' future-adjusted EBITDA (Option to Exchange).

## G. Currency Impacts

The weakening of the U.S. dollar has decreased the U.S. dollar-denominated long-term debt balances, mainly the senior notes and tax equity financings, by \$28 million as at Dec. 31, 2025 (2024 – increased \$90 million due to the strengthening of the U.S. dollar). Almost all of the U.S.-dollar-denominated debt is hedged either through financial contracts or a hedge of net investments in U.S. operations.

Additionally, the strengthening of the Australian dollar has increased the Australian-dollar-denominated non-recourse senior secured notes balance by approximately \$16 million as at Dec. 31, 2025 (2024 – \$5 million). As this debt is issued by an Australian subsidiary, the foreign currency translation impacts are recognized within other comprehensive income (loss).

The Company classified the Exchangeable Securities as current liabilities, as the conversion option has been exercisable at any time after Dec. 31, 2024, although there is no obligation to deliver cash equivalent resources and the holder cannot call for repayment.

## A. \$750 Million Exchangeable Securities

As at	Dec. 31, 2025			Dec. 31, 2024		
	Carrying value	Face value	Interest	Carrying value	Face value	Interest
Exchangeable debentures – due May 1, 2039 <sup>(1)</sup>	350	350	7%	350	350	7%
Exchangeable preferred shares <sup>(2)</sup>	400	400	7%	400	400	7%
<b>Total exchangeable securities</b>	<b>750</b>	<b>750</b>		<b>750</b>	<b>750</b>	

(1) Seven per cent unsecured subordinated debentures due May 1, 2039.

(2) Redeemable, retractable first preferred shares (Series I). Exchangeable preferred share dividends are reported as interest expense.

On Dec. 12, 2025, the Company declared a dividend of \$7 million, in aggregate, for the Exchangeable Preferred Shares at the fixed rate of 1.764 per cent, per share, payable on March 2, 2026. The Exchangeable Preferred Shares are

considered debt for accounting purposes and, as such, dividends are reported as interest expense (Note 10).

## B. Option to Exchange

As at	Dec. 31, 2025		Dec. 31, 2024	
	Base fair value	Sensitivity	Base fair value	Sensitivity
Option to exchange – embedded derivative	—	+nil -41	—	+nil -30

The Investment Agreement allows Brookfield the option to exchange all of the outstanding exchangeable securities after Dec. 31, 2024, into an equity ownership interest of up to a maximum 49 per cent in an entity that has been formed to hold the Alberta Hydro Assets. The fair value of the option to exchange is considered a Level III fair value measurement as there is no available market-observable data. It is therefore valued using a mark-to-forecast model with inputs that are based on historical data and changes in underlying discount rates only when it represents a long-term change in the value of the option to exchange.

Sensitivity ranges for the base fair value are determined using reasonably possible alternative assumptions for key unobservable inputs, which is mainly the change in the implied discount rate of future cash flows. The sensitivity analysis has been prepared using the Company's assessment that a change in the implied discount rate of 7.9 per cent (2024 – 10.5 per cent) of future cash flows of one per cent is a reasonably possible change.

The maximum equity interest Brookfield can own with respect to the Alberta Hydro Assets is 49 per cent. If Brookfield's ownership interest is less than 49 per cent at conversion, Brookfield has a one-time option payable in cash to increase its ownership to up to 49 per cent, exercisable up until Dec. 31, 2028, provided Brookfield holds at least 8.5 per cent of TransAlta's common shares. Under this top-up option, Brookfield will be able to acquire an additional 10 per cent interest in the entity holding the Alberta Hydro Assets, provided the 20-day volume-weighted average price (VWAP) of TransAlta's common shares is not less than \$14 per share prior to the exercise of the option, and up to the full 49 per cent if the 20-day VWAP of TransAlta's common shares at that time is not less than \$17 per share. To the extent the value of the investment would exceed a 49 per cent equity interest, Brookfield will be entitled to receive the balance of the redemption price in cash.

In connection with the Investment Agreement, Brookfield is entitled to nominate two directors for election to the Board.

## 27. Defined Benefit Obligation and Other Long-Term Liabilities

The components of defined benefit obligation and other long-term liabilities are as follows:

<b>As at Dec. 31</b>	<b>2025</b>	<b>2024</b>
Defined benefit obligation (Note 32)	143	146
Retail power contract liability	17	45
Other	13	11
<b>Total</b>	<b>173</b>	<b>202</b>

The liability for pension and post-employment benefits and associated costs included in compensation expenses are impacted by estimates related to changes in key actuarial assumptions, including discount rates.

A one per cent increase in discount rates would result in a \$31 million decrease in the defined benefit obligation. Refer to Note 32 for additional sensitivities impacting the defined benefit obligation.

The retail power contract liability represents an obligation arising from the purchase and sale agreement for customer retail contracts to deliver power, gas and power and gas financial swaps. The retail power contracts represent certain off-market customer contracts, where the value of the contract is based on the differential between the contractual and market rates on the closing date. The retail contract liability is amortized to depreciation over the remaining term of the contracts based on volumes that will be delivered each month.

## 28. Common Shares

### A. Issued and Outstanding

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

<b>As at Dec. 31</b>	<b>2025</b>		<b>2024</b>	
	<b>Common shares (millions)</b>	<b>Amount</b>	<b>Common shares (millions)</b>	<b>Amount</b>
Issued and outstanding, beginning of period	297.5	3,179	306.9	3,285
Reversal of provision for repurchase of common shares under the automatic share purchase plan	—	—	1.7	19
Purchased and cancelled under the NCIB <sup>(1)(2)</sup>	(1.9)	(20)	(13.5)	(146)
Share-based payment plans	0.8	7	0.8	9
Stock options exercised	0.3	3	1.6	12
<b>Issued and outstanding, end of year</b>	<b>296.7</b>	<b>3,169</b>	<b>297.5</b>	<b>3,179</b>

(1) 2025 includes nil of tax on share buybacks (2024 – 2 million) on the fair value of the shares repurchased.

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

## B. Normal Course Issuer Bid (NCIB) Program

The effects of the Company's purchase and cancellation of common shares during the period are as follows:

<b>For the year ended Dec. 31</b>	<b>2025</b>	<b>2024</b>
Total shares purchased	1,932,800	13,467,400
Average purchase price per share	12.42	10.59
Total cost (millions)	24	143
Book value of shares cancelled	20	146
Amount recorded in deficit	(4)	3

On May 27, 2025, the Company announced that it had received approval from the Toronto Stock Exchange to repurchase up to a maximum of 14 million common shares during the 12-month period that commenced May 31, 2025 and terminates on the earlier of May 30, 2026 or such earlier date on which the maximum number of Common Shares are purchased under the NCIB or the NCIB is terminated at the Company's election. Any common shares purchased under the NCIB will be cancelled.

## C. Shareholder Rights Plan

The Company initially adopted the Shareholder Rights Plan in 1992, which was amended and restated on April 28, 2022. As required, the Shareholder Rights Plan must be put before the Company's shareholders every three years for approval. It was last approved on April 24, 2025, and will

need to be approved at the annual meeting of shareholders in 2028. The primary objective of the Shareholder Rights Plan is to encourage a potential acquirer to meet certain minimum standards designed to promote the fair and equal treatment of all common shareholders. When an acquiring shareholder acquires 20 per cent or more of the Company's common shares, except in limited circumstances including by way of a "permitted bid" or a "competing permitted bid" (as defined in the Shareholder Rights Plan), the rights granted under the Shareholder Rights Plan become exercisable by all shareholders except those held by the acquiring shareholder. Each right will entitle a shareholder, other than the acquiring shareholder, to purchase additional common shares at a significant discount to market, thus exposing the person acquiring 20 per cent or more of the shares to substantial dilution of their holdings.

## D. (Loss) Earnings per Share

<b>Year ended Dec. 31</b>	<b>2025</b>	<b>2024</b>
Net (loss) earnings attributable to common shareholders	(190)	177
Basic and diluted weighted average number of common shares outstanding (millions)	297	302
Net (loss) earnings per share attributable to common shareholders, basic and diluted	(0.64)	0.59

## E. Dividends

On Dec. 12, 2025, the Company declared a quarterly dividend of \$0.065 per common share, payable on April 1, 2026.

On Feb. 25, 2026, the Company declared a quarterly dividend of \$0.070 per common share, payable on July 1, 2026.

There have been no transactions involving common shares between the reporting date and the date of completion of these Consolidated Financial Statements.

## 29. Preferred Shares

### A. Issued and Outstanding

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

As at Dec. 31	2025		2024	
	Number of shares (millions)	Amount	Number of shares (millions)	Amount
Series A	9.6	235	9.6	235
Series B	2.4	58	2.4	58
Series C	10.0	243	10.0	243
Series D	1.0	26	1.0	26
Series E	9.0	219	9.0	219
Series G	6.6	161	6.6	161
<b>Issued and outstanding, end of year</b>	<b>38.6</b>	<b>942</b>	38.6	942

(1) The Series I Preferred Shares are accounted for as debt. Refer to Note 26.

### Series G Cumulative Redeemable Rate Reset Preferred Shares

During the third quarter of 2024, after taking into account all election notices received for the conversion of the Cumulative Redeemable Rate Reset Preferred Shares, Series G (Series G shares), 20,607 Series G shares out of 6.6 million outstanding, were tendered for conversion, which is less than the 1 million shares required to give effect to conversion into Series H shares. As a result, none of the Series G Shares were converted into Series H Shares on Sept. 30, 2024 and the next conversion date was reset to Sept. 30, 2029.

### Preferred Share Series Information

Holders of preferred shares are entitled to receive cumulative fixed quarterly cash dividends at specified rates, as approved by the Board. After an initial period of approximately five years from issuance and every five years thereafter (Rate Reset Date), the fixed rate for the preferred

shares resets to the sum of the five-year Government of Canada bond yield (the fixed rate Benchmark) plus a specified spread. Upon each Rate Reset Date, the shares are also:

- Redeemable at the option of the Company, in whole or in part, for \$25.00 per share, plus all declared and unpaid dividends at the time of redemption.
- Convertible at the holder's option into a specified series of non-voting cumulative redeemable floating rate first preferred shares that pay cumulative floating rate quarterly cash dividends, as approved by the Board, based on the sum of the Government of Canada 90-day Treasury Bill rate (the floating rate Benchmark) plus a specified spread. The cumulative floating rate first preferred shares are also redeemable at the option of the Company and convertible back into each original cumulative fixed rate first preferred share series, at each subsequent Rate Reset Date, on the same terms as noted above.

Characteristics specific to each first preferred share series as at Dec. 31, 2025, are as follows:

Series <sup>(1)</sup>	Rate during term	Annual dividend rate per share (\$) <sup>(2)</sup>	Next conversion date	Rate spread over benchmark (per cent)	Convertible to Series
A	Fixed	0.71924	March 31, 2026	2.03	B
B	Floating	1.15541	March 31, 2026	2.03	A
C	Fixed	1.46352	June 30, 2027	3.10	D
D	Floating	1.42290	June 30, 2027	3.10	C
E	Fixed	1.72352	Sept. 30, 2027	3.65	F
G	Fixed	1.69324	Sept. 30, 2029	3.80	H

(1) The Series I Preferred Shares are accounted for as debt. Refer to Note 26.

(2) The annual dividend rate per share represents dividends declared in 2025.

## B. Dividends

The following table summarizes the preferred share dividends declared in 2025 and 2024:

Series	Total dividends declared	
	2025	2024
A	7	7
B <sup>(1)</sup>	3	4
C	15	15
D <sup>(2)</sup>	1	2
E	16	15
G	10	9
<b>Total for the year</b>	<b>52</b>	<b>52</b>

(1) Series B Preferred Shares pay quarterly dividends at a floating rate based on the 90-day Government of Canada Treasury Bill rate, plus 2.03 per cent.

(2) Series D Preferred Shares pay quarterly dividends at a floating rate based on the 90-day Government of Canada Treasury Bill rate, plus 3.10 per cent.

On Dec. 12, 2025, the Company declared a quarterly dividend of \$0.17981 per share on the Series A preferred shares, \$0.26186 per share on the Series B preferred shares, \$0.36588 per share on the Series C preferred shares, \$0.32782 per share on the Series D preferred shares, \$0.43088 per share on the Series E preferred shares and \$0.42331 per share on the Series G preferred shares, payable on March 31, 2026.

## 30. Accumulated Other Comprehensive (Loss) Income

The components of and changes in, accumulated other comprehensive (loss) income are as follows:

	2025	2024
<b>Currency translation adjustment</b>		
Opening balance, Jan. 1	(34)	(36)
(Losses) gains on translating net assets of foreign operations, net of reclassifications to net earnings	(12)	30
Gains (losses) on financial instruments designated as hedges of foreign operations, net of reclassifications to net earnings, net of tax <sup>(1)</sup>	11	(28)
<b>Balance, Dec. 31</b>	<b>(35)</b>	<b>(34)</b>
<b>Cash flow hedges</b>		
Opening balance, Jan. 1	65	(129)
(Losses) gains on derivatives designated as cash flow hedges, net of reclassifications to net earnings, net of tax <sup>(2)</sup>	(69)	194
<b>Balance, Dec. 31</b>	<b>(4)</b>	<b>65</b>
<b>Employee future benefits</b>		
Opening balance, Jan. 1	12	3
Net actuarial gains on defined benefit plans, net of tax <sup>(3)</sup>	5	9
<b>Balance, Dec. 31</b>	<b>17</b>	<b>12</b>
<b>Other</b>		
Opening balance, Jan. 1	(2)	(2)
<b>Balance, Dec. 31</b>	<b>(2)</b>	<b>(2)</b>
<b>Accumulated other comprehensive (loss) income</b>	<b>(24)</b>	<b>41</b>

(1) Net of income tax expense of \$1 million for the year ended Dec. 31, 2025 (Dec. 31, 2024 – \$4 million recovery).

(2) Net of income tax recovery of \$14 million for the year ended Dec. 31, 2025 (Dec. 31, 2024 – \$53 million expense).

(3) Net of income tax expense of \$1 million for the year ended Dec. 31, 2025 (Dec. 31, 2024 – \$3 million expense).

## 31. Share-Based Payment Plans

The Company has the following share-based payment plans:

### A. Performance Share Unit (PSU) and Restricted Share Unit (RSU) Plan

Under the Share Unit Plan, grants of PSUs and RSUs may be made annually, but are measured and assessed over a three-year performance period. Grants are determined as a percentage of participants' base pay and are converted to PSUs or RSUs on the basis of the Company's common share price at the time of grant. Vesting of PSUs is subject to achieving, over a three-year period, specific performance measures that are established at the time of each grant. RSUs are subject to a three-year cliff-vesting requirement. RSUs and PSUs track the Company's share price over the three-year period and accrue dividends as additional units at the same rate as dividends paid on the Company's common shares.

The pre-tax compensation expense related to PSUs and RSUs in 2025 was \$26 million (2024 – \$23 million), which is included in OM&A in the consolidated statements of (loss) earnings.

### B. Deferred Share Unit (DSU) Plan

Under the Share Unit Plan, members of the Board and executives may, at their option, purchase DSUs using

The total options outstanding and exercisable under the Stock Option Plan at Dec. 31, 2025, are outlined below:

#### Options outstanding

Range of exercise prices (\$ per share)	Number of options (millions) <sup>(1)</sup>	Weighted average remaining contractual life (years)	Weighted average exercise price (\$ per share)
9.28-20.46	1.6	4.3	12.91

(1) Includes 1.2 million options exercisable as at Dec. 31, 2025.

certain components of their fees or pay. A DSU is a notional share that has the same value as one common share of the Company and fluctuates based on the changes in the value of the Company's common shares in the marketplace. DSUs accrue dividends as additional DSUs at the same rate as dividends are paid on the Company's common shares. DSUs are redeemable in cash and may not be redeemed until the termination or retirement of the director or executive from the Company.

The Company accrues a liability and expense for the appreciation in the common share value in excess of the DSU's purchase price and for dividend equivalents earned.

The pre-tax compensation expense related to the DSUs was \$2 million in 2025 (2024 – \$8 million).

### C. Stock Option Plan

In 2025, the Company granted executive officers of the Company a total of 0.3 million stock options with a weighted average exercise price of \$20.40 that vest over a three-year period and expire seven years after issuance (2024 – 0.7 million stock options at \$10.88). The expense recognized relating to these grants during 2025 was \$3 million (2024 – \$1 million).

## 32. Employee Future Benefits

### A. Description

The Company sponsors registered pension plans in Canada and the U.S. covering substantially all employees of the Company in both countries and specific named employees working internationally. The Canadian plans have defined benefit and defined contribution options, as well as a non-registered supplemental plan for eligible employees whose annual earnings exceed the Canadian income tax limit. The U.S. plan has a defined contribution option only.

As of June 30, 2025, all Canadian and U.S. defined benefit pension plans were closed to new members, following closure of the Sunhills plan. The U.S. defined benefit pension plan was frozen effective Dec. 31, 2010, resulting in no future benefits being earned. The supplemental pension plan was closed as of Dec. 31, 2015, and a new defined contribution supplemental pension plan commenced for executive members effective Jan. 1, 2016. Executives current as of Dec. 31, 2015, were grandfathered into the old supplemental plan.

The Company's U.S. defined benefit pension plan was terminated effective June 30, 2024 and annuitized in October 2024.

The measurement date used for all plans to determine the fair value of plan assets and the present value of the defined benefit obligation was Dec. 31, 2025.

Funding of the registered pension plans complies with applicable regulations that require actuarial valuations of the pension funds at least once every three years in Canada, or more, depending on funding status. The supplemental pension plan is solely the obligation of the Company. The Company is not obligated to fund the supplemental plan but

is obligated to pay benefits under the terms of the plan as they come due. The Company posted a letter of credit in March 2025 in the amount of \$92 million, and provided \$62 million in surety bonds, to secure the obligations under the supplemental plan and the Canadian defined benefit plan, respectively.

The Company provides other health and dental benefits to certain eligible employees to the age of 65 for both disabled members and retired members through its other post-employment benefits plans. The measurement date used to determine the present value obligation for both plans was Dec. 31, 2025.

The Company provides several defined contribution plans, including the acquired Heartland plan, an Australian superannuation plan and a U.S. 401(k) savings plan, that provide for company contributions from 5.0 to 11.5 per cent, depending on the plan.

Optional employee contributions are allowed for all the defined contribution plans.

The Company's Canadian registered pension Plan was amended effective April 26, 2025 following TransAlta's acquisition of Heartland.

Pursuant to this amendment, certain employees of Heartland, who started their employment with the Company between December 4, 2024 to April 26, 2025 and met eligibility provisions, commenced their participation with the plan.

During the year ended Dec. 31, 2025, the Heartland members' balances in their previous plan were transferred to the Company's plan.

## B. Costs Recognized

The costs recognized in net (loss) earnings during the year on the defined benefit, defined contribution and other post-employment benefits plans are as follows:

<b>Year ended Dec. 31, 2025</b>	<b>Registered</b>	<b>Supplemental</b>	<b>Other</b>	<b>Total</b>
Current service cost	1	—	—	1
Administration expenses	1	—	—	1
Interest cost on defined benefit obligation	13	4	—	17
Interest on plan assets	(11)	(1)	—	(12)
Defined benefit expense	4	3	—	7
Defined contribution expense	14	—	—	14
<b>Net expense</b>	<b>18</b>	<b>3</b>	<b>—</b>	<b>21</b>

<b>Year ended Dec. 31, 2024</b>	<b>Registered</b>	<b>Supplemental</b>	<b>Other</b>	<b>Total</b>
Current service cost	1	1	1	3
Administration expenses	1	—	—	1
Interest cost on defined benefit obligation	14	4	1	19
Interest on plan assets	(12)	(1)	—	(13)
Defined benefit expense	4	4	2	10
Defined contribution expense	12	—	—	12
Net expense	16	4	2	22

## C. Status of Plans

The status of the defined benefit pension and other post-employment benefit plans is as follows:

<b>Year ended Dec. 31, 2025</b>	<b>Registered</b>	<b>Supplemental</b>	<b>Other</b>	<b>Total</b>
Fair value of plan assets	229	16	—	245
Present value of defined benefit obligation	(285)	(88)	(17)	(390)
<b>Funded status – plan deficit</b>	<b>(56)</b>	<b>(72)</b>	<b>(17)</b>	<b>(145)</b>

Amount recognized in the Consolidated Financial Statements:

Accrued current liabilities	(1)	—	(1)	(2)
Other long-term liabilities	(55)	(72)	(16)	(143)
<b>Total amount recognized</b>	<b>(56)</b>	<b>(72)</b>	<b>(17)</b>	<b>(145)</b>

<b>Year ended Dec. 31, 2024</b>	<b>Registered</b>	<b>Supplemental</b>	<b>Other</b>	<b>Total</b>
Fair value of plan assets	241	16	—	257
Present value of defined benefit obligation	(303)	(90)	(18)	(411)
Funded status – plan deficit	(62)	(74)	(18)	(154)

Amount recognized in the Consolidated Financial Statements:

Accrued current liabilities	(1)	(6)	(1)	(8)
Other long-term liabilities	(61)	(68)	(17)	(146)
Total amount recognized	(62)	(74)	(18)	(154)

## D. Plan Assets

The fair value of the plan assets of the defined benefit pension and other post-employment benefit plans is as follows:

	Registered	Supplemental	Other	Total
As at Dec. 31, 2023	269	15	—	284
Interest on plan assets	12	1	—	13
Net return on plan assets	13	(1)	—	12
Contributions <sup>(1)</sup>	1	6	1	8
Benefits paid	(31)	(5)	(1)	(37)
Administration expenses	(1)	—	—	(1)
Effect of settlement from annuitization of the U.S. defined benefit plan	(23)	—	—	(23)
Change in foreign exchange rates	1	—	—	1
As at Dec. 31, 2024	241	16	—	257
Interest on plan assets	<b>11</b>	<b>1</b>	—	<b>12</b>
Net return on plan assets	<b>2</b>	<b>(1)</b>	—	<b>1</b>
Contributions <sup>(1)</sup>	<b>4</b>	<b>6</b>	<b>1</b>	<b>11</b>
Benefits paid	<b>(28)</b>	<b>(6)</b>	<b>(1)</b>	<b>(35)</b>
Administration expenses	<b>(1)</b>	—	—	<b>(1)</b>
<b>As at Dec. 31, 2025</b>	<b>229</b>	<b>16</b>	—	<b>245</b>

(1) The Company made a voluntary contribution of \$4 million (2024 – nil) to further improve the funded status of its defined benefit pension plan.

## Notes to the Consolidated Financial Statements

The fair value of the Company's defined benefit plan assets by major category is as follows:

<b>As at Dec. 31, 2025</b>	<b>Level I</b>	<b>Level II</b>	<b>Level III</b>	<b>Total</b>
<b>Equity securities</b>				
Canadian	—	11	—	11
International	—	52	—	52
Private	—	—	1	1
<b>Bonds</b>				
A - AAA	—	16	80	96
BBB	—	1	11	12
Below BBB	—	—	6	6
<b>Loans<sup>(1)</sup></b>				
	—	2	—	2
<b>Other</b>				
Alternative funds <sup>(2)</sup>	—	—	42	42
Money market and cash and cash equivalents	18	3	2	23
<b>Total</b>	<b>18</b>	<b>85</b>	<b>142</b>	<b>245</b>

(1) Includes A credit rating loans of \$1 million.

(2) Alternative funds include investments in infrastructure and real estate funds.

<b>As at Dec. 31, 2024</b>	<b>Level I</b>	<b>Level II</b>	<b>Level III</b>	<b>Total</b>
<b>Equity securities</b>				
Canadian	—	12	—	12
International	—	53	—	53
Private	—	—	1	1
<b>Bonds</b>				
A - AAA	—	18	81	99
BBB	—	1	16	17
Below BBB	—	—	5	5
<b>Loans<sup>(1)</sup></b>				
	—	1	—	1
<b>Other</b>				
Alternative funds <sup>(2)</sup>	—	—	46	46
Money market and cash and cash equivalents	2	19	2	23
<b>Total</b>	<b>2</b>	<b>104</b>	<b>151</b>	<b>257</b>

(1) Includes A credit rating loans of \$1 million.

(2) Alternative funds include investments in infrastructure and real estate funds.

Plan assets did not include any common shares of the Company as at Dec. 31, 2025 and Dec. 31, 2024.

## E. Defined Benefit Obligation

The present value of the obligation for the defined benefit pension and other post-employment benefit plans is as follows:

	Registered	Supplemental	Other	Total
Present value of defined benefit obligation as at Dec. 31, 2023	340	89	17	446
Current service cost	1	—	1	2
Interest cost	14	4	1	19
Benefits paid	(31)	(5)	(1)	(37)
Actuarial loss arising from financial assumptions	1	1	—	2
Actuarial loss arising from experience adjustments	—	1	—	1
Effect of settlement from the termination of the U.S. defined benefit plan	(23)	—	—	(23)
Change in foreign exchange rates	1	—	—	1
Present value of defined benefit obligation as at Dec. 31, 2024	303	90	18	411
Current service cost	<b>1</b>	—	—	<b>1</b>
Interest cost	<b>13</b>	<b>4</b>	—	<b>17</b>
Benefits paid	<b>(28)</b>	<b>(5)</b>	<b>(1)</b>	<b>(34)</b>
Actuarial gain arising from financial assumptions	<b>(5)</b>	<b>(2)</b>	—	<b>(7)</b>
Actuarial loss arising from experience adjustments	<b>1</b>	<b>1</b>	—	<b>2</b>
<b>Present value of defined benefit obligation as at Dec. 31, 2025<sup>(1)</sup></b>	<b>285</b>	<b>88</b>	<b>17</b>	<b>390</b>

(1) The weighted average duration of the defined benefit plan obligation as at Dec. 31, 2025, is 9.4 years.

## F. Contributions

The expected employer contributions for 2026 for the defined benefit pension and other post-employment benefit plans are as follows:

	Registered	Supplemental	Other	Total
Expected employer contributions	<b>1</b>	—	<b>1</b>	<b>2</b>

## G. Assumptions

The significant actuarial assumptions used in measuring the Company's defined benefit obligation for the defined benefit pension and other post-employment benefit plans are as follows:

As at Dec. 31 (per cent)	2025			2024		
	Registered	Supplemental	Other	Registered	Supplemental	Other
<b>Accrued benefit obligation</b>						
Discount rate	4.7	4.7	4.8	4.5	4.5	4.8
Rate of compensation increase	2.9	3.0	—	2.9	3.0	—
Assumed health-care cost trend rate						
Health-care cost escalation <sup>(1)(3)</sup>	—	—	6.5	—	—	6.7
Dental-care cost escalation	—	—	4.1	—	—	4.1
<b>Benefit cost for the year</b>						
Discount rate	4.5	4.5	4.8	4.6	4.6	4.7
Rate of compensation increase	2.9	3.0	—	2.9	3.0	—
Assumed health-care cost trend rate						
Health-care cost escalation <sup>(2)(4)</sup>	—	—	6.5	—	—	6.7
Dental-care cost escalation	—	—	4.6	—	—	4.6

- (1) 2025 Post- and pre-65 rates: decreasing gradually to 4.5 per cent by 2035 and remaining at that level thereafter for the U.S. and decreasing gradually by 0.3 per cent per year to 4.5 per cent in 2030 for Canada.
- (2) 2025 Post- and pre-65 rates: decreasing gradually to 4.5 per cent by 2034 and remaining at that level thereafter for the U.S. and decreasing gradually by 0.3 per cent per year to 4.5 per cent in 2030 for Canada.
- (3) 2024 Post- and pre-65 rates: decreasing gradually to 4.5 per cent by 2034 and remaining at that level thereafter for the U.S. and decreasing gradually by 0.3 per cent per year to 4.5 per cent in 2030 for Canada.
- (4) 2024 Post- and pre-65 rates: decreasing gradually to 4.5 per cent by 2033 and remaining at that level thereafter for the U.S. and decreasing gradually by 0.3 per cent per year to 4.5 per cent in 2030 for Canada.

## H. Sensitivity Analysis

The following table outlines the estimated increase in the net defined benefit obligation assuming certain changes in key assumptions:

As at Dec. 31, 2025	Canadian plans			U.S. plans
	Registered	Supplemental	Other	Pension
1 per cent decrease in the discount rate	25	10	1	—
1 per cent increase in the salary scale	1	—	—	—
1 per cent increase in the health-care cost trend rate	—	—	2	—
10 per cent improvement in mortality rates	12	3	—	—

## 33. Cash Flow Information

### A. Change in Non-Cash Operating Working Capital

Year ended Dec. 31	2025	2024
Source (use):		
Accounts receivable	75	155
Prepaid expenses	19	85
Income taxes receivable	(41)	22
Inventory	22	34
Accounts payable, accrued liabilities and provisions	(78)	(273)
Income taxes payable	6	15
<b>Change in non-cash operating working capital</b>	<b>3</b>	<b>38</b>

### B. Changes in Liabilities from Financing Activities

	Balance Dec. 31, 2024	Cash issuances <sup>(1)</sup>	Repayments and dividends paid <sup>(2)</sup>	Dividends declared	Foreign exchange impact	Other	Balance Dec. 31, 2025
Long-term debt and lease liabilities <sup>(2)</sup>	3,809	991	(1,188)	—	(12)	(7)	3,593
Exchangeable securities	750	—	—	—	—	—	750
Dividends payable (common and preferred)	49	—	(127)	130	—	—	52
<b>Total liabilities from financing activities</b>	<b>4,608</b>	<b>991</b>	<b>(1,315)</b>	<b>130</b>	<b>(12)</b>	<b>(7)</b>	<b>4,395</b>

(1) Includes the issuance of US\$400 million 5.9 per cent senior notes at \$541 million and \$450 million 5.6 per cent senior notes. Refer to Note 25.

(2) Repayments of long-term debt and lease liabilities include the repayment of US\$400 million 7.8 per cent senior notes at \$573 million, repayment of the \$400 million term facility, \$175 million of long-term debt repayments, a \$48 million of repayments, net of cash drawings, under the under the syndicated credit facility, and a decrease in finance lease obligations of \$4 million.

	Balance Dec. 31, 2023	Debt assumed	Repayments and dividends paid <sup>(1)</sup>	New leases	Dividends declared	Foreign exchange impact	Other	Balance Dec. 31, 2024
Long-term debt and lease liabilities <sup>(2)</sup>	3,469	232	6	5	—	86	11	3,809
Exchangeable securities	744	—	—	—	—	—	6	750
Dividends payable (common and preferred)	49	—	(123)	—	123	—	—	49
<b>Total liabilities from financing activities</b>	<b>4,262</b>	<b>232</b>	<b>(117)</b>	<b>5</b>	<b>123</b>	<b>86</b>	<b>17</b>	<b>4,608</b>

(1) Includes a decrease of \$131 million related to the repayment of long-term debt, a \$143 million net increase in borrowings under credit facilities and a decrease in finance lease obligations of \$6 million.

(2) Includes bank overdraft of \$1 million and new debt assumed of \$232 million as part of the Heartland acquisition. Refer to Note 4.

## 34. Capital

TransAlta's capital is comprised of the following:

As at Dec. 31	2025	2024	Increase/ (decrease)
Long-term debt <sup>(1)</sup>	3,593	3,808	(215)
Exchangeable securities	750	750	—
Bank overdraft	—	1	(1)
Equity			
Common shares	3,169	3,179	(10)
Preferred shares	942	942	—
Contributed surplus	42	42	—
Deficit	(2,730)	(2,458)	(272)
Accumulated other comprehensive (loss) income	(24)	41	(65)
Non-controlling interests	66	97	(31)
Less: Available cash and cash equivalents <sup>(2)</sup>	(205)	(337)	132
Less: Principal portion of restricted cash on TransAlta OCP bonds <sup>(3)</sup>	(17)	(17)	—
Less: Fair value of hedging instruments on long-term debt, liability (asset) <sup>(4)</sup>	4	(7)	11
<b>Total capital</b>	<b>5,590</b>	<b>6,041</b>	<b>(451)</b>

(1) Includes lease liabilities, amounts outstanding under credit facilities, tax equity liabilities and current portion of long-term debt.

(2) The Company includes available cash and cash equivalents, as a reduction in the calculation of capital, as capital is managed using a net debt position. These funds may be available and used to facilitate repayment of debt.

(3) The Company includes the principal portion of restricted cash on TransAlta OCP bonds as this cash is restricted specifically to repay outstanding debt.

(4) The Company includes the fair value of economic and designated hedging instruments on debt in an asset, or liability position as a reduction, or an increase, in the calculation of capital, as the carrying value of the related debt has either increased, or decreased, due to changes in foreign exchange rates.

The Company's overall capital management strategy and its objectives in managing capital are as follows:

### A. Maintain a Strong Financial Position

The Company operates in a long-cycle and capital-intensive commodity business and it is therefore a priority to maintain a strong financial position that enables the Company to access capital markets at reasonable interest rates. Maintaining a strong balance sheet also allows our commercial team to contract the Company's portfolio with a variety of counterparties on terms and prices that are favourable to the Company's financial results and provides the Company with better access to capital markets through commodity and credit cycles. The Company has an investment grade credit rating from Morningstar DBRS. In 2025, Moody's reaffirmed the Company's long-term rating of Ba1 with a stable outlook. Morningstar DBRS reaffirmed the Company's issuer rating and unsecured debt/medium-term notes rating of BBB (low) and the Company's preferred shares rating of Pfd-3 (low), all with stable outlooks, and

S&P Global Ratings reaffirmed the Company's senior unsecured debt rating and issuer credit rating of BB+ with a stable outlook. The Company remains focused on maintaining a strong financial position and cash flow coverage ratios. Credit ratings provide information relating to the Company's financing costs, liquidity and operations and affect the Company's ability to obtain short and long-term financing and/or the cost of such financing. Management routinely monitors forecasted net earnings, cash flows, capital expenditures and scheduled repayment of debt with a goal of maintaining its credit ratings and to meet dividend and PP&E expenditure requirements.

### B. Liquidity

The Company manages variations in working capital using existing liquidity under credit facilities to ensure sufficient cash and credit are available to fund operations, pay dividends, distribute payments to subsidiaries' non-controlling interests and invest in PP&E.

For the years ended Dec. 31, 2025 and 2024, cash inflows and outflows are summarized below.

Year ended Dec. 31	2025	2024	Increase (decrease)
Cash flow from operating activities	646	796	(150)
Change in non-cash working capital	(3)	(38)	35
Cash flow from operations before changes in working capital	643	758	(115)
Dividends paid on common shares	(74)	(71)	(3)
Dividends paid on preferred shares	(52)	(52)	—
Distributions paid to subsidiaries' non-controlling interests	(11)	(40)	29
Property, plant and equipment expenditures	(249)	(311)	62
<b>Inflow</b>	<b>257</b>	<b>284</b>	<b>(27)</b>

TransAlta maintains sufficient cash balances and committed credit facilities to fund periodic net cash outflows related to its business. At Dec. 31, 2025, \$1.5 billion (2024 – \$1.5 billion) of the Company's credit facilities were fully available.

From time to time, TransAlta accesses capital markets, as required, to help fund some of these periodic net cash outflows to maintain its available liquidity and maintain its capital structure and credit metrics within targeted ranges.

## 35. Related-Party Transactions

Details of the Company's principal operating subsidiaries at Dec. 31, 2025, are as follows:

Subsidiary	Country	Ownership (per cent)	Principal activity
TransAlta Generation Partnership	Canada	100	Generation and sale of electricity
TransAlta Cogeneration, L.P.	Canada	50.01	Generation and sale of electricity
TransAlta Centralia Generation, LLC	U.S.	100	Generation and sale of electricity
TransAlta Energy Marketing Corp.	Canada	100	Energy marketing
TransAlta Energy Marketing (U.S.), Inc.	U.S.	100	Energy marketing
TransAlta Energy (Australia), Pty Ltd.	Australia	100	Generation and sale of electricity
TransAlta Renewables Inc.	Canada	100	Generation and sale of electricity
Heartland Generation Ltd.	Canada	100 <sup>(1)</sup>	Generation and sale of electricity
Alberta Power (2000) Ltd.	Canada	100 <sup>(1)</sup>	Generation and sale of electricity

(1) On Dec. 4, 2024, the Company completed the acquisition of Heartland. Refer to Note 4 for more details.

Transactions between the Company and its subsidiaries have been eliminated on consolidation and are not disclosed.

Joint arrangements at Dec. 31, 2025, included the following:

Joint operations	Segment	Ownership (per cent)	Description
Goldfields Power	Gas	50	Gas-fired facility in Western Australia operated by TransAlta
Fort Saskatchewan	Gas	60	Cogeneration facility in Alberta, of which TA Cogen has a 60 per cent interest, operated by TransAlta
Fortescue River Gas Pipeline	Gas	43	Natural gas pipeline in Western Australia, operated by DBP Development Group
McBride Lake	Wind and Solar	50	Wind generation facility in Alberta operated by TransAlta
Soderglen	Wind and Solar	50	Wind generation facility in Alberta operated by TransAlta
Pingston	Hydro	50	Hydro facility in British Columbia operated by TransAlta
Joffre	Gas	40	Cogeneration plant in Alberta operated by TransAlta
McMahon	Gas	50	Cogeneration plant in British Columbia operated by NorthRiver Midstream Inc.
Primrose	Gas	50	Cogeneration plant in Alberta operated by Canadian Natural Resources Limited

Joint venture	Segment	Ownership (per cent)	Description
Skookumchuck	Wind and Solar	49	Wind generation facility in Washington operated by Southern Power

Associates and joint ventures have been equity accounted for by the Company.

## A. Transactions with Key Management Personnel

TransAlta's key management personnel include the President and Chief Executive Officer (CEO), members of the senior management team and the members of the Board. Key management personnel compensation is as follows:

Year ended Dec. 31	2025	2024
Total compensation	22	36
Comprising:		
Short-term employee benefits	12	13
Post-employment benefits	1	1
Termination benefits	1	4
Share-based payments	8	18

## B. Transactions with Associates

In connection with the exchangeable securities issued to Brookfield, the Investment Agreement entitles Brookfield to nominate two directors to the TransAlta Board. This allows Brookfield to participate in the financial and operating policy decisions of the Company, and as such, they are considered associates of the Company.

In addition to the exchangeable securities disclosed in Note 26, the Company may, in the normal course of operations,

enter into transactions on market terms with associates that have been measured at exchange value and recognized in the Consolidated Financial Statements, including power purchase and sale agreements, derivative contracts and asset management fees. Transactions and balances between the Company and associates do not eliminate.

Transactions with Brookfield include the following:

Year ended Dec. 31	2025	2024
Power sales	98	58
Purchased power	2	4

## 36. Commitments and Contingencies

In addition to the commitments disclosed elsewhere in the financial statements, the Company has incurred the following contractual commitments, either directly or through its interests in joint operations and joint ventures.

Approximate future payments under these agreements are as follows:

	2026	2027	2028	2029	2030	2031 and thereafter	Total
Natural gas, transportation and other contracts	83	67	67	63	62	350	692
Transmission	29	31	22	20	21	114	237
Long-term service agreements	55	44	21	14	15	105	254
Operating leases	5	2	2	2	2	59	72
Growth	7	—	11	—	—	—	18
<b>Total</b>	<b>179</b>	<b>144</b>	<b>123</b>	<b>99</b>	<b>100</b>	<b>628</b>	<b>1,273</b>

### Commitments

#### Natural Gas, Transportation and Other Contracts

The Company has natural gas transportation contracts, for a total of up to 400 terajoules (TJ) per day on a firm basis, related to the Sundance and Keephills facilities, ending in 2036 to 2038. In addition, the Company has natural gas transportation agreements for approximately 150 TJ per day for Sheerness. The Company currently expects to use approximately 160 TJ per day on average and up to approximately 450 TJ per day during peak periods, while remarketing excess capacity.

#### Transmission

The Company has several agreements to purchase transmission network capacity in the Pacific Northwest. Provided certain conditions for delivering the service are met, the Company is committed to the transmission at the supplier's tariff rate whether it is awarded immediately or delivered in the future after additional facilities are constructed.

Transmission commitments also include multi-year U.S.-dollar-denominated contracts to secure transmission capacity. The majority of the transmission capacity supports a dedicated revenue capacity agreement, held with a counterparty in the U.S., for similar duration as the associated transmission capacity.

#### Long-Term Service Agreements

TransAlta has various service agreements in place, primarily for inspections, repairs and maintenance that may be required on natural gas facilities, equipment for gas and turbines at various wind facilities.

#### Operating Leases

Operating leases include lease commitments not recognized under IFRS 16 and lease commitments that have not yet commenced, mainly related to buildings, vehicles and land. Certain lease commitments extend out to 2072 which is the end of life of the related facilities.

#### Growth

Commitments for growth include primarily payments towards early-stage development projects in Alberta.

## Contingencies

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

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

### Brazeau Facility – Well Licence Applications to Consider Hydraulic Fracturing Activities

The Alberta Energy Regulator (AER) issued a subsurface order on May 27, 2019, which does not permit any hydraulic fracturing within three kilometres of the Brazeau facility, but permits hydraulic fracturing in all formations (except the Duvernay) within three to five kilometres of the Brazeau facility.

## 37. Segment Disclosures

### A. Description of Reportable Segments

The Company has six reportable segments as described in Note 1.

The following tables provides each segment's results in the format that the TransAlta's President and Chief Executive Officer (the chief operating decision maker) (CODM) reviews the Company's segments to make operating decisions and assess performance. The CODM assesses the performance of the operating segments based on a measure of adjusted EBITDA. This measurement basis represents (loss) earnings before income taxes, adjusted for the effects of: depreciation of property, plant and equipment and amortization of intangibles, depreciation of right-of-use assets, finance lease income, unrealized mark-to-market gains or losses, unrealized foreign exchange gains or losses on commodity transactions, Brazeau penalties, acquisition-related transaction and restructuring costs, ERP integration costs, termination, restructuring and facility shutdown costs, revenues and fuel and purchased power related to the Required Divestitures, items within the Energy Transition segment that may not be reflective of ongoing operations

Subsequently, two oil and gas operators submitted applications to the AER for 10 well licences (which include hydraulic fracturing activities) within three to five kilometres of the Brazeau facility.

The Company's position, based on independent expert analysis commissioned by the Government of Alberta, is that hydraulic fracturing activities within five kilometres of the Brazeau facility pose an unacceptable risk and that the applications should be denied. The regulatory hearing to consider these applications - Proceeding 379 - has been adjourned to the fourth quarter of 2026.

### Brazeau Facility – Claim against the Government of Alberta

On Sept. 9, 2022, the Company filed a Statement of Claim against the Government of Alberta in the Alberta Court of King's Bench seeking a declaration that: (a) granting mineral leases within five kilometres of the Brazeau facility is a breach of a 1960 agreement between the Company and the Government of Alberta; and (b) the Government of Alberta is required to indemnify the Company for any costs or damages that result from the risks of hydraulic fracturing near the Brazeau facility. On Sept. 29, 2022, the Government of Alberta filed its Statement of Defence, which asserts, among other things, that the Company: (a) is trying to usurp the jurisdiction of the AER; and (b) is out of time under the *Limitations Act* (Alberta). The trial is scheduled to be heard in the second or third quarter of 2026 if the parties are unable to resolve the dispute before then.

including certain costs related to decisions made to accelerate our transition off-coal in Alberta and our planned transition off-coal for Centralia, fair value change in contingent consideration, Sundance A decommissioning costs reimbursement, insurance recoveries, asset impairment (reversals) charges, share of profit or loss of joint venture and other costs or income adjustments.

For internal reporting purpose, the earnings information from the Company's investment in Skookumchuck has been presented in the Wind and Solar segment on a proportionate basis. Information on a proportionate basis reflects the Company's share of Skookumchuck's statement of earnings on a line-by-line basis. Proportionate financial information is not and is not intended to be, presented in accordance with IFRS. Under IFRS, the investment in Skookumchuck has been accounted for as a joint venture using the equity method.

The tables below show the reconciliation of the total segmented results and Adjusted EBITDA to the statement of earnings reported under IFRS.

## B. Reported Adjusted Segment Earnings and Segment Assets

### I. Reconciliation of Adjusted EBITDA to Earnings before Income Tax

Year ended Dec. 31, 2025	Hydro	Wind & Solar <sup>(1)</sup>	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments <sup>(1)</sup>	Reclass adjustments	IFRS financials
Revenues	368	227	1,267	495	130	(61)	2,426	(21)	—	2,405
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	(4)	265	26	9	(8)	—	288	—	(288)	—
Decrease in finance lease receivable	—	3	27	—	—	—	30	—	(30)	—
Finance lease income	—	5	18	—	—	—	23	—	(23)	—
Revenues from Required Divestitures	—	—	(11)	—	—	—	(11)	—	11	—
Unrealized foreign exchange gain on commodity	—	—	1	—	—	—	1	—	(1)	—
<b>Adjusted Revenue</b>	<b>364</b>	<b>500</b>	<b>1,328</b>	<b>504</b>	<b>122</b>	<b>(61)</b>	<b>2,757</b>	<b>(21)</b>	<b>(331)</b>	<b>2,405</b>
Fuel and purchased power	(20)	(31)	(549)	(328)	—	(7)	(935)	—	—	(935)
Reclassifications and adjustments:										
Fuel and purchased power related to Required Divestitures	—	—	2	—	—	—	2	—	(2)	—
<b>Adjusted Fuel and Purchased Power</b>	<b>(20)</b>	<b>(31)</b>	<b>(547)</b>	<b>(328)</b>	<b>—</b>	<b>(7)</b>	<b>(933)</b>	<b>—</b>	<b>(2)</b>	<b>(935)</b>
Carbon compliance (costs) recovery	—	(3)	(115)	—	—	68	(50)	—	—	(50)
<b>Adjusted Gross Margin</b>	<b>344</b>	<b>466</b>	<b>666</b>	<b>176</b>	<b>122</b>	<b>—</b>	<b>1,774</b>	<b>(21)</b>	<b>(333)</b>	<b>1,420</b>
OM&A	(56)	(106)	(257)	(75)	(37)	(185)	(716)	5	—	(711)
Reclassifications and adjustments:										
Termination, restructuring and facility shutdown costs	—	—	1	2	—	12	15	—	(15)	—
OM&A related to required divestitures	—	—	5	—	—	—	5	—	(5)	—
ERP integration costs	—	—	—	—	—	25	25	—	(25)	—
Acquisition-related transaction and restructuring costs	—	—	—	—	—	7	7	—	(7)	—
<b>Adjusted OM&amp;A</b>	<b>(56)</b>	<b>(106)</b>	<b>(251)</b>	<b>(73)</b>	<b>(37)</b>	<b>(141)</b>	<b>(664)</b>	<b>5</b>	<b>(52)</b>	<b>(711)</b>
Taxes, other than income taxes	(3)	(23)	(21)	(3)	—	(1)	(51)	1	—	(50)
Net other operating income	—	3	44	—	—	—	47	—	—	47
Reclassifications and adjustments:										
Insurance recovery	—	(2)	—	—	—	—	(2)	—	2	—
Adjusted Net Other Operating Income	—	1	44	—	—	—	45	—	2	47
<b>Adjusted EBITDA<sup>(2)</sup></b>	<b>285</b>	<b>338</b>	<b>438</b>	<b>100</b>	<b>85</b>	<b>(142)</b>	<b>1,104</b>			
Equity income										6
Finance lease income										23
Depreciation and amortization										(579)
Asset impairment reversals										13
Interest income										28
Interest expense										(347)
Foreign exchange loss										(21)
Fair value change in contingent consideration										37
Loss on sale of assets and other										(7)
<b>Loss before income taxes</b>										<b>(141)</b>

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

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

## Notes to the Consolidated Financial Statements

Year ended Dec. 31, 2024	Hydro	Wind & Solar <sup>(1)</sup>	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity-accounted investments <sup>(1)</sup>	Reclass adjustments	IFRS financials
Revenues	409	357	1,350	616	168	(34)	2,866	(21)	—	2,845
Reclassifications and adjustments:										
Unrealized mark-to-market loss (gain)	1	84	(60)	(36)	14	—	3	—	(3)	—
Decrease in finance lease receivable	—	2	19	—	—	—	21	—	(21)	—
Finance lease income	—	6	8	—	—	—	14	—	(14)	—
Revenues from Required Divestitures	—	—	(1)	—	—	—	(1)	—	1	—
Brazeau penalty	(20)	—	—	—	—	—	(20)	—	20	—
Unrealized foreign exchange gain on commodity	—	—	(2)	—	—	—	(2)	—	2	—
Adjusted Revenues	390	449	1,314	580	182	(34)	2,881	(21)	(15)	2,845
Fuel and purchased power	(16)	(30)	(475)	(418)	—	—	(939)	—	—	(939)
Reclassifications and adjustments:										
Fuel and purchased power related to the Required Divestitures	—	—	1	—	—	—	1	—	(1)	—
Adjusted Fuel and Purchased Power	(16)	(30)	(474)	(418)	—	—	(938)	—	(1)	(939)
Carbon compliance costs	—	—	(145)	(1)	—	34	(112)	—	—	(112)
Adjusted Gross Margin	374	419	695	161	182	—	1,831	(21)	(16)	1,794
OM&A	(86)	(97)	(198)	(69)	(36)	(173)	(659)	4	—	(655)
Reclassifications and adjustments:										
Brazeau penalties	31	—	—	—	—	—	31	—	(31)	—
ERP integration costs	—	—	—	—	—	14	14	—	(14)	—
Acquisition-related transaction and restructuring costs	—	—	—	—	—	24	24	—	(24)	—
Adjusted OM&A	(55)	(97)	(198)	(69)	(36)	(135)	(590)	4	(69)	(655)
Taxes, other than income taxes	(3)	(16)	(13)	(3)	—	(1)	(36)	—	—	(36)
Net other operating income	—	10	40	9	—	—	59	—	—	59
Reclassifications and adjustments:										
Sundance A decommissioning cost	—	—	—	(9)	—	—	(9)	—	9	—
Adjusted Net Other Operating Income	—	10	40	—	—	—	50	—	9	59
Adjusted EBITDA <sup>(2)(3)</sup>	316	316	524	89	146	(136)	1,255			
Equity income										5
Finance lease income										14
Depreciation and amortization										(531)
Asset impairment charges										(46)
Interest income										30
Interest expense										(324)
Foreign exchange gain										5
Gain on sale of assets and other										4
Earnings before income taxes										319

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

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

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

## II. Selected Consolidated Statements of Financial Position Information

<b>As at Dec. 31, 2025</b>	<b>Hydro</b>	<b>Wind and Solar</b>	<b>Gas</b>	<b>Energy Transition</b>	<b>Energy Marketing</b>	<b>Corporate</b>	<b>Total</b>
PP&E	514	3,223	1,664	163	—	101	5,665
Right-of-use assets	8	88	5	—	—	10	111
Intangible assets	14	113	79	3	1	33	243
Goodwill	258	177	51	—	30	—	516

<b>As at Dec. 31, 2024</b>	<b>Hydro</b>	<b>Wind and Solar</b>	<b>Gas</b>	<b>Energy Transition</b>	<b>Energy Marketing</b>	<b>Corporate</b>	<b>Total</b>
PP&E	501	3,428	1,805	206	—	80	6,020
Right-of-use assets	7	96	6	—	—	11	120
Intangible assets	3	133	108	4	3	30	281
Goodwill	258	178	51	—	30	—	517

## III. Selected Consolidated Statements of Cash Flows Information

Additions to non-current assets are as follows:

<b>Year ended Dec. 31, 2025</b>	<b>Hydro</b>	<b>Wind and Solar</b>	<b>Gas</b>	<b>Energy Transition</b>	<b>Energy Marketing</b>	<b>Corporate</b>	<b>Total</b>
Additions to non-current assets:							
PP&E	50	57	106	9	—	27	249
Intangible assets	—	—	—	—	—	11	11

<b>Year ended Dec. 31, 2024</b>	<b>Hydro</b>	<b>Wind and Solar</b>	<b>Gas</b>	<b>Energy Transition</b>	<b>Energy Marketing</b>	<b>Corporate</b>	<b>Total</b>
Additions to non-current assets:							
PP&E <sup>(1)</sup>	64	97	100	13	—	37	311
Intangible assets <sup>(1)</sup>	—	—	—	—	—	10	10

(1) Excludes additions attributable to the Heartland acquisition on Dec. 4, 2024.

## C. Geographic Information

### I. Revenues

Year ended Dec. 31	2025	2024
Canada	1,759	2,009
U.S.	497	676
Western Australia	149	160
<b>Total revenue</b>	<b>2,405</b>	<b>2,845</b>

### II. Non-Current Assets

As at Dec. 31	Property, plant and equipment		Right-of-use assets		Intangible assets		Other assets	
	2025	2024	2025	2024	2025	2024	2025	2024
Canada	3,624	3,828	39	41	149	170	73	85
U.S.	1,677	1,852	67	74	70	86	24	36
Western Australia	364	340	5	5	24	25	59	58
<b>Total</b>	<b>5,665</b>	<b>6,020</b>	<b>111</b>	<b>120</b>	<b>243</b>	<b>281</b>	<b>156</b>	<b>179</b>

## 38. Subsequent Events

### Acquisition of Far North

On Feb. 2, 2026, the Company acquired all issued and outstanding common shares of Far North Corporation (Far North) from an affiliate of Hut 8 Corp. (the Far North Acquisition). The Far North Acquisition, which includes Far North and its subsidiaries' entire business operations in Ontario consisting of four natural gas-fired generation facilities totaling 310 MW, was completed for an aggregate purchase price of \$95 million, subject to working capital and other adjustments. The Far North Acquisition was funded through a combination of cash on hand and draws on the Company's credit facilities.

The Far North Acquisition will be accounted for as a business combination using the acquisition method where

the acquired tangible assets and intangible assets, if any, and assumed liabilities are recorded at their estimated fair values at the date of acquisition. Any amount less than or exceeding the purchase price will be presented as goodwill or a bargain purchase gain, respectively.

The fair values of Far North's identifiable assets and liabilities to be assumed and the impact of applying acquisition accounting have not been fully determined. Due to the proximity of the acquisition date to the release date of the Company's Consolidated Financial Statements, the preliminary purchase price allocation will be disclosed in the Consolidated Financial Statements for the three months ended March 31, 2026.