TRANSALTA CORPORATION

Management's Discussion and Analysis

First Quarter Report for 2023

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

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This MD&A should be read in conjunction with the unaudited interim condensed consolidated financial statements of TransAlta Corporation as at and for the three months ended March 31, 2023 and 2022, and should also be read in conjunction with the audited annual consolidated financial statements and MD&A ("2022 Annual MD&A") contained within our 2022 Annual Integrated Report. In this MD&A, unless the context otherwise requires, "we", "our", "us", the "Company" and "TransAlta" refers to TransAlta Corporation and its subsidiaries. Our unaudited interim condensed consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") International Accounting Standards ("IAS") 34 Interim Financial Reporting for Canadian publicly accountable enterprises as issued by the International Accounting Standards Board ("IASB") and in effect at March 31, 2023. All tabular amounts in the following discussion are in millions of Canadian dollars unless otherwise noted. This MD&A is dated May 4, 2023. Additional information respecting TransAlta, including our Annual Information Form ("AIF") for the year ended Dec. 31, 2022, is available on SEDAR at **www.sedar.com**, on EDGAR at **www.sec.gov** and on our website at **www.transalta.com**. Information on or connected to our website is not incorporated by reference herein.

Forward-Looking Statements

This MD&A includes "forward-looking information" within the meaning of applicable Canadian securities laws and "forward-looking statements" within the meaning of applicable United States ("US") securities laws, including the United States Private Securities Litigation Reform Act of 1995 (collectively referred to herein as "forward-looking statements"). All forward-looking statements are based on our beliefs as well as assumptions based on information available at the time the assumptions were made and on management's experience and perception of historical trends, current conditions and expected future developments, as well as other factors deemed appropriate in the circumstances. Forward-looking statements are not facts, but only predictions and generally can be identified by the use of statements that include phrases such as "may", "will", "can", "could", "would", "shall", "believe", "expect", "estimate", "anticipate", "intend", "plan", "forecast", "foresee", "potential", "enable", "continue" or other comparable terminology. These statements are not guarantees of our future performance, events or results and are subject to risks, uncertainties and other important factors that could cause our actual performance, events or results to be materially different from that set out in or implied by the forward-looking statements.

In particular, this MD&A contains forward-looking statements including, but not limited to, statements relating to: our Clean Electricity Growth Plan and ability to achieve the target of 2 gigawatts ("GW") of incremental renewables capacity with an estimated capital investment of $3.6 billion that is expected to deliver incremental average annual EBITDA of $315 million; advancing an additional 374 MW of advanced-stage projects towards achieving final investment decision later in 2023; the Company's projects under construction, including the timing of commercial operations, expected annual EBITDA and associated costs, including in respect of the Horizon Hill wind project, the White Rock wind projects, Northern Goldfields solar project, Garden Plain wind project and the Mount Keith 132kV transmission expansion; the development of the early-stage Tent Mountain Renewable Energy Complex; the execution of the Company's early, and advanced-stage development pipeline, including the size, cost and expected EBITDA from such projects; the expansion of the Company's early stage development pipeline to 5 GW; the proportion of EBITDA to be generated from renewable sources by the end of 2025; the 2023 Financial Outlook (defined below), including adjusted EBITDA, free cash flow and annualized dividend per share; the Company's ability to enhance shareholder value through its NCIB (as defined below); the reduction of carbon emissions by 75 per cent from 2015 emissions levels by 2026; the rehabilitation of the Kent Hills 1 and 2 wind facilities, including, the timing and cost of such rehabilitation, the resulting impact of such rehabilitation on the Company's revenues and the potential battery storage project at and repowering of, the Kent Hills facilities; the expected impact and quantum of carbon compliance costs; the expected costs and impacts of reclamation activities associated with the Centralia facility; regulatory developments and their expected impact on the Company, including the Canadian federal climate plan and the implementation of the major aspects thereof (including increased carbon pricing and increased funding for clean technology), the proposed new Clean Electricity Regulation and the ability of the Company to realize benefits from Canadian, United States and Australian regulatory developments, including receiving funding or favourable tax treatment for clean electricity projects; the potential value of emission reduction credits; sustaining and productivity capital in 2023; expected power prices in Alberta, Ontario and the Pacific Northwest; AECO gas prices; the hedge assumptions for the remainder of 2023, 2024 and 2025, including production and price; the cyclicality of the business, including as it relates to maintenance costs, production and loads; expectations regarding refinancing debt maturing from 2023 and 2025; the Company continuing to maintain a strong financial position and significant liquidity without any significant impact from the current economic environment; and the Company's expectation that a portion of current tax expenses will reverse during the balance of the year as projects under construction are expected to be completed.

The forward-looking statements contained in this MD&A are based on many assumptions including, but not limited to, the following: no significant changes to applicable laws and regulations beyond those that have already been announced; no significant changes to fuel and purchased power costs; no material adverse impacts to long-term investment and credit markets; no significant changes to power price and hedging assumptions, including Alberta spot prices of$125 to $145 per MWh in 2023, Mid-Columbia spot prices of US$90 to US$100 per MWh in 2023, and AECO gas prices of $2.50 per GJ in 2023; hedged volumes and prices in 2023; sustaining capital of $140 million - $170 million in 2023; Energy Marketing gross margin of $130 million - $150 million in 2023; no significant changes to gas commodity prices and transport costs; no significant changes to the decommissioning and restoration costs of the retired Alberta assets; no significant changes to interest rates; no significant changes to the demand and growth of renewables generation; no significant changes to the Company's debt and credit ratings; and the Company's proportionate ownership of TransAlta Renewables Inc. ("TransAlta Renewables") not changing materially.

Forward-looking statements are subject to a number of significant risks and uncertainties that could cause actual plans, performance, results or outcomes to differ materially from current expectations. Factors that may adversely impact what is expressed or implied by forward-looking statements contained in this MD&A include risks relating to: fluctuations in power prices, including lower merchant pricing in Alberta, Ontario and Mid-Columbia; reductions in production; restricted access to capital and increased borrowing costs, including any difficulty raising debt, equity or tax equity, as applicable, on reasonable terms or at all; reduced labour availability and ability to continue to staff our operations and facilities; disruptions to our supply chains, including our ability to secure necessary equipment; force majeure claims; our ability to obtain regulatory and any other third-party approvals on the expected timelines or at all in respect of our growth projects; risks associated with development and construction projects, including as it pertains to increased capital costs, permitting, labour and engineering risks, disputes with contractors and potential delays in the construction or commissioning of such projects; significant fluctuations in the Canadian dollar against the US dollar and Australian dollar; changes in short-term and long-term electricity supply and demand; counterparty credit risk and any higher rate of losses on our accounts receivables; inability to achieve our targets relating to ESG (as defined below); impairments and/or write-downs of assets; adverse impacts on our information technology systems and our internal control systems, including increased cybersecurity threats; commodity risk management and energy trading risks, including the effectiveness of the Company’s risk management tools associated with hedging and trading procedures to protect against significant losses; our ability to contract our generation for prices that will provide expected returns and to replace contracts as they expire; changes to the legislative, regulatory and political environments in the jurisdictions in which we operate; environmental requirements and changes in, or liabilities under, these requirements; disruptions in the transmission and distribution of electricity; the effects of weather, including man-made or natural disasters and other climate-change related risks; increases in costs; reductions to our generating units’ relative efficiency or capacity factors; disruptions in the source of fuels, including natural gas, coal, water, solar or wind resources required to operate our facilities; operational risks, unplanned outages and equipment failure and our ability to carry out or have completed any repairs in a cost-effective or timely manner or at all, including as it applies to the rehabilitation and replacement of turbine foundations of the Kent Hills 1 and 2 wind facilities; general economic risks, including deterioration of equity markets, increasing interest rates or rising inflation; failure to meet financial expectations; general domestic and international economic and political developments; armed hostilities, including the war in Ukraine and associated impacts; the threat of terrorism; adverse diplomatic developments or other similar events that could adversely affect our business; industry risk and competition; fluctuations in the value of foreign currencies; structural subordination of securities; public health crisis risks, including any further impacts of COVID-19; changes to our relationship with, or ownership of, TransAlta Renewables; changes in the payment or receipt of future dividends, including from TransAlta Renewables; inadequacy or unavailability of insurance coverage; our provision for income taxes and any risk of reassessment; legal, regulatory and contractual disputes and proceedings involving the Company; reliance on key personnel; and labour relations matters. The foregoing risk factors, among others, are described in further detail in the Governance and Risk Management section of our 2022 Annual MD&A and the Risk Factors section in our AIF for the year ended Dec. 31, 2022.

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

Description of the Business

Portfolio of Assets

TransAlta is a Canadian corporation and one of Canada's largest publicly traded power generators with over 111 years of operating experience. We own, operate and manage a geographically diversified portfolio of assets utilizing a broad range of input resources that includes water, wind, solar, natural gas and thermal coal. We are one of the largest producers of wind power in Canada and the largest producer of hydro power in Alberta.

The following table provides our consolidated ownership of our facilities across the regions in which we operate as of March 31, 2023:

As at March 31, 2023		Hydro	Wind and Solar	Gas	Energy Transition	Total
Alberta	Gross installed capacity (MW)(1)	834	636	1,960	—	3,430
	Number of facilities	17	13	7	—	37
	Weighted average contract life (years)(2)(3)(4)	—	6	1	—	2
Canada, Excluding Alberta	Gross installed capacity (MW)(1)	88	751	645	—	1,484
	Number of facilities	7	9	3	—	19
	Weighted average contract life (years)(3)	6	11	9	—	10
US	Gross installed capacity (MW)(1)	—	519	29	671	1,219
	Number of facilities	—	7	1	2	10
	Weighted average contract life (years)(3)	—	11	3	3	6
Australia	Gross installed capacity (MW)(1)	—	—	450	—	450
	Number of facilities	—	—	6	—	6
	Weighted average contract life (years)(3)	—	—	16	—	16
Total	**Gross installed capacity (MW)(1)**	**922**	**1,906**	**3,084**	**671**	**6,583**
	Number of facilities	**24**	**29**	**17**	**2**	**72**
	Weighted average contract life (years)(3)	**1**	**9**	**5**	**3**	**5**

(1) Gross installed capacity for consolidated reporting represents 100 per cent output of a facility. Capacity figures for the Wind and Solar segment includes 100 per cent of the Kent Hills wind facilities; Gas includes 50 per cent of the Ottawa and Windsor facilities, 100 per cent of the Poplar Creek facility, 50 per cent of the Sheerness facility and 60 per cent of the Fort Saskatchewan facility.

(2) The weighted average contract life for Hydro and certain gas and wind assets in Alberta are nil as they are operating primarily on a merchant basis in the Alberta market. Refer to the Alberta Electricity Portfolio section of this MD&A for more information.

(3) For power generated under long-term power purchase agreements ("PPA"), power hedge contracts and short-term and long-term industrial contracts, the PPAs have a weighted-average remaining contract life based on long-term average gross installed capacity.

(4) The weighted-average remaining contract life is related to the contract period for McBride Lake (38 MW), Windrise (206 MW), Poplar Creek (115 MW) and Fort Saskatchewan (71 MW), with the remaining wind and gas facilities operated on a merchant basis in the Alberta market.

Highlights

Consolidated Financial Highlights

	3 months ended March 31	
(in millions of Canadian dollars except where noted)	2023	2022
Adjusted availability (%)	**92.0**	89.1
Production (GWh)	**5,972**	5,359
Revenues	**1,089**	735
Fuel and purchased power	**325**	238
Carbon compliance	**32**	19
Operations, maintenance and administration	**124**	112
Adjusted EBITDA(1)(2)	**503**	259
Earnings before income taxes	**383**	242
Net earnings attributable to common shareholders	**294**	186
Cash flow from operating activities	**462**	451
Funds from operations(1)(2)	**374**	179
Free cash flow(1)(2)	**263**	108
Net earnings per share attributable to common shareholders, basic and diluted	**1.10**	0.69
Funds from operations per share(1)(3)	**1.40**	0.66
Free cash flow per share(1)(3)	**0.98**	0.40

As at	March 31, 2023	Dec. 31, 2022
Total assets	**9,857**	10,741
Total consolidated net debt(1)(4)	**2,722**	2,854
Total long-term liabilities	**5,793**	5,864
Total liabilities	**7,624**	8,752

(1) These items are not defined and have no standardized meaning under IFRS. Presenting these items from period to period provides management and investors with the ability to evaluate earnings (loss) trends more readily in comparison with prior periods' results. Refer to the Segmented Financial Performance and Operating Results section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS. Also, refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

(2) During the second quarter of 2022, our adjusted EBITDA composition was amended to include the impact of closed exchange positions that are effectively settled by offsetting positions with the same counterparty to reflect the performance of the assets and the Energy Marketing segment in the period in which the transactions occur. The Company has applied this composition to all previously reported periods.

(3) Funds from operations ("FFO") per share and free cash flow ("FCF") per share are calculated using the weighted average number of common shares outstanding during the period. The weighted average number of common shares outstanding for March 31, 2023, was 268 million shares (March 31, 2022 – 271 million). Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A for the purpose of these non-IFRS ratios.

(4) Total consolidated net debt includes long-term debt, including the current portion, amounts due under credit facilities, exchangeable securities, US tax equity financing and lease liabilities, net of available cash and cash equivalents, the principal portion of restricted cash on our subsidiary TransAlta OCP LP ("TransAlta OCP") and the fair value of economic hedging instruments on debt. Refer to the table in the Financial Capital section of this MD&A for more details on the composition of total consolidated net debt.

Adjusted availability for the three months ended March 31, 2023, was 92.0 per cent compared to 89.1 per cent for the same period in 2022. The increase was primarily due to lower unplanned outages related to Gas and Energy Transition and improved performance at the Windrise wind facility, partially offset by higher unplanned outages at our Alberta Hydro Assets.

Production for the three months ended March 31, 2023, was 5,972 gigawatt hours ("GWh") compared to 5,359 GWh for the same period in 2022. Overall, the increase in production in the Gas and Energy Transition segments was due to stronger market conditions in Alberta and the Pacific Northwest and from higher fleet availability. This was partially offset by lower production in Ontario from weaker market conditions, lower wind resources in all regions and icing constraints at our Alberta Hydro Assets.

Revenues for the three months ended March 31, 2023, increased by $354 million compared to the same period in 2022, mainly as a result of increased production, higher realized energy prices within the Alberta electricity market, higher realized ancillary services prices in the Hydro segment and increased production and pricing in the Energy Transition segment from the Centralia facility. In addition, the Company captured revenue through forward hedging for the Alberta Hydro Assets and realized gains from the hedging strategy compared to the same period in 2022. The Hydro and Wind and Solar segments also had higher environmental attribute revenues partially offset by lower production. Energy Marketing revenues were higher mainly due to short-term trading of both physical and financial power and gas products across all North American deregulated markets.

Fuel and purchased power costs for the three months ended March 31, 2023, increased by $87 million compared to the same period in 2022, mainly due to higher purchased power and higher coal costs in the Energy Transition segment.

Carbon compliance costs for the three months ended March 31, 2023, increased by $13 million compared to the same period in 2022, primarily due an increase in the carbon price per tonne and higher production in the Gas segment.

Operations, maintenance and administration ("OM&A") expenses for the three months ended March 31, 2023, increased by $12 million compared to the same period in 2022. OM&A expenses increased primarily due to higher spending on strategic and growth initiatives, increased costs due to inflationary pressures and higher performance-related incentive accruals for the Energy Marketing segment.

Adjusted EBITDA for the three months ended March 31, 2023, increased by $244 million compared to the same period in 2022. The increase is largely due to increased revenue from the Alberta electricity portfolio, driven primarily by gas, hydro and wind facilities as a result of higher merchant prices, increased revenue in the Energy Transition segment due to higher production at Centralia Unit 2 and stronger market prices in the Pacific Northwest and higher production in the Gas segment due to stronger market conditions in Alberta. Adjusted EBITDA was further improved by higher ancillary services revenues in Hydro, higher environmental attribute revenues in the Hydro and Wind and Solar segments and higher earnings from the Energy Marketing segment due to short-term trading of both physical and financial power and gas products across all North American deregulated markets. These increases were partially offset by higher fuel and purchased power resulting from higher market price of coal and higher coal usage, higher carbon compliance costs in the Gas segment due to higher carbon price per tonne and higher gas production, lower production in the Wind and Solar segment due to stronger wind resources in the first quarter of 2022 and higher OM&A in the Energy Marketing and Corporate segments. Changes in segmented adjusted EBITDA are discussed in the Segmented Financial Performance and Operating Results section of this MD&A.

Earnings before income taxes for the three months ended March 31, 2023, increased by $141 million compared to the same period in 2022. **Net earnings attributable to common shareholders** for the three months ended March 31, 2023, were $294 million compared to $186 million in the same period in 2022. During the first quarter of 2023, the Company benefited from higher revenues, partially offset by higher fuel and purchased power, higher carbon compliance costs, higher depreciation due to the acceleration of useful lives on certain facilities in 2022, higher OM&A costs related to the Corporate and Energy Marketing segments, lower asset impairment reversals, and higher income tax expense due to higher earnings before tax. Net earnings attributable to common shareholders in the current period were impacted by higher net earnings allocated to non-controlling interests.

Cash flow from operating activities for the three months ended March 31, 2023, increased by $11 million compared with the same period in 2022, primarily due to higher revenues net of unrealized gains and losses from risk management activities. This was partially offset by higher unfavourable changes in working capital, mainly from changes in collateral paid and received and higher fuel and purchase power and carbon compliance costs.

FCF, one of the Company's key financial metrics, totaled $263 million for the three months ended March 31, 2023 compared to $108 million in the same period in 2022. This represents an increase of $155 million, driven primarily by higher adjusted EBITDA and lower interest expense. This was partially offset by higher current income tax expense, higher distributions paid to subsidiaries' non-controlling interests and changes in provisions compared to 2022. The Company expects a portion of the current tax expenses to reverse during the balance of the year as projects under construction are completed including the Garden Plain wind project and projects in Australia.

Significant and Subsequent Events

Annual Shareholder Meeting

On April 28, 2023, the Company held its annual meeting of shareholders. All of the director nominees were elected to the Board, including Candace MacGibbon, a new member to the Board. The Company also received strong support on all other items of business, including say-on-pay and the proposed amendment to the Company's Share Unit Plan.

Automatic Share Purchase Plan

On March 27, 2023, the Company entered into an automatic share purchase plan ("ASPP") in order to facilitate repurchases of TransAlta's common shares under its previously announced normal course issuer bid ("NCIB"). The Company has received approval from the Toronto Stock Exchange to purchase up to 14,000,000 common shares during the 12-month period that commenced May 31, 2022 and terminates May 30, 2023, representing approximately 5.2 per cent of the Company's currently issued and outstanding Common Shares as at Dec. 31, 2022.

Under the ASPP, the Company's broker may purchase common shares from the effective date of the ASPP until the end of the NCIB. All purchases of common shares made under the ASPP will be included in determining the number of common shares purchased under the NCIB. Any common shares purchased by the Company pursuant to the NCIB will be cancelled. The ASPP will terminate on the earliest of the date on which: (a) the maximum purchase limits under the ASPP are reached; (ii) the NCIB expires; or (iii) the Company terminates the ASPP in accordance with its terms.

During the three months ended March 31, 2023, the Company purchased and cancelled a total of 3,169,300 common shares at an average price of $11.23 per common share, for a total cost of $36 million.

Early-Stage Pumped Hydro Development Project

On Feb. 16, 2023, the Company entered into a definitive agreement to acquire a 50 per cent interest in the Tent Mountain Renewable Energy Complex ("Tent Mountain"), an early-stage 320 MW pumped hydro energy storage development project, located in southwest Alberta, owned by Montem Resources Limited ("Montem"). The acquisition includes the land rights, fixed assets and intellectual property associated with the pumped hydro development project. The transaction closed on April 24, 2023. The Company paid Montem approximately $8 million on closing of the transaction and additional contingent payments of up to $17 million (approximately $25 million total) may become payable to Montem based on the achievement of specific development and commercial milestones. The Company and Montem own the Tent Mountain project within a special purpose partnership that is jointly managed, with the Company acting as project developer. The partnership is actively seeking an offtake agreement for the energy and environmental attributes generated by the facility.

Refer to the audited annual 2022 consolidated financial statements within our 2022 Annual Integrated Report and our unaudited interim condensed consolidated financial statements for the three months ended March 31, 2023, for significant events impacting both prior and current year results.

Segmented Financial Performance and Operating Results

Segmented information is prepared on the same basis that the Company manages its business, evaluates financial results and makes key operating decisions.

The following table reflects the generation and summary financial information on a consolidated basis for each of our segments:

	LTA generation (GWh)[1]		Actual production (GWh)[2]		Adjusted EBITDA[3]	
As at March 31,	2023	2022	2023	2022	2023	2022[4]
Hydro	**402**	408	**306**	372	**106**	61
Wind and Solar	**1,423**	1,423	**1,197**	1,269	**88**	89
Renewables	**1,825**	1,831	**1,503**	1,641	**194**	150
Gas			**3,172**	2,665	**240**	105
Energy Transition			**1,297**	1,053	**54**	5
Energy Marketing					**39**	17
Corporate					**(24)**	(18)
Total			**5,972**	5,359	**503**	259
Earnings before income taxes					**383**	242

(1) Long-term average production ("LTA Generation (GWh)") is calculated based on our portfolio as at March 31, 2023, on an annualized basis from the average annual energy yield predicted from our simulation model based on historical resource data performed over a period of typically greater than 25 years. LTA Generation (GWh) for Energy Transition is not considered as we are currently transitioning these units with the expectation that they will retire by the end of 2025 and the LTA Generation (GWh) for Gas is not considered as it is largely dependent on market conditions and merchant demand. LTA Generation (GWh) for the three months ended March 31, 2023, excluding the Kent Hills 1 and 2 wind facilities which are currently not in operation, is approximately 1,317 GWh.

(2) Actual production levels are compared against the long-term average to highlight the impact of an important factor that affects the variability in our business results. In the short-term, for each of the Hydro and Wind and Solar segments, the conditions will vary from one period to the next and over time facilities will continue to produce in line with their long-term averages, which has proven to be a reliable indicator of performance.

(3) This item is not defined and has no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

(4) Adjustments to the Gas and Energy Marketing segment were made for the impact of realized gains and losses on closed exchange positions. Refer to the Additional IFRS Measures and Non-IFRS Measures section under the Reconciliation of Non-IFRS Measures section of this MD&A.

Hydro

	3 months ended March 31	
	2023	**2022**
Gross installed capacity (MW)(1)	**922**	925
LTA (GWh)	**402**	408
Availability (%)	**94.1**	96.7
Production		
Contract production (GWh)	**23**	36
Merchant production (GWh)	**283**	336
Total energy production (GWh)	**306**	372
Ancillary service volumes (GWh)(2)	**643**	742
Alberta Hydro Assets revenues(3)(4)	**71**	36
Other Hydro Assets and other revenues(3)(5)	**6**	7
Alberta Hydro ancillary services revenues(2)	**39**	33
Environmental attribute revenues	**8**	1
Revenues(6)	**124**	77
Fuel and purchased power	**5**	4
Gross margin(7)	**119**	73
OM&A	**12**	11
Taxes, other than income taxes	**1**	1
Adjusted EBITDA(7)	**106**	61
Supplemental Information:		
Gross revenues per MWh		
Alberta Hydro Assets energy ($/MWh)(3)(4)	**258**	110
Alberta Hydro Assets ancillary ($/MWh)(2)	**60**	45
Sustaining capital	**6**	6

(1) In 2022, the Company closed the sale of two Hydro assets resulting in a reduction in capacity of 3 MW.
(2) Ancillary services as described in the AESO Consolidated Authoritative Document Glossary.
(3) Alberta Hydro Assets include 13 hydro facilities on the Bow and North Saskatchewan river systems. Other Hydro assets includes our hydro facilities in BC and Ontario, hydro facilities in Alberta (other than the Alberta Hydro Assets) and transmission revenues.
(4) The Company entered into forward hedges for the first quarter of 2023 that are included in the Alberta Hydro Asset revenues.
(5) Other revenue includes revenues from our transmission business and other contractual arrangements, including the flood mitigation agreement with the Government of Alberta and black start services.
(6) For details of the adjustments to revenues included in adjusted EBITDA refer to the Additional IFRS and Non-IFRS Measures section of this MD&A.
(7) Adjusted EBITDA and gross margin are not defined and have no standardized meaning under IFRS. Refer to the Additional IFRS and Non-IFRS Measures section of this MD&A.

Availability for the three months ended March 31, 2023, decreased compared to the same period in 2022, primarily due to higher unplanned outages at our Alberta Hydro Assets.

Production for the three months ended March 31, 2023, decreased by 66 GWh compared to the same period in 2022, mainly due to lower availability and icing constraints at our Alberta Hydro Assets.

Ancillary services volumes for the three months ended March 31, 2023, decreased by 99 GWh compared to the same period in 2022, due to lower availability.

Adjusted EBITDA for the three months ended March 31, 2023, increased by $45 million compared to the same period in 2022, primarily due to higher power and ancillary service prices in the Alberta market and higher environmental attribute revenues. In addition, the Company captured revenue through forward hedging for the Alberta Hydro Assets and realized gains from the hedging strategy in the first quarter of 2023. For further discussion on the Alberta market conditions and pricing, refer to the Alberta Electricity Portfolio section of this MD&A.

Sustaining capital expenditures for the three months ended March 31, 2023, were consistent compared to the same period in 2022.

Wind and Solar

	3 months ended March 31	
	2023	**2022**
Gross installed capacity (MW)	**1,906**	1,906
LTA (GWh)	**1,423**	1,423
Availability (%)	**82.9**	78.7
Contract production (GWh)	**871**	909
Merchant production (GWh)	**326**	360
Total production (GWh)	**1,197**	1,269
Wind and Solar revenues	**102**	101
Environmental attribute revenues	**13**	7
Revenues(1)	**115**	108
Fuel and purchased power	**9**	8
Gross margin(2)	**106**	100
OM&A	**17**	16
Taxes, other than income taxes	**3**	2
Net other operating income	**(2)**	(7)
Adjusted EBITDA(2)	**88**	89
Supplemental information:		
Sustaining capital	**3**	4
Kent Hills wind rehabilitation expenditures(3)	**21**	—
Insurance proceeds - Kent Hills	**(1)**	—

(1) For details of the adjustments to revenues included in adjusted EBITDA refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.
(2) Adjusted EBITDA and gross margin are not defined and have no standardized meaning under IFRS. Refer to the Additional IFRS and Non-IFRS Measures section of this MD&A.
(3) The Kent Hills wind facilities rehabilitation capital expenditures are segregated from the sustaining capital expenditures due to the extraordinary nature of the expenditures and have been reflected separately.

Availability for the three months ended March 31, 2023, increased compared to the same period in 2022, primarily as a result of the improved performance at the Windrise wind facility. Availability was impacted by the Kent Hills rehabilitation project which is expected to fully return to service in the second half of 2023. In addition, the Company experienced an extended forced outage at the Windrise facility in the first quarter of 2023 caused by a manufacturing defect on a transformer bushing. This has since been repaired under warranty and resolved.

Production for the three months ended March 31, 2023, decreased 72 GWh compared to the same period in 2022, primarily due to lower wind resources in all regions which was partially offset by increased availability.

Adjusted EBITDA for the three months ended March 31, 2023, decreased by $1 million compared to the same period in 2022, primarily due to lower production and lower liquidated damages recognized at the Windrise wind facility, partially offset by higher environmental attribute revenues and higher power pricing.

Sustaining capital expenditures for the three months ended March 31, 2023, were consistent compared to the same period in 2022.

Gas

	3 months ended March 31	
	2023	2022
Gross installed capacity (MW)	**3,084**	3,084
Availability (%)	**96.4**	93.8
Contract production (GWh)	**1,003**	939
Merchant production (GWh)	**2,249**	1,741
Purchased power (GWh)	**(80)**	(15)
Total production (GWh)	**3,172**	2,665
Revenues(1)	**435**	291
Fuel and purchased power(1)	**129**	130
Carbon compliance	**32**	18
Gross margin(2)	**274**	143
OM&A	**41**	44
Taxes, other than income taxes	**4**	4
Net other operating income	**(11)**	(10)
Adjusted EBITDA(2)	**240**	105
Supplemental information:		
Sustaining capital:	**3**	5

(1) For details of the adjustments to revenues and fuel and purchased power included in adjusted EBITDA, refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.
(2) Adjusted EBITDA and gross margin are not defined and have no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

Availability for the three months ended March 31, 2023, increased by 2.6 per cent compared to the same period in 2022, primarily due to lower unplanned outages.

Production for the three months ended March 31, 2023, increased by 507 GWh compared to the same period in 2022, mainly due to stronger market conditions for our Alberta merchant assets and higher availability, partially offset by lower contract and merchant production in Ontario due to weaker market conditions.

Adjusted EBITDA for the three months ended March 31, 2023, increased by $135 million compared to the same period in 2022, mainly due to higher realized energy prices for our Alberta merchant assets, net of hedging, lower natural gas prices and lower OM&A due to staffing reductions in Alberta. This was partially offset by increased natural gas consumption and carbon compliance costs driven by higher production, higher carbon price per tonne and lower Ontario merchant pricing and steam generation.

Sustaining capital expenditures for the three months ended March 31, 2023, decreased by $2 million compared to the same period in 2022, due to a reduction in planned projects.

Energy Transition

	3 months ended March 31	
	2023	**2022**
Gross installed capacity (MW)[(1)]	**671**	784
Availability (%)	**94.5**	88.5
Adjusted availability (%)[(2)]	**94.5**	88.5
Contract sales volume (GWh)	**820**	820
Merchant sales volume (GWh)	**1,343**	1,201
Purchased power (GWh)	**(866)**	(968)
Total production (GWh)	**1,297**	1,053
Revenues[(3)]	**253**	117
Fuel and purchased power	**181**	94
Carbon compliance	**—**	1
Gross margin[(4)]	**72**	22
OM&A	**17**	16
Taxes, other than income taxes	**1**	1
Adjusted EBITDA[(4)]	**54**	5
Supplemental information:		
Highvale mine reclamation spend	**2**	2
Centralia mine reclamation spend	**3**	4

(1) The gross installed capacity for the first quarter of 2023, excludes capacity for Sundance Unit 4 (113 MW retired on March 31, 2022).
(2) Adjusted for dispatch optimization.
(3) For details of the adjustments to revenues included in adjusted EBITDA refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.
(4) Adjusted EBITDA and gross margin are not defined and have no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

Adjusted availability for the three months ended March 31, 2023, increased compared with the same period in 2022 due to lower unplanned outages at Centralia Unit 2.

Production increased by 244 GWh for the three months ended March 31, 2023, compared to the same period in 2022, primarily due to increased production stemming from strong market prices in the Pacific Northwest and higher availability at Centralia Unit 2.

Adjusted EBITDA increased by $49 million for the three months ended March 31, 2023, as compared to the same period in 2022, primarily due to higher merchant prices and higher production, partially offset by higher purchased power and higher coal usage.

Mine reclamation spend for the Centralia mine decreased due to the timing of reclamation activities compared to 2022.

There was no sustaining capital incurred for both periods in 2023 and 2022.

Energy Marketing

	3 months ended March 31	
	2023	**2022**
Revenues[1]	**53**	24
OM&A	**14**	7
Adjusted EBITDA[2]	**39**	17

(1) For details of the adjustments to revenues included in adjusted EBITDA, refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A. Adjusted EBITDA is not defined and has no standardized meaning under IFRS.
(2) Adjusted EBITDA is not defined and has no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

Adjusted EBITDA for the three months ended March 31, 2023, increased by $22 million compared to the same period in 2022. Results exceeded segment expectations from short-term trading of both physical and financial power and gas products across all North American deregulated markets. The Company was able to capitalize on short-term volatility in the trading markets while maintaining the overall risk profile of the business unit.

Corporate

	3 months ended March 31	
	2023	**2022**
OM&A	**24**	18
Adjusted EBITDA[1]	**(24)**	(18)
Supplemental information:		
Sustaining capital:	**8**	2

(1) Adjusted EBITDA is not defined and has no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

Adjusted EBITDA for the three months ended March 31, 2023, decreased by $6 million compared to the same period in 2022, primarily due to recoveries realized in 2022, increased spending to support strategic and growth initiatives, lower allocations of corporate costs to the generation segments and increased costs due to inflationary pressures.

For the three months ended March 31, 2023, sustaining capital expenditures increased by $6 million, compared to the same period in 2022, mainly due to higher spend on information technology and leasehold improvements associated with the relocation of the Company's head office.

Performance by Segment with Supplemental Geographical Information

The following table provides adjusted EBITDA performance of our facilities across the regions we operate in:

3 months ended March 31, 2023	Hydro	Wind and Solar	Gas	Energy Transition[2]	Energy Marketing	Corporate	Total
Alberta	106	31	178	(2)	39	(24)	328
Canada, excluding Alberta	—	30	25	—	—	—	55
US	—	27	2	56	—	—	85
Australia	—	—	35	—	—	—	35
Adjusted EBITDA[1]	**106**	**88**	**240**	**54**	**39**	**(24)**	**503**
Earnings before income taxes							**383**

3 months ended March 31, 2022	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing[3]	Corporate	Total
Alberta	61	30	47	(3)	17	(18)	134
Canada, excluding Alberta	—	34	22	—	—	—	56
US	—	25	2	8	—	—	35
Australia	—	—	34	—	—	—	34
Adjusted EBITDA[1][4]	61	89	105	5	17	(18)	259
Earnings before income taxes							242

(1) Adjusted EBITDA is not defined and has no standardized meaning under IFRS. Presenting this from period to period provides management and investors with the ability to evaluate earnings (loss) trends more readily in comparison with prior periods' results. Refer to the Segmented Financial Performance and Operating Results section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS. Also, refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.
(2) The Sundance Unit 4 was retired March 31, 2022.
(3) The adjusted EBITDA for the Energy Marketing segment was reclassified to the Alberta region to reflect where the operations reside.
(4) In 2022, adjustments to the Gas and Energy Marketing segments were made for the impact of realized gains and losses on closed exchange positions. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

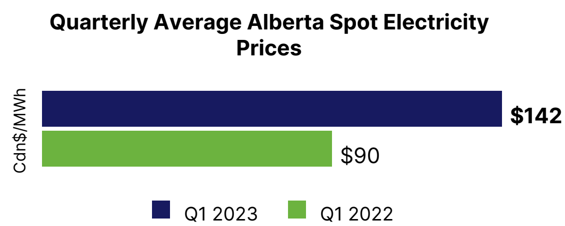
Alberta Electricity Portfolio

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

Approximately 52 per cent of our gross installed capacity is located in Alberta. Our portfolio of merchant assets in Alberta consists of hydro facilities, wind facilities, a battery storage facility, cogeneration facilities and converted natural-gas-fired thermal facilities. Some of the wind and gas facilities within the Alberta electricity portfolio operate on long-term contracts. Optimization of portfolio performance is driven by the diversity of fuel types, which enables portfolio management and allows for maximization of operating margins. It also provides us with capacity that can be monetized as ancillary services or dispatched into the energy market during times of supply tightness. A portion of the installed generation capacity in the portfolio has been hedged to provide cash flow certainty.

Alberta power prices for the first quarter of 2023 were higher compared to same period in 2022 as a result of generally higher demand in the province, and significantly lower net power imports due to stronger prices in adjacent power markets. As a result, demand growth was approximately 0.2% compared to the same period in 2022.

The average pool price increased as a result of these factors from $90 per MWh in 2022 to $142 per MWh in 2023.



3 months ended March 31	2023 Hydro	2023 Wind & Solar	2023 Gas	2023 Energy Transition	2023 Total	2022 Hydro	2022 Wind & Solar	2022 Gas	2022 Energy Transition	2022 Total
Total production (GWh)	**283**	**502**	**2,369**	**—**	**3,154**	336	503	1,718	19	2,576
Contract production (GWh)	**—**	**176**	**150**	**—**	**326**	—	142	133	—	275
Merchant production (GWh)	**283**	**326**	**2,219**	**—**	**2,828**	336	361	1,585	19	2,301
Revenues[(1)]	**121**	**44**	**325**	**2**	**492**	74	35	164	5	278
Fuel and purchased power	**4**	**7**	**103**	**—**	**114**	4	5	85	4	98
Carbon compliance	**—**	**—**	**29**	**—**	**29**	—	—	15	1	16
Gross margin	**117**	**37**	**193**	**2**	**349**	70	30	64	—	164

(1) Revenue has been adjusted to exclude the impact of unrealized mark-to-market gains or losses and realized gains and losses on closed exchange positions in order to depict revenue realized in the year.

For the three months ended March 31, 2023, the Alberta electricity portfolio generated 3,154 GWh of energy, an increase of 578 GWh compared to the same period in 2022. Higher production is mainly due to increased merchant production in the Gas segment driven by market opportunities, partially offset by lower production from the Hydro segment due to higher unplanned outages and icing constraints at our Alberta Hydro Assets.

Gross margin for the three months ended March 31, 2023, was $349 million, an increase of $185 million compared to the same period in 2022. Higher gross margin was the result of increased merchant production and higher realized prices for our Gas and Hydro segment, merchant hedging contributions and growing contribution from contracted wind.

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

	3 months ended March 31	
	2023	**2022**
Spot power price average per MWh	**$142**	$90
Natural gas price (AECO) per GJ	**$3.08**	$4.50
Carbon compliance price per tonne	**$65**	$50
Realized merchant power price per MWh(1)	**$156**	$107
Hydro energy spot power price per MWh	**$168**	$108
Hydro ancillary spot price per MWh	**$60**	$45
Wind energy spot power price per MWh	**$89**	$58
Gas and Energy Transition spot power price per MWh	**$156**	$103
Hedged volume (GWh)(2)	**2,046**	1,738
Hedged power price average per MWh	**$136**	$84
Fuel and purchased power per MWh(3)	**$48**	$56
Carbon compliance cost per MWh(3)	**$12**	$9

(1) Realized merchant power price for the Alberta electricity portfolio is the average price realized as a result of the Company's merchant power sales (excluding assets under long-term contract and ancillary revenues) and portfolio optimization activities divided by total merchant GWh produced.
(2) Hedge volumes are for production volumes primarily from the Gas segment.
(3) Fuel and purchased power per MWh and carbon compliance cost per MWh are calculated on production from carbon-emitting generation in the Gas and Energy Transition segments, and carbon compliance cost per MWh may include compliance credits to settle a portion of our GHG carbon pricing obligations.

For the three months ended March 31, 2023, the realized merchant power price per MWh of production increased by $49 per MWh, compared with the same period in 2022. Higher realized merchant power pricing for energy across the fleet was due to higher market prices and optimization of our available capacity across all fuel types. The segment spot prices exclude gains and losses from hedging positions that are entered into in order to mitigate the impact of unfavourable market pricing.

For the three months ended March 31, 2023, the fuel and purchased power cost per MWh of production decreased by $8 per MWh compared to the same period in 2022 primarily due to lower natural gas prices.

For the three months ended March 31, 2023, carbon compliance costs per MWh of production increased by $3 per MWh in the same period in 2022, due to an increase in carbon compliance prices from $50 per tonne in 2022 to $65 per tonne in 2023.

Selected Quarterly Information

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

	Q2 2022	Q3 2022	Q4 2022	Q1 2023
Revenues	458	929	854	**1,089**
Earnings (loss) before income taxes	(22)	126	7	**383**
Cash flow (used in) from operating activities[1]	(129)	204	351	**462**
Net earnings (loss) attributable to common shareholders	(80)	61	(163)	**294**
Net earnings (loss) per share attributable to common shareholders, basic and diluted[2]	(0.30)	0.23	(0.61)	**1.10**
	Q2 2021	**Q3 2021**	**Q4 2021**	**Q1 2022**
Revenues	619	850	610	735
Earnings (loss) before income taxes	72	(441)	(32)	242
Cash flow from operating activities	80	610	54	451
Net earnings (loss) attributable to common shareholders	(12)	(456)	(78)	186
Net earnings (loss) per share attributable to common shareholders, basic and diluted[2]	(0.04)	(1.68)	(0.29)	0.69

(1) The cash flow used in operating activities for the second quarter of 2022 was negative due to unfavourable changes in working capital mainly due to movements in our collateral accounts related to higher commodity prices and volatility in the markets.

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

Net earnings (loss) attributable to common shareholders over the prior eight quarters has also been impacted by the following variations and events:

- Higher revenues arising from higher overall availability during periods of peak pricing and higher power prices in Alberta in 2022 and 2023;
- Lower natural gas pricing in 2023 and higher natural gas pricing in 2022;
- Increased natural gas consumption in 2022 and 2023 for the units that were converted to gas in 2021;
- Lower carbon costs in 2022 related to our transition off coal and the utilization of renewable energy compliance credits to settle a portion of our GHG obligation in the second quarter of 2022. Higher carbon costs in the first quarter of 2023 was due to higher production and higher carbon costs per tonne;
- The continued extended outage of the Kent Hills 1 and 2 wind facilities from the fourth quarter of 2021 through the first quarter of 2023. The extended outage is expected to continue into second half of 2023;
- The effects of asset impairment reversals recognized in the first quarter of 2023 and the effects of asset impairment charges and reversals during all periods shown;
- The effects of changes in decommissioning provisions for retired assets from changes in discount rates in 2023;
- The effects of changes in decommissioning provisions for retired assets from changes in estimated cash flows and discount rates in all other periods shown;
- Accelerated timing of decommissioning cash flows and changes in useful lives recognized in the third quarter of 2022;
- Insurance proceeds for the single tower failure at Kent Hills wind facilities of $7 million recognized in the second quarter of 2022;
- Liquidated damages recoverable from turbine availability being below the contractual target at the Windrise wind facility were recorded in each of the quarters in 2022 and the first quarter of 2023;
- Keephills Unit 1 being retired in the fourth quarter of 2021 and Sundance Unit 4 being retired in the first quarter of 2022;
- The acquisition of North Carolina Solar facility in the fourth quarter of 2021;
- Commissioning of the Windrise wind facility in the fourth quarter of 2021;
- The suspension of the Sundance Unit 5 repowering project in the third quarter of 2021;
- The retirement of the Sundance Unit 5 in 2021;
- Gains relating to the sales of assets being recognized in the fourth quarter of 2022, the sale of the Pioneer Pipeline in the second quarter of 2021 and gains on sale of Gas equipment in the third quarter of 2021;
- The unplanned steam supply outages at the Sarnia facility in the second quarter of 2021;
- Accelerated plans to shut down the Highvale mine resulting in remaining future royalty payments being recognized as an onerous contract in the third quarter of 2021;
- Accelerated shutdown of the Highvale mine increasing mine depreciation included in the cost of coal. Coal inventory write-down incurred in the first three quarters of 2021;
- Coal-related parts and materials inventory write-down incurred in the second and third quarters of 2021;
- Fluctuations in the Canadian dollar relative to the US dollar resulting in foreign exchange gains and losses on our US denominated long-term debt balances not designated as hedges; and
- Current and future tax expense fluctuate with earnings before tax across the quarters. Future tax expense increased from 2022 mainly due to a reversal of a previous deferred tax write-down taken against part of the US and Canadian operations and gains on mark-to-market hedging.

Financial Position

The following table highlights significant changes in the Consolidated Statements of Financial Position from Dec. 31, 2022, to March 31, 2023:

Assets	March 31, 2023	Dec. 31, 2022	Increase/ (decrease)
Current assets			
Cash and cash equivalents	**1,247**	1,134	113
Trade and other receivables	**928**	1,589	(661)
Risk management assets	**342**	709	(367)
Other current assets[1]	**247**	282	(35)
Total current assets	**2,764**	3,714	(950)
Non-current assets			
Risk management assets	**122**	161	(39)
Property, plant and equipment, net	**5,686**	5,556	130
Other non-current assets[2]	**1,285**	1,310	(25)
Total non-current assets	**7,093**	7,027	66
Total assets	**9,857**	10,741	(884)
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	**840**	1,346	(506)
Risk management liabilities	**634**	1,129	(495)
Other current liabilities[3]	**357**	413	(56)
Total current liabilities	**1,831**	2,888	(1,057)
Non-current liabilities			
Credit facilities, long-term debt and lease liabilities	**3,453**	3,475	(22)
Decommissioning and other provisions (long-term)	**682**	659	23
Risk management liabilities (long-term)	**272**	333	(61)
Other non-current liabilities[4]	**1,386**	1,397	(11)
Total non-current liabilities	**5,793**	5,864	(71)
Total liabilities	**7,624**	8,752	(1,128)
Equity			
Equity attributable to shareholders	**1,386**	1,110	276
Non-controlling interests	**847**	879	(32)
Total equity	**2,233**	1,989	244
Total liabilities and equity	**9,857**	10,741	(884)

(1) Includes restricted cash, prepaid expenses, inventory, and assets held for sale.
(2) Includes investments, long-term portion of finance lease receivables, right-of-use assets, intangible assets, goodwill, deferred income tax assets and other assets.
(3) Includes bank overdraft, current portion of decommissioning and other provisions, current portion of contract liabilities, income taxes payable, dividend payable and current portion of credit facilities, long term debt, and lease obligations.
(4) Includes exchangeable securities, deferred income tax liabilities, contract liabilities and defined benefit obligation and other long term liabilities.

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

Working Capital

Current assets decreased by $950 million to $2,764 million as at March 31, 2023, from $3,714 million as at Dec. 31, 2022, primarily due to lower trade receivables related to collections from higher revenues recognized in the fourth quarter of 2022 and lower receivables in the Energy Marketing segment. Additionally, collateral provided and risk management assets decreased due to lower market prices and contract settlements since year-end. This was partially offset by higher cash and cash equivalents. As at March 31, 2023, the Company had provided $118 million (Dec. 31, 2022 – $304 million) of cash collateral related to derivative instruments in a net liability position.

Current liabilities decreased by $1,057 million from $2,888 million as at Dec. 31, 2022, to $1,831 million as at March 31, 2023, mainly due to a decrease in accounts payable and accrued liabilities due to lower accruals and payables in the Energy Marketing segment. Additionally, collateral held and risk management liabilities decreased due to lower market prices and contract settlements since year-end. As at March 31, 2023, the Company held $42 million (Dec. 31, 2022 – $260 million) of cash collateral received related to derivative instruments in a net asset position.

The excess of current assets over current liabilities, including the current portion of long-term debt and lease liabilities, was $933 million as at March 31, 2023 (Dec. 31, 2022 – $826 million). Our working capital increased mainly due to lower accounts payable, including collateral held, of $506 million and lower risk management liabilities of $495 million primarily from lower market prices and contract settlements and an increase in cash. This was partially offset by lower trade and other receivables of $661 million due to collections from higher revenues recognized in the fourth quarter of 2022, lower receivables for the Energy Marketing segment and lower risk management assets of $367 million primarily from lower market prices and contract settlements.

Non-Current Assets

Non-current assets as at March 31, 2023, were $7,093 million, an increase of $66 million from $7,027 million as at Dec. 31, 2022. The increase was mainly due to additions to property, plant and equipment ("PP&E") of $284 million mainly related to the construction of the White Rock wind projects, Horizon Hill wind project the Kent Hills rehabilitation costs, and other planned major maintenance. The increases to PP&E also includes revisions and additions to decommissioning and restoration costs of $14 million, the asset impairment reversals of $10 million, partially offset by depreciation of $170 million, as well as lower risk management assets due to lower market pricing across multiple markets and contract settlements.

Non-Current Liabilities

Non-current liabilities as at March 31, 2023, were $5,793 million, a decrease of $71 million from $5,864 million as at Dec. 31, 2022, mainly due to lower risk management liabilities of $61 million due to lower market pricing and contract settlements and a $22 million decrease in long-term debt and lease liabilities related to scheduled repayments. This was partially offset by higher decommissioning and other provisions of $23 million as a result of decreased discount rates.

Total Equity

As at March 31, 2023, the increase in total equity of $244 million was due to net earnings of $294 million and gains on derivatives from cash flow hedges of $69 million, partially offset by distributions to non-controlling interests of $76 million, share repurchases under the NCIB of $36 million, the effect of share-based payment plans of $11 million and a provision for repurchase of common shares of $37 million.

Financial Capital

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

Capital Structure

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

	March 31, 2023		Dec. 31, 2022	
	$	**%**	$	%
TransAlta Corporation				
Net senior unsecured debt				
Recourse debt - CAD debentures	**251**	**5**	251	5
Recourse debt - US senior notes	**933**	**17**	934	18
Term Facility	**397**	**7**	396	8
Other	**(1)**	**—**	1	—
Less: cash and cash equivalents(1)	**(1,032)**	**(19)**	(884)	(17)
Less: other cash and liquid assets(2)	**(3)**	**—**	(20)	—
Net senior unsecured debt	**545**	**10**	678	14
Other debt liabilities				
Exchangeable debentures	**341**	**6**	339	6
Non-recourse debt				
TAPC Holdings LP bond	**92**	**2**	94	2
OCP Bond	**229**	**5**	241	4
Lease liabilities	**112**	**2**	112	2
Total net debt(3) - TransAlta Corporation	**1,319**	**25**	1,464	28
TransAlta Renewables				
Net TransAlta Renewables reported debt				
Committed credit facility	**47**	**1**	32	1
Pingston bond	**45**	**1**	45	1
Melancthon Wolfe Wind bond	**202**	**4**	202	4
New Richmond Wind bond	**112**	**2**	112	2
Kent Hills Wind bond	**203**	**4**	206	4
Windrise Wind bond	**167**	**3**	170	3
Lease liabilities	**24**	**—**	23	—
Less: cash and cash equivalents(4)	**(213)**	**(4)**	(234)	(4)
Debt on TransAlta Renewables Economic Investments				
US tax equity financing(5)	**119**	**2**	123	2
South Hedland non-recourse debt(5)	**697**	**13**	711	14
Total net debt(3) - TransAlta Renewables	**1,403**	**26**	1,390	27
Total consolidated net debt(3)(6)(7)	**2,722**	**51**	2,854	55
Non-controlling interests	**847**	**16**	879	17
Exchangeable preferred securities(7)	**400**	**7**	400	7
Equity attributable to shareholders				
Common shares	**2,799**	**52**	2,863	54
Preferred shares	**942**	**18**	942	18
Contributed surplus, deficit and accumulated other comprehensive income	**(2,355)**	**(44)**	(2,695)	(51)
Total capital	**5,355**	**100**	5,243	100

(1) Cash and cash equivalents is net of bank overdraft.
(2) Includes principal portion of the TransAlta OCP restricted cash related to the TransAlta OCP non-recourse bonds as this cash is restricted specifically to repay outstanding debt and also includes the fair value of economic and designated hedging instruments on debt, as the carrying value of the related debt is impacted by changes in foreign exchange rates.
(3) These items are not defined and have no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A for further discussion, including, reconciliations to measures calculated in accordance with IFRS.
(4) Includes $115 million (AU$127 million) cash held within TransAlta Energy (Australia) Pty Ltd. reserved for future funding of Australia growth projects by TransAlta Renewables.
(5) TransAlta Renewables has an economic interest in the US entities, which includes the US tax equity financings of US$92 million (Dec. 31, 2022 - US$95 million) and an economic interest in the Australian entities, which includes the AU$780 million (Dec. 31, 2022 – AU$786 million) senior secured notes.
(6) The tax equity financing for the Skookumchuck wind facility, an equity accounted joint venture, is not represented in these amounts.
(7) The total consolidated net debt excludes the exchangeable preferred securities as they are considered equity with dividend payments for credit purposes.

Between 2023 and 2025, we have $808 million of debt maturing, including $400 million of recourse debt relating to the Term Facility, with the balance mainly related to scheduled non-recourse debt repayments.

Credit Facilities

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

As at March 31, 2023		Utilized			
Credit facilities	Facility size	Outstanding letters of credit(1)	Cash drawings	Available capacity	Maturity date
Committed					
TransAlta Corporation syndicated credit facility	1,250	404	—	846	Q2 2026
TransAlta Renewables syndicated credit facility	700	3	48	649	Q2 2026
TransAlta Corporation bilateral credit facilities	240	162	—	78	Q2 2024
TransAlta Corporation Term Facility	400	—	400	—	Q3 2024
Total Committed	**2,590**	**569**	**448**	**1,573**	
Non-Committed					
TransAlta Corporation demand facilities	250	105	—	145	n/a
TransAlta Renewables demand facility	150	98	—	52	n/a
Total Non-Committed	**400**	**203**	**—**	**197**	

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

Non-Recourse Debt

The Melancthon Wolfe Wind LP, Pingston Power Inc., TAPC Holdings LP, New Richmond Wind LP, Kent Hills Wind LP, TEC Hedland Pty Ltd, Windrise Wind LP and TransAlta OCP LP non-recourse bonds, are subject to customary financing conditions and covenants that may restrict the Company’s ability to access funds generated by the facilities’ operations. Upon meeting certain distribution tests, typically performed once per quarter, the funds are able to be distributed by the subsidiary entities to their respective parent entity. These conditions include meeting a debt service coverage ratio prior to distribution, which was met by these entities in the first quarter of 2023 with the exception of Kent Hills Wind LP and TAPC Holdings LP. Kent Hills Wind LP cannot make any distributions to its partners until the foundation replacement work has been completed and TAPC Holdings LP has been impacted by higher interest rates in 2023. The funds in these entities that have accumulated since the fourth quarter test will remain there until the next debt service coverage ratio can be calculated in the second quarter of 2023. At March 31, 2023, $67 million (Dec. 31, 2022 – $50 million) of cash was subject to these financial restrictions. 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.

Returns to Providers of Capital

Net Interest Expense

The components of net interest expense are shown below:

	3 months ended March 31	
	2023	2022
Interest on debt	**50**	41
Interest on exchangeable debentures	**7**	7
Interest on exchangeable preferred shares	**7**	7
Interest income	**(15)**	(3)
Capitalized interest	**(13)**	(1)
Interest on lease liabilities	**2**	1
Credit facility fees, bank charges and other interest	**8**	6
Tax shield on tax equity financing	**(1)**	—
Accretion of provisions	**14**	9
Net interest expense	**59**	67

Net interest expense for the three months ended March 31, 2023, was lower than the same period in 2022 primarily due to higher capitalized interest and interest income due to higher cash balances and favourable interest rates. This is partially offset by interest on credit facility borrowings, higher interest paid on cash collateral held and higher accretion of provisions.

Share Capital

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

	Number of shares (millions)		
As at	**May 4, 2023**	**March 31, 2023**[1]	**Dec. 31, 2022**
Common shares issued and outstanding, end of period	**263.1**	**266.0**	268.1
Preferred shares			
Series A	9.6	9.6	9.6
Series B	2.4	2.4	2.4
Series C	10.0	10.0	10.0
Series D	1.0	1.0	1.0
Series E	9.0	9.0	9.0
Series G	6.6	6.6	6.6
Preferred shares issued and outstanding in equity	**38.6**	**38.6**	38.6
Series I - Exchangeable Securities[2]	**0.4**	**0.4**	0.4
Preferred shares issued and outstanding	**39.0**	**39.0**	39.0

(1) The common shares issued and outstanding for the three months ended March 31, 2023, excludes the provision of 3 million common shares under the ASPP for the repurchase of shares during the blackout period Refer to Note 15 of of the unaudited interim condensed consolidated financial statements for further details.

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

Non-Controlling Interests

As at March 31, 2023, the Company owns 60.1 per cent (March 31, 2022 – 60.1 per cent) of TransAlta Renewables Inc. TransAlta Renewables is a publicly traded company whose common shares are listed on the TSX under the symbol "RNW." TransAlta Renewables holds a diversified, highly contracted portfolio of assets with comparatively lower carbon intensity.

We also own 50.01 per cent TransAlta Cogeneration, LP ("TA Cogen") (March 31, 2022 – 50.01 per cent), which owns, operates or has an interest in three natural-gas-fired cogeneration facilities (Ottawa, Windsor and Fort Saskatchewan) and one natural-gas-fired facility (Sheerness). Sheerness operated as a dual-fuel generating facility in 2021.

Since we own a controlling interest in TA Cogen and TransAlta Renewables, we consolidate the entire earnings, assets and liabilities in relation to those subsidiaries.

The reported net earnings attributable to non-controlling interests for the three months ended March 31, 2023, increased by $20 million compared to the same period in 2022. TA Cogen net earnings attributable to non-controlling interests have increased by $16 million compared to the same period in 2022, primarily due to higher merchant pricing in the Alberta market.

TransAlta Renewables net earnings attributable to non-controlling interests increased by $4 million compared to the same period in 2022. The increase was primarily due to asset impairment reversals due to favourable changes in estimated future cash flows, higher finance income related to subsidiaries of TransAlta, and lower depreciation. This was partially offset by lower revenues mainly from lower production, lower net other operating income from improved performance at the Windrise wind facility, higher OM&A expenses mainly from higher insurance and escalation of long term service agreement costs and higher income tax expense. Finance income related to subsidiaries of TransAlta was higher mainly due to higher dividends from Australia. Refer to Note 8 of the unaudited interim condensed consolidated financial statements for further details.

Other Consolidated Analysis

Commitments

In addition to the commitments disclosed elsewhere in the financial statements and those disclosed in the 2022 annual audited financial statements, during 2023 the Company has incurred the following additional contractual commitments, either directly or through its interests in joint operations for the three months ended, March 31, 2023. Approximate future payments under these agreements are as follows:

	2024	2025	2026	2027	2028	2029 and thereafter	Total
Transmission	2	2	2	2	3	23	34
Total	**2**	**2**	**2**	**2**	**3**	**23**	**34**

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. The above table includes the incremental change in transmission agreements, as compared to the amounts disclosed in the 2022 annual audited consolidated financial statements.

Contingencies

For the current material outstanding contingencies, please refer to Note 37 of the 2022 audited annual consolidated financial statements. Material changes to the contingencies have been described below.

Hydro Power Purchase Arrangement ("Hydro PPA") Emissions Performance Credits

The Balancing Pool claimed entitlement to 1,750,000 emission performance credits earned by the Alberta Hydro facilities as a result of TransAlta opting those facilities into the Carbon Competitiveness Incentive Regulation and Technology Innovation and Emissions Reduction Regulation from 2018-2020 inclusive. The emission performance credits have no recorded book value as they were internally generated. The Balancing Pool claimed ownership of the EPCs because it believed the change-in-law provisions under the Hydro PPA required the EPCs to be passed through to the Balancing Pool. TransAlta disputed this claim. The parties have reached a confidential settlement in principle and this matter is now resolved.

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 kilometers of the Brazeau Facility but permits hydraulic fracturing in all formations (except the Duvernay) within three-to-five kilometers of the Brazeau Facility. Subsequently, two oil and gas operators submitted applications to the AER for 10 well licenses (which include hydraulic fracturing activities) within three-to-five kilometers of the Brazeau Facility. The regulatory hearing to consider these applications - Proceeding 379 - was scheduled to be heard from Feb. 27 to March 10, 2023, but was adjourned to permit the O'Chiese First Nation to intervene and make submissions. While we do not have a new hearing date, we anticipate it will be heard in the second half of 2023.

The Company's position is that hydraulic fracturing activities within five kilometers of the Brazeau Facility pose an unacceptable risk and the applications should be denied.

Brazeau Facility - Claim against the Government of Alberta

On Sept. 9, 2022, the Company filed a Statement of Claim against the Alberta Government in the Alberta Court of King's Bench seeking a declaration that: (i) granting mineral leases within 5 km of the Brazeau Facility is a breach of the 1960 agreement between the Company and the Alberta Government; and (ii) the Alberta Government 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 Alberta Government filed its Statement of Defence, which asserts, among other things, that the Company: (i) is trying to usurp the jurisdiction of the AER; and (ii) is out of time under the Limitations Act (Alberta). Trial has been scheduled for two weeks starting Feb. 26, 2024.

Cash Flows

The following highlights significant changes in the Consolidated Statements of Cash Flows for the years ended March 31, 2023 and March 31, 2022:

	3 months ended March 31		
	2023	2022	**Increase/ (decrease)**
Cash and cash equivalents, beginning of period	**1,134**	947	187
Provided by (used in):			
Operating activities	**462**	451	11
Investing activities	**(182)**	(72)	(110)
Financing activities	**(165)**	(106)	(59)
Translation of foreign currency cash	**(2)**	1	(3)
Cash and cash equivalents, end of period	**1,247**	1,221	26

Cash from operating activities for the three months ended March 31, 2023, increased compared with the same period in 2022 primarily due to higher revenues net of unrealized gains and losses from risk management activities. This was partially offset by higher unfavourable changes in working capital, mainly from changes in collateral paid and received, and higher fuel and purchased power and carbon compliance costs. Movements in the collateral accounts relate to high commodity prices and volatility in the markets.

Cash from investing activities for the three months ended March 31, 2023, decreased compared with the same period 2022, largely due to:

- Higher cash spent on growth projects and Kent Hills rehabilitation construction activities in PP&E ($212 million), partially offset by:
    - Favourable change in non-cash working capital mainly related to the timing of construction payables for the assets under construction ($63 million);
    - Higher proceeds from the sale of property, plant and equipment ($23 million); and
    - Lower additions to intangibles during the year ($18 million).

Cash from financing activities for the three months ended March 31, 2023, decreased compared with the same period in 2022, largely due to:

- Increased distributions paid to subsidiaries' non-controlling interests ($34 million); and
- Higher common share repurchases under the NCIB ($19 million).

Financial Instruments

Refer to Note 14 of the notes to the audited annual 2022 consolidated financial statements, and Note 10 and 11 of our unaudited interim condensed consolidated financial statements as at and for the three months ended March 31, 2023, for details on Financial Instruments.

We may enter into commodity transactions involving non-standard features for which observable market data is not available. These are defined under IFRS as Level III financial instruments. Level III financial instruments are not traded in an active market and fair value is, therefore, developed using valuation models based upon internally developed assumptions or inputs. Our Level III fair values are determined using data such as unit availability, transmission congestion, or demand profiles. Fair values are validated every quarter by using reasonably possible alternative assumptions as inputs to valuation techniques and any material differences are disclosed in the notes to the financial statements.

At March 31, 2023, Level III instruments had a net liabilities carrying value of $442 million (Dec. 31, 2022 – net liabilities $782 million). Our risk management profile and practices have not changed materially from Dec. 31, 2022.

Additional IFRS Measures and Non-IFRS Measures

An additional IFRS measure is a line item, heading or subtotal that is relevant to an understanding of the consolidated financial statements but is not a minimum line item mandated under IFRS, or the presentation of a financial measure that is relevant to an understanding of the consolidated financial statements but is not presented elsewhere in the consolidated financial statements. We have included line items entitled gross margin and operating income (loss) in our unaudited interim condensed consolidated statements of earnings (loss) for the three months ended March 31, 2023 and 2022. Presenting these line items provides management and investors with a measurement of ongoing operating performance that is readily comparable from period to period.

We use a number of financial measures to evaluate our performance and the performance of our business segments, including measures and ratios that are presented on a non-IFRS basis, as described below. Unless otherwise indicated, all amounts are in Canadian dollars and have been derived from our audited annual 2022 consolidated financial statements and the unaudited interim condensed consolidated statements of earnings (loss) for the three months ended March 31, 2023, prepared in accordance with IFRS. We believe that these non-IFRS amounts, measures and ratios, read together with our IFRS amounts, provide readers with a better understanding of how management assesses results.

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

Non-IFRS Financial Measures

Adjusted EBITDA, FFO, FCF, total net debt, total consolidated net debt and adjusted net debt are non-IFRS measures that are presented in this MD&A. Refer to the Segmented Financial Performance and Operating Results, Segmented Financial Performance and Operating Results for the Fourth Quarter, Selected Quarterly Information, Financial Capital and Key Non-IFRS Financial Ratios sections of this MD&A for additional information, including a reconciliation of such non-IFRS measures to the most comparable IFRS measure.

Adjusted EBITDA

Each business segment assumes responsibility for its operating results measured by adjusted EBITDA. Adjusted EBITDA is an important metric for management that represents our core business profitability. In the second quarter of 2022, our adjusted EBITDA composition was adjusted to include the impact of closed positions that are effectively settled by offsetting positions with the same counterparty to reflect the performance of the assets and the Energy Marketing segment in the period in which the transactions occur. Accordingly, the Company has applied this composition to all previously reported periods. Interest, taxes, depreciation and amortization are not included, as differences in accounting treatments may distort our core business results. In addition, certain reclassifications and adjustments are made to better assess results, excluding those items that may not be reflective of ongoing business performance. This presentation may facilitate the readers' analysis of trends.

The following are descriptions of the adjustments made.

Adjustments to revenue

- Certain assets that we own in Canada and in Australia are fully contracted and recorded as finance leases under IFRS. We believe that it is more appropriate to reflect the payments we receive under the contracts as a capacity payment in our revenues instead of as finance lease income and a decrease in finance lease receivables.
- Adjusted EBITDA is adjusted to exclude the impact of unrealized mark-to-market gains or losses and unrealized foreign exchange gains or losses on commodity transactions.
- Gains and losses related to closed positions effectively settled by offsetting positions with exchanges that have been recorded in the period the positions are settled.

Adjustments to fuel and purchased power

- On the commissioning of the South Hedland facility in July 2017, we prepaid approximately $74 million of electricity transmission and distribution costs. Interest income is recorded on the prepaid funds. We reclassify this interest income as a reduction in the transmission and distribution costs expensed each period to reflect the net cost to the business.

Adjustments to earnings (loss) in addition to interest, taxes, depreciation and amortization

- Asset impairment charges and reversals are not included as these are accounting adjustments that impact depreciation and amortization and do not reflect ongoing business performance.
- Any gains or losses on asset sales or foreign exchange gains or losses are not included as these are not part of operating income.

Adjustments for equity accounted investments

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

Average Annual EBITDA

Average annual EBITDA is a non-IFRS financial measure that is forward-looking, used to show the average annual EBITDA that the project currently under construction is expected to generate upon completion.

Funds From Operations ("FFO")

FFO is an important metric as it provides a proxy for cash generated from operating activities before changes in working capital and provides the ability to evaluate cash flow trends in comparison with results from prior periods. FFO is a non-IFRS measure.

Adjustments to cash flow from operations

- Includes FFO related to the Skookumchuk wind facility, which is treated as an equity accounted investment under IFRS and equity income, net of distributions from joint ventures is included in cash flow from operations under IFRS. As this investment is part of our regular power generating operations, we have included our proportionate share of FFO.
- Payments received on finance lease receivables are reclassified to reflect cash from operations.
- Cash received/paid on closed positions are reflected in the period that the position is settled.
- Other adjustments include payments/receipts for production tax credits, which are reductions to tax equity debt and include distributions from equity accounted joint venture.

Free Cash Flow ("FCF")

FCF is an important metric as it represents the amount of cash that is available to invest in growth initiatives, make scheduled principal repayments on debt, repay maturing debt, pay common share dividends or repurchase common shares. Changes in working capital are excluded so FFO and FCF are not distorted by changes that we consider temporary in nature, reflecting, among other things, the impact of seasonal factors and timing of receipts and payments. FCF is a non-IFRS measure.

Non-IFRS Ratios

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

FFO per Share and FCF per Share

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

Supplementary Financial Measures

Financial highlights presented on a proportional basis of TransAlta Renewables, deconsolidated adjusted EBITDA, deconsolidated FFO and deconsolidated adjusted EBITDA to deconsolidated FFO are supplementary financial measures that the Company uses to present adjusted EBITDA on a deconsolidated basis. Refer to the Financial Highlights on a Proportional Basis of TransAlta Renewables and Key Non-IFRS Financial Ratios sections of this MD&A for additional information.

The Alberta electricity portfolio metrics disclosed are also supplementary financial measures used to present the gross margin by segment for the Alberta market. Refer to the Alberta Electricity Portfolio section of this MD&A for additional information.

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

The following table reflects adjusted EBITDA by segment and provides reconciliation to earnings (loss) before income taxes for the period ended March 31, 2023:

	Hydro	Wind & Solar(1)	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity accounted investments(1)	Reclass adjustments	IFRS financials
Revenues	125	115	495	267	92	—	1,094	(5)	—	1,089
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	(1)	—	(64)	(14)	16	—	(63)	—	63	—
Realized gain (loss) on closed exchange positions	—	—	(13)	—	(55)	—	(68)	—	68	—
Decrease in finance lease receivable	—	—	13	—	—	—	13	—	(13)	—
Finance lease income	—	—	4	—	—	—	4	—	(4)	—
Adjusted revenues	124	115	435	253	53	—	980	(5)	114	1,089
Fuel and purchased power	5	9	130	181	—	—	325	—	—	325
Reclassifications and adjustments:										
Australian interest income	—	—	(1)	—	—	—	(1)	—	1	—
Adjusted fuel and purchased power	5	9	129	181	—	—	324	—	1	325
Carbon compliance	—	—	32	—	—	—	32	—	—	32
Gross margin	119	106	274	72	53	—	624	(5)	113	732
OM&A	12	17	41	17	14	24	125	(1)	—	124
Taxes, other than income taxes	1	3	4	1	—	—	9	—	—	9
Net other operating income	—	(2)	(11)	—	—	—	(13)	—	—	(13)
Adjusted EBITDA(2)	106	88	240	54	39	(24)	503			
Equity income										2
Finance lease income										4
Depreciation and amortization										(176)
Asset impairment reversals										3
Net interest expense										(59)
Foreign exchange loss										(3)
Earnings before income taxes										383

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.
(2) Adjusted EBITDA is not defined and has no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

The following table reflects adjusted EBITDA by segment and provides reconciliation to earnings (loss) before income taxes for the period ended March 31, 2022:

	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	77	95	434	106	26	1	739	(4)	—	735
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	—	13	(162)	11	10	—	(128)	—	128	—
Realized gain (loss) on closed exchange positions[2]	—	—	3	—	(10)	—	(7)	—	7	—
Decrease in finance lease receivable	—	—	11	—	—	—	11	—	(11)	—
Finance lease income	—	—	5	—	—	—	5	—	(5)	—
Unrealized foreign exchange gain on commodity	—	—	—	—	(2)	—	(2)	—	2	—
Adjusted revenues	77	108	291	117	24	1	618	(4)	121	735
Fuel and purchased power	4	8	131	94	—	1	238	—	—	238
Reclassifications and adjustments:										
Australian interest income	—	—	(1)	—	—	—	(1)	—	1	—
Adjusted fuel and purchased power	4	8	130	94	—	1	237	—	1	238
Carbon compliance	—	—	18	1	—	—	19	—	—	19
Gross margin	73	100	143	22	24	—	362	(4)	120	478
OM&A	11	16	44	16	7	18	112	—	—	112
Taxes, other than income taxes	1	2	4	1	—	—	8	—	—	8
Net other operating income	—	(7)	(10)	—	—	—	(17)	—	—	(17)
Adjusted EBITDA[3]	61	89	105	5	17	(18)	259			
Equity income										2
Finance lease income										5
Depreciation and amortization										(117)
Asset impairment reversals										42
Net interest expense										(67)
Foreign exchange gain and other gains										2
Earnings before income taxes										242

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.
(2) In 2022, our adjusted EBITDA composition was adjusted to include the impact of closed positions that are effectively settled by offsetting positions with the same counterparty to reflect the performance of the assets and the Energy Marketing segment in the period in which the transactions occur.
(3) Adjusted EBITDA is not defined and has no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

Reconciliation of Cash Flow from Operations to FFO and FCF

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

	3 months ended March 31	
	2023	**2022**
Cash flow from operating activities[1]	**462**	451
Change in non-cash operating working capital balances	**(42)**	(284)
Cash flow from operations before changes in working capital	**420**	167
Adjustments		
Share of adjusted FFO from joint venture[1]	**3**	3
Decrease in finance lease receivable	**13**	11
Realized gain on closed positions with same counterparty	**(68)**	(7)
Other[2]	**6**	5
FFO[3]	**374**	179
Deduct:		
Sustaining capital[1]	**(20)**	(17)
Productivity capital	**—**	(1)
Dividends paid on preferred shares	**(13)**	(10)
Distributions paid to subsidiaries' non-controlling interests	**(76)**	(42)
Principal payments on lease liabilities	**(2)**	(1)
FCF[3]	**263**	108
Weighted average number of common shares outstanding in the period	**268**	271
FFO per share[3]	**1.40**	0.66
FCF per share[3]	**0.98**	0.40

(1) Includes our share of amounts for Skookumchuck, an equity accounted joint venture.
(2) Other consists of production tax credits, which is a reduction to tax equity debt, less distributions from equity accounted joint venture.
(3) These items are not defined and have no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

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

	3 months ended March 31	
	2023	**2022**
Adjusted EBITDA[1][4]	**503**	259
Provisions	**3**	10
Interest expense	**(45)**	(54)
Current income tax expense[2]	**(60)**	(12)
Realized foreign exchange gain (loss)	**(7)**	2
Decommissioning and restoration costs settled	**(7)**	(7)
Other non-cash items	**(13)**	(19)
FFO[3][4]	**374**	179
Deduct:		
Sustaining capital[4]	**(20)**	(17)
Productivity capital	**—**	(1)
Dividends paid on preferred shares	**(13)**	(10)
Distributions paid to subsidiaries' non-controlling interests	**(76)**	(42)
Principal payments on lease liabilities	**(2)**	(1)
FCF[3]	**263**	**108**

(1) Adjusted EBITDA is defined in the Additional IFRS Measures and Non-IFRS Measures section of this MD&A and reconciled to earnings (loss) before income taxes above.
(2) The Company incurred higher current tax expense for the first quarter of 2023, due to utilizing a large portion of its loss carryforwards during the fourth quarter of 2022. The Company expects a portion of the current tax expense to reverse during the balance of the year as projects under construction are completed including the Garden Plain wind project and projects in Australia.
(3) These items are not defined and have no standardized meaning under IFRS. FFO and FCF are defined in the Additional IFRS Measures and Non-IFRS Measures section of this MD&A and reconciled to cash flow from operating activities above.
(4) Includes our share of amounts for Skookumchuck wind facility, an equity accounted joint venture.

Financial Highlights on a Proportional Basis of TransAlta Renewables

The proportionate financial information below reflects TransAlta's share of TransAlta Renewables relative to TransAlta's total consolidated figures. The financial highlights presented on a proportional basis of TransAlta Renewables are supplementary financial measures to reflect TransAlta Renewables' portion of the consolidated figures.

Consolidated Results

The following table reflects the generation and summary financial information on a consolidated basis for the period ended March 31:

	Actual generation (GWh)		Adjusted EBITDA[1]		Earnings before income taxes[2]	
As at March 31	2023	2022	2023	2022	2023	2022
TransAlta Renewables						
Hydro	**27**	41	**(1)**	1		
Wind and Solar[3]	**1,192**	1,269	**77**	88		
Gas[3]	**802**	935	**58**	56		
Corporate	**—**	—	**(6)**	(6)		
TransAlta Renewables before adjustments	**2,021**	2,245	**128**	139	**73**	33
Less: Proportion of TransAlta Renewables not owned by TransAlta Corporation	**(806)**	(896)	**(51)**	(55)	**(29)**	(13)
Portion of TransAlta Renewables owned by TransAlta Corporation	**1,215**	1,349	**77**	84	**44**	20
Add: TransAlta Corporation's owned assets excluding TransAlta Renewables						
Hydro	**279**	331	**107**	60		
Wind and Solar	**5**	—	**11**	1		
Gas	**2,370**	1,730	**182**	49		
Energy Transition	**1,297**	1,053	**54**	5		
Energy Marketing	**—**	—	**39**	17		
Corporate	**—**	—	**(18)**	(12)		
TransAlta Corporation with proportionate share of TransAlta Renewables	**5,166**	4,463	**452**	204	**354**	229
Non-controlling interests	**806**	896	**51**	55	**29**	13
TransAlta consolidated	**5,972**	5,359	**503**	259	**383**	242

(1) Adjusted EBITDA is defined in the Additional IFRS Measures and Non-IFRS Measures section of this MD&A and reconciled to earnings (loss) before income taxes above.
(2) TransAlta Renewables amounts are comprised of its reported earnings before income taxes plus the reported earnings before income taxes of the assets in which it holds an economic interest less finance income related to subsidiaries of TransAlta.
(3) Wind and Solar and Gas segments include those assets in which TransAlta Renewables holds an economic interest.

Key Non-IFRS Financial Ratios

The methodologies and ratios used by rating agencies to assess our credit rating are not publicly disclosed. We have developed our own definitions of ratios and targets to help evaluate the strength of our financial position. These metrics and ratios are not defined and have no standardized meaning under IFRS and may not be comparable to those used by other entities or by rating agencies.

Adjusted Net Debt to Adjusted EBITDA

As at	March 31, 2023	Dec. 31, 2022
Period-end long-term debt[1]	**3,630**	3,653
Exchangeable securities	**341**	339
Less: Cash and cash equivalents[2]	**(1,245)**	(1,118)
Add: 50 per cent of issued preferred shares and exchangeable preferred shares[3]	**671**	671
Other[4]	**(3)**	(20)
Adjusted net debt[5]	**3,394**	3,525
Adjusted EBITDA[6]	**1,878**	1,634
Adjusted net debt to adjusted EBITDA(times)	**1.8**	2.2

(1) Consists of current and long-term portion of debt, which includes lease liabilities and tax equity financing.
(2) Cash and cash equivalents, net of bank overdraft.
(3) Exchangeable preferred shares are considered equity with dividend payments for credit-rating purposes. For accounting purposes, they are accounted for as debt with interest expense in the consolidated financial statements. For purposes of this ratio, we consider 50 per cent of issued preferred shares, including those classified as debt.
(4) Includes principal portion of TransAlta OCP restricted cash (nil for the period ended March 31, 2023) and fair value of hedging instruments on debt (included in risk management assets and/or liabilities on the Consolidated Statements of Financial Position).
(5) The tax equity financing for the Skookumchuck wind facility, an equity accounted joint venture, is not represented in this amount. Adjusted net debt is not defined and has no standardized meaning under IFRS. Presenting this item from period to period provides management and investors with the ability to evaluate earnings trends more readily in comparison with prior periods' results. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.
(6) Last 12 months.

The Company's capital is managed internally and evaluated by management using a net debt position. We use the adjusted net debt to adjusted EBITDA ratio as a measurement of financial leverage and to assess our ability to service debt. Our target for adjusted net debt to adjusted EBITDA is 3.0 to 3.5 times. Our adjusted net debt to adjusted EBITDA ratio for March 31, 2023 was better than the low end of our target and improved compared to Dec. 31, 2022, due to strong adjusted EBITDA and lower adjusted net debt.

Deconsolidated Adjusted EBITDA by Segment

We invest in our assets directly as well as with joint venture partners. Deconsolidated financial information is a supplementary financial measure and is not intended to be presented in accordance with IFRS.

Adjusted EBITDA is a key metric for TransAlta and TransAlta Renewables and provides management and shareholders a representation of core business profitability. Deconsolidated adjusted EBITDA is used in key planning and credit metrics, and segment results highlight the operating performance of assets held directly at TransAlta that are comparable from period to period.

A reconciliation of adjusted EBITDA to deconsolidated adjusted EBITDA by segment results is set out below:

	3 months ended March 31, 2023			3 months ended March 31, 2022		
	TransAlta Consolidated	**TransAlta Renewables**	**TransAlta Deconsolidated**	TransAlta Consolidated	TransAlta Renewables	TransAlta Deconsolidated
Hydro	**106**	**(1)**		61	1	
Wind and Solar	**88**	**77**		89	88	
Gas	**240**	**58**		105	56	
Energy Transition	**54**	**—**		5	—	
Energy Marketing	**39**	**—**		17	—	
Corporate	**(24)**	**(6)**		(18)	(6)	
Adjusted EBITDA	**503**	**128**	**375**	259	139	120
Less: TA Cogen adjusted EBITDA			**(56)**			(14)
Add: Dividend from TransAlta Renewables			**38**			38
Add: Dividend from TA Cogen			**41**			10
Deconsolidated TransAlta adjusted EBITDA			**398**			154

Deconsolidated FFO

The Company has set capital allocation targets based on deconsolidated FFO available to shareholders. Deconsolidated financial information is a supplementary financial measure and is not defined, has no standardized meaning under IFRS and may not be comparable to those used by other entities or by rating agencies. See also the Additional IFRS Measures and Non-IFRS Measures section of this MD&A for further details. Deconsolidated FFO for the period ended March 31, 2023 and 2022 is detailed below:

	3 months ended March 31, 2023			3 months ended March 31, 2022		
	TransAlta Consolidated	**TransAlta Renewables**	**TransAlta Deconsolidated**	TransAlta Consolidated	TransAlta Renewables	TransAlta Deconsolidated
Cash flow from operating activities	**462**	**67**		451	103	
Change in non-cash operating working capital balances	**(42)**	**2**		(284)	(17)	
Cash flow from operations before changes in working capital	**420**	**69**		167	86	
Adjustments:						
Decrease in finance lease receivable	**13**	**—**		11	—	
Share of FFO from joint venture	**3**	**—**		3	—	
Realized (gain) loss on closed exchange positions	**(68)**	**—**		(7)	—	
Finance income - economic interests	**—**	**(23)**		—	(19)	
FFO - economic interests(1)	**—**	**52**		—	49	
Other(2)	**6**	**—**		5	—	
FFO	**374**	**98**	**276**	179	116	63
Dividend from TransAlta Renewables			**38**			38
Distributions to TA Cogen's Partner			**(51)**			(18)
Deconsolidated TransAlta FFO			**263**			83

(1) FFO - economic interests calculated as FCF economic interests plus sustaining capital expenditures economic interests.
(2) Other consists of production tax credits, which is a reduction to tax equity debt, less distributions from equity accounted joint venture.

Deconsolidated Net Debt to Deconsolidated Adjusted EBITDA

In addition to reviewing fully consolidated ratios and results, management reviews net debt to adjusted EBITDA on a deconsolidated basis to highlight TransAlta's financial flexibility, balance sheet strength and leverage. Deconsolidated financial information is a supplementary financial measure and is not defined under IFRS, and may not be comparable to measures used by other entities or by rating agencies. Also, refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A for further details.

As at	March 31, 2023	Dec. 31, 2022
Adjusted net debt(1)	**3,394**	3,525
Add: TransAlta Renewables cash and cash equivalents(2)	**213**	234
Less: TransAlta Renewables long-term debt	**(800)**	(790)
Less: US tax equity financing and South Hedland debt(3)	**(816)**	(834)
Deconsolidated net debt	**1,991**	2,135
Deconsolidated adjusted EBITDA(4)(5)	**1,398**	1,153
Deconsolidated net debt to deconsolidated adjusted EBITDA(6) (times)	**1.4**	1.9

(1) Adjusted net debt is a Non-IFRS measure. Refer to the Adjusted Net Debt to Adjusted EBITDA calculation under the Key Financial Non-IFRS Financial Ratios section of this MD&A for the reconciliation and composition of adjusted net debt.
(2) Includes cash held within TransAlta Energy (Australia) Pty Ltd. reserved for future funding of Australian growth projects by TransAlta Renewables.
(3) Relates to assets where TransAlta Renewables has economic interests.
(4) Refer to the Deconsolidated Adjusted EBITDA by Segment section of this MD&A for the reconciliation and composition of deconsolidated adjusted EBITDA and the Additional IFRS Measures and Non-IFRS Measures section of this MD&A for the composition of adjusted EBITDA.
(5) Last 12 months.
(6) The non-IFRS ratio is not a standardized financial measure under IFRS and might not be comparable to similar financial measures disclosed by other issuers.

Our target for deconsolidated net debt to deconsolidated adjusted EBITDA is 2.5 to 3.0 times. Our deconsolidated net debt to deconsolidated adjusted EBITDA ratio for March 31, 2023 improved compared with Dec. 31, 2022, as higher deconsolidated adjusted EBITDA more than offset the increase in deconsolidated net debt. Lower deconsolidated net debt is a result of higher cash and cash equivalent balances at TransAlta Corporation.

2023 Outlook

Our annual outlook highlights continued strong cash flow expectations for 2023. Our fleet remains well positioned to capture the ongoing strength that we see in the Alberta merchant market. The Company is focused on redeploying these cash flows towards growing our contracted renewables asset base.

The following table outlines our expectations on key financial targets and related assumptions for 2023 and should be read in conjunction with the narrative discussion that follows and the Governance and Risk Management section of this MD&A:

Measure	Updated Target 2023	Original Target 2023	2022 Actuals
Adjusted EBITDA(1)(2)	$1,450 million - $1,550 million	$1,200 million -$1,320 million	$1,634 million
FCF(1)(2)	$650 million - $750 million	$560 million - $660 million	$961 million
Dividend	no change	$0.22 per share annualized	$0.20 per share annualized

(1) These items are not defined and have no standardized meaning under IFRS. Refer to the Reconciliation of Non-IFRS Measures section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS. See also the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.
(2) During the first quarter of 2023, the Company revised and increased our 2023 guidance for adjusted EBITDA and FCF based on the strong financial performance attained to date and our expectations for the balance of the year.

Range of key 2023 power and gas price assumptions

Market	Updated 2023 Assumptions	2023 Original Assumptions
Alberta Spot ($/MWh)	$125 to $145	$105 to $135
Mid-C Spot (US$/MWh)	US$90 to US$100	US$75 to US$85
AECO Gas Price ($/GJ)	$2.50	$4.60

Alberta spot price sensitivity: a +/- $1 per MWh change in spot price is expected to have a +/- $5 million impact on adjusted EBITDA for 2023.

Other assumptions relevant to the 2023 outlook	Updated 2023 Expectations	Original Expectations
Sustaining capital	no change	$140 million - $170 million
Energy Marketing gross margin	$130 million - $150 million	$90 million - $110 million

Alberta Hedging

Range of hedging assumptions	Q2 2023	Q3 2023	Q4 2023	Full year 2024	Full year 2025
Hedged production (GWh)	1,727	1,630	1,411	4,192	2,349
Hedge price ($/MWh)	$90	$89	$77	$80	$82
Hedged gas volumes (GJ)	16 million	16 million	15 million	33 million	—
Hedge gas prices ($/GJ)	$2.32	$2.31	$2.26	$2.55	—

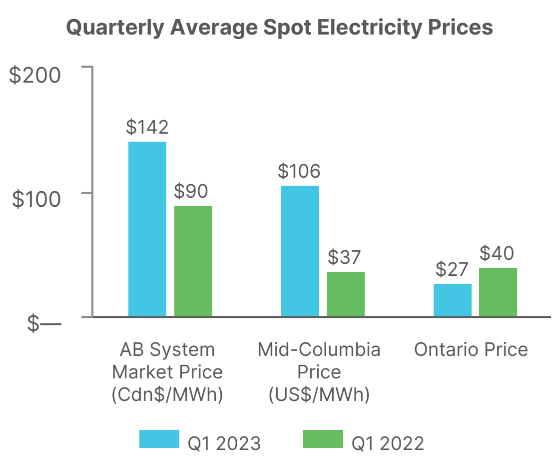
Refer to the 2023 Financial Outlook section in our 2022 Annual MD&A for further details relating to our Outlook and related assumptions.

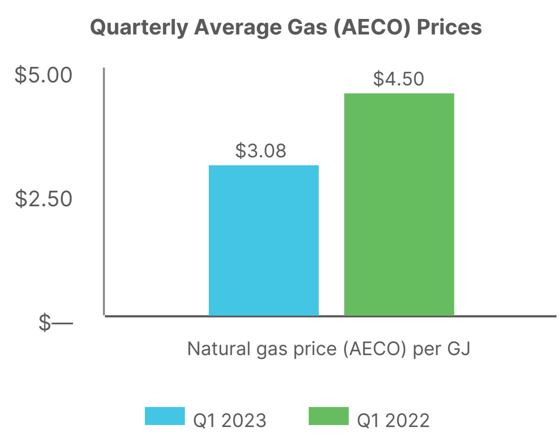
Operations

The following provides an update to our assumptions included in the 2023 Outlook.

Market Pricing

The following graphs include 2023 pricing based on a range of assumptions and are subject to change:





For 2023, we are seeing stronger merchant pricing levels in Alberta and the Pacific Northwest relative to our initial guidance ranges. Higher pricing in Alberta is expected to be driven by tighter supply conditions resulting from outage extensions, delays in new asset entrants, transmission announcements limiting imports as well as supportive prices in adjacent power and natural gas markets driving export demand. We are also seeing stronger pricing in the Pacific Northwest which is being driven by lower than normal hydrology for the region. Ontario power prices for 2023 are expected to be lower than 2022 due to lower natural gas prices despite ongoing nuclear refurbishment outages.

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

Sustaining Capital Expenditures

Our estimate for total sustaining capital is as follows:

	March 31, 2023	March 31, 2022	Expected spend in 2023
Total sustaining capital	**20**	17	140-170

Total sustaining capital expenditures for the three months ended March 31, 2023, were $3 million higher compared to the same period in 2022, mainly due to higher spending on information technology and leasehold improvements associated with the relocation of the Company's head office.

The Kent Hills foundation rehabilitation capital expenditure has been segregated from our sustaining capital range due to the extraordinary and rare nature of this expenditure.

Kent Hills Rehabilitation

The Kent Hills 1 and 2 wind facilities are not currently in operation following the tower failure event that occurred in September 2021. This event has taken approximately 150 MW of gross production offline temporarily as the Company replaces all 50 turbine foundations at the Kent Hills 1 and 2 wind facilities. The extended outage is expected to result in foregone revenue of approximately $3 million per month on an annualized basis (to the extent all 50 turbines at the Kent Hills 1 and 2 wind facilities are offline), based on average historical wind production, with revenue expected to be earned as the wind turbines are returned to service. Each turbine at Kent Hills 1 and 2 wind facilities will return to service as soon as its foundation is replaced and the turbine is reassembled and tested.

Rehabilitation of the Kent Hills 1 and 2 wind facilities is well underway. All of the towers have been fully disassembled with foundation demolition and removal nearing completion. Construction of new foundations is progressing well, with approximately two-thirds of foundations poured. Tower reassembly is also progressing with 13 turbines reassembled to date and associated commissioning activities commenced. We continue to target returning all turbines to service in the second half of 2023. The current estimate of the capital expenditures is approximately $120 million, inclusive of insurance proceeds.

During the first quarter of 2023, the Company filed and served a statement of claim in the New Brunswick Court of King’s Bench against certain defendants who the Company believes are responsible for, or contributed to, the failure of the turbine foundations at the Kent Hills 1 and 2 wind facilities. The claim seeks damages for lost profits, replacement costs, and other related costs to perform the remediation of Kent Hills 1 and 2, net of any insurance recoveries. The ability to recover any amounts is uncertain at this time.

Liquidity and Capital Resources

We expect to maintain adequate available liquidity under our committed credit facilities. We currently have access to $2.6 billion in liquidity, including $1.2 billion in cash. The funds required for committed growth, sustaining capital and productivity projects are not expected to be significantly impacted by the current economic environment.

Strategy and Capability to Deliver Results

Our goal is to be a leading customer-centred electricity company, committed to a sustainable future, focused on increasing shareholder value by growing our portfolio of high-quality generation facilities with stable and predictable cash flows. Our strategy includes meeting our customers' needs for clean, safe, low-cost, reliable electricity and providing operational excellence and continuous improvement in everything we do.

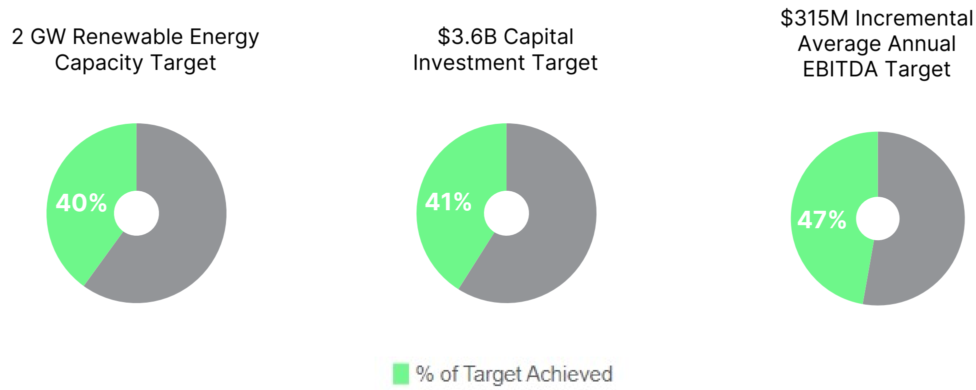
The Company's enhanced focus on renewable generation and storage solutions for customers is driven largely by global decarbonization policies and the increase in demand and growth projections in the renewable sector, namely by companies seeking to achieve their ESG ambitions. For additional information on regulatory developments, refer to the Regulatory Updates section of this MD&A.

On Sept. 28, 2021, TransAlta announced its strategic growth targets and a five-year Clean Electricity Growth Plan. Our 2023 priorities for the Clean Electricity Growth Plan include:

- Reaching final investment decision on 500 MW of additional clean energy projects across Canada, the US and Australia; and
- Adding at least 1,500 MW of new development sites to our pipeline.

We expect the Company's adjusted EBITDA generated from renewable sources, including hydro, wind and solar technologies, to increase to 70 per cent by the end of 2025. The Clean Electricity Growth Plan will largely be funded from current cash balances, cash generated from operations and asset-level financing.

As of May 4, 2023, we continue to make progress towards achieving the targets of the Clean Electricity Growth Plan.



Our progress towards achieving our strategic targets is summarized below:

Strategic Targets

Goals	Target	Results	Comments
Accelerate Growth in Customer-centered Renewables and Storage	Deliver 2 GW of renewable capacity with an estimated capital investment of $3.6 billion by the end of 2025.	On track	Construction projects for 678 MW of renewable capacity and transmission is currently underway and expected to reach commercial operations later in 2023. The Company is currently advancing an additional 374 MW of advanced-stage projects towards achieving final investment decision later in 2023.
	Deliver incremental average annual EBITDA of $315 million.	On track	The cumulative progress towards our incremental EBITDA target is approximately $149 million. This comprises the acquisition of the North Carolina Solar project as well as the 678 MW of growth and transmission projects that are currently in the construction stage.
	Expand the Company's development pipeline to 5 GW by 2025 to enable a two-fold increase in its renewables fleet between 2025 and 2030.	On track	The Company is actively developing this pipeline. Subsequent to the first quarter, the Company acquired an opportunity to develop 160 MW of hydro pumped storage.
Take a Targeted Approach to Diversification	Grow our asset base in our core geographies of Canada, Australia and the US to realize diversification and value creation.	On track	The Company has successfully added new contracted renewable assets in each of its three core geographies. We have diversified within the US market through our North Carolina Solar facility acquisition in 2021 and the new Oklahoma investments, which added three new investment-grade customers in 2022.
Maintain Our Financial Strength and Capital Allocation Discipline	Deliver strong cash flow from our existing portfolio to allocate towards our funding priorities including growth, dividends and share buybacks.	On track	The Company had liquidity of $2.6 billion as at March 31, 2023. The Company returned $36 million to shareholders through share buybacks in the first quarter of 2023 under our NCIB. The Company increased the annual common share dividend by 10 per cent to $0.22 per year effective Jan. 1, 2023.
Define the Next Generation of Energy Solutions and Technologies	Meet the needs of our customers and communities through the implementation of innovative energy solutions and parallel investments in new complementary sectors by the end of 2025.	On track	The Company established an Energy Innovation team to progress our goals in this area. The team has completed an equity investment in Ekona Power Inc., an early-stage hydrogen production company, in order to pursue commercialization of low cost, net-zero aligned hydrogen. The Company also committed to invest US$25 million over the next four years in the Energy Impact Partners Frontier Fund, which provides a portfolio approach to investing in emerging technologies focused on net-zero emissions. In 2022, the Company invested $10 million (US$8 million) to this fund.
Lead in ESG Policy Development	Actively participate in policy development to ensure the electricity that we provide contributes to emissions reduction, grid reliability and competitive energy prices to enable the successful evolution of the markets in which we operate and compete.	On track	The Company is actively engaging the Government of Canada and Government of Alberta regarding the proposed federal Clean Electricity Regulations. TransAlta continues to provide input regarding how to achieve emissions reductions while maintaining reliability and affordability. The Company continues to work with the Government of Canada on the design details of the investment tax credits and clean technology funding provided through the Government of Canada's 2023 budget.

Growth

We have established, and are continuing to expand, our pipeline of potential growth projects. Our pipeline includes 374 MW of advanced-stage development projects along with 3,891 MW to 4,991 MW of projects in earlier stages of development.

During the three months ended March 31, 2023, we expanded our pipeline of potential growth projects by 286 MW.

We are primarily evaluating greenfield opportunities in Alberta, Western Australia and the US along with acquisitions in markets in which we have existing operations.

Projects under Construction

The following projects have been approved by the Board of Directors, have executed PPAs and are currently under construction. The projects under construction will be financed through existing liquidity in the near term. We will continue to explore project financing or tax equity as a long-term financing solution on an asset-by-asset basis.

				Total project (millions)					
Project	Type	Region	MW	Estimated spend	Spent to date	Target completion date[1]	PPA Term[2]	Average annual EBITDA[3]	Status
Canada									
Garden Plain	Wind	AB	130	$ 190 — $200	$ 171	H1 2023	17	$14-$15	• Fully contracted • All major equipment deliveries are complete • Grid interconnection completed • Turbine erection is complete and commissioning is now underway
United States									
White Rock	Wind	OK	300	US$ 470 — US$490	US$347	H2 2023	—	US$48-US$52	• Long-term PPAs executed • Wind turbine component deliveries in progress • Construction activities are underway • On track to be completed on schedule
Horizon Hill	Wind	OK	200	US$ 300 — US$315	US$231	H2 2023	—	US$30-US$33	• Long-term PPA executed • Wind turbine component deliveries are complete • Construction activities are underway • On track to be completed on schedule
Australia									
Northern Goldfields	Hybrid Solar	WA	48	AU$ 69 — AU$73	AU$63	H1 2023	16	AU$9-AU$10	• All major equipment deliveries are complete • Solar panel installation is complete • On track to be completed in the first half of 2023
Mount Keith 132kV Expansion	Transmission	WA	n/a	AU$ 50 — AU$53	AU$25	H2 2023	15	AU$6-AU$7	• Engineering, procurement, and construction agreement executed • Construction activities have commenced • On track to be completed on schedule
Total [4]			**678**	**$ 1,321 — $ 1,384**	**1,021**			**$131 - $143**	

(1) H1 or H2 is defined as the first or second half of the year.
(2) The PPA term is confidential for the White Rock wind projects and Horizon Hill wind project.
(3) This item is not defined and has no standardized meaning under IFRS and is forward-looking. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A for further discussion.
(4) Total expected spending and average annual EBITDA was converted using a Canadian dollar forward exchange rate for 2023. Spend to date was converted using the period end closing rate.

Advanced-Stage Development

These projects have detailed engineering, advanced position in the interconnection queue and are progressing offtake opportunities. The following table shows the pipeline of future growth projects currently under advanced-stage development:

Project	Type	Region	Target completion date	MW	Estimated spend	Average annual EBITDA[1]
Tempest	Wind	Alberta	2025	100	$210-$230	$20-$23
SCE Capacity Expansion	Gas	Western Australia	2025	94	AU$180-AU$200	AU$24-AU$28
WaterCharger	Battery Storage	Alberta	2024	180	$195-$215	$17-$20
Australia Transmission Expansion	Transmission	Western Australia	2024	n/a	AU$70-AU$75	AU$7-AU$8
Total[2]				**374**	**$588 - $660**	**$62 - $73**

(1) This item is not defined, has no standardized meaning under IFRS and is forward-looking. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A for further discussion.
(2) Total expected spending and average annual EBITDA was adjusted using a Canadian dollar forward exchange rate for 2023.

Early-Stage Development

These projects are in the early stages and may or may not move ahead. Generally, these projects will have:

- Collected meteorological data;
- Begun securing land control;
- Started environmental studies;
- Confirmed appropriate access to transmission; and
- Started preliminary permitting and other regulatory approval processes.

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

Project	Type	Region	Potential completion date[1]	MW
Canada				
Riplinger Wind	Wind	Alberta	2026	300
Red Rock	Wind	Alberta	2028	100
Willow Creek 1	Wind	Alberta	2027	70
Willow Creek 2	Wind	Alberta	2027	70
Sunhills Solar	Solar	Alberta	2025	115
McNeil Solar	Solar	Alberta	2026	57
Canadian Battery opportunity	Battery	New Brunswick	2025	10
Canadian Wind opportunities	Wind	Various	2027+	370
Tent Mountain Pumped Storage	Hydro	Alberta	2028-2030	160
Brazeau Pumped Hydro	Hydro	Alberta	2037	300-900
Alberta Thermal Redevelopment	Various	Alberta	TBD	250-500
		Total		**1,802-2,652**
United States				
Old Town	Wind	Illinois	2025	185
Trapper Valley	Wind	Wyoming	2028	225
Monument Road	Wind	Nebraska	2025	152
Dos Rios	Wind	Oklahoma	2026	242
Prairie Violet	Wind	Illinois	2027	130
Big Timber	Wind	Pennsylvania	2027	50
Oklahoma Solar	Solar	Oklahoma	2026	100
Milligan 3	Wind	Nebraska	2026	126
Other Wind and Solar prospects	Wind and Solar	Various	2025+	409
Centralia site redevelopment	Various	Washington	TBD	250-500
		Total		**1,869-2,119**
Australia				
Australian prospects	Gas, Solar, Wind	Western Australia	2025+	170
South Hedland Solar	Solar	Western Australia	2026	50
		Total		**220**
Canada, United States and Australia		**Total**		**3,891-4,991**

(1) Potential completion date is to be determined ("TBD").

Material Accounting Policies and Critical Accounting Estimates

The preparation of unaudited interim condensed consolidated financial statements requires management to make judgments, estimates and assumptions that could affect the reported amounts of assets, liabilities, revenues, expenses and disclosures of contingent assets and liabilities during the period. These estimates are subject to uncertainty. Actual results could differ from these estimates due to factors such as fluctuations in interest rates, foreign exchange rates, inflation and commodity prices, and changes in economic conditions, legislation and regulations. The following were material changes in estimates in the quarter:

Decommissioning and Restoration Provisions

The Company recognizes provisions for decommissioning obligations. 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.

During the first quarter of 2023, the decommissioning and restoration provision increased by $21 million due to a decrease in discount rates, largely driven by decreases in market benchmark rates. On average, discount rates decreased with rates ranging from 6.7 to 9.5 per cent as at March 31, 2023 from 7.0 to 9.7 per cent as at Dec. 31, 2022. This has resulted in a corresponding increase in PP&E of $14 million on operating assets and recognition of a $7 million impairment charge in net earnings related to retired assets.

Reversals of Impairment of PP&E

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

During the three months ended March 31, 2023, the Company recognized asset impairment reversals, net of impairment charges of $3 million. Refer to Note 5 of the unaudited condensed consolidated financial statements for the three months ended March 31, 2023.

Accounting Changes

Current Accounting Changes

Amendments to IAS 12 Deferred Tax Related to Assets and Liabilities Arising from a Single Transaction

On May 7, 2021, the International Accounting Standards Board (“IASB”) issued amendments to IAS 12 Deferred Tax Related to Assets and Liabilities Arising from a Single Transaction. The amendments clarify that the initial recognition exemption under IAS 12 does not apply to transactions such as leases and decommissioning obligations. These transactions give rise to equal and offsetting temporary differences in which deferred tax should be recognized.

The amendments are effective for annual periods beginning on or after Jan. 1, 2023, and were adopted by the Company on that date. The Company's accounting aligns with the amendment and no financial impact arose upon adoption.

Future Accounting Changes

Please refer to Note 3 of the audited annual consolidated financial statements for the future accounting policies impacting the Company. For the three months ended, March 31, 2023, no additional future accounting policy changes impacting the Company were identified.

Governance and Risk Management

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

Please refer to the Governance and Risk Management section of our 2022 Annual MD&A and Note 11 of our unaudited interim condensed consolidated financial statements for details on our risks and how we manage them. Our risk management profile and practices have not changed materially from Dec. 31, 2022.

Regulatory Updates

Refer to the Policy and Legal Risks discussion in our 2022 annual MD&A for further details that supplement the recent developments as discussed below:

Canadian Federal Government

Federal Climate Plan
In April 2021, the Government of Canada announced a revised national greenhouse gas ("GHG") emissions reduction target of 40 per cent to 45 per cent below 2005 levels by 2030.

In 2022, the Government of Canada’s Department of Environment and Climate Change Canada (“ECCC”) released the proposed framework for the Clean Electricity Regulation to achieve a net-zero electricity sector in Canada by 2035. ECCC continues to develop the proposed regulation with the publication of a draft regulation now expected late in the second quarter of 2023.

In the 2023 federal budget, the government announced additional investment tax credit ("ITC") categories and details aimed at supporting the net zero transition. The ITCs are expected to support investments in net zero technologies in the electricity sector.

Federal Carbon Pricing on Greenhouse Gas Emissions
On June 21, 2018, the Canadian federal Greenhouse Gas Pollution Pricing Act ("GGPPA") came into force. Under the GGPPA, the Canadian federal government implemented a national price on GHG emissions. Amendments to Schedule 4 of the GGPPA were completed in October 2022. These amendments aligned facility emission charges with the government's updated carbon price trajectory of $65 per tonne of CO_2 in 2023 with increases of $15 per year to $170 per tonne by 2030.

On April 12, 2023, the federal government published Regulations Amending Schedule 2 to the GGPPA, Amending the Fuel Charge Regulations and Repealing the Part 1 of the Greenhouse Gas Pollution Pricing Act Regulations (Alberta) under sections 166 and 168 of the GGPPA. The amending regulations add a new table to Schedule 2 to the GGPPA that specifies the fuel charge rates out to 2030. These rates reflect the annual increase in the price on carbon pollution of $15 per tonne from 2023 to 2030 (from $65 per tonne in 2023–2024 to $170 per tonne in 2030–2031). This amendment is not expected to impact TransAlta as the Company received exemption certificates from the fuel charge due to coverage under the Alberta TIER and Ontario EPS regulations.

Alberta
On April 19, 2023, the Government of Alberta released the Emissions Reduction and Energy Development Plan, which commits to an aspiration to achieve a carbon neutral economy by 2050. The plan frames Alberta's approach to enhance the province's position as a global leader in emissions reductions, clean technology and innovation, while maintaining Alberta's competitiveness from a sustainable resource development perspective. The plan is guided by eight strategic principles and outlines the actions, opportunities and new commitments that will reduce emissions and maintain energy security.

United States

On March 21, 2022, the U.S. Securities and Exchange Commission ("SEC") released proposed rules to enhance and standardize climate-related disclosure for investors. The proposed rules cover climate risk governance and risk management, disclosure of material impacts over all time horizons, impacts on business models, and the impact of climate-related events. The SEC invited comments on the proposed rules before finalization and we anticipate the final rules will face legal challenges. Both the Canadian Securities Administrators and the SEC have signalled that they are likely to release their climate disclosure rules in 2023. The Company is prepared to assess our disclosures to ensure compliance once the new rules are in force.

On Aug. 16, 2022, the Inflation Reduction Act ("IRA") of 2022 was signed into law by President Biden. This Act will invest approximately US$369 billion in Energy Security and Climate Change programs over the next 10 years. The administration estimates this funding will help reduce national carbon emissions by approximately 40 per cent by 2030, lower energy costs and increase clean energy production. The Treasury Department released a roadmap on March 22, 2023, to provide additional certainty regarding the timing for remaining guidance on the various components of the renewables and hydrogen tax incentives in the IRA. Over the coming months, the department is expected to release guidance relating to domestic content, direct pay and transferability of tax credits and prevailing wages and apprenticeship standards. Additional guidance on the IRA Energy Community Tax Credit Bonus (for ITC and PTC) for projects, facilities and technologies located in energy communities was released on April 4, 2023, with a searchable mapping tool that helps identify areas that may be eligible for the energy communities bonus. It includes areas that have significant employment or local tax revenues from fossil fuels and higher than average unemployment. The guidance process has lagged behind expectations and is expected to continue through 2023.

Australia

Since the Labour Party formed the government on May 21, 2022, Australia has increased its Nationally Determined Contribution commitment to increase the country’s 2030 emissions reduction goal to 43 per cent below 2005 levels and confirmed its intent to boost renewable electricity production to 82 per cent of the electricity supply by 2030.

Prime Minister Anthony Albanese has worked quickly to implement one of his government’s key energy policies, the Powering Australia Plan, which includes; the Rewiring the Nation initiative that will provide AUD$20 billion to support the Australian Energy Market Operator’s (“AEMO”) integrated system plan to modernize the transmission system and enable additional renewable penetration; Powering the Regions Fund ($1.9 billion) supporting industry to decarbonize, developing new clean energy industries, and supporting workforce development; and a $15 billion National Reconstruction Fund to diversify and transform Australia’s economy and industry, including investments in green metals, clean energy component manufacturing, and deployment of low-emissions technologies.

Disclosure Controls and Procedures

Management is responsible for establishing and maintaining adequate internal control over financial reporting ("ICFR") and disclosure controls and procedures ("DC&P"). During the three months ended March 31, 2023, the majority of our workforce supporting and executing our ICFR and DC&P continue to work remotely on a hybrid basis. The Company has implemented appropriate controls and oversight for both in-office and remote work. There has been minimal impact to the design and performance of our internal controls.

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

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

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

Management has evaluated, with the participation of our Chief Executive Officer and Chief Financial Officer, the effectiveness of our ICFR and DC&P as of the end of the period covered by this MD&A. Based on the foregoing evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as at March 31, 2023, the end of the period covered by this MD&A, our ICFR and DC&P were effective.

Condensed Consolidated Statements of Earnings

(in millions of Canadian dollars except where noted)

	3 months ended March 31	
Unaudited	**2023**	**2022**
Revenues (Note 3)	**1,089**	735
Fuel and purchased power (Note 4)	**325**	238
Carbon compliance	**32**	19
Gross margin	**732**	478
Operations, maintenance and administration (Note 4)	**124**	112
Depreciation and amortization	**176**	117
Asset impairment reversals (Note 5)	**(3)**	(42)
Taxes, other than income taxes	**9**	8
Net other operating income	**(13)**	(17)
Operating income	**439**	300
Equity income	**2**	2
Finance lease income	**4**	5
Net interest expense (Note 6)	**(59)**	(67)
Foreign exchange gain (loss)	**(3)**	2
Earnings before income taxes	**383**	242
Income tax expense (Note 7)	**49**	36
Net earnings	**334**	206
Net earnings attributable to:		
TransAlta shareholders	**294**	186
Non-controlling interests (Note 8)	**40**	20
	334	206
Weighted average number of common shares outstanding in the period (millions)	**268**	271
Net earnings per share attributable to common shareholders, basic and diluted (Note 15)	**1.10**	0.69

See accompanying notes.

Condensed Consolidated Statements of Comprehensive Income

(in millions of Canadian dollars)

Unaudited	3 months ended March 31 2023	2022
Net earnings	**334**	206
Other comprehensive gain (loss)		
Net actuarial gains on defined benefit plans, net of tax[1]	**—**	18
Losses on derivatives designated as cash flow hedges, net of tax	**—**	(1)
Total items that will not be reclassified subsequently to net earnings	**—**	17
Losses on translating net assets of foreign operations, net of tax	**—**	(14)
Gains on financial instruments designated as hedges of foreign operations, net of tax	**1**	10
Gains (losses) on derivatives designated as cash flow hedges, net of tax[2]	**29**	(82)
Reclassification of losses (gains) on derivatives designated as cash flow hedges to net earnings (loss), net of tax[3]	**40**	(15)
Total items that will be reclassified subsequently to net earnings (loss)	**70**	(101)
Other comprehensive gain (loss)	**70**	(84)
Total comprehensive gain	**404**	122
Total comprehensive income attributable to:		
TransAlta shareholders	**360**	146
Non-controlling interests (Note 8)	**44**	(24)
	404	122

(1) Net of income tax expense of nil for the three months ended March 31, 2023 (March 31, 2022 – $5 million expense).
(2) Net of income tax expense of $8 million for the three months ended March 31, 2023 (March 31, 2022 – $23 million recovery).
(3) Net of reclassification of income tax expense of $11 million for the three months ended March 31, 2023 (March 31, 2022 – $4 million recovery).

See accompanying notes.

Condensed Consolidated Statements of Financial Position

(in millions of Canadian dollars)

Unaudited	March 31, 2023	Dec. 31, 2022
Current assets		
Cash and cash equivalents	**1,247**	1,134
Restricted cash (Note 14)	**47**	70
Trade and other receivables (Note 9)	**928**	1,589
Prepaid expenses	**56**	33
Risk management assets (Note 10 and 11)	**342**	709
Inventory	**144**	157
Assets held for sale	**—**	22
	2,764	3,714
Non-current assets		
Investments	**130**	129
Long-term portion of finance lease receivables	**125**	129
Risk management assets (Note 10 and 11)	**122**	161
Property, plant and equipment (Note 12)		
Cost	**14,304**	14,012
Accumulated depreciation	**(8,618)**	(8,456)
	5,686	5,556
Right-of-use assets	**126**	126
Intangible assets	**244**	252
Goodwill	**464**	464
Deferred income tax assets (Note 7)	**36**	50
Other assets	**160**	160
Total assets	**9,857**	10,741
Current liabilities		
Bank overdraft	**2**	16
Accounts payable and accrued liabilities (Note 9)	**840**	1,346
Current portion of decommissioning and other provisions (Note 13)	**72**	70
Risk management liabilities (Note 10 and 11)	**634**	1,129
Current portion of contract liabilities	**6**	8
Income taxes payable	**60**	73
Dividends payable (Note 15 and 16)	**40**	68
Current portion of long-term debt and lease liabilities (Note 14)	**177**	178
	1,831	2,888
Non-current liabilities		
Credit facilities, long-term debt and lease liabilities (Note 14)	**3,453**	3,475
Exchangeable securities	**741**	739
Decommissioning and other provisions (Note 13)	**682**	659
Deferred income tax liabilities	**346**	352
Risk management liabilities (Note 10 and 11)	**272**	333
Contract liabilities	**12**	12
Defined benefit obligation and other long-term liabilities	**287**	294
Equity		
Common shares (Note 15)	**2,799**	2,863
Preferred shares (Note 16)	**942**	942
Contributed surplus	**23**	41
Deficit	**(2,222)**	(2,514)
Accumulated other comprehensive (loss)	**(156)**	(222)
Equity attributable to shareholders	**1,386**	1,110
Non-controlling interests (Note 8)	**847**	879
Total equity	**2,233**	1,989
Total liabilities and equity	**9,857**	10,741

Commitments and contingencies (Note 17)
See accompanying notes.

Condensed Consolidated Statements of Changes in Equity

(in millions of Canadian dollars)

Unaudited 3 months ended March 31, 2023	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income (loss)	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec. 31, 2022	2,863	942	41	(2,514)	(222)	1,110	879	1,989
Net earnings	**—**	**—**	**—**	**294**	**—**	**294**	**40**	**334**
Other comprehensive income (loss):								
Net gains on translating net assets of foreign operations, net of hedges and tax	**—**	**—**	**—**	**—**	**1**	**1**	**—**	**1**
Net gains on derivatives designated as cash flow hedges, net of tax	**—**	**—**	**—**	**—**	**69**	**69**	**—**	**69**
Intercompany and third-party FVTOCI investments	**—**	**—**	**—**	**—**	**(4)**	**(4)**	**4**	**—**
Total comprehensive income	**—**	**—**	**—**	**294**	**66**	**360**	**44**	**404**
Shares purchased under normal course issuer bid ("NCIB") (Note 15)	**(34)**	**—**	**—**	**(2)**	**—**	**(36)**	**—**	**(36)**
Provision for repurchase of shares under the automatic share purchase plan (Note 15)	**(37)**	**—**	**—**	**—**	**—**	**(37)**	**—**	**(37)**
Effect of share-based payment plans	**7**	**—**	**(18)**	**—**	**—**	**(11)**	**—**	**(11)**
Distributions paid and payable, to non-controlling interests (Note 8)	**—**	**—**	**—**	**—**	**—**	**—**	**(76)**	**(76)**
Balance, March 31, 2023	**2,799**	**942**	**23**	**(2,222)**	**(156)**	**1,386**	**847**	**2,233**

3 months ended March 31, 2022	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec. 31, 2021	2,901	942	46	(2,453)	146	1,582	1,011	2,593
Net earnings	—	—	—	186	—	186	20	206
Other comprehensive income (loss):								
Net losses on translating net assets of foreign operations, net of hedges and of tax	—	—	—	—	(4)	(4)	—	(4)
Net losses on derivatives designated as cash flow hedges, net of tax	—	—	—	—	(98)	(98)	—	(98)
Net actuarial gains on defined benefits plans, net of tax	—	—	—	—	18	18	—	18
Intercompany FVTOCI investments	—	—	—	—	44	44	(44)	—
Total comprehensive income (loss)	—	—	—	186	(40)	146	(24)	122
Shares purchased under NCIB program (Note 15)	(15)	—	—	(3)	—	(18)	—	(18)
Effect of share-based payment plans	6	—	(21)	—	—	(15)	—	(15)
Distributions paid, and payable, to non-controlling interests (Note 8)	—	—	—	—	—	—	(42)	(42)
Balance, March 31, 2022	2,892	942	25	(2,270)	106	1,695	945	2,640

See accompanying notes.

Condensed Consolidated Statements of Cash Flows

(in millions of Canadian dollars)

	3 months ended March 31	
Unaudited	**2023**	**2022**
Operating activities		
Net earnings	**334**	206
Depreciation and amortization (Note 18)	**176**	117
Accretion of provisions (Note 6 and 13)	**14**	9
Decommissioning and restoration costs settled (Note 13)	**(7)**	(7)
Deferred income tax expense (recovery) (Note 7)	**(11)**	24
Unrealized gain from risk management activities	**(64)**	(129)
Unrealized foreign exchange (gain) loss	**2**	(2)
Provisions and contract liabilities	**—**	5
Asset impairment reversals (Note 5)	**(3)**	(42)
Equity income, net of distributions from investments	**(1)**	(1)
Other non-cash items	**(20)**	(13)
Cash flow from operations before changes in working capital	**420**	167
Change in non-cash operating working capital balances	**42**	284
Cash flow from operating activities	**462**	451
Investing activities		
Additions to property, plant and equipment (Note 12 and 18)	**(284)**	(72)
Additions to intangible assets	**(3)**	(21)
Restricted cash (Note 14)	**23**	22
Repayment from loan receivable	**4**	—
Proceeds on sale of property, plant and equipment	**23**	—
Realized gain (loss) on financial instruments	**6**	(1)
Decrease in finance lease receivable	**13**	11
Other	**(5)**	11
Change in non-cash investing working capital balances	**41**	(22)
Cash flow used in investing activities	**(182)**	(72)
Financing activities		
Repayment of long-term debt	**(29)**	(25)
Dividends paid on common shares (Note 15)	**(15)**	(14)
Dividends paid on preferred shares (Note 16)	**(13)**	(10)
Repurchase of common shares under NCIB (Note 15)	**(34)**	(15)
Proceeds on issuance of common shares	**2**	1
Distributions paid to subsidiaries' non-controlling interests (Note 8)	**(76)**	(42)
Decrease in lease liabilities	**(2)**	(1)
Financing fees and other	**2**	—
Cash flow used in financing activities	**(165)**	(106)
Cash flow from operating, investing and financing activities	**115**	273
Effect of translation on foreign currency cash	**(2)**	1
Increase in cash and cash equivalents	**113**	274
Cash and cash equivalents, beginning of period	**1,134**	947
Cash and cash equivalents, end of period	**1,247**	1,221
Cash taxes paid	**37**	18
Cash interest paid	**62**	47

See accompanying notes.

Notes to the Condensed Consolidated Financial Statements

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

1. Corporate Information

A. Description of the Business

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

B. Basis of Preparation

These unaudited interim condensed consolidated financial statements have been prepared in compliance with International Accounting Standard ("IAS") 34 Interim Financial Reporting using the same accounting policies as those used in the Company's most recent audited annual consolidated financial statements, except as outlined in Note 2. These unaudited interim condensed consolidated financial statements do not include all of the disclosures included in the Company's audited annual consolidated financial statements. Accordingly, they should be read in conjunction with the Company's most recent audited annual consolidated financial statements which are available on SEDAR at www.sedar.com and on EDGAR at www.sec.gov.

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

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

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

These unaudited interim condensed consolidated financial statements were authorized for issue by the Audit, Finance and Risk Committee on behalf of TransAlta's Board of Directors (the "Board") on May 4, 2023.

C. Significant Accounting Judgements and Key Sources of Estimation Uncertainty

The preparation of these unaudited interim condensed consolidated financial statements in accordance with IAS 34 requires management to use judgment and make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and disclosures of contingent assets and liabilities. These estimates are subject to uncertainty. Actual results could differ from these estimates due to factors such as fluctuations in interest rates, foreign exchange rates, inflation and commodity prices, and changes in economic conditions, legislation and regulations.

During the three months ended March 31, 2023, estimates continue to be subject to uncertainty to the extent the geopolitical events may, directly or indirectly, impact the Company's operations, financial results and conditions in future periods. Uncertainty related to geopolitical events and Consumer Price Index inflation have been considered in the Company's estimates.

During the three months ended March 31, 2023, there were changes in estimates relating to decommissioning and other provisions (Note 13) and asset impairment reversals (Note 5).

Refer to Note 2(P) of the Company's 2022 audited annual consolidated financial statements for further details on the significant accounting judgments and key sources of estimation uncertainty.

2. Material Accounting Policies

The accounting policies adopted in the preparation of the unaudited interim condensed consolidated financial statements are consistent with those followed in the preparation of the Company's annual consolidated financial statements for the year ended Dec. 31, 2022, except for the adoption of new standards effective as of Jan. 1, 2023 and interpretations or amendments that have been issued but are not yet effective.

A. Current Accounting Changes

Amendments to IAS 12 Deferred Tax Related to Assets and Liabilities Arising from a Single Transaction

On May 7, 2021, the International Accounting Standards Board ("IASB") issued amendments to IAS 12 Deferred Tax Related to Assets and Liabilities Arising from a Single Transaction. The amendments clarify that the initial recognition exemption under IAS 12 does not apply to transactions such as leases and decommissioning obligations. These transactions give rise to equal and offsetting temporary differences in which deferred tax should be recognized.

The amendments are effective for annual periods beginning on or after Jan. 1, 2023, and were adopted by the Company on that date. The Company's accounting aligns with the amendment and no financial impact arose upon adoption.

B. Future Accounting Changes

Please refer to Note 3 of the audited annual consolidated financial statements for the future accounting policies impacting the Company. For the three months ended, March 31, 2023, no additional future accounting policy changes impacting the Company were identified.

3. Revenue

A. Disaggregation of Revenue

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

3 months ended March 31, 2023	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
Revenues from contracts with customers							
Power and other	**4**	**59**	**99**	**3**	**—**	**—**	**165**
Environmental attributes[1]	**8**	**13**	**—**	**—**	**—**	**—**	**21**
Revenue from contracts with customers	**12**	**72**	**99**	**3**	**—**	**—**	**186**
Revenue from leases[2]	**—**	**—**	**8**	**—**	**—**	**—**	**8**
Revenue from derivatives and other trading activities[3]	**25**	**(1)**	**29**	**78**	**92**	**—**	**223**
Revenue from merchant sales	**86**	**34**	**357**	**186**	**—**	**—**	**663**
Other[4]	**2**	**5**	**2**	**—**	**—**	**—**	**9**
Total revenue	**125**	**110**	**495**	**267**	**92**	**—**	**1,089**
Revenues from contracts with customers							
Timing of revenue recognition							
At a point in time	**8**	**13**	**—**	**3**	**—**	**—**	**24**
Over time	**4**	**59**	**99**	**—**	**—**	**—**	**162**
Total revenue from contracts with customers	**12**	**72**	**99**	**3**	**—**	**—**	**186**

(1) The environmental attributes represent environmental attribute sales not bundled with power and other sales.
(2) Total lease income from long-term contracts that meet the criteria of operating leases.
(3) Represents realized and unrealized gains or losses from hedging and derivative positions.
(4) Other revenue includes production tax credits related to US wind facilities and other miscellaneous.

3 months ended March 31, 2022	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
Revenues from contracts with customers							
Power and other	5	63	104	4	—	—	176
Environmental attributes(1)	1	7	—	—	—	—	8
Revenue from contracts with customers	6	70	104	4	—	—	184
Revenue from leases(2)	—	—	4	—	—	—	4
Revenue from derivatives and other trading activities(3)	—	(13)	150	48	26	1	212
Revenue from merchant sales	70	28	175	54	—	—	327
Other(4)	1	6	1	—	—	—	8
Total revenue	77	91	434	106	26	1	735
Revenues from contracts with customers							
Timing of revenue recognition							
At a point in time	1	7	—	4	—	—	12
Over time	5	63	104	—	—	—	172
Total revenue from contracts with customers	6	70	104	4	—	—	184

(1) The environmental attributes represent environmental attribute sales not bundled with power and other sales.
(2) Total lease income from long-term contracts that meet the criteria of operating leases.
(3) Represents realized and unrealized gains or losses from hedging and derivative positions. The Wind and Solar segment has been revised to present revenue classifications consistent with the current period.
(4) Other revenue includes production tax credits related to the US wind facilities, government incentives, and other miscellaneous.

4. Expenses by Nature

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

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

	3 months ended March 31			
	2023		2022	
	Fuel and purchased power	**OM&A**	Fuel and purchased power	OM&A
Gas fuel costs	**110**	**—**	122	—
Coal fuel costs	**54**	**—**	39	—
Royalty, land lease, other direct costs	**8**	**—**	7	—
Purchased power	**152**	**—**	69	—
Salaries and benefits	**1**	**64**	1	58
Other operating expenses	**—**	**60**	—	54
Total	**325**	**124**	238	112

Carbon Compliance

As at March 31, 2023, the Company holds 607,243 emission credits in inventory purchased externally with a recorded book value of $21 million (Dec. 31, 2022 – 963,068 emission credits with a recorded book value of $27 million). The Company also has approximately 1,739,437 (Dec. 31, 2022 – 1,869,450) of internally generated eligible emission credits from the Company's Wind and Solar and Hydro segments with no recorded book value. As at March 31, 2023, the Company holds approximately 1,750,000 eligible emission performance credits ("EPCs") with no recorded book value generated from assets formerly subject to the Hydro Power Purchase Arrangement ("Hydro PPA") with the Balancing Pool. These EPCs were subject to a dispute which subsequent to the period end has been resolved in principle. Refer to Note 17 for details.

The emission credits can be sold externally or can be used to offset future emission obligations from our gas facilities located in Canada, where the compliance price of carbon is expected to increase, resulting in a reduced cash cost for carbon compliance. The compliance price of carbon for the 2022 obligation to be settled during the current year was $50 per tonne and has increased to $65 per tonne in the current year.

5. Asset Impairment Reversals

The Company recognized the following asset impairment reversals:

	3 months ended March 31	
	2023	2022
Segments:		
Wind and Solar	**(10)**	—
Changes in decommissioning and restoration provisions on retired assets[(1)]	**7**	(42)
Asset impairment reversals	**(3)**	(42)

(1) Changes relate to revisions in discount rates and cash flow revisions on retired assets during March 31, 2023 and revisions in discount rates on retired assets during March 31, 2022. Refer to Note 13 for further details.

Wind and Solar

During the first quarter of 2023, internal valuations indicated the fair value less costs of disposal of the assets exceeded the carrying value due to changes in Ontario power price assumptions, favourably impacting estimated future cash flows and resulting in a full recoverability test. As a result of the recoverability test an impairment reversal of $10 million was recognized. The recoverable amounts of $253 million in total were estimated based on fair value less costs of disposal utilizing a discounted cash flow approach and are categorized as a level III fair value measurements. The discount rate used in the fair value measurements was 6.94 per cent.

6. Net Interest Expense

The components of net interest expense are as follows:

	3 months ended March 31	
	2023	2022
Interest on debt	**50**	41
Interest on exchangeable debentures	**7**	7
Interest on exchangeable preferred shares	**7**	7
Interest income	**(15)**	(3)
Capitalized interest (Note 12)	**(13)**	(1)
Interest on lease liabilities	**2**	1
Credit facility fees, bank charges and other interest	**8**	6
Tax shield on tax equity financing	**(1)**	—
Accretion of provisions (Note 13)	**14**	9
Net interest expense	**59**	67

On April 27, 2023, the Company declared a dividend of $7 million in aggregate for Exchangeable Preferred Shares ("Series I Preferred Shares") at the fixed rate of 1.726 per cent, per share, payable on May 31, 2023. The Exchangeable Preferred Shares are considered debt for accounting purposes, and as such, dividends are reported as interest expense.

7. Income Taxes

The components of income tax expense are as follows:

	3 months ended March 31	
	2023	2022
Current income tax expense	**60**	12
Deferred income tax expense related to the origination and reversal of temporary differences	**49**	158
Deferred income tax recovery related to temporary difference on investment in subsidiary	**(1)**	(3)
Deferred income tax recovery arising from unrecognized deferred income tax assets[1]	**(59)**	(131)
Income tax expense	**49**	36
Current income tax expense	**60**	12
Deferred income tax expense (recovery)	**(11)**	24
Income tax expense	**49**	36

(1) During the three months ended March 31, 2023, the Company recognized deferred tax assets of $59 million (March 31, 2022 – $131 million recognition). The deferred income tax assets mainly relate to the tax benefits of losses associated with the Company's directly owned Canadian and US operations and other deductible differences. The Company undertakes an analysis of the recoverability of its tax assets on an annual basis.

8. Non-Controlling Interests

The Company's subsidiaries with significant non-controlling interests are TransAlta Renewables Inc. ("TransAlta Renewables") and TransAlta Cogeneration L.P. The net earnings, distributions, and equity attributable to TransAlta Renewables' non-controlling interests include the 17 per cent non-controlling interest in Kent Hills Wind LP, which owns the 167 MW Kent Hills wind farm located in New Brunswick.

	3 months ended March 31	
	2023	2022
Net earnings		
TransAlta Cogeneration L.P.	**23**	7
TransAlta Renewables	**17**	13
	40	20
Total comprehensive income (loss)		
TransAlta Cogeneration L.P.	**23**	7
TransAlta Renewables	**21**	(31)
	44	(24)
Distributions paid to non-controlling interests		
TransAlta Cogeneration L.P.	**51**	17
TransAlta Renewables	**25**	25
	76	42

As at	March 31, 2023	Dec. 31, 2022
Equity attributable to non-controlling interests		
TransAlta Cogeneration L.P.	**118**	147
TransAlta Renewables	**729**	732
	847	879
Non-controlling interests (per cent)		
TransAlta Cogeneration L.P.	**50.0**	50.0
TransAlta Renewables	**39.9**	39.9

9. Trade and Other Receivables and Accounts Payable

As at	March 31, 2023	Dec. 31, 2022
Trade accounts receivable	**739**	1,165
Collateral provided (Note 11)	**118**	304
Current portion of finance lease receivables	**43**	52
Loan receivable	**—**	4
Income taxes receivable	**28**	64
Trade and other receivables	**928**	1,589

As at	March 31, 2023	Dec. 31, 2022
Accounts payable and accrued liabilities	**777**	1,069
Interest payable	**21**	17
Collateral held (Note 11)	**42**	260
Accounts payable and accrued liabilities	**840**	1,346

10. Financial Instruments

A. Financial Assets and Liabilities — Classification and Measurement

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

B. Fair Value of Financial Instruments

I. Level I, II and III Fair Value Measurements

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

a. Level I

Fair values are determined using inputs that are quoted prices (unadjusted) in active markets for identical assets or liabilities that the Company has the ability to access at the measurement date.

b. Level II

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

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

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

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

c. Level III

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

For assets and liabilities that are recognized at fair value on a recurring basis, the Company determines whether transfers have occurred between levels in the hierarchy by re-assessing categorization (based on the lowest level input that is significant to the fair value measurement as a whole) at the end of each reporting period.

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. For additional information, please refer to Note 14 of the 2022 audited annual consolidated financial statements.

II. Commodity Risk Management Assets and Liabilities

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

Commodity risk management assets and liabilities classified by fair value levels as at March 31, 2023, are as follows: Level I – $6 million net asset (Dec. 31, 2022 – $23 million net asset), Level II – $4 million net asset (Dec. 31, 2022 – $173 million net asset) and Level III – $441 million net liability (Dec. 31, 2022 – $782 million net liability).

Significant changes in commodity net risk management assets (liabilities) during the three months ended March 31, 2023, are primarily attributable to contract settlements and volatility in market prices across multiple markets on both existing contracts and new contracts.

The following table summarizes the key factors impacting the fair value of the Level III commodity risk management assets and liabilities by classification during the three months ended March 31, 2023 and 2022, respectively:

	3 months ended March 31, 2023			3 months ended March 31, 2022		
	Hedge	**Non-hedge**	**Total**	Hedge	Non-hedge	Total
Opening balance	**(347)**	**(435)**	**(782)**	285	(126)	159
Changes attributable to:						
Market price changes on existing contracts	**(26)**	**106**	**80**	(132)	(205)	(337)
Market price changes on new contracts	**—**	**(4)**	**(4)**	—	(37)	(37)
Contracts settled	**118**	**135**	**253**	(14)	29	15
Change in foreign exchange rates	**1**	**—**	**1**	(7)	4	(3)
Transfers out of Level III	**—**	**11**	**11**	—	—	—
Net risk management assets (liabilities) at end of period	**(254)**	**(187)**	**(441)**	132	(335)	(203)
Additional Level III information:						
Losses recognized in other comprehensive loss	**(25)**	**—**	**(25)**	(139)	—	(139)
Total gains (losses) included in earnings (loss) before income taxes	**(118)**	**102**	**(16)**	14	(238)	(224)
Unrealized gains (losses) included in earnings (loss) before income taxes relating to net assets held at period end	**—**	**237**	**237**	—	(209)	(209)

As at March 31, 2023, the total Level III risk management asset balance was $52 million (Dec. 31, 2022 – $31 million) and Level III risk management liability balance was $494 million (Dec. 31, 2022 – $813 million). The fair value of the level III long-term power sale - US contract has decreased mainly due to contract settlements and the fair value of the full requirements - eastern US contracts has decreased due to contract settlements and lower power prices.

The information on risk management contracts or groups of risk management contracts that are included in Level III measurements and the related unobservable inputs and sensitivities are outlined in the following table. These include the effects on fair value of discounting, liquidity and credit value adjustments; however, the potential offsetting effects of Level II positions are not considered. Sensitivity ranges for the base fair values are determined using reasonably possible alternative assumptions for the key unobservable inputs, which may include forward commodity prices, volatility in commodity prices and correlations, delivery volumes, escalation rates and cost of supply.

As at	March 31, 2023			
Description	**Sensitivity**	**Valuation technique**	**Unobservable input**	**Reasonably possible change**
Long-term power sale – US	+11 -124	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of US$5 or price increase of US$55
Coal transportation – US	+10 -13	Numerical derivative valuation	Illiquid future power prices (per MWh)	Price decrease of US$5 or price increase of US$55
			Volatility	80% to 120%
			Rail rate escalation	zero to 10%
Full requirements – Eastern US	+5	Scenario analysis	Volume	96% to 104%
	-9		Cost of supply	Decrease of $1.20 per MWh or increase of $2.20 per MWh
Long-term wind energy sale – Eastern US	+23	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease or increase of US$6
			Illiquid future REC prices (per unit)	Price decrease of US$2 or increase of US$4
	-23		Wind discounts	0% decrease or 5% increase
Long-term wind energy sale – Canada	+44	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of C$82 or increase of C$5
	-23		Wind discounts	29% decrease or 5% increase
Long-term wind energy sale - Central US	+101	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease or increase of US$2
	-33		Wind discounts	3% decrease or 2% increase
Others	+13			
	-14			

As at			Dec. 31, 2022	
Description	Sensitivity	Valuation technique	Unobservable input	Reasonably possible change
Long-term power sale – US	+15 -163	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of US$5 or a price increase of US$55
Coal transportation – US			Illiquid future power prices (per MWh)	Price decrease of US$5 or a price increase of US$55
	+14	Numerical derivative valuation	Volatility	80% to 120%
	-13		Rail rate escalation	zero to 10%
Full requirements – Eastern US	+3	Scenario analysis (1)	Volume	96% to 104%
	-21		Cost of supply	Decrease of US$0.5 per MWh or increase of US$3.30 per MWh
Long-term wind energy sale – Eastern US	+22		Illiquid future power prices (per MWh)	Price increase or decrease of US$6
			Illiquid future REC prices (per unit)	Price decrease or increase of US$2
	-18	Long-term price forecast	Wind discounts	0% decrease or 5% increase
Long-term wind energy sale – Canada	+47	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of C$85 or increase of C$5
	-25		Wind discounts	28% decrease or 5% increase
Long-term wind energy sale – Central US	+74	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease or increase of US$2
	-28		Wind discounts	2% decrease or 5% increase
Others	+18 -19			

(1) The valuation technique for Full requirements - Eastern US was updated to scenario analysis to provide a more representative description and did not result in changes to the value.

i. Long-Term Power Sale – US

The Company has a long-term fixed price power sale contract in the US for delivery of power at the following capacity levels: 380 MW through Dec. 31, 2024, and 300 MW through Dec. 31, 2025. The contract is designated as an all-in-one cash flow hedge.

The contract is denominated in US dollars. The US dollar relative to the Canadian dollar did not change significantly from Dec. 31, 2022 to March 31, 2023 and did not have an impact on the base fair value or sensitivity values.

ii. Coal Transportation – US

The Company has a coal rail transport agreement that includes an upside sharing mechanism until Dec. 31, 2025. Option pricing techniques have been utilized to value the obligation associated with this component of the agreement.

iii. Full Requirements – Eastern US

The Company has a portfolio of full requirement service contracts, whereby the Company agrees to supply specific utility customer needs for a range of products that may include electrical energy, capacity, transmission, ancillary services, renewable energy credits ("RECs") and independent system operator costs.

iv. Long-Term Wind Energy Sale – Eastern US

The Company entered into 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 matures in December 2034. The contract is accounted for as a derivative. Changes in fair value are presented in revenue.

v. Long-Term Wind Energy Sale – Canada

The Company entered into two Virtual Power Purchase Agreements ("VPPAs") for the offtake of 100 per cent of the generation from its 130 MW Garden Plain wind project. 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. The customer is also entitled to the physical delivery of environmental attributes. Both VPPAs commence on commercial operation of the facility and extend for a weighted average of approximately 17 years. The commercial operation date is expected to be in the second quarter of 2023.

In addition to the VPPAs, the Company has entered into a bridge contract that initially was for 16 months from Sept. 1, 2021, through Dec. 31, 2022, and will remain in effect at one of the VPPAs price until the commercial operation date is achieved. The customer is also entitled to the physical delivery of environmental attributes.

The energy component of these contracts is accounted for as derivatives. Changes in fair value are presented in revenue.

Under a separate agreement, Pembina Pipeline Corporation ("Pembina") had the option to purchase a 37.7 per cent equity interest in the project. In the first quarter of 2023, this option was waived and the option agreement was terminated.

vi. Long-Term Wind Energy Sale – Central US

The Company entered into two long-term VPPAs for the offtake of 100 per cent of the generation from its 300 MW White Rock East and White Rock West wind power projects. The VPPAs, together with the sale of electricity generated into the US Southwest Power Pool ("SPP") market at the relevant price nodes, achieve the fixed contract prices per MWh. Under the VPPAs, if the SPP pricing is lower than the fixed contract price the customer pays the Company the difference and if the SPP pricing is higher than the fixed contract price the Company refunds the difference to the customer. The customer is also entitled to the physical delivery of environmental attributes. The VPPAs commence on commercial operation of the facilities, which is expected within the second half of 2023.

The Company entered into a long-term VPPA for the offtake of 100 per cent of the generation from its 200 MW Horizon Hill wind project. The VPPA, together with the sale of electricity generated into the US 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 commences on commercial operation of the facility, which is expected within the second half of 2023.

The energy component of these contracts is accounted for as derivatives. Changes in fair value are presented in revenue.

III. Other Risk Management Assets and Liabilities

Other risk management assets and liabilities primarily include risk management assets and liabilities that are used in managing 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 liability fair value of $11 million as at March 31, 2023 (Dec. 31, 2022 – $6 million net liability) are classified as Level II fair value measurements. The changes in other net risk management assets and liabilities during the three months ended March 31, 2023, are primarily attributable to settlement of contracts in a gain position at December 31, 2022, partially offset by favourable market price changes on existing contracts and favourable foreign exchange rates on new contracts entered into during 2023.

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(1)				Total carrying value(1)
	Level I	Level II	Level III	Total	
Exchangeable securities — March 31, 2023	**—**	**697**	**—**	**697**	**741**
Long-term debt — March 31, 2023	**—**	**3,275**	**—**	**3,275**	**3,494**
Loan receivable — March 31, 2023	**—**	**32**	**—**	**32**	**32**
Exchangeable securities — Dec. 31, 2022	—	685	—	685	739
Long-term debt — Dec. 31, 2022	—	3,200	—	3,200	3,518
Loan receivable — Dec. 31, 2022	—	37	—	37	37

(1) Includes current portion.

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.

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 10 above for fair value Level III valuation techniques used. In some instances, a difference may arise between the fair value of a financial instrument at initial recognition (the "transaction price") and the amount calculated through a valuation model. This unrealized gain or loss at inception is recognized in net 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 condensed 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. The difference between the transaction price and the fair value determined using a valuation model, yet to be recognized in net earnings (loss) and a reconciliation of changes is as follows:

	3 months ended March 31	
	2023	2022
Unamortized net loss at beginning of period	**(213)**	(102)
New inception gains	**2**	9
Change in foreign exchange rates	**—**	3
Amortization recorded in net earnings during the period	**(7)**	(4)
Unamortized net loss at end of period	**(218)**	(94)

11. Risk Management Activities

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 its risk tolerance. For additional information on the Company's Risk Management Activities please refer to Note 15 of the 2022 audited annual consolidated financial statements.

A. Net Risk Management Assets and Liabilities

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

As at March 31, 2023	**Cash flow hedges**	**Not designated as a hedge**	**Total**
Commodity risk management			
Current	**(182)**	**(99)**	**(281)**
Long-term	**(72)**	**(78)**	**(150)**
Net commodity risk management liabilities	**(254)**	**(177)**	**(431)**
Other			
Current	**—**	**(11)**	**(11)**
Long-term	**—**	**—**	**—**
Net other risk management liabilities	**—**	**(11)**	**(11)**
Total net risk management liabilities	**(254)**	**(188)**	**(442)**

As at Dec. 31, 2022	Cash flow hedges	Not designated as a hedge	Total
Commodity risk management			
Current	(271)	(143)	(414)
Long-term	(76)	(96)	(172)
Net commodity risk management liabilities	(347)	(239)	(586)
Other			
Current	—	(6)	(6)
Long-term	—	—	—
Net other risk management liabilities	—	(6)	(6)
Total net risk management liabilities	(347)	(245)	(592)

B. Nature and Extent of Risks Arising from Financial Instruments

I. Market Risk

i. Commodity Price Risk Management – Proprietary Trading
The Company's Energy Marketing segment conducts proprietary trading activities and uses a variety of instruments to manage risk, earn trading revenue and gain market information.

Value at Risk ("VaR") is used to determine the potential change in value of the Company's proprietary trading portfolio, over a three-day period within a 95 per cent confidence level, resulting from normal market fluctuations. Changes in market prices associated with proprietary trading activities affect net earnings in the period that the price changes occur. VaR at March 31, 2023, associated with the Company's proprietary trading activities was $5 million (Dec. 31, 2022 – $4 million).

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

VaR at March 31, 2023, associated with the Company's commodity derivative instruments used in generation hedging activities was $42 million (Dec. 31, 2022 – $97 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 March 31, 2023, associated with these transactions was $31 million (Dec. 31, 2022 – $54 million), of which $21 million related to VPPAs (Dec. 31, 2022 – $26 million).

II. Credit Risk
The Company uses external credit ratings, as well as internal ratings in circumstances where external ratings are not available, to establish credit limits for customers and counterparties. The following table outlines the Company's maximum exposure to credit risk without taking into account collateral held, including the distribution of credit ratings, as at March 31, 2023:

	Investment grade (Per cent)	Non-investment grade (Per cent)	Total (Per cent)	Total amount
Trade and other receivables[(1)(2)]	88	12	100	**928**
Long-term finance lease receivable	100	—	100	**125**
Risk management assets[(1)]	95	5	100	**464**
Loan receivable[(2)]	—	100	100	**32**
Total				**1,549**

(1) Letters of credit and cash and cash equivalents are the primary types of collateral held as security related to these amounts.
(2) Includes $32 million loan receivable included within other assets with a counterparty that has no external credit rating.

The Company did not have significant expected credit losses as at March 31, 2023.

The Company's maximum exposure to credit risk at March 31, 2023, without taking into account collateral held or right of set-off, is represented by the current carrying amounts of receivables and risk management assets as per the condensed consolidated statements of financial position. Letters of credit 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 March 31, 2023, was $39 million (Dec. 31, 2022 – $64 million).

III. Liquidity Risk
The Company has sufficient existing liquidity available to meet its upcoming debt maturities. The next major debt repayment is scheduled for September 2024. Our highly diversified asset portfolio, by both fuel type and operating region, provide stability in our cash flows and highlight the strength of our long-term contracted asset base.

Liquidity risk relates to the Company’s ability to access capital to be used for capital projects, debt refinancing, proprietary trading activities, commodity hedging and general corporate purposes. A maturity analysis of the Company's financial liabilities as well as financial assets that are expected to generate cash inflows to meet cash outflows on financial liabilities, is as follows:

	2023	2024	2025	2026	2027	2028 and thereafter	Total
Bank overdraft	2	—	—	—	—	—	2
Accounts payable and accrued liabilities	840	—	—	—	—	—	840
Long-term debt(1)	139	527	142	191	153	2,386	3,538
Exchangeable securities(2)	—	—	750	—	—	—	750
Commodity risk management (assets) liabilities	209	173	(12)	12	9	40	431
Other risk management (assets) liabilities	12	(2)	1	1	—	(1)	11
Lease liabilities(3)	(8)	4	4	4	4	128	136
Interest on long-term debt and lease liabilities(4)	165	194	168	159	150	833	1,669
Interest on exchangeable securities(2)(4)	40	60	—	—	—	—	100
Dividends payable	40	—	—	—	—	—	40
Total	**1,439**	**956**	**1,053**	**367**	**316**	**3,386**	**7,517**

(1) Excludes impact of hedge accounting and derivatives.
(2) The exchangeable securities can be exchanged, at the earliest, on Jan. 1, 2025.
(3) Lease liabilities include a lease incentive of $12 million expected to be received in 2023.
(4) Not recognized as a financial liability on the condensed consolidated statements of financial position.

C. Collateral

I. Financial Assets Provided as Collateral

At March 31, 2023, the Company provided $118 million (Dec. 31, 2022 — $304 million) in cash and cash equivalents as collateral to regulated clearing agents and certain utility customers as security for commodity trading activities. These funds are held in segregated accounts by the clearing agents. The utility customers are obligated to pay interest on the outstanding balances. Collateral provided is included within trade and other receivables in the condensed consolidated statements of Financial Position.

II. Financial Assets Held as Collateral

At March 31, 2023, the Company held $42 million (Dec. 31, 2022 – $260 million) in cash collateral associated with counterparty obligations. Under the terms of the contracts, the Company may be obligated to pay interest on the outstanding balances and to return the principal when the counterparties have met their contractual obligations or when the amount of the obligation declines as a result of changes in market value. Interest payable to the counterparties on the collateral received is calculated in accordance with each contract. Collateral held is related to physical and financial derivative transactions in a net asset position and is included in accounts payable and accrued liabilities in the condensed consolidated statements of financial position.

III. Contingent Features in Derivative Instruments

Collateral is posted in the normal course of business based on the Company’s senior unsecured credit rating as determined by certain major credit rating agencies. Certain of the Company’s derivative instruments contain financial assurance provisions that require collateral to be posted only if a material adverse credit-related event occurs.

At March 31, 2023, the Company had posted collateral of $423 million (Dec. 31, 2022 – $820 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 $377 million (Dec. 31, 2022 – $656 million) of collateral to its counterparties.

12. Property, Plant and Equipment

During the three months ended March 31, 2023, the Company had additions of $263 million, mainly related to assets under construction for White Rock wind project, Horizon Hill wind project and other planned major maintenance. The Company also continued its rehabilitation plan for the Kent Hills wind facilities and capitalized additions of $21 million in 2023.

There was an increase in the decommissioning provision resulting from a decrease in discount rates, largely driven by decreases in market benchmark rates. This resulted in an increase in the related assets included in property, plant and equipment by $14 million (March 31, 2022 — $56 million). Refer to Note 13 for further details.

During the three months ended March 31, 2023, the Company capitalized $13 million (March 31, 2022 — $1 million) of interest to property, plant and equipment ("PP&E") at a weighted average rate of 6.1 per cent (March 31, 2022 — 6.1 per cent).

13. Decommissioning and Other Provisions

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

	Decommissioning and restoration	Other provisions	Total
Balance, Dec. 31, 2022	688	41	729
Liabilities settled	**(7)**	**(2)**	**(9)**
Accretion (Note 6)	**14**	**—**	**14**
Revisions in discount rates	**21**	**—**	**21**
Change in foreign exchange rates	**(1)**	**—**	**(1)**
Balance, March 31, 2023	**715**	**39**	**754**

Included in the condensed consolidated statements of financial position as:		
As at	**March 31, 2023**	Dec. 31, 2022
Current portion	**72**	70
Non-current portion	**682**	659
Total Decommissioning and other provisions	**754**	729

A. Decommissioning and Restoration

During the first quarter of 2023, the decommissioning and restoration provision increased by $21 million due to a decrease in discount rates, largely driven by decreases in market benchmark rates. On average, discount rates decreased with rates ranging from 6.7 to 9.5 per cent as at March 31, 2023 from 7.0 to 9.7 per cent as at Dec. 31, 2022. This has resulted in a corresponding increase in PP&E of $14 million on operating assets and recognition of a $7 million impairment charge in net earnings related to retired assets.

B. Other Provisions

Other provisions include provisions arising from ongoing business activities, amounts related to commercial disputes between the Company and customers or suppliers and onerous contract provisions. The onerous contract provisions occurred as a result of decisions to no longer operate on coal in Canada. Future royalty payments related to the extraction of coal at the Highvale mine will occur until the end of 2023 under the royalty contract. Payments related to coal contracts for Sheerness are required until 2025. At March 31, 2023, the remaining balance of the provision for the onerous royalty contract was $7 million and the remaining balance of the onerous coal contract was $9 million.

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

A. Amounts Outstanding

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

As at March 31, 2023		Utilized			
Credit Facilities	Facility size	Outstanding letters of credit(1)	Cash drawings	Available capacity	Maturity date
Committed					
TransAlta Corporation syndicated credit facility	1,250	404	—	846	Q2 2026
TransAlta Renewables syndicated credit facility	700	3	48	649	Q2 2026
TransAlta Corporation bilateral credit facilities	240	162	—	78	Q2 2024
TransAlta Corporation Term Facility	400	—	400	—	Q3 2024
Total Committed	**2,590**	**569**	**448**	**1,573**	
Non-Committed					
TransAlta Corporation demand facilities	250	105	—	145	n/a
TransAlta Renewables demand facility	150	98	—	52	n/a
Total Non-Committed	**400**	**203**	**—**	**197**	

(1) TransAlta has obligations to issue letters of credit and cash collateral to secure potential liabilities to certain parties, including those related to potential environmental obligations, commodity risk management and hedging activities, pension plan obligations, construction projects and purchase obligations. Letters of credit drawn against the non-committed facilities reduce the available capacity under the committed syndicated credit facilities. At March 31, 2023, TransAlta provided cash collateral of $119 million.

These facilities are the primary source for short-term liquidity after the cash flow generated from the Company's business.

The Company is in compliance with the terms of the credit facilities and all undrawn amounts are fully available. In addition to the $1.4 billion of committed capacity available under the credit facilities, the Company also has $1.2 billion of available cash and cash equivalents, net of bank overdraft. TransAlta's debt has terms and conditions, including financial covenants, that are considered normal and customary. As at March 31, 2023, the Company was in compliance with all debt covenants.

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

The Melancthon Wolfe Wind LP, Pingston Power Inc., TAPC Holdings LP, New Richmond Wind LP, Kent Hills Wind LP, TEC Hedland Pty Ltd notes, Windrise Wind LP and TransAlta OCP LP non-recourse bonds are subject to customary financing conditions and covenants that may restrict the Company's ability to access funds generated by the facilities' operations. Upon meeting certain distribution tests, typically performed once per quarter, the funds are able to be distributed by the subsidiary entities to their respective parent entity. These conditions include meeting a debt service coverage ratio prior to distribution, which was met by these entities in the first quarter of 2023, with the exception of Kent Hills Wind LP and TAPC Holdings LP, which has been impacted by higher interest rates. The funds in these entities will remain there until the next debt service coverage ratio can be calculated in the second quarter of 2023. At March 31, 2023, $67 million (Dec. 31, 2022 – $50 million) of cash was subject to certain financial restrictions. In accordance with the supplemental indenture, Kent Hills Wind LP cannot make any distributions to its partners until the foundation replacement work has been completed. A foundation replacement reserve account was set up in accordance with the supplemental indenture, with funds in the account being used to pay foundation replacement costs. The account is funded quarterly with the last planned funding requirement received on March 31, 2023. The balance in the account is $64 million as at March 31, 2023 ($65 million – Dec 31, 2022).

During the first quarter of 2023, the Company had $47 million of restricted cash related to the TEC Hedland Pty Ltd bond; reserves are required to be held under commercial arrangements and for debt service. Cash reserves may be replaced by letters of credit in the future.

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.

15. Common Shares

A. Issued and Outstanding

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

	3 months ended March 31			
	2023		2022	
	Common shares (millions)	**Amount**	Common shares (millions)	Amount
Issued and outstanding, beginning of period	**268.1**	**2,863**	271.0	2,901
Purchased and cancelled under the NCIB(1)	**(3.2)**	**(34)**	(1.4)	(15)
Effects of share-based payment plans	**0.8**	**5**	0.9	5
Stock options exercised	**0.3**	**2**	0.1	1
Shares outstanding, end of period	**266.0**	**2,836**	270.6	2,892
Provision for repurchase of common shares under ASPP	**(3.0)**	**(37)**	—	—
Issued and outstanding, net of provision, end of period	**263.0**	**2,799**	270.6	2,892

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

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

On March 27, 2023, the Company entered into an Automatic Share Purchase Plan ("ASPP") which permits an independent broker to repurchase shares under the NCIB during the blackout periods through to the end of the current program expiry on May 30. The Company has recognized a provision of $37 million for the repurchase of common shares under the ASPP within accounts payables and accrued liabilities as at March 31, 2023, as an estimate of the maximum number of shares that could be repurchased during the blackout period.

During the three months ended March 31, 2023, the Company purchased and cancelled a total of 3,169,300 common shares at an average price of $11.23 per common share, for a total cost of $36 million.

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

	March 31, 2023	Dec. 31, 2022
Total shares purchased(1)	**3,169,300**	4,342,300
Average purchase price per share	**11.23**	12.48
Total cost (millions)	**36**	54
Weighted average book value of shares cancelled	**34**	46
Amount recorded in deficit	**(2)**	(8)

(1) The three months ended March 31, 2023 include 312,400 shares (Dec. 31, 2022 - 164,300 shares) that were repurchased but were not cancelled due to timing differences between the transaction date and settlement date. The Company paid $34 million in the period and the remaining amount was paid subsequent to the period end.

C. Dividends

On April 27, 2023, the Company declared a quarterly dividend of $0.055 per common share, payable on July 1, 2023.

There have been no other transactions involving common shares between the reporting date and the date of completion of these condensed consolidated financial statements.

16. Preferred Shares

A. Issued and Outstanding

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

	March 31, 2023		Dec. 31, 2022	
Series[(1)]	Number of shares (millions)	Amount	Number of shares (millions)	Amount
Series A	**9.6**	**235**	9.6	235
Series B	**2.4**	**58**	2.4	58
Series C	**10.0**	**243**	10.0	243
Series D	**1.0**	**26**	1.0	26
Series E	**9.0**	**219**	9.0	219
Series G	**6.6**	**161**	6.6	161
Issued and outstanding, end of period	**38.6**	**942**	38.6	942

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

B. Dividends

On April 27, 2023, the Company declared a quarterly dividend of $0.17981 per share on the Series A preferred shares, $0.41100 per share on the Series B preferred shares, $0.36588 per share on the Series C preferred shares, $0.47769 per share on the Series D preferred shares, $0.43088 per share on the Series E preferred shares and $0.31175 per share on the Series G preferred shares, all payable on June 30, 2023.

17. Commitments and Contingencies

Commitments

In addition to the commitments disclosed elsewhere in the financial statements and those disclosed in note 37 of the 2022 annual audited financial statements, the Company has incurred the following additional contractual commitments in the first quarter of 2023, either directly or through its interests in joint operations.

Approximate future payments under these agreements are as follows:

	2024	2025	2026	2027	2028	2029 and thereafter	Total
Transmission	2	2	2	2	3	23	34
Total	**2**	**2**	**2**	**2**	**3**	**23**	**34**

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. The above table includes the incremental change in transmission agreements, as compared to the amounts disclosed in the 2022 annual audited consolidated financial statements.

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. For the current material outstanding contingencies, please refer to Note 37 of the 2022 audited annual consolidated financial statements. Material changes to the contingencies have been described below.

Hydro Power Purchase Arrangement ("Hydro PPA") Emissions Performance Credits

The Balancing Pool claimed entitlement to 1,750,000 emission performance credits earned by the Alberta Hydro facilities as a result of TransAlta opting those facilities into the Carbon Competitiveness Incentive Regulation and Technology Innovation and Emissions Reduction Regulation from 2018-2020 inclusive. The emission performance credits have no recorded book value as they were internally generated. The Balancing Pool claimed ownership of the EPCs because it believed the change-in-law provisions under the Hydro PPA required the EPCs to be passed through to the Balancing Pool. TransAlta disputed this claim. The parties have reached a confidential settlement in principle and this matter is now resolved.

Brazeau Facility - Well License 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 kilometers of the Brazeau Facility but permits hydraulic fracturing in all formations (except the Duvernay) within three-to-five kilometers of the Brazeau Facility. Subsequently, two oil and gas operators submitted applications to the AER for 10 well licenses (which include hydraulic fracturing activities) within three-to-five kilometers of the Brazeau Facility. The regulatory hearing to consider these applications - Proceeding 379 - was scheduled to be heard from Feb. 27 to March 10, 2023, but was adjourned to permit the O'Chiese First Nation to intervene and make submissions. While we do not have a new hearing date, we anticipate it will be heard in the second half of 2023.

The Company's position is that hydraulic fracturing activities within five kilometers of the Brazeau Facility pose an unacceptable risk and the applications should be denied.

Brazeau Facility - Claim against the Government of Alberta

On Sept. 9, 2022, the Company filed a Statement of Claim against the Alberta Government in the Alberta Court of King's Bench seeking a declaration that: (i) granting mineral leases within 5 km of the Brazeau Facility is a breach of the 1960 agreement between the Company and the Alberta Government; and (ii) the Alberta Government 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 Alberta Government filed its Statement of Defence, which asserts, among other things, that the Company: (i) is trying to usurp the jurisdiction of the Alberta Energy Regulator, and (ii) is out of time under the Limitations Act (Alberta). The trial has been scheduled for two weeks starting Feb. 26, 2024.

18. Segment Disclosures

A. Description of Reportable Segments

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"), review the Company's segments to make operating decisions and assess performance. The tables below show the reconciliation of the total segmented results and adjusted EBITDA to the statement of earnings (loss) reported under IFRS.

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

B. Reported Adjusted Segment Earnings and Segment Assets

I. Reconciliation of Adjusted EBITDA to Earnings before Income Tax

3 months ended March 31, 2023	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	125	115	495	267	92	—	1,094	(5)	—	1,089
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	(1)	—	(64)	(14)	16	—	(63)	—	63	—
Realized gain (loss) on closed exchange positions	—	—	(13)	—	(55)	—	(68)	—	68	—
Decrease in finance lease receivable	—	—	13	—	—	—	13	—	(13)	—
Finance lease income	—	—	4	—	—	—	4	—	(4)	—
Adjusted revenues	124	115	435	253	53	—	980	(5)	114	1,089
Fuel and purchased power	5	9	130	181	—	—	325	—	—	325
Reclassifications and adjustments:										
Australian interest income	—	—	(1)	—	—	—	(1)	—	1	—
Adjusted fuel and purchased power	5	9	129	181	—	—	324	—	1	325
Carbon compliance	—	—	32	—	—	—	32	—	—	32
Gross margin	119	106	274	72	53	—	624	(5)	113	732
OM&A	12	17	41	17	14	24	125	(1)	—	124
Taxes, other than income taxes	1	3	4	1	—	—	9	—	—	9
Net other operating income	—	(2)	(11)	—	—	—	(13)	—	—	(13)
Adjusted EBITDA[2]	106	88	240	54	39	(24)	503			
Equity income										2
Finance lease income										4
Depreciation and amortization										(176)
Asset impairment reversals										3
Net interest expense										(59)
Foreign exchange loss										(3)
Earnings before income taxes										383

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.
(2) Adjusted EBITDA is not defined and has no standardized meaning under IFRS.

3 months ended March 31, 2022	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	77	95	434	106	26	1	739	(4)	—	735
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	—	13	(162)	11	10	—	(128)	—	128	—
Realized gain (loss) on closed exchange positions[2]	—	—	3	—	(10)	—	(7)	—	7	—
Decrease in finance lease receivable	—	—	11	—	—	—	11	—	(11)	—
Finance lease income	—	—	5	—	—	—	5	—	(5)	—
Unrealized foreign exchange gain on commodity	—	—	—	—	(2)	—	(2)	—	2	—
Adjusted revenues	77	108	291	117	24	1	618	(4)	121	735
Fuel and purchased power	4	8	131	94	—	1	238	—	—	238
Reclassifications and adjustments:										
Australian interest income	—	—	(1)	—	—	—	(1)	—	1	—
Adjusted fuel and purchased power	4	8	130	94	—	1	237	—	1	238
Carbon compliance	—	—	18	1	—	—	19	—	—	19
Gross margin	73	100	143	22	24	—	362	(4)	120	478
OM&A	11	16	44	16	7	18	112	—	—	112
Taxes, other than income taxes	1	2	4	1	—	—	8	—	—	8
Net other operating income	—	(7)	(10)	—	—	—	(17)	—	—	(17)
Adjusted EBITDA[3]	61	89	105	5	17	(18)	259			
Equity income										2
Finance lease income										5
Depreciation and amortization										(117)
Asset impairment reversals										42
Net interest expense										(67)
Foreign exchange gain and other gains										2
Earnings before income taxes										242

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.
(2) In 2022, our adjusted EBITDA composition was adjusted to include the impact of closed positions that are effectively settled by offsetting positions with the same counterparty to reflect the performance of the assets and the Energy Marketing segment in the period in which the transactions occur.
(3) Adjusted EBITDA is not defined and has no standardized meaning under IFRS.

19. Related-Party Transactions

Transactions with Associates

In connection with the exchangeable securities issued to Brookfield, the investment agreement entitles Brookfield to nominate two directors to the TransAlta Board. As such, they are considered associates of the Company.

The Company may, in the normal course of operations, enter into transactions on market terms with related parties 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. Refer to Note 26 and 36 of the 2022 audited annual consolidated financial statements.

Transactions with Brookfield include the following:

	3 months ended March 31	
	2023	2022
Power sales	**42**	20

20. Subsequent Events

On April 24, 2023, the Company formally executed the definitive agreements related to the Tent Mountain Renewable Energy Complex. The acquisition includes the land rights, fixed assets and intellectual property associated with the pumped hydro development project. The Project leverages Montem’s existing assets at Tent Mountain, which include large legacy water reservoirs from past mining operations. The Company's initial payment of $8 million and contingent payments of $17 million will be treated as a joint venture investment.

Glossary of Key Terms

Adjusted Availability

Availability is adjusted when economic conditions exist, such that planned routine and major maintenance activities are scheduled to minimize expenditures. In high price environments, actual outage schedules would change to accelerate the generating unit's return to service.

Alberta Electric System Operator (AESO)

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

Alberta Hydro Assets

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

Alberta Thermal

The business segment previously disclosed as Canadian Coal has been renamed to reflect the ongoing conversion of the boilers to burn gas in place of coal. The segment includes the legacy and converted generating units at our Sundance and Keephills sites and includes the Highvale Mine.

Ancillary Services

As defined by the Electric Utilities Act, Ancillary Services are those services required to ensure that the interconnected electric system is operated in a manner that provides a satisfactory level of service with acceptable levels of voltage and frequency.

Automatic Share Purchase Plan (ASPP)

The ASPP is intended to facilitate repurchases of common shares under the NCIB, including at times when the Corporation would ordinarily not be permitted to make purchases due to regulatory restrictions or self-imposed blackout periods.

Availability

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

Balancing Pool

The Balancing Pool was established in 1999 by the Government of Alberta to help manage the transition to competition in Alberta's electric industry. Its current obligations and responsibilities are governed by the Electric Utilities Act (effective June 1, 2003) and the Balancing Pool Regulation. For more information go to www.balancingpool.ca.

Capacity

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

Cogeneration

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

Disclosure Controls and Procedures (DC&P)

Refers to controls and other procedures designed to ensure that information required to be disclosed in the reports filed by the Company or submitted under securities legislation is recorded, processed, summarized and reported within the time frame specified in applicable securities legislation. DC&P include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Company in its reports that it files or submits under applicable securities legislation is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Dispatch optimization

Purchasing power to fulfill contractual obligations, when economical.

Emissions Performance Standards (EPS)

Under the Government of Ontario, emission performance standards establish greenhouse gas (GHG) emissions limits for covered facilities.

EPCs

Emission Performance Credits.

Force Majeure

Literally means "greater force." These clauses excuse a party from liability if some unforeseen event beyond the control of that party prevents it from performing its obligations under the contract.

Free Cash Flow (FCF)

Represents the amount of cash that is available to invest in growth initiatives, make scheduled principal repayments on debt, repay maturing debt, pay common share dividends or repurchase common shares. Amount is calculated as cash generated by the Company through its operations (cash from operations) minus the funds used by the Company for the purchase improvement, or maintenance of the long-term assets to improve the efficiency or capacity of the Company (capital expenditures).

Funds from Operations (FFO)

Represents a proxy for cash generated from operating activities before changes in working capital and provides the ability to evaluate cash flow trends in comparison with results from prior periods. Amount is calculated as cash flow from operating activities before changes in working capital and is adjusted for transactions and amounts that the Company believes are not representative of ongoing cash flows from operations.

Gigajoule (GJ)

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

Gigawatt (GW)

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

Gigawatt hour (GWh)

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

Greenhouse Gas (GHG)

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

ICFR

Internal control over financial reporting.

IFRS

International Financial Reporting Standards.

ITC

The investment tax credit ("ITC") is a federal income tax credit for investments in certain types of qualifying clean electricity projects.

Megawatt (MW)

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

Megawatt Hour (MWh)

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

Merchant

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

NCIB

Normal Course Issuer Bid.

OM&A

Operations, maintenance and administration costs.

Other Hydro Assets

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

Pioneer Pipeline

The Pioneer gas pipeline jointly owned and operated by TransAlta and Tidewater Midstream and Infrastructure Ltd..

Planned outage

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

Power Purchase Agreement (PPA)

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

PP&E

Property, plant and equipment.

Turbine

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

Unplanned outage

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

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