TRANSALTA CORPORATION
Management's Discussion and Analysis

Second Quarter Report for 2022
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. See the Forward-Looking Statements section of this MD&A for additional information.

Table of Contents

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 and six months ended June 30, 2022 and 2021, and should also be read in conjunction with the audited annual consolidated financial statements and MD&A ("2021 Annual MD&A") contained within our 2021 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 June 30, 2022. All tabular amounts in the following discussion are in millions of Canadian dollars unless otherwise noted. This MD&A is dated August 4, 2022. Additional information respecting TransAlta, including our Annual Information Form ("AIF") for the year ended December 31, 2021, 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 US 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 billion that is expected to deliver incremental average annual EBITDA of $250 million; the Company's projects under construction, including the timing of commercial operations, expected annual EBITDA and the costs of the 200 MW Horizon Hill wind project ("Horizon Hill wind project"), the White Rock East and White Rock West Wind Power Projects ("White Rock Wind projects"), Northern Goldfields Solar project, Garden Plain wind project, and the Mount Keith 132kV transmission expansion; the effectiveness of the capacity commitments of the industrial customers at the Sarnia cogeneration facility; the Ontario Independent Electricity System Operator (the "IESO") announcement of the Company's successful bid in the third quarter of 2022 with respect to the Sarnia cogeneration facility; 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 2022 Financial Outlook (defined below), including adjusted EBITDA and free cash flow; the Company's ability to enhance shareholder value through its NCIB (defined below); the reduction of carbon emissions by 75 per cent from 2015 emissions levels by 2026; the remediation of the Kent Hills 1 and 2 wind facilities, including, the timing and cost of such remediation, timing and cost to replace all 50 turbine foundations and the resulting impact such incident could have on the Company's revenues; the expected impact and quantum of carbon compliance costs; the ability to realize future growth opportunities with BHP (as defined below); 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 Energy Standard, the Clean Fuel Regulations and Canadian Greenhouse Gas Offset Credit System Regulations and the ability of the Company to realize benefits from Canadian, United States and Australian regulatory developments, including receiving funding for clean electricity projects; the potential increase in value of emission reduction credits; sustaining and productivity capital in 2022; expected power prices in Alberta, Ontario and the Pacific Northwest; AECO gas price assumptions; the cyclicality of the business, including as it relates to maintenance costs, production and loads; expectations regarding refinancing the debt maturing in 2022; and the Company continuing to maintain a strong financial position and significant liquidity without any significant impact from the current economic environment.

The forward-looking statements contained in this MD&A are based on many assumptions including, but not limited to, the following: the impacts arising from COVID-19 not becoming significantly more onerous on the Company; 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 the long-term investment and credit markets; no significant changes to power price and hedging assumptions including, Alberta spot prices of $90/MWh to $100/MWh in 2022 and Mid-Columbia spot prices of US$55/MWh to US$65/MWh in 2022; AECO gas prices of between $4.50/GJ and $5.50/GJ; sustaining capital of $150 million to $170 million; Energy Marketing adjusted gross margin of $110 to $130 million; no significant changes to gas commodity prices and transport costs; the Company's proportionate ownership of TransAlta Renewables Inc. ("TransAlta Renewables") not changing materially; no decline in the dividends to be received from TransAlta Renewables; and the growth of TransAlta Renewables.

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: the impact of COVID-19, including more restrictive directives of government and public health authorities; increased force majeure claims; reduced labour availability and ability to continue to staff our operations and facilities; failure to satisfy the conditions precedent to the capacity commitments for each of the industrial offtakers at Sarnia cogeneration facility; disruptions to our supply chains, including our ability to secure necessary equipment; our ability to obtain regulatory approvals on the expected timelines or at all in respect of our growth projects; restricted access to capital and increased borrowing costs; changes in short-term and long-term electricity supply and demand; fluctuations in market prices, including lower merchant pricing in Alberta, Ontario and Mid-Columbia; reductions in production; increased costs; a higher rate of losses on our accounts receivables due to credit defaults; impairments and/or write-downs of assets; insurance recoveries, and in particular the ability to recover costs and damages with respect to the Kent Hills 1 and 2 wind facilities; 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; changes in demand for electricity and capacity and our ability to contract our generation for prices that will provide expected returns and 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; operational risks involving our facilities, including unplanned outages; disruptions in the transmission and distribution of electricity; the effects of weather, including man made or natural disasters and other climate-change related risks; unexpected increases in cost structure; reductions to our generating units' relative efficiency or capacity factors; disruptions in the source of fuels, including natural gas, water, solar or wind resources required to operate our facilities; equipment failure and our ability to carry out or have completed the repairs in a cost-effective manner or timely manner or at all, including if the remediation and replacement of turbine foundations of the Kent Hills 1 and 2 wind facilities is more costly or time consuming than expected; failure to secure a successful bid with respect to the Sarnia cogeneration facility contract extension with the IESO; general economic risks, including deterioration of equity markets, increasing interest rates or rising inflation; failure to refinance the Company's senior notes maturing in 2022 on favorable terms; 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, including cyberattacks, 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; counterparty credit risk; changes to our relationship with, or ownership of, TransAlta Renewables; changes in the payment or receipt of future dividends, including from TransAlta Renewables; risks associated with development projects and acquisitions, including capital costs, permitting, labour and engineering risks and delays in the construction or commissioning of projects; inadequacy or unavailability of insurance coverage; our provision for income taxes; 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 2021 Annual MD&A and the Risk Factors section in our AIF for the year ended Dec. 31, 2021.

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 fuels that includes water, wind, solar and natural gas.

The Company has retired the remaining assets located in Alberta within the Energy Transition segment. Effective Dec 31, 2021, the Keephills Unit 1 was retired and the Sundance Unit 4 was retired from service effective March 31, 2022, resulting in a reduction in capacity of 801 MW within the Energy Transition segment from Dec. 31, 2021.

The following table provides our consolidated ownership of our facilities across the regions in which we operate as at June 30, 2022:

As at June 30, 2022		Hydro	Wind and Solar(4)	Gas(4)(5)	Energy Transition(6)	Total
Alberta	Gross installed capacity (MW)(1)	834	636	1,960	—	**3,430**
	Number of facilities	17	13	7	—	**37**
	Weighted average contract life(2)(3)(4)	—	6	1	—	**2**
Canada, Excl. Alberta	Gross installed capacity (MW)(1)	91	751	645	—	**1,487**
	Number of facilities	9	9	3	—	**21**
	Weighted average contract life(3)	7	9	5	—	**7**
United States	Gross installed capacity (MW)(1)	—	519	29	671	**1,219**
	Number of facilities	—	7	1	2	**10**
	Weighted average contract life(3)	—	12	4	4	**7**
Australia	Gross installed capacity (MW)(1)	—	—	450	—	**450**
	Number of facilities	—	—	6	—	**6**
	Weighted average contract life(3)	—	—	16	—	**16**
Total	**Gross installed capacity (MW)(1)**	**925**	**1,906**	**3,084**	**671**	**6,586**
	Number of facilities	**26**	**29**	**17**	**2**	**74**
	Weighted average contract life(3)	**1**	**9**	**4**	**4**	**5**

(1) Gross installed capacity for consolidated reporting represents 100 per cent output of a facility. Capacity figures for Wind and Solar includes 100 per cent of the Kent Hills wind facilities; Gas includes 100 per cent of the Ottawa, Sarnia 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, Gas and certain 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 for more information.
(3) For power generated under long-term power purchase agreements ("PPA"), power hedge contracts and short- 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 Wind (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.
(5) The Gas segment includes the segments previously known as Australian Gas and North American Gas and the coal-fired generation assets converted to gas from the segment previously known as Alberta Thermal.
(6) The Energy Transition segment includes the Centralia Unit 2 and the Skookumchuck dam.

Highlights

Unaudited Interim Condensed Consolidated Financial Highlights

	3 months ended June 30		6 months ended June 30	
	2022	2021	**2022**	2021
Adjusted availability (%)	**87.3**	84.8	**88.2**	86.7
Production (GWh)	**4,461**	4,688	**9,820**	10,229
Revenues	**458**	619	**1,193**	1,261
Fuel and purchased power(1)	**231**	215	**469**	460
Carbon compliance	**9**	42	**28**	92
Operations, maintenance and administration(1)	**117**	148	**229**	251
Adjusted EBITDA(2)	**279**	319	**538**	641
Earnings (loss) before income tax	**(22)**	72	**220**	93
Net earnings (loss) attributable to common shareholders	**(80)**	(12)	**106**	(42)
Cash flow (used in) from operating activities	**(129)**	80	**322**	337
Funds from operations(2)	**220**	267	**399**	490
Free cash flow(2)	**145**	155	**253**	296
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**(0.30)**	(0.04)	**0.39**	(0.16)
Dividends declared per common share(3)	**0.0500**	0.0450	**0.0500**	0.0450
Dividends declared per preferred share(3)	**0.2557**	0.2536	**0.2557**	0.2536
Funds from operations per share(2)(4)	**0.81**	0.99	**1.47**	1.81
Free cash flow per share(2)(4)	**0.54**	0.57	**0.93**	1.09

As at	**June 30, 2022**	Dec. 31, 2021
Total assets	**9,586**	9,226
Total consolidated net debt(5)	**2,616**	2,636
Total long-term liabilities	**4,596**	4,702
Total liabilities	**7,112**	6,633

(1) During the three and six months ended June 30, 2021, $3 and $5 million related to station service costs for the Hydro segment was reclassified from OM&A to fuel and purchased power for comparative purposes. This did not impact previously reported net earnings.
(2) 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. Please 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. See also the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.
(3) Weighted average of the Series A, B, C, E and G preferred share dividends declared. Dividends declared vary period over period due to timing of dividend declarations.
(4) 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 the three and six months ended June 30, 2022, was 271 million shares (June 30, 2021 - 270 million and 271 million shares, respectively). Please refer to the Additional IFRS Measures and Non-IFRS Measures section in this MD&A for the purpose of these non-IFRS ratios.
(5) Total consolidated net debt includes long-term debt, including 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. See the table in the Financial Capital section of this MD&A for more details on the composition of total consolidated net debt.

For the three and six months ended June 30, 2022, the Company demonstrated strong performance led by the Wind and Solar segment with the addition of new contracted assets, namely the Windrise wind facility and North Carolina Solar (as defined below), partially offset by the Kent Hills wind facilities outages. The Alberta Electricity Portfolio performed ahead of expectations despite higher natural gas prices and compressed market heat rates. Performance in the Alberta Electricity Portfolio was led by the Alberta Wind and Hydro segments which benefited from the higher pricing environment and stronger production. The Alberta Gas segment was highly hedged in the quarter resulting in limited opportunity to benefit from high power prices. These factors contributed to the portfolio's overall performance and together demonstrate the value of our strategically diversified fleet in Alberta and its ability to generate cash flow under dynamic market conditions. The Energy Marketing segment has also exceeded expected results due to short-term trading of both physical and financial power and gas products across all North American markets. The Energy Marketing team was able to capitalize on short-term volatility in the markets in which we trade without materially changing the risk profile of the business unit.

Adjusted availability for the three and six months ended June 30, 2022, was 87.3 per cent and 88.2 per cent, respectively, compared to 84.8 per cent and 86.7 per cent for the same periods in 2021. The increase was primarily due to lower planned outages within the Gas segment and Hydro segment, partially offset by the unplanned outage at the Kent Hills 1 and 2 wind facilities and certain early-stage operational issues at the Windrise wind facility in Alberta. Adjusted availability improved within the Gas segment as there were lower planned outages in the current period with the completion of the coal-to-gas conversions in 2021.

Production for the three and six months ended June 30, 2022, was 4,461 gigawatt hours ("GWh") and 9,820 gigawatt hours, respectively, compared to 4,688 GWh and 10,229 GWh in the same periods in 2021. The decrease in production was primarily due to the retirement of Keephills Unit 1 and Sundance Unit 4, portfolio optimization activities, lower water resources from delayed spring runoff and the unplanned outage at the Kent Hills 1 and 2 wind facilities in the Wind and Solar segment. This was partially offset by higher wind resources, higher production at our Ada cogeneration facility within our Gas segment and incremental production from the newly-commissioned Windrise wind facility and the acquired 122 MW portfolio of operating solar sites located in North Carolina (collectively, "North Carolina Solar"), in our Wind and Solar segment.

Revenues decreased by $161 million and $68 million, respectively, for the three and six months ended June 30, 2022, compared to the same periods in 2021, mainly as a result of lower production in the Gas segment and in the Energy Transition segment and lower realized prices for the Hydro ancillary services, partially offset by an increase in production, higher realized prices and higher environmental attribute revenues within the Wind and Solar segment. In addition, during the second quarter of 2021, the Company experienced unplanned steam supply outages and steam reconciliation adjustments within the Gas segment that did not reoccur within the current period.

Fuel and purchased power costs increased by $16 million and $9 million, respectively, in the three and six months ended June 30, 2022, compared to the same periods in 2021. In our Gas segment, our fuel and purchased power costs increased compared to 2021 due to higher natural gas pricing and increased natural gas consumption for our converted units in 2022, partially offset by our hedged positions on gas, lower coal costs and no mine depreciation occurring in 2022.

Carbon compliance costs decreased by $33 million and $64 million, respectively, in the three and six months ended June 30, 2022, compared to the same periods in 2021, primarily due to reductions in greenhouse gas ("GHG") emissions stemming from changes in the fuel mix ratio, as we now operate on natural gas in Alberta rather than coal, partially offset by an increase in the carbon price per tonne, as well as lower production and utilization of the Company's compliance credits to settle a portion of our GHG obligation.

Operations, maintenance and administration ("OM&A") expenses decreased by $31 million and $22 million, respectively, for the three and six months ended June 30, 2022, compared to the same periods in 2021. During the second quarter 2021, the Company recorded a write-down of $25 million on parts and material inventory related to the Highvale mine and coal operations at our converted gas facilities. Variability caused by the total return swap resulted in a favourable period-over-period change of $2 million in the three months ended June 30, 2022 and an unfavourable period over period change of $6 million in the six months ended June 30, 2022. In addition, during the first quarter of 2021, the Company recognized the Canada Emergency Wage Subsidy ("CEWS") of $8 million. Excluding the impact of the total return swap, the CEWS funding and the parts and material write-downs, OM&A expenses were lower by $5 million and $13 million, respectively, for the three and six months ended June 30, 2022, compared to the same periods in 2021, due to lower staffing costs, lower incentive payments and lower legal costs.

Adjusted EBITDA decreased by $40 million and $103 million, respectively, for the three and six months ended June 30, 2022, compared to the same periods in 2021, largely due to lower adjusted EBITDA at our Gas, Energy Transition and Hydro segments and period to date higher corporate costs. This was partially offset by higher adjusted EBITDA in our Wind and Solar segment. On a year-to-date basis, our Energy Marketing segment results were in line with expectations compared with the strong 2021 results. Significant changes in segmented adjusted EBITDA are highlighted in the Segmented Financial Performance and Operating Results section within this MD&A.

Earnings (loss) before income taxes decreased by $94 million for the three months ended June 30, 2022, and increased by $127 million for the six months ended June 30, 2022, compared to the same periods in 2021.

Net loss attributable to common shareholders for the three months ended June 30, 2022, increased by $68 million to a net loss of $80 million compared to a net loss of $12 million in the same period in 2021. Loss before income taxes and net loss attributable to common shareholders in the three months ended June 30, 2022, increased primarily due to lower revenues and higher fuel and purchased power costs, partially offset by lower carbon compliance costs, reversal of asset impairment charges impacted by the increase in discount rates, lower OM&A, recognition of insurance related to the replacement costs for a tower at the Kent Hills facility and liquidated damages recognized related to turbine availability at the Windrise wind facility. The previous period was impacted by higher gains on sales with the sale of Pioneer Pipeline in the second quarter of 2021.

Net earnings attributable to common shareholders for the six months ended, June 30, 2022, increased by $148 million to net earnings of $106 million compared to a net loss of $42 million in the same period in 2021. Earnings before income tax and net earnings attributable to common shareholders in the six month period ended June 30, 2022, increased primarily due to reversal of asset impairment charges impacted by the increase in discount rates, lower carbon compliance costs, lower depreciation, lower OM&A and recognition of insurance related to the replacement costs for a tower at the Kent Hills facility and the liquidated damages recognized related to turbine availability at the Windrise wind facility partially offset by lower revenue and higher fuel and purchased power costs. The previous period also was impacted by higher gains on sales with the sale of Pioneer Pipeline in the second quarter of 2021.

Cash flow from operating activities for the three and six months ended June 30, 2022, decreased by $209 million and $15 million, respectively, compared to the same periods in 2021, mainly due to lower cash flows resulting from lower production and lower revenues within all segments except for the Wind and Solar segment. In addition, for the three months ended June 30, 2022, operating cash flows decreased with an unfavourable change in working capital; whereas, for the six month period ended June 30, 2022, operating cash flow increased as a result of favourable working capital changes. The change in working capital for the three and six months ended, June 30, 2022 is primarily due to movements in our collateral accounts related to high commodity prices and volatility in the markets.

FCF, one of the Company's key financial metrics, for the three and six months ended June 30, 2022, totaled $145 and $253 million, respectively, for the three and six months ended June 30, 2022, compared to $155 million and $296 million, respectively, in the same periods in 2021. This represents a decrease to FCF of $10 million and $43 million, driven primarily by lower adjusted EBITDA, partially offset by higher realized foreign exchange gains and a decrease in sustaining capital spending related to fewer planned maintenance turnarounds.

Significant and Subsequent Events

TransAlta Debuts New Brand Reiterating Commitment to a Clean Energy Future

On June 20, 2022, the Company announced a new visual identity including logo and tagline "Energizing the Future". The new visual identity encapsulates the TransAlta of today while reinforcing the Company's focus as a leader in creating a carbon-neutral future for our customers.

Conversion Results for Series C and D Preferred Shares

On June 16, 2022, the Company announced that 1,044,299 of its 11,000,000 currently outstanding Cumulative Redeemable Rate Reset First Preferred Shares, Series C ("Series C Shares") were tendered for conversion, on a one-for-one basis, into Cumulative Redeemable Floating Rate First Preferred Shares, Series D ("Series D Shares") after having taken into account all election notices following the June 15, 2022 conversion deadline.

Court of Appeal Upholds TransAlta's Favourable Force Majeure Arbitration Decision

On June 9, 2022, the Alberta Court of Appeal released a unanimous decision dismissing ENMAX Energy Corporation ("ENMAX") and the Balancing Pool's application seeking to set aside an arbitration decision in favour of the Company. The Court of Appeal upheld the Company's claim of force majeure that arose when its Keephills 1 generating unit tripped offline in 2013. As a result of the decision, the Company's claim of force majeure remains valid and the associated costs of the force majeure event will not be reassessed against TransAlta.

Kent Hills Wind Facilities Outage Update

On June 2, 2022, TransAlta Renewables announced its rehabilitation plan for the Kent Hills wind facilities together with the execution of amended and extended contracts with New Brunswick Power Corporation ("NB Power") in respect of each of the Kent Hills 1, 2 and 3 wind facilities providing for an additional 10-year period to December 2045 and an effective 10 per cent reduction to the original contract prices from January 2023 through December 2033. In addition, both parties have agreed to work in good faith to evaluate the installation of a battery energy storage system at Kent Hills and to consider a potential repowering of Kent Hills at the end of life in 2045. The Company also obtained a waiver for the Kent Hills wind non-recourse bonds ("KH Bonds") from the project bond holders and entered into a supplemental indenture with the bond holders that facilitates the rehabilitation of the Kent Hills 1 and 2 wind facilities. Refer to the Kent Hills Wind Facilities Rehabilitation section and Financial Capital section of this MD&A for further detail.

TSX Acceptance of Normal Course Issuer Bid

On May 24, 2022, the Toronto Stock Exchange ("TSX") accepted the notice filed by the Company to renew its normal course issuer bid ("NCIB") for a portion of its common shares. Pursuant to the NCIB, TransAlta may repurchase up to a maximum of 14,000,000 common shares, representing approximately 7.16 per cent of its public float of common shares as at May 17, 2022. Purchases under the NCIB may be made through open market transactions on the TSX and any alternative Canadian trading platforms on which the common shares are traded, based on the prevailing market price. Any common shares purchased under the NCIB will be cancelled. The period during which TransAlta is authorized to make purchases under the NCIB commenced on May 31, 2022 and ends on May 30, 2023, or such earlier date on which the maximum number of common shares are purchased under the NCIB or the NCIB is terminated at the Company's election.

The NCIB provides the Company with a capital allocation alternative with a view to ensuring long-term shareholder value. TransAlta's Board of Directors and Management believe that, from time to time, the market price of the common shares does not reflect their underlying value and purchases of common shares for cancellation under the NCIB may provide an opportunity to enhance shareholder value.

During the six months ended June 30, 2022, the Company purchased and cancelled a total of 1.4 million common shares at an average price of $12.50 per common share, for a total cost of $18 million.

Mount Keith 132kV Transmission Expansion

On May 3, 2022, TransAlta Renewables exercised its option to acquire an economic interest in the expansion of the Mount Keith 132kV transmission system in Western Australia, to support the Northern Goldfields-based operations of BHP Nickel West ("BHP"). Total construction capital is estimated at between AU$50 million and AU$53 million. Southern Cross Energy, a subsidiary of the Company, has entered into an engineering, procurement and construction agreement for the expansion. The project is being developed under the existing PPA with BHP, which has a term of 15 years. It is expected to be completed in the second half of 2023 and will generate annual adjusted EBITDA in the range of AU$6 million and AU$7 million. The project will facilitate the connection of additional generating capacity to our network to support BHP's operations and increase its competitiveness as a supplier of low-carbon nickel.

Sarnia Cogeneration Facility Contract Extensions

During the second quarter of 2022, the Company executed contract extensions for the supply of electricity and/or steam with the remaining three of its industrial customers at the Sarnia cogeneration facility. These agreements will extend the delivery term for electricity and/or steam from Dec. 31, 2022 to April 30, 2031, in one case, and to Dec. 31, 2032, for the other two, with all agreements being subject to certain conditions, including the Company entering into a new contract with the Ontario Independent Electricity System Operator (the "IESO"). The current contract with the IESO, in respect of the Sarnia cogeneration facility expires on Dec. 31, 2025. On July 19, 2021, the IESO released its Annual Acquisition Report, which included draft details for medium- and long-term procurement mechanisms for capacity for 2026 and beyond for existing and new generation. The Company has bid into the procurement process developed by the IESO and is seeking to secure a contract extension for the Sarnia cogeneration facility following the end of the current contract term. The Company expects the IESO to announce the successful bids in the third quarter of 2022.

Executed Long Term PPA for Remaining 30 MW at Garden Plain

During the second quarter of 2022, the Company entered into a long-term PPA for the remaining 30 MW of renewable electricity and environmental attributes at the Garden Plain wind project in Alberta with a new investment-grade globally recognized customer. The 130 MW Garden Plain wind project, which was announced in May 2021 with a 100 MW PPA contracted to Pembina Pipeline Corporation ("Pembina"), is now fully contracted with a weighted average contract life of approximately 17 years. Construction is underway with a target commercial operation date in the second half of 2022.

Energy Impact Partners ("EIP") Investment

During the second quarter of 2022, the Company has entered into a commitment to invest US$25 million over the next four years in EIP's Deep Decarbonization Frontier Fund 1 (the "Frontier Fund"). The Company invested US$6 million in May 2022. The investment in the Frontier Fund provides the Company with a portfolio approach to investing in emerging technologies and the opportunity to identify, pilot, commercialize and bring to market emerging technologies that will facilitate the transition to net-zero emissions.

Customer Update at White Rock Wind Projects

During the second quarter of 2022, TransAlta identified Amazon Energy LLC ("Amazon") as the customer for the 300 MW White Rock Wind projects, to be located in Caddo County, Oklahoma. On Dec. 22, 2021, Amazon and TransAlta entered into two long-term PPAs for the supply of 100 per cent of the generation from the projects. Construction is expected to begin in the second half of 2022 with a target commercial operation date in the second half of 2023.

MSCI Environmental, Social and Governance ("ESG") Rating Upgrade

During the second quarter of 2022, TransAlta's MSCI ESG Rating was upgraded to 'A' from 'BBB'. The upgrade reflects the Company's strong renewable energy growth compared to peers. In 2021, the Company grew its installed renewable energy capacity by 15 per cent through acquisition and construction of solar and wind facilities and secured 600 MW in additional renewable energy projects. In line with its goal to reduce carbon emissions by 75 per cent from 2015 emissions levels by 2026, TransAlta also completed coal-to-gas conversions of its Canadian coal-fired facilities in 2021, nine years ahead of Alberta's coal phase-out plan.

Horizon Hill Wind Project and Fully Executed Corporate PPA with Meta

On April 5, 2022, TransAlta executed a long-term renewable energy PPA with a subsidiary of Meta Platforms Inc. ("Meta"), formerly known as Facebook, Inc., for 100 per cent of the generation from its 200 MW Horizon Hill wind project to be located in Logan County, Oklahoma. Under this agreement, Meta will receive both renewable electricity and environmental attributes from the Horizon Hill facility. The facility will consist of a total of 34 Vestas turbines with construction expected to begin in late 2022 and a target commercial operation date in the second half of 2023. TransAlta will construct, operate and own the facility. Total construction capital is estimated between US$290 million and US$310 million and is expected to be financed with a combination of existing liquidity and tax equity financing. Over 90 per cent of project costs are fixed under executed turbine supply agreements and engineering, procurement and construction agreements. The project is expected to generate average annual EBITDA between US$27 million and US$30 million, inclusive of production tax credits.

Refer to the audited annual 2021 consolidated financial statements within our 2021 Annual Integrated Report and our unaudited interim condensed consolidated financial statements for the three and six months ended June 30, 2022, for significant events impacting both prior and current year results.

Performance by Segment with Supplemental Geographical Information

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

3 months ended June 30, 2022	**Hydro**	**Wind and Solar**	**Gas[1]**	**Energy Transition[2]**	**Energy Marketing**	**Corporate and Other**	**Total**
Alberta	**82**	**41**	**8**	**(3)**	**—**	**(23)**	**105**
Canada, excluding Alberta	**6**	**22**	**21**	**—**	**50**	**—**	**99**
United States	**—**	**25**	**2**	**14**	**—**	**—**	**41**
Australia	**—**	**—**	**34**	**—**	**—**	**—**	**34**
Adjusted EBITDA[3]	**88**	**88**	**65**	**11**	**50**	**(23)**	**279**
Loss before income taxes							**(22)**

3 months ended June 30, 2021	Hydro	Wind and Solar	Gas[1]	Energy Transition[2]	Energy Marketing	Corporate and Other	Total
Alberta	90	8	84	11	—	(24)	169
Canada, excluding Alberta	6	30	7	—	43	—	86
United States	—	17	2	14	—	—	33
Australia	—	—	31	—	—	—	31
Adjusted EBITDA[3]	96	55	124	25	43	(24)	319
Earnings before income taxes							72

6 months ended June 30, 2022	**Hydro**	**Wind and Solar**	**Gas[1]**	**Energy Transition[2]**	**Energy Marketing**	**Corporate and Other**	**Total**
Alberta	**143**	**71**	**55**	**(6)**	**—**	**(41)**	**222**
Canada, excluding Alberta	**6**	**56**	**43**	**—**	**67**	**—**	**172**
United States	**—**	**50**	**4**	**22**	**—**	**—**	**76**
Australia	**—**	**—**	**68**	**—**	**—**	**—**	**68**
Adjusted EBITDA[3]	**149**	**177**	**170**	**16**	**67**	**(41)**	**538**
Earnings before income taxes							**220**

6 months ended June 30, 2021	Hydro	Wind and Solar	Gas[1]	Energy Transition[2]	Energy Marketing	Corporate and Other	Total
Alberta	167	20	133	15	—	(32)	303
Canada, excluding Alberta	6	71	29	—	98	—	204
United States	—	40	5	26	—	—	71
Australia	—	—	63	—	—	—	63
Adjusted EBITDA[3]	173	131	230	41	98	(32)	641
Earnings before income taxes							93

(1) The Gas segment includes the segments previously known as Australian Gas and North American Gas and the coal-fired generation assets converted to gas from the segment previously known as Alberta Thermal.
(2) The Energy Transition segment includes the segment previously known as Centralia and the coal-fired generation assets not converted to gas and the mining assets from the segment previously known as Alberta Thermal. Keephills Unit 1 was retired Dec. 31, 2021 and Sundance Unit 4 was retired March 31, 2022.
(3) 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. Please 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. See also the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

Alberta Electricity Portfolio

Approximately 52 per cent of our gross installed capacity is located in Alberta. Our portfolio of merchant assets in Alberta is a combination of hydro facilities, wind facilities, a battery storage facility, cogeneration facilities and converted natural gas-fired thermal facilities. Optimization of portfolio performance is driven by the diversity in 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. Some of the wind, hydro and gas facilities within the Alberta Electricity Portfolio operate on long-term contracts.

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

	2022					2021				
3 months ended June 30	**Hydro**	**Wind and Solar**	**Gas**	**Energy Transition**	**Total**	Hydro	Wind and Solar	Gas	Energy Transition	Total
Total Production (GWh)(1)	**406**	**450**	**1,826**	**—**	**2,682**	423	204	2,098	393	3,118
Revenues(2)	**96**	**49**	**134**	**2**	**281**	105	16	189	45	355
Fuel and purchased power	**4**	**4**	**99**	**1**	**108**	1	2	62	12	77
Carbon compliance	**—**	**—**	**9**	**(4)**	**5**	—	—	28	9	37
Gross margin	**92**	**45**	**26**	**5**	**168**	104	14	99	24	241

	2022					2021				
6 months ended June 30	**Hydro**	**Wind and Solar**	**Gas**	**Energy Transition**	**Total**	Hydro	Wind and Solar	Gas	Energy Transition	Total
Total Production (GWh)(1)	**742**	**953**	**3,544**	**19**	**5,258**	750	507	3,928	816	6,001
Revenues(2)	**170**	**84**	**298**	**7**	**559**	192	35	339	90	656
Fuel and purchased power(3)	**8**	**9**	**184**	**5**	**206**	2	3	119	31	155
Carbon compliance	**—**	**—**	**24**	**(3)**	**21**	—	—	60	20	80
Gross margin	**162**	**75**	**90**	**5**	**332**	190	32	160	39	421

(1) Units in the Gas and Energy Transition segments in prior period operated on coal. Keephills Unit 1 was retired Dec. 31, 2021 and Sundance Unit 4 was retired March 31, 2022.
(2) Adjustments to revenues include the impact of unrealized mark-to-market gains or losses and realized gains and losses on closed exchange positions.
(3)Adjustments to fuel and purchased power include the impact of coal mine depreciation and coal inventory write-downs at the Highvale mine in 2021.

For the three and six months ended June 30, 2022, the Alberta Electricity Portfolio generated 2,682 GWh and 5,258 GWh of production, a decrease of 436 GWh and 743 GWh, respectively, compared to the same periods in 2021. Production was impacted by dispatch optimization and the retirement of Keephills Unit 1 on Dec. 31, 2021 and Sundance Unit 4 on March 31, 2022, partially offset by increased wind resources.

Gross margin for the three and six months ended June 30, 2022, was $168 million and $332 million, a decrease of $73 million and $89 million, respectively, compared to the same periods in 2021. Gross margin was negatively impacted by lower weather-driven demand and a better supplied market in 2022. Ancillary services revenue from the Hydro segment was lower in both periods as a result of lower ancillary prices driven by increasing competition in the ancillary services market. In addition, the Gas and Energy Transition segment results were impacted by lower production due to unit retirements and higher dispatch optimization in response to lower market heat rates. A significant portion of the portfolio was hedged below spot prices, which was partially offset by our favourable gas hedge positions and lower carbon costs. The decrease in gross margins were partially offset by higher gross margins in the Wind and Solar segment mainly due to higher production and higher realized prices.

The following table provides information for the Company's Alberta Electricity Portfolio:

	3 months ended June 30		6 months ended June 30	
	2022	2021	**2022**	2021
Spot power price average per MWh	**$122**	$105	**$106**	$100
Natural gas price (AECO) per GJ	**$6.86**	$2.93	**$5.69**	$2.95
Carbon compliance price per tonne	**$50**	$40	**$50**	$40
Realized merchant power price per MWh(1)	**$105**	$114	**$106**	$109
Hydro energy spot power price per MWh	**$131**	$122	**$121**	$120
Hydro ancillary spot price per MWh	**$47**	$63	**$46**	$64
Wind energy spot power price per MWh	**$96**	$63	**$75**	$51
Gas and Energy Transition spot power price per MWh	**$127**	$121	**$116**	$115
Hedged Volume	**1,901**	1,694	**3,639**	3,295
Hedge position (percentage)(2)	**100**	88	**91**	81
Hedged power price average per MWh	**$73**	$62	**$78**	$63
Fuel and purchased power per MWh(3)	**$59**	$31	**$58**	$33
Carbon compliance cost per MWh(3)	**$3**	$15	**$6**	$17

(1) Realized 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 portfolio optimization activities divided by total GWh produced.
(2) Represents the percentage of production sold forward at the end of the reporting period for 2022. The hedge program is focused primarily on generation from the merchant assets in the Gas and Energy Transition segments.
(3) Fuel and purchased power per MWh and carbon compliance cost per MWh are calculated on production from carbon-emitting generation segments in Gas and Energy Transition and carbon compliance cost per MWh includes compliance credits to settle a portion of our GHG obligation.

The spot power price increased to $122 per MWh and $106 per MWh, respectively, for the three and six months ended June 30, 2022, from $105 per MWh and $100 per MWh compared to the same periods in 2021. Pool prices were higher on average for the first and second quarter as well as year to date, mainly as a result of a higher natural gas prices.

For the three and six months ended June 30, 2022, the realized power price per MWh of production decreased by $9 and $3 per MWh, respectively, compared with the same periods in 2021. Lower realized merchant power pricing for energy across the fleet was due to optimization and was offset by lower realized pricing from ancillary services. 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 and six months ended June 30, 2022, the Hydro ancillary spot power price decreased mainly due to higher ancillary price discounts driven by increased participants and supply into the ancillary market compared with the same periods in 2021.

For the three and six months ended June 30, 2022, the fuel and purchased power cost per MWh of production increased by $28 per MWh and $25 per MWh, respectively, compared to the same periods in 2021, due to higher natural gas pricing, higher fixed gas transportation costs, partially offset by our hedge positions for gas prices and lower coal costs due to the cessation of mining operations in 2021.

For the three and six months ended June 30, 2022, carbon compliance costs per MWh of production decreased by $12 per MWh and $11 per MWh, respectively, compared with the same periods in 2021, primarily due to the retirement of our coal fleet which resulted in lower carbon compliance costs and the usage of compliance credits to settle a portion of our GHG obligation from 2021. Carbon compliance prices have increased from $40 per tonne to $50 per tonne; however, the shift to gas-fired generation effectively lowered our GHG compliance costs as natural gas combustion produces less GHG emissions than coal combustion.

Segmented Financial Performance and Operating Results

Reporting Segment Changes

Segmented information is prepared on the same basis that the Company manages its business, evaluates financial results and makes key operating decisions. With the completion of the Clean Energy Transition plan and the announcement of our strategic focus on customer-centered renewable generation, the Company realigned its current operating segments during the fourth quarter of 2021 to better reflect the Company's current strategic focus and to align with the Company's Clean Electricity Growth Plan. The segment reporting changes reflect a corresponding change in how the President and Chief Executive Officer assesses the performance of the Company.

The primary changes are the elimination of the Alberta Thermal and the Centralia segments and the reorganization of the North American Gas and Australia Gas segments into a new "Gas" segment. The Alberta Thermal facilities that have been converted to gas are included in the Gas segment. The remaining assets previously included in Alberta Thermal, including the mining assets and those facilities not converted to gas and the remaining Centralia unit are included in a new "Energy Transition" segment. No changes have been made to the Hydro, Wind and Solar, Energy Marketing or the Corporate and Other segments. Prior year's metrics were restated to reflect the re-alignment of the operating segments.

Consolidated Results

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)	
3 months ended June 30	**2022**	2021	**2022**	2021	**2022**	2021
Hydro	**567**	567	**533**	554	**88**	96
Wind and Solar	**1,121**	911	**1,072**	826	**88**	55
Renewables			**1,605**	1,380	**176**	151
Gas			**2,566**	2,824	**65**	124
Energy Transition			**290**	484	**11**	25
Energy Marketing					**50**	43
Corporate and Other					**(23)**	(24)
Total			**4,461**	4,688	**279**	319
Total earnings (loss) before income taxes					**(22)**	72

	LTA Generation (GWh)(1)		Actual Production (GWh)(2)		Adjusted EBITDA(3)	
6 months ended June 30	**2022**	2021	**2022**	2021	**2022**	2021
Hydro	**975**	975	**905**	914	**149**	173
Wind and Solar	**2,574**	2,081	**2,341**	1,957	**177**	131
Renewables			**3,246**	2,871	**326**	304
Gas			**5,231**	5,458	**170**	230
Energy Transition			**1,343**	1,900	**16**	41
Energy Marketing					**67**	98
Corporate and Other					**(41)**	(32)
Total			**9,820**	10,229	**538**	641
Total earnings before income taxes					**220**	93

(1) Long-term average production ("LTA Generation (GWh)") is calculated based on our portfolio as at June 30, 2022, 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 30-35 years for the Wind and Solar segments and 36 years for Hydro segment. LTA Generation (GWh) for Energy Transition is not considered as we are currently transitioning these units completely 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 and six months ended June 30, 2022, excluding the Kent Hills 1 and 2 wind facilities which are currently not in operation, is approximately 1,031 GWh and 2,379 GWh, respectively.
(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 have proven to be reliable indicators of performance.
(3) These items are not defined and have no standardized meaning under IFRS. Please refer below in 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.

Hydro

	3 months ended June 30		6 months ended June 30	
	2022	2021	**2022**	2021
Gross installed capacity (MW)	**925**	925	**925**	925
LTA Generation (GWh)	**567**	567	**975**	975
Availability (%)	**95.5**	93.2	**96.1**	92.6
Contract production (GWh)	**127**	130	**163**	164
Merchant production (GWh)	**406**	424	**742**	750
Total energy production (GWh)	**533**	554	**905**	914
Ancillary service volumes (GWh)(1)	**785**	749	**1,527**	1,498
Alberta Hydro Assets(2)	**53**	52	**89**	91
Other Hydro assets and other revenue(2)(3)	**15**	14	**22**	20
Alberta Hydro Ancillary services(1)	**37**	48	**70**	95
Environmental attribute revenue	**—**	1	**1**	1
Total gross revenues	**105**	115	**182**	207
Net payment relating to Alberta Hydro PPA(4)	**—**	(1)	**—**	(4)
Revenues	**105**	114	**182**	203
Fuel and purchased power(5)	**6**	6	**10**	9
Gross margin	**99**	108	**172**	194
OM&A(5)	**10**	11	**21**	19
Taxes, other than income taxes	**1**	1	**2**	2
Adjusted EBITDA	**88**	96	**149**	173
Supplemental Information:				
Gross Revenues per MWh				
Alberta Hydro Assets energy ($/MWh)	**131**	122	**121**	120
Alberta Hydro Assets ancillary ($/MWh)	**47**	63	**46**	64
Sustaining capital	**6**	7	**12**	12

(1) Ancillary services as described in the AESO Consolidated Authoritative Document Glossary.
(2) Alberta Hydro Assets include 13 hydro facilities on the Bow and North Saskatchewan river systems. Other Hydro energy include our hydro facilities in BC and Ontario, hydro facilities in Alberta other than the Alberta Hydro Assets and transmission revenues.
(3) Other revenue includes revenues from our transmission business and other contractual arrangements including the flood mitigation agreement with the Alberta government and black start services.
(4) The net payment relating to the Alberta Hydro PPA represents the Company's financial obligations for notional amounts of energy and ancillary services in accordance with the Alberta Hydro PPA that expired on Dec. 31, 2020. The amount in the first and second quarter of 2021 related to adjustments for the final payment under the Alberta PPA.
(5) During the three and six months ended June 30, 2021, $3 and $5 million related to station service costs for the Hydro segment was reclassified from OM&A to fuel and purchased power for comparative purposes. This did not impact previously reported net earnings.

Availability, for the three and six months ended June 30, 2022, increased compared to the same periods in 2021, primarily due to lower planned and lower unplanned outages at our Alberta Hydro Assets.

Production, for the three and six months ended June 30, 2022, decreased by 21 GWh and 9 GWh, respectively, compared to the same periods in 2021, mainly due to lower water resources from a delayed spring runoff for our Alberta Hydro Assets.

Ancillary service volumes, for the three and six months ended June 30, 2022, increased by 36 GWh and 29 GWh, respectively, compared to the same periods in 2021, in line with normal annual variation.

Adjusted EBITDA, for the three and six months ended June 30, 2022, decreased by $8 million and $24 million, respectively, compared to the same periods in 2021, primarily due to weaker ancillary service realized prices in the Alberta market driven by increased participants and supply into the ancillary services market as a result of higher gas prices, as well as higher OM&A costs due to increased insurance premiums. For further discussion on the Alberta market conditions and pricing, refer to the 2022 Financial Outlook section and Alberta Electricity Portfolio section of this MD&A.

Sustaining capital expenditures for the three and six months ended June 30, 2022, were consistent with the same periods in 2021.

Wind and Solar

	3 months ended June 30		6 months ended June 30	
	2022	2021	**2022**	2021
Gross installed capacity (MW)(1)	**1,906**	1,572	**1,906**	1,572
LTA Generation (GWh)	**1,121**	911	**2,574**	2,081
Availability (%)	**85.7**	95.5	**82.2**	95.3
Contract production (GWh)	**802**	622	**1,711**	1,450
Merchant production (GWh)	**270**	204	**630**	507
Total energy production (GWh)	**1,072**	826	**2,341**	1,957
Wind and Solar revenues	**88**	71	**189**	162
Environmental attribute revenue	**23**	4	**30**	9
Revenues(2)	**111**	75	**219**	171
Fuel and purchased power	**6**	3	**14**	7
Carbon compliance	**1**	—	**1**	—
Gross margin(2)	**104**	72	**204**	164
OM&A	**15**	15	**31**	28
Taxes, other than income taxes	**4**	2	**6**	5
Net other operating income(2)	**(3)**	—	**(10)**	—
Adjusted EBITDA(2)	**88**	55	**177**	131
Supplemental information:				
Sustaining capital	**3**	3	**7**	4
Kent Hills wind rehabilitation expenditures(3)	**10**	—	**10**	—
Insurance proceeds - Kent Hills	**(7)**	—	**(7)**	—

(1) The gross installed capacity in 2022 includes incremental capacity related to new facilities: Windrise wind facility (206 MW), North Carolina Solar (122 MW) and Oldman wind facility (4 MW).
(2) For details of the adjustments to revenues and net other operating income included in adjusted EBITDA, refer to the Additional IFRS and Non-IFRS Measures section of this MD&A.
(3)The Kent Hills wind facilities rehabilitation capital expenditures were segregated from the sustaining capital expenditures due to the extraordinary nature of the expenditures and have been reflected separately. Refer to the Kent Hills Wind Facilities Rehabilitation section of this MD&A for further details.

Availability, for the three and six months ended June 30, 2022, decreased compared to the same periods in 2021, primarily as a result of the unplanned outage at the Kent Hills 1 and 2 wind facilities and early-stage operational issues related to our Windrise wind facility in Alberta. As at June 30, 2022, the operational issues have been largely resolved and the facility is performing in line with expectations.

Production, for the three and six months ended June 30, 2022, increased by 246 GWh and 384 GWh, respectively, compared to the same periods in 2021, primarily due to higher incremental production from the Windrise wind facility and North Carolina Solar and higher wind resources, partially offset by lower production due to the extended site outage at the Kent Hills 1 and 2 wind facilities.

Adjusted EBITDA, for the three and six months ended June 30, 2022, increased by $33 million and $46 million, respectively, compared to the same periods in 2021, primarily due to higher production, higher realized merchant pricing in Alberta, higher environmental attribute revenues and recognition of liquidated damages related to turbine availability at the Windrise wind facility, partially offset by an increase in transmission rates. The three and six month periods in 2021 included a one-time reimbursement as a result of the AESO transmission line loss ruling.

Sustaining capital expenditures for the three months ended June 30, 2022, were consistent with the same period in 2021. For the six months ended June 30, 2022, the sustaining capital expenditures were $3 million higher compared to the same period in 2021, due to higher major component replacement in 2022.

Gas

	3 months ended June 30		6 months ended June 30	
	2022	2021	**2022**	2021
Gross installed capacity (MW)	**3,084**	3,084	**3,084**	3,084
Availability (%)	**93.9**	83.8	**93.9**	84.4
Contract production (GWh)	**831**	843	**1,771**	1,766
Merchant production (GWh)	**1,746**	2,039	**3,486**	3,797
Purchased power (GWh)	**(11)**	(58)	**(26)**	(105)
Total production (GWh)	**2,566**	2,824	**5,231**	5,458
Revenues(1)	**262**	276	**553**	536
Fuel and purchased power(1)	**146**	83	**276**	163
Carbon compliance	**12**	32	**30**	71
Gross margin(1)	**104**	161	**247**	302
OM&A(1)	**45**	43	**89**	85
Taxes, other than income taxes	**4**	4	**8**	7
Net other operating income	**(10)**	(10)	**(20)**	(20)
Adjusted EBITDA(1)	**65**	124	**170**	230
Supplemental information:				
Sustaining capital	**3**	41	**8**	66

(1) For details of the adjustments to revenues, fuel and purchased power and OM&A included in adjusted EBITDA, refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

The Gas segment is a new segment as described in the Segmented Financial Performance and Operating Results section of this MD&A. Included in the Gas segment is the previous North American Gas segment, Australian Gas segment and the facilities from the previous Alberta Thermal segment which have been converted to gas. The previous Alberta thermal facilities included in the Gas segment include Sheerness Units 1 and 2, Keephills Units 2 and 3 and Sundance Unit 6. Prior periods have been adjusted to be comparable to the current period and reflect operations as coal units.

Availability, for the three and six months ended June 30, 2022, increased compared to the same periods in 2021, primarily due to lower planned outages due to the completion of the coal-to-gas conversion of Keephills Unit 2 in the second quarter of 2021 and improved performance at Keephills Unit 3. The six month period availability was also positively impacted by the completion of the coal-to-gas conversion of Sheerness Unit 1 in the first quarter of 2021.

Production for the three and six months ended June 30, 2022, decreased by 258 GWh and 227 GWh, respectively, compared to the same periods in 2021, mainly due to dispatch optimization of our Alberta assets, partially offset by higher production from our Ada cogeneration facility. The six month period was also partially offset by higher production in Ontario driven by strong demand.

Adjusted EBITDA, for the three and six months ended June 30, 2022, decreased by $59 million and $60 million, respectively, compared to the same periods in 2021. The decreases were primarily due to lower production, higher natural gas prices and increased natural gas consumption, partially offset by lower carbon costs. The three and six months ended June 30, 2021, were additionally impacted by the unplanned short-term steam supply outages at the Sarnia cogeneration facility. Carbon costs in the period were lower as the facilities in the segment no longer operate on coal. The Company utilized 0.7 million tonnes of emission credits to settle the 2021 carbon compliance obligation, reducing our carbon compliance costs by $7 million in the period. In addition, during the three months ended June 30, 2022, adjusted EBITDA was negatively impacted by lower realized prices in Alberta resulting from hedging activities. For the six months ended June 30, 2022, legal fees were lower related to the South Hedland PPA dispute settlement. Refer to the Alberta Electricity Portfolio section within this MD&A for further details.

Sustaining capital expenditures for the three and six months ended June 30, 2022, decreased by $38 million and $58 million, respectively, compared to the same periods in 2021, mainly due to the timing of the Keephills Unit 2, Sundance Unit 6 and Sheerness Unit 1 coal-to-gas conversion outages being completed in 2021.

Energy Transition

	3 months ended June 30		6 months ended June 30	
	2022	2021	**2022**	2021
Gross installed capacity (MW)(1)	**671**	1,876	**671**	1,876
Availability (%)	**45.2**	55.9	**68.4**	71.3
Adjusted availability (%)(2)	**52.7**	69.9	**71.9**	78.3
Contract sales volume (GWh)	**830**	830	**1,650**	1,650
Merchant sales volume (GWh)	**328**	489	**1,529**	2,063
Purchased power (GWh)	**(868)**	(835)	**(1,836)**	(1,813)
Total production (GWh)	**290**	484	**1,343**	1,900
Revenues(3)	**96**	124	**213**	269
Fuel and purchased power(3)	**71**	65	**165**	158
Carbon compliance	**(4)**	10	**(3)**	21
Gross margin(3)	**29**	49	**51**	90
OM&A(3)	**17**	23	**33**	46
Taxes, other than income taxes	**1**	2	**2**	4
Net other operating income	**—**	(1)	**—**	(1)
Adjusted EBITDA(3)	**11**	25	**16**	41
Supplemental information:				
Highvale mine reclamation spend	**3**	1	**5**	2
Centralia mine reclamation spend	**3**	3	**7**	4
Sustaining capital	**16**	12	**16**	13

(1) The gross installed capacity for the three and six months ended June 30, 2022, excludes Keephills Unit 1 (395 MW retired on Dec. 31, 2021), Sundance Unit 5 (406 MW retired on Nov. 1 2021) and, in addition, the three months ended June 30, 2022, excludes Sundance Unit 4 (406 MW retired on March 31, 2022).
(2) Adjusted for dispatch optimization.
(3) For details of the adjustments to revenues, fuel and purchased power and OM&A included in adjusted EBITDA, refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

Energy Transition segment is a new segment as described in the Segmented Financial Performance and Operating Results section of this MD&A. Included in the Energy Transition segment is the previous Centralia segment, mine assets and the previous Alberta Thermal segment facilities that were not converted to gas. The previous Alberta thermal facilities included in the Energy Transition segment includes Keephills Unit 1 and Sundance Unit 4. Previous periods have been adjusted to be comparable to the current period.

Adjusted availability, for the three and six months ended June 30, 2022, decreased mainly due to the retirement of Keephills Unit 1 and Sundance Unit 4, partially offset by lower planned and unplanned outages at Centralia Unit 2 compared to the same periods in 2021.

Production, decreased by 194 GWh and 557 GWh, respectively, for the three and six months ended June 30, 2022, compared to the same periods in 2021, primarily due the retirement of Keephills Unit 1 and Sundance Unit 4, partially offset by higher availability on Centralia Unit 2.

Adjusted EBITDA, decreased by $14 million and $25 million, respectively, for the three and six months ended June 30, 2022, compared to the same periods in 2021. The decrease is primarily due to the retirements of Keephills Unit 1 and Sundance Unit 4 and higher purchased power costs incurred due to higher power prices during the planned outage at Centralia in 2022, partially offset by higher production at Centralia and lower carbon costs in Alberta. Carbon costs were lower as the Alberta facilities in the segment no longer operated on coal and have now been retired. The Company utilized 0.5 million tonnes of emission credits to settle the 2021 carbon compliance obligation, reducing our carbon compliance costs by $5 million in the both the three and six months ended June 30, 2022.

Mine reclamation spend for the Highvale and Centralia mines for the three and six months ended June 30, 2022, increased due to advancement of reclamation activities compared to the same periods in 2021.

The sustaining capital expenditures for the three and six months ended June 30, 2022, increased by $4 million and $3 million, respectively, compared to the same periods in 2021, primarily due to planned maintenance for Centralia Unit 2.

Energy Marketing

	3 months ended June 30		6 months ended June 30	
	2022	2021	**2022**	2021
Revenues(1)	**57**	50	**81**	115
OM&A	**7**	7	**14**	17
Adjusted EBITDA(1)	**50**	43	**67**	98

(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, for the three and six months ended June 30, 2022, increased by $7 million and decreased $31 million, respectively compared to the same periods in 2021. The higher gross margin for the three months ended June 30, 2022, was due to short-term trading of both physical and financial power and gas products across all North American markets. The Energy Marketing team was able to capitalize on short-term volatility in the markets in which we trade without materially changing the risk profile of the business unit.

For the six months ended June 30, 2022, results exceeded expectations due to favourable trading of both physical and financial power and gas products across all North American markets. The higher revenues for the six months ended June 30, 2021 were due to exceptional short-term volatility in the market.

Corporate

	3 months ended June 30		6 months ended June 30	
	2022	2021	**2022**	2021
OM&A	**23**	24	**41**	32
Adjusted EBITDA	**(23)**	(24)	**(41)**	(32)
Adjusted EBITDA	**(23)**	(24)	**(41)**	(32)
Total return swap (gains) losses	**—**	2	**1**	(5)
CEWS funding received	**—**	—	**—**	(8)
CEWS funding applied to incremental employment	**2**	1	**3**	1
Adjusted EBITDA excluding impact of total return swap and CEWS	**(21)**	(21)	**(37)**	(44)
Supplemental information:				
Total sustaining capital	**3**	3	**5**	5

Corporate overhead costs and adjusted EBITDA are in line with expectations and consistent with the prior period for the three months ended June 30, 2022.

Corporate overhead costs increased by $9 million for the six months ended June 30, 2022, compared to the same period in 2021. The six month period ended June 30, 2022, was impacted by higher realized gains from the total return swap on our share-based payment plans partially offset by the receipt of CEWS funding in the first quarter 2021.

Adjusted EBITDA, after removing the impact of the CEWS funding and total return swap for the six months ended June 30, 2022, increased by $7 million, compared to the same period in 2021, primarily due to lower staffing costs, lower incentive payments and lower legal costs.

For the three and six months ended June 30, 2022, sustaining capital expenditures were consistent with the same period in 2021.

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, as 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.

	Q3 2021	Q4 2021	Q1 2022	**Q2 2022**
Revenues	850	610	735	**458**
Adjusted EBITDA(1)(2)	402	243	259	**279**
Earnings (loss) before income taxes	(441)	(32)	242	**(22)**
Cash flow (used in) from operating activities(3)	610	54	451	**(129)**
FFO(1)(2)	318	186	179	**220**
FCF(1)(2)	210	79	108	**145**
Net earnings (loss) attributable to common shareholders	(456)	(78)	186	**(80)**
Net earnings (loss) per share attributable to common shareholders, basic and diluted(4)	(1.68)	(0.29)	0.69	**(0.30)**

	Q3 2020	Q4 2020	Q1 2021	Q2 2021
Revenues	514	544	642	619
Adjusted EBITDA(1)(2)	246	223	322	319
Earnings (loss) before income taxes	(129)	(168)	21	72
Cash flow from operating activities	257	110	257	80
FFO(1)(2)	183	150	223	267
FCF(1)(2)	96	41	141	155
Net loss attributable to common shareholders	(136)	(167)	(30)	(12)
Net loss per share attributable to common shareholders, basic and diluted(4)	(0.50)	(0.61)	(0.11)	(0.04)

(1) 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.
(2) The current quarter composition was updated and the previous periods have been reported to be consistent. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.
(3) The cash flow used in operating activities for the second quarter of 2022, decreased compared to prior quarters 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.
(4) Basic and diluted earnings (loss) per share attributable to common shareholders is calculated each period using the weighted average common shares outstanding during the period. 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 has also been impacted by the following variations and events:

- The continued extended outage of the Kent Hills 1 and 2 wind facilities from the fourth quarter of 2021 to the first and second quarter of 2022;
- Insurance proceeds for the single collapsed tower at Kent Hills wind facilities of $7 million recognized in the second quarter of 2022;
- Liquidated damages related to turbine availability at the Windrise wind facility recorded in the first and second quarter of 2022;
- Lower carbon costs in the first quarter of 2022 related to going off-coal and utilization of compliance credits to settle a portion of our GHG obligation in the second quarter of 2022;
- Keephills Unit 1 was retired in the fourth quarter of 2021 and Sundance Unit 4 was retired in the first quarter of 2022;
- Acquisition of North Carolina Solar in the fourth quarter of 2021;
- Sundance Unit 5 Repowering was suspended in the third quarter of 2021 and retired during 2021;
- Gains relating to 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 outages at Sarnia facility in the second quarter of 2021;
- Alberta hydro facilities, Keephills Units 1 and 2 and Sheerness began operating on a merchant basis in the Alberta market effective Jan. 1, 2021;
- Revenues declined due to weaker market conditions in 2020 as a result of the COVID-19 pandemic and low oil prices;
- Sundance Unit 3 was retired in the third quarter of 2020;
- Accelerated plans to shut down the Highvale mine resulted in remaining future royalty payments being recognized as an onerous contract in the third quarter of 2021;
- Sheerness going off-coal resulted in the remaining coal supply payments on the existing coal supply agreement being recognized as an onerous contract in the fourth quarter of 2020;
- Accelerated shut-down of the Highvale mine increased mine depreciation included in the cost of coal. Coal inventory write-down incurred in the first three quarters of 2021 and third and fourth quarters of 2020;
- Coal-related parts and materials inventory write-down incurred in the second and third quarters of 2021;
- The impact of the updated provision estimates for the AESO transmission line loss rule during the first quarter of 2021 and the last two quarters of 2020;
- Significant foreign exchange gains in the last two quarters of 2020;
- The effects of asset impairment charges and reversals during all periods shown;
- The effects of changes in decommissioning and restoration provisions for retired assets in all periods shown;
- The effects of changes in useful lives of certain assets during the third quarter of 2020; and
- Current tax expense consistently fluctuates with earnings before tax over the quarters due to the Energy Marketing and Australian operations continuing to be taxable. Future tax expense increased from 2021 mainly due to a valuation allowance taken against part of the Canadian operations.

Strategy and Capability to Deliver Results

The Corporate strategy remains unchanged from that disclosed in the 2021 Annual MD&A.

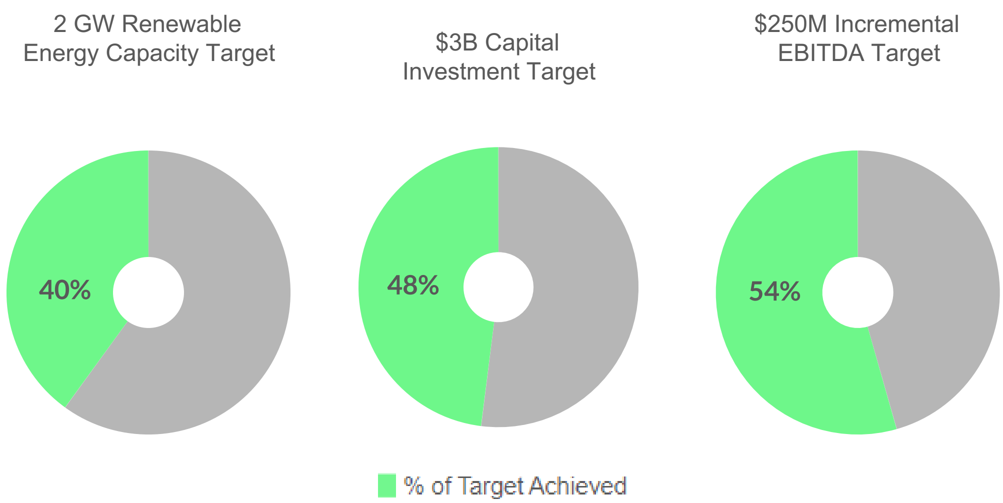
Our goal is to be a leading customer-centered electricity company, committed to a sustainable future, focused on increasing shareholder value by growing our portfolio of high-quality generation facilities with stable and predictable cash flows. Our strategy includes meeting our customer needs for clean, 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 for companies to achieve their environment, social and governance ("ESG") ambitions. Refer to the ESG sections within our 2021 Annual MD&A for further details.

We expect the Company's adjusted EBITDA generated from renewable sources, including hydro, wind, solar and storage technologies, to increase from 35 per cent in 2020 to approximately 70 per cent by the end of 2025.

On Sept. 28, 2021, the Company announced the strategic targets and a five-year Clean Electricity Growth Plan that sets a focus towards investing in clean energy solutions that meet the needs of our industrial and corporate customers and communities. The Clean Electricity Growth Plan will largely be funded from current cash balances, cash generated from operations and asset-level financing.

As of Aug. 4, 2022, we have made significant progress in 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 billion by the end of 2025.	Ahead of Plan	The Company delivered 200 MW of growth in the first quarter with the Horizon Hill wind project. We have also advanced the Mount Keith 132kV transmission expansion to construction in Australia. Our cumulative progress towards our target is 800 MW.
	Deliver incremental average annual EBITDA of $250 million.	Ahead of Plan	The Horizon Hill wind project will add incremental EBITDA in the range of US$27 - US$30 million and the Mount Keith 132kV transmission project will add incremental EBITDA in the range of AU$6 - AU$7 million. Our cumulative progress towards our incremental EBITDA target is approximately $135 million.
	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 continues to evaluate several opportunities to add new development sites to our pipeline. These include acquisitions of individual early stage development sites, small development portfolios and prospecting of new sites. In 2022, we have grown our renewable development pipeline by approximately 325 MW, in the United States and Canada.
Take a Targeted Approach to Diversification	Grow our asset base in our core geographies of Canada, Australia and the United States 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 United States market through our North Carolina Solar acquisition and new Oklahoma investments which also added three new investment-grade customers.
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 $1.9 billion as of June 30, 2022. The Company returned $18 million in share buybacks in the first quarter of 2022.
Define the Next Generation of Energy Solutions and Technologies	Meet the needs of our customers and communities through implementation of innovative energy solutions and parallel investments in new complementary sectors by the end of 2025.	On track	The Company has established an Energy Innovation team to progress our goals in this area. The team has recently completed an 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 an investment in EIP's Deep Decarbonization Frontier Fund 1, which provides a portfolio approach to investing in emerging technologies focused on net-zero emissions.
Lead in ESG Policy Development	Actively participate in policy development to ensure the electricity 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 Standard. Throughout the engagement, TransAlta continues to provide input regarding how to achieve emissions reduction while maintaining necessary reliability and affordability.
Successfully Navigate through the COVID-19 Pandemic	Continue to maintain an effective response to COVID-19 and plan a safe return to our offices.	On track	Continuing to monitor local public health authority and government guidelines in all jurisdictions in which we operate to promote the health and safety of all employees and contractors with our health and safety protocols.

Growth

The Company announced 200 MW of new build projects on April 5, 2022. In addition, the Company has 140 MW in advanced-stage development that it is actively pursuing. The current growth pipeline has a potential capacity ranging from 2,950 - 4,050 MW from projects in the early stages of development.

We are primarily evaluating greenfield opportunities in Alberta, Western Australia and the United States 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					
Project	**Type**	**Region**	**MW**	**Estimated spend**	**Spent to date**	**Target completion date(1)**	**PPA Term (2)**	**Average annual EBITDA(3)**	**Status**
Canada									
Garden Plain(4)	Wind	AB	130	$190 — $200	$81	H2 2022	18	$14 - $15	• Fully contracted • Construction underway • Turbine deliveries commence in July • On track to be completed on schedule
United States									
White Rock Wind	Wind	OK	300	US$460 — US$470	US$56	H2 2023	—	US$42 - US$46	• Long-term PPAs executed • All major equipment supply and EPC agreements executed • Detailed design and final permitting on track • On track to be completed on schedule
Horizon Hill	Wind	OK	200	US$290 — US$310	US$35	H2 2023	—	US$27 - US$30	• Long-term PPA executed • All major equipment supply and EPC agreements executed • On track to be completed on schedule
Australia									
Northern Goldfields Solar	Hybrid Solar	WA	48	AU$69 — AU$73	AU$45	H2 2022	16	AU$9 - AU$10	• Construction underway • Racking and panels have been delivered and battery is in transit to site • On track to be completed on schedule
Mount Keith 132kV Expansion	Transmission	WA	n/a	AU$50 — AU$53	AU$5	H2 2023	15	AU$6 - AU$7	• EPC Agreement executed • On track to be completed on schedule

(1) H2 is defined as the 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. Please refer to the Additional IFRS measures and Non-IFRS Measures section of this MD&A for further discussion.
(4) The Garden Plain wind project PPA is fully contracted, with Pembina, off-taking 100 MW of the total 130 MW capacity of the facility and the remaining 30 MW contracted to an investment-grade globally recognized customer. Refer to the Significant and Subsequent Events section of this MD&A for further details.

Advanced Stage Development

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

Project	Type	Region	Gross Installed Capacity (MW)	Estimated Spend	Average annual EBITDA[1]
Tempest	Wind	Alberta	100	$190 - $200	$15 - $18
SCE Capacity Expansion	Gas	Western Australia	40	AU$80 - AU$100	AU$9 - AU$12

(1) This item is not defined and have no standardized meaning under IFRS and is forward-looking. Please refer to the Additional IFRS measures and Non-IFRS Measures section of this MD&A for further discussion.

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		Gross Installed Capacity (MW)
Early Stage Development				
Canada				
Riplinger Wind	Wind	Alberta		300
Willow Creek 1	Wind	Alberta		70
Willow Creek 2	Wind	Alberta		70
WaterCharger	Battery Storage	Alberta		180
Sunhills Solar	Solar	Alberta		80
McNeil Solar	Solar	Alberta		40
Canadian Wind Opportunities	Wind	Various		300
Brazeau Pumped Hydro	Hydro	Alberta		300 - 900
Alberta Thermal Redevelopment	Gas, Solar, Storage	Alberta		250 - 500
			Total	**1,590 - 2,440**
United States				
Prairie Violet	Wind	Illinois		130
Old Town	Wind	Illinois		185
Big Timber	Wind	Pennsylvania		50
Other Wind Prospects in the United States	Wind	Various		535
Centralia site Redevelopment	Gas, Solar, Storage	Washington		250 - 500
			Total	**1,150 - 1,400**
Australia				
Goldfields Expansions	Gas, Solar, Wind	Western Australia		160
South Hedland Solar	Solar	Western Australia		50
			Total	**210**
Canada, United States and Australia			**Total**	**2,950 - 4,050**

2022 Financial Outlook

Refer to the 2022 Financial Outlook section in our 2021 Annual MD&A for full details on our Outlook and related assumptions.

The following table outlines our expectations on key financial targets and related assumptions for 2022:

Measure	2022 Target	2021 Actual
Adjusted EBITDA(1)(2)	$1,065 million - $1,185 million	$1,286 million
FCF(1)(2)	$455 million - $555 million	$585 million
Dividend	$0.20 per share annualized	$0.20 per share annualized

(1) These items are not defined and have no standardized meaning under IFRS. Please 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)The 2021 Adjusted EBITDA and FCF were revised during the second quarter of 2022. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

Range of key 2022 power and gas price assumptions

Market	Original Expectations	Updated Expectations
Alberta Spot ($/MWh)	$80 - $90	$115 - $125
Mid-C Spot (US$/MWh)	US$45 - US$55	US$55 - US$65
AECO Gas Price ($/GJ)	$3.60	$6.50 - $7.50

Alberta spot price sensitivity: a +/- $1/MWh change in spot price is expected to have a +/- $3 million impact on Adjusted EBITDA for the balance of 2022.

Other assumptions relevant to the 2022 financial outlook

	Original Expectations	Updated Expectations
Sustaining capital	$150 million - $170 million	no revision
Energy Marketing adjusted gross margin(1)	$95 million -$115 million	$110 million - $130 million

(1) During 2022, the Company updated expectations for adjusted gross margin and is tracking above the midpoint.

Alberta Hedging

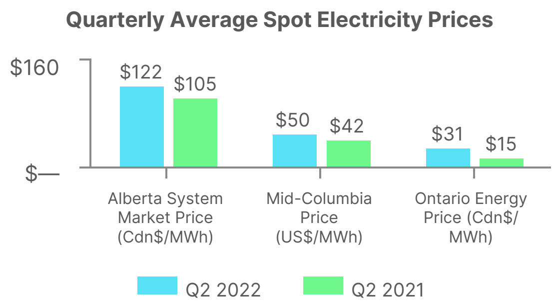
Range of hedging assumptions	Q3 2022	Q4 2022	Full year 2023
Hedged production (GWh)	1,653	1,410	4,629
Hedge price ($/MWh)	77	74	72
Hedged gas volumes (GJ)	17 Million	14 Million	58 million
Hedge gas prices ($/GJ)	3.90	3.50	2.24

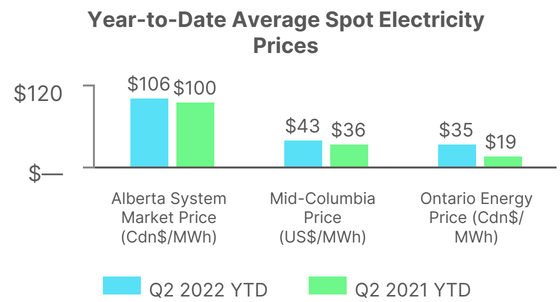
Our overall performance for the second quarter of 2022 was within expectations. Although the Company has raised annual expectations for Energy Marketing, the Company continues to track against stated guidance for 2022.

Operations

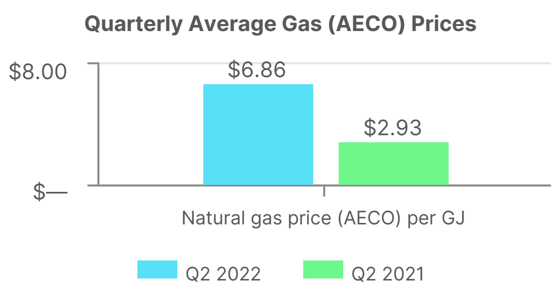
The following provides updates to our original assumptions included in the 2022 Financial Outlook.

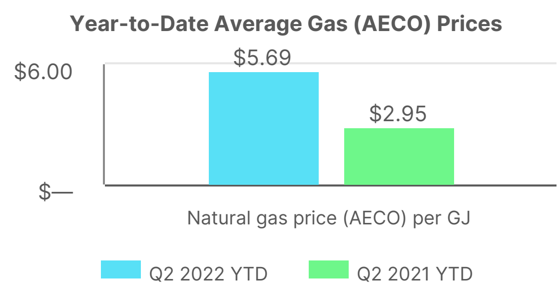
Market Pricing





For the second quarter of 2022, we saw continuing strong merchant pricing levels in Alberta and the Pacific Northwest as a result of higher natural gas prices across North America. Prices in Alberta for the balance of year are now trading above prices last year due to higher natural gas prices, which also raises the cost to import power from the Pacific Northwest. This is offset by fewer planned outages and the forecasted additions of new wind and solar supply expected to achieve commercial operation in late 2022. Higher quarter-over-quarter pricing in the Pacific Northwest is being impacted by elevated US natural gas prices and cooler weather that delayed runoff until late in the quarter. Ontario power prices for the second half of 2022 are expected to be higher compared to the same periods in 2021 due to higher natural gas prices and additional nuclear refurbishment outages.





AECO natural gas prices for the balance of 2022 are almost $2/GJ higher than for the same periods in 2021 due to overall tighter market conditions across North America.

Sustaining Capital Expenditures

Our estimate for total sustaining capital is as follows:

Category	Spend for 3 months ended June 30, 2022	Spend to date as at June 30, 2022	Expected spend in 2022
Total sustaining capital	31	48	$150 - $170

Total sustaining capital expenditures for the six months ended June 30, 2022, were $52 million lower compared to the same period in 2021, mainly due to lower planned major maintenance turnarounds on the coal-to-gas conversions related to Keephills Unit 2, Sundance Unit 6 and Sheerness Unit 1.

The Kent Hills wind facilities rehabilitation capital expenditure has been segregated from our sustaining capital assumptions range due to the extraordinary nature of this expenditure. Refer to the Kent Hills Wind Facilities Rehabilitation section of this MD&A for further details.

Liquidity and Capital Resources

We expect to maintain adequate available liquidity under our committed credit facilities. We currently have access to $1.9 billion in liquidity, including $0.9 billion in cash. We also expect to be well positioned to refinance the upcoming debt maturity in 2022 in due course. The funds required for committed growth, Kent Hills wind facilities rehabilitation and sustaining capital and productivity projects are not expected to be significantly impacted by the current economic environment.

Kent Hills Wind Facilities 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[1]. Following extensive independent engineering assessments and a root cause failure analysis, it was determined that all 50 turbine foundations at the Kent Hills 1 and 2 wind facilities require full foundation replacements. The outage is expected to result in foregone revenue of approximately $3 million per month on an annualized basis (assuming 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.

Following the identification of the foundation issues at the Kent Hills 1 and 2 wind facilities, Kent Hills Wind LP ("KHLP") provided notice to BNY Trust Company of Canada, as trustee (the “Trustee”) that events of default may have occurred under the trust indenture governing the terms of such bonds. On June 1, 2022, the Company obtained a waiver from the Trustee to remedy the events of default and concurrently entered into a supplemental indenture that facilitates the rehabilitation of the Kent Hills 1 and 2 wind facilities.

KHLP has entered into agreements with vendors to complete the rehabilitation of the Kent Hills 1 and 2 wind facilities and has commenced execution of its rehabilitation plan which consists of dismantling all 49 remaining turbines, demolishing and removing all existing tower foundations, replacing them with newly-designed foundations, reassembling the wind turbine towers and generators, replacing the wind turbine that collapsed and testing each wind turbine generator before returning it 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. The current estimate of the capital expenditures is approximately $120 million, inclusive of contingency. Rehabilitation for the Kent Hills 1 and 2 wind facilities is targeted to be completed by mid-2023.

The Company is actively evaluating all options that may be available to recover the rehabilitation costs from third parties and their insurance providers and intends to pursue claims to recover costs and related damages from those parties. On June 30, 2022, the Company recognized a $7 million insurance recovery within net operating other income, related to the replacement costs for the single collapsed tower.

In addition, during the second quarter of 2022, KHLP completed negotiations with NB Power and amended the existing power purchase agreements ("PPAs") to provide NB Power with an effective 10 per cent reduction to the original contract period from January 2023 to December 2033 and to extend the original contract terms for an additional 10-year period through to December 2045. During the extended period after 2035, the contract prices in the agreements have been set to align with current competitive pricing for wind generation and include escalators intended to reflect inflation.

During the second quarter of 2022, KHLP received repayment of $10 million of the Kent Hills Wind LP loan receivable, which was required as part of the waiver and amendment made to the KH Bonds. In addition, the loan receivable agreement with KHLP's 17 per cent partner, Natural Forces Technologies Inc was amended and its original maturity date of Oct. 2, 2022 was extended to October 2027. As at June 30, 2022, $45 million (Dec. 31, 2021 — $55 million) was outstanding.

[1] The Kent Hills 1 and 2 wind facilities lost production is based on average historical wind production.

Financial Position

The following table highlights significant changes in the unaudited interim condensed consolidated statements of financial position from Dec. 31, 2021, to June 30, 2022:

Assets	June 30, 2022	Dec. 31, 2021	Increase/ (decrease)
Current assets			
Cash and cash equivalents	**898**	947	(49)
Trade and other receivables	**1,027**	651	376
Risk management assets	**603**	308	295
Other current assets(1)	**287**	291	(4)
Total current assets	**2,815**	2,197	618
Non-current assets			
Risk management assets	**308**	399	(91)
Property, plant and equipment, net	**5,145**	5,320	(175)
Other non-current assets(2)	**1,318**	1,310	8
Total non-current assets	**6,771**	7,029	(258)
Total assets	**9,586**	9,226	360
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	**1,146**	689	457
Risk management liabilities	**588**	261	327
Credit facilities, long-term debt and lease liabilities (current)	**690**	844	(154)
Other current liabilities(3)	**92**	137	(45)
Total current liabilities	**2,516**	1,931	585
Non-current liabilities			
Credit facilities, long-term debt and lease liabilities	**2,489**	2,423	66
Decommissioning and other provisions (long-term)	**588**	779	(191)
Risk management liabilities (long-term)	**205**	145	60
Defined benefit obligation and other long-term liabilities	**212**	253	(41)
Other non-current liabilities(4)	**1,102**	1,102	—
Total non-current liabilities	**4,596**	4,702	(106)
Total liabilities	**7,112**	6,633	479
Equity			
Equity attributable to shareholders	**1,574**	1,582	(8)
Non-controlling interests	**900**	1,011	(111)
Total equity	**2,474**	2,593	(119)
Total liabilities and equity	**9,586**	9,226	360

(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 current portion of decommissioning and other provisions, current portion of contract liabilities, income taxes payable and dividends payable.
(4) Includes exchangeable securities, deferred income tax liabilities and contract liabilities.

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

Working Capital

The excess of current assets over current liabilities, including the current portion of long-term debt and lease liabilities, was $299 million as at June 30, 2022, (Dec. 31, 2021 - $266 million). Our working capital increased compared to the previous period mainly due to the reclassification of the KH Bonds to long-term liabilities as a result of the waiver obtained and lower operational payables. This was partially offset by movements in the collateral accounts. Our collateral received (included in accounts payable and accrued liabilities) is significantly higher at June 30, 2022, compared to Dec. 31, 2021 and is partially offset by the collateral paid to counterparties (included in trade and other receivables). The change in the collateral posted is largely related to high commodity prices and volatility in the markets.

Current assets increased by $618 million to $2,815 million as at June 30, 2022, from $2,197 million as at Dec. 31, 2021, mainly due to higher trade and other receivables due to higher collateral posted, higher risk management assets resulting from volatility in market prices partially offset by lower cash and cash equivalents. As at June 30, 2022, the Company had posted $403 million (Dec. 31, 2021 - $55 million) of cash collateral received related to derivative instruments in a net asset position.

Current liabilities increased by $585 million from $1,931 million as at Dec. 31, 2021 to $2,516 million as at June 30, 2022, mainly due to an increase in collateral received associated with counterparty obligations in accounts payable, an increase in risk management liabilities primarily due to volatility in market prices; partially offset by the reclassification of the KH Bonds to long-term as a result of the waiver obtained. As at June 30, 2022, the Company held $604 million (Dec. 31, 2021 - $18 million) of cash collateral received related to derivative instruments in a net asset position.

Non-current Assets

Non-current assets at June 30, 2022, are $6,771 million, a decrease of $258 million from $7,029 million as at Dec. 31, 2021. The decrease was primarily due to lower PP&E relating to increased discount rates on decommissioning provisions of $106 million, impairment of assets of $27 million and depreciation expense recognized in the period. In addition, risk management assets are lower due to volatility in market pricing and contract settlements. These impacts were partially offset by increases to PP&E for the construction of the Horizon Hill wind project, White Rock Wind projects, Northern Goldfields Solar project and Garden Plain wind project.

Non-current Liabilities

Non-current liabilities as at June 30, 2022, are $4,596 million, a decrease of $106 million from $4,702 million as at Dec. 31, 2021, mainly due to a $211 million decrease in the long-term decommissioning and restoration provision as a result of increased discount rates and a $46 million decrease in defined benefit obligation due to changes in discount rate assumptions, partially offset by a $66 million increase in long-term debt and lease liabilities resulting from the reclassification of the KH Bonds to long-term as a result of the waiver obtained, net of the scheduled debt repayments and an increase in risk management liabilities due to the volatility in the market and new contracts.

Total Equity

As at June 30, 2022, the decrease in total equity of $119 million was mainly due to net losses on cash flow hedges of $169 million, distributions to non-controlling interests of $72 million, share repurchases under the NCIB of $18 million, the effect of share-based payment plans of $11 million and common share and preferred share dividends of $13 million and $10 million, respectively, partially offset by net earnings for the period of $147 million and actuarial gains on defined benefit plans of $36 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:

	June 30, 2022		Dec. 31, 2021	
	$	**%**	$	%
TransAlta Corporation				
Net senior unsecured debt				
Recourse debt - CAD debentures	**251**	**5**	251	4
Recourse debt - US senior notes	**896**	**16**	888	16
Other	**3**	**—**	4	—
Less: cash and cash equivalents	**(680)**	**(12)**	(703)	(12)
Less: other cash and liquid assets(1)	**(2)**	—	(19)	—
Net senior unsecured debt	**468**	**9**	421	8
Other debt liabilities				
Exchangeable debentures	**337**	**6**	335	6
Non-recourse debt				
TAPC Holdings LP bond	**99**	**2**	102	2
OCP bond	**252**	**5**	263	5
Lease liabilities	**80**	**1**	78	1
Total net debt - TransAlta Corporation	**1,236**	**23**	1,199	22
TransAlta Renewables				
Net TransAlta Renewables reported debt				
Pingston bond	**45**	**1**	45	1
Melancthon Wolfe Wind bond	**219**	**4**	235	4
New Richmond Wind bond	**116**	**2**	120	2
Kent Hills Wind bond	**212**	**4**	221	4
Windrise Wind bond	**170**	**3**	171	3
Lease liabilities	**23**	**—**	22	—
Less: cash and cash equivalents	**(218)**	**(3)**	(244)	(4)
Debt on TransAlta Renewables Economic Investments				
US tax equity financing(2)	**122**	**2**	135	2
South Hedland non-recourse debt(3)	**691**	**13**	732	13
Total net debt - TransAlta Renewables	**1,380**	**26**	1,437	25
Total consolidated net debt(4)(5)	**2,616**	**49**	2,636	47
Non-controlling interests	**900**	**16**	1,011	18
Exchangeable preferred securities(5)	**400**	**7**	400	7
Equity attributable to shareholders				
Common shares	**2,893**	**53**	2,901	51
Preferred shares	**942**	**17**	942	17
Contributed surplus, deficit and accumulated other comprehensive income	**(2,261)**	**(41)**	(2,261)	(40)
Total capital	**5,490**	**101**	5,629	100

(1) Includes principal portion of OCP restricted cash in 2021 and fair value asset (liability) of hedging instruments on debt.
(2) TransAlta Renewables has an economic interest in the entities holding these debts.
(3) TransAlta Renewables has an economic interest in the Australia entities, which includes the AU$789 million senior secured notes.
(4) The tax equity financing for Skookumchuck wind, an equity accounted joint venture, is not represented in these amounts.
(5) The total consolidated net debt excludes the exchangeable preferred securities as they are considered equity with dividend payments for credit purposes.

Credit Facilities

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

As at June 30, 2022	Facility size	Utilized: Outstanding letters of credit[1]	Utilized: Actual drawings	Available capacity	Maturity date
TransAlta Corporation					
Committed syndicated bank facility[2]	1,250	888	—	362	Q2 2026
Canadian committed bilateral credit facilities	240	168	—	72	Q2 2024
TransAlta Renewables					
Committed credit facility[2]	700	102	—	598	Q2 2026
Total	**2,190**	**1,158**	**—**	**1,032**	

(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. At June 30, 2022, we provided cash collateral of $403 million.
(2) TransAlta has letters of credit of $150 million and TransAlta Renewables has letters of credit of $102 million issued from uncommitted demand facilities; these obligations are backstopped and reduce the available capacity on the committed credit facilities.

During the second quarter of 2022, the committed syndicated credit facilities were extended by one year to June 30, 2026 and the committed bilateral credit facilities were extended by one year to June 30, 2024.

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 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 second quarter of 2022, except in relation to the KH Bonds as discussed below. The next debt service coverage ratio is calculated in the third quarter of 2022.

Kent Hills Wind Facilities Rehabilitation

In the fourth quarter of 2021, the Company provided notice to the Trustee that events of default may have occurred under the trust indenture governing the terms of the KH Bonds. During the second quarter of 2022, the Company obtained a waiver and entered into a supplemental indenture that facilitated the rehabilitation of the Kent Hills 1 and 2 wind facilities. Upon obtaining the waiver, the Company reclassified a portion of the carrying value outstanding of $212 million (face value $215 million) for the KH Bonds to non-current liabilities with the exception of the scheduled principal repayments due within the next twelve months from June 30, 2022. 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.

Between 2022 and 2024, we have $865 million of debt maturing, including $518 million of recourse debt, with the balance mainly related to scheduled non-recourse debt repayments. We currently expect to refinance the senior notes maturing in 2022.

Returns to Providers of Capital

Net Interest Expense

The components of net interest expense are shown below:

	3 months ended June 30		6 months ended June 30	
	2022	2021	**2022**	2021
Interest on debt	**40**	40	**81**	80
Interest on exchangeable debentures	**8**	7	**15**	14
Interest on exchangeable preferred shares	**7**	7	**14**	14
Interest income	**(4)**	(3)	**(7)**	(6)
Capitalized interest	**(3)**	(3)	**(4)**	(8)
Interest on lease liabilities	**2**	2	**3**	4
Credit facility fees, bank charges and other interest	**5**	3	**11**	10
Tax shield on tax equity financing	**(3)**	—	**(3)**	1
Accretion of provisions	**10**	7	**19**	14
Net interest expense	**62**	60	**129**	123

Net interest expense for the three months ended June 30, 2022, was consistent with the same period in 2021. Net interest expense increased for the six months ended June 30, 2022, mainly due to higher interest expense related to the Windrise wind bond issued in the fourth quarter of 2021, higher accretion of provisions and lower capitalized interest on development projects.

Share Capital

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

As at	**Aug 4, 2022**	**June 30, 2022**	**Dec. 31, 2021**
	Number of shares (millions)		
Common shares issued and outstanding, end of period	**270.7**	**270.7**	271.0
Preferred shares			
Series A	9.6	**9.6**	9.6
Series B	2.4	**2.4**	2.4
Series C	10.0	**10.0**	11.0
Series D	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, end of period	**38.6**	**38.6**	38.6
Series I - Exchangeable Securities(1)	**0.4**	**0.4**	0.4
Preferred shares issued and outstanding, end of period	**39.0**	**39.0**	39.0

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

On June 16, 2022, the Company announced that 1,044,299 of its 11,000,000 currently outstanding Series C Shares were tendered for conversion, on a one-for-one basis, into Series D Shares after having taken into account all election notices following the June 15, 2022 conversion deadline.

Non-Controlling Interests

As at June 30, 2022, the Company owns 60.1 per cent (June 30, 2021 - 60.1 per cent) of TransAlta Renewables. 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 (June 30, 2021 - 50.01 per cent) of TA Cogen, which owns, operates or has an interest in five natural-gas-fired facilities (Ottawa, Windsor, Fort Saskatchewan and Sheerness Unit 1 and Unit 2). Since we own a controlling interest in TA Cogen and TransAlta Renewables, we consolidate the entire earnings, assets and liabilities in relation to those assets.

Reported earnings attributable to non-controlling interests for the three and six months ended June 30, 2022, was $11 million and $31 million, respectively, a decrease of $19 million and $30 million compared to the same periods in 2021. Earnings from TA Cogen for the three and six months ended June 30, 2022, decreased compared with the same periods in 2021, mainly due to higher gas commodity prices, transportation costs and lower production for our Sheerness units. Earnings from TransAlta Renewables for the three and six months ended June 30, 2022, decreased compared with the same periods in 2021, primarily due lower finance income related to subsidiaries of TransAlta, higher asset impairments, higher interest and depreciation costs associated with the commissioning and financing of the Windrise wind facility, higher income tax expense and lower foreign exchange gains. This was partially offset by higher revenues, the receipt of insurance proceeds for the replacement costs for the single collapsed tower at the Kent Hills facility, and recording liquidated damages related to turbine availability on the Windrise wind facility. Finance income related to subsidiaries of TransAlta was lower as more distributions were classified as return of capital.

Other Consolidated Analysis

Commitments

Please refer to our Other Consolidated Analysis section of the 2021 Annual MD&A for a complete listing of commitments we have incurred either directly or through interests in joint operations. The Company has entered into the following material contractual commitments, as at June 30, 2022:

During the second quarter of 2022, the Company entered into an engineering, procurement and construction agreement for approximately $37 million (AU$41 million) related to the Mount Keith 132kV Expansion Project.

Additionally, in the second quarter of 2022, the Company entered into agreements for $86 million to complete the rehabilitation at the Kent Hills 1 and 2 wind facilities.

For updates on the Company's Growth projects, refer to the Strategy and Capability to Deliver Results section of the this MD&A for further details.

Contingencies

For the current material outstanding contingencies, please refer to Note 36 of the 2021 audited annual consolidated financial statements. Material changes to the contingencies have been described below.

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

The Balancing Pool is claiming entitlement to the emission performance credits ("EPCs") 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 Balancing Pool claims ownership of the EPCs because it believes the change-in-law provisions under the Hydro PPA require the EPCs to be passed through to the Balancing Pool. TransAlta has not received any benefit from the EPCs nor from any purported change in law and believes that the Balancing Pool has no rights to these credits. An arbitration has commenced and the hearing is scheduled for Feb. 6 to 10, 2023. TransAlta holds approximately 1.75 million EPCs with no recorded book value that were created between 2018-2020, which are at risk as a result of the Balancing Pool's claim.

Keephills 1 Stator Force Majeure

The Balancing Pool and ENMAX Energy Corporation ("ENMAX") were seeking to set aside an arbitration award on the basis that they did not receive a fair hearing. The Alberta Court of Queen's Bench dismissed the Balancing Pool and ENMAX's allegations of unfairness on June 26, 2019. The Balancing Pool and ENMAX, appealed this decision to the Court of Appeal, which was heard on Jan. 27, 2022.

On June 9, 2022, the Court of Appeal released a unanimous decision dismissing ENMAX and the Balancing Pool's application. The Court of Appeal upheld the Company's claim of force majeure that arose when its Keephills 1 generating unit tripped offline in 2013. As a result of the decision, the Company's claim of force majeure remains valid and the associated costs of the force majeure event will not be reassessed against TransAlta. ENMAX and the Balancing Pool have until Aug. 8, 2022 to file an application at the Supreme Court of Canada for permission to appeal the Court of Appeal's decision.

Sarnia Outages

The Sarnia cogeneration facility experienced three separate outage events between May 19, 2021 and June 9, 2021 that resulted in steam interruptions to its industrial customers. As a result, the customers submitted claims for liquidated damages under the applicable agreements. Steam supply disruptions of this nature are atypical and infrequent at the Sarnia cogeneration facility. A root cause failure analysis was completed for the three outages, which concluded that all three outages do not qualify as events of force majeure. As such, liquidated damages in the amount of $12 million have been paid by TransAlta (SC) LP for the three outages in the second quarter of 2022.

There have been no other material updates to any of the contingencies in the three and six month period ended June 30, 2022.

Cash Flows

The following chart highlights significant changes in the consolidated statements of cash flows:

	6 months ended June 30		
	2022	2021	**Increase/ (decrease)**
Cash and cash equivalents, beginning of period	**947**	703	244
Provided by (used in):			
Operating activities	**322**	337	(15)
Investing activities	**(166)**	(121)	(45)
Financing activities	**(201)**	(273)	72
Translation of foreign currency cash	**(4)**	(4)	—
Cash and cash equivalents, end of period	**898**	642	256

Cash provided by operating activities for the six months ended June 30, 2022, decreased compared with the same period in 2021 primarily due to lower cash flow resulting from lower production and revenues for all segments except the Wind and Solar segment, offset by higher production and higher revenues in the Wind and Solar segment and favourable changes in working capital from movements in the collateral accounts related to high commodity prices and volatility in the markets.

Cash used in investing activities for the six months ended June 30, 2022, increased compared with the same period in 2021, largely due to:

- Previous year included proceeds received on the sale of the Pioneer Pipeline sold in 2021 ($128 million); partially offset by;
- Lower cash spend on project construction activities in PP&E ($16 million);
- Lower non-cash working capital related to the timing of construction payables for the assets under construction ($38 million);
- Higher loan receivable receipts and lower advances on loans receivable ($12 million); and
- Higher restricted cash receipts related to funding principal debt repayments ($10 million).

Cash used in financing activities for the six months ended June 30, 2022, decreased compared with the same period in 2021, largely due to:

- Lower repayments under the Company's credit facilities ($114 million); partially offset by:
- Higher repayments on long-term debt ($14 million);
- Higher common share repurchases under the NCIB ($14 million);
- Higher dividends paid on common shares ($3 million);
- Increased distributions paid to subsidiaries' non-controlling interests ($5 million); and
- Lower proceeds on issuances of common shares ($7 million).

Financial Instruments

Refer to Note 15 of the notes to the audited annual 2021 consolidated financial statements and Note 11 and 12 of our unaudited interim condensed consolidated financial statements as at and for the six months ended June 30, 2022, 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 on a quarterly basis 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 June 30, 2022, Level III instruments had a net liability carrying value of $407 million (Dec. 31, 2021 - net asset of $159 million), mainly due to market price changes on existing and new contracts.

Our risk management profile and practices have not changed materially from Dec. 31, 2021.

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 unaudited interim condensed 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 and six months ended June 30, 2022 and 2021. 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 2021 consolidated financial statements and the unaudited interim condensed consolidated statements of earnings (loss) for the three and six months ended June 30, 2022, 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, or as an alternative for, 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. See the Segmented Financial Performance and Operating Results, Selected Quarterly Information, Financial Capital and Key Financial Non-IFRS 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

In the fourth quarter of 2021, comparable EBITDA was relabeled as adjusted EBITDA to align with industry standard terminology. Each business segment assumes responsibility for its operating results measured to adjusted EBITDA. Adjusted EBITDA is an important metric for management that represents our core business profitability. In the second quarter of 2022, our reported 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 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. Adjusted EBITDA is a non-IFRS measure. The following are descriptions of the adjustments made.

Adjustments to revenue

- Certain assets we own in Canada and in Australia are fully contracted and recorded as finance leases under IFRS. We believe 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 position with exchanges have been recorded in the period the positions are settled.

Adjustments to fuel and purchased power

- We adjust for depreciation on our mining equipment included in fuel and purchased power.
- We adjust for items resulting from the decision to accelerate being off-coal and accelerating the shut-down of the Highvale mine at the end of 2021 as it is not reflective of ongoing business performance. Within fuel and purchased power this included coal inventory write-downs.
- 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 (reversals) are removed as these are accounting adjustments that impact depreciation and amortization and do not reflect current 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 to Net Other Operating Income

- Insurance recoveries related to the Kent Hills tower collapse are not included as these relate to investing activities and are not reflective of on-going business performance. Refer to the Kent Hills Wind Facilities Rehabilitation section of this MD&A for further details.

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 Skookumchuck wind facility in our total adjusted EBITDA. In addition, in the Wind and Solar segment 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 equity interest in EMG'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 from operations

- Includes FFO related to the Skookumchuck wind facility, which is treated as an equity accounted investment under IFRS and equity income, net of distributions from joint ventures is included in cash flow from operations under IFRS. As this investment is part of our regular power generating operations, we have included our proportionate share of FFO.
- Payments received on finance lease receivables reclassified to reflect cash from operations.
- We adjust for items included in cash from operations related to the decision in 2020 to accelerate being off-coal and accelerating the shut-down of the Highvale mine by the end of 2021 and the write-down on parts and material inventory for our coal operations ("Clean energy transition provisions and adjustments").
- Cash received/paid on closed positions are reflected in the period that the position is settled.

Free Cash Flow

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. See the Reconciliation of Cash Flow from Operations to FFO and FCF and Key Financial Non-IFRS 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 is a non-IFRS ratio.

Supplementary Financial Measures

Financial highlights presented on a proportional basis of TransAlta Renewables, deconsolidated adjusted EBITDA, deconsolidated FFO and deconsolidated net debt to deconsolidated adjusted EBITDA are supplementary financial measures the Company uses to present adjusted EBITDA on a deconsolidated basis and excludes the portion of TransAlta Renewables and TA Cogen that are not owned by TransAlta. See the Financial Highlights on a Proportional Basis of TransAlta Renewables and Key Financial Non-IFRS 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 within the Alberta Electricity Portfolio. 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 Loss before income taxes for the three months ended June 30, 2022:

	Hydro	Wind & Solar[1]	Gas[2]	Energy Transition[3]	Energy Marketing	Corporate	Total	Equity accounted investments[1]	Reclass Adjustments	IFRS Financials
Revenues	105	96	127	96	36	1	461	(3)	—	458
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	—	15	128	—	(56)	—	87	—	(87)	—
Realized gain (loss) on closed exchange positions	—	—	(10)	—	75	—	65	—	(65)	—
Decrease in finance lease receivable	—	—	11	—	—	—	11	—	(11)	—
Finance lease income	—	—	6	—	—	—	6	—	(6)	—
Unrealized foreign exchange (gain) loss on commodity	—	—	—	—	2	—	2	—	(2)	—
Adjusted revenues	105	111	262	96	57	1	632	(3)	(171)	458
Fuel and purchased power	6	6	147	71	—	1	231	—	—	231
Reclassifications and adjustments:										
Australian interest income	—	—	(1)	—	—	—	(1)	—	1	—
Adjusted fuel and purchased power	6	6	146	71	—	1	230	—	1	231
Carbon compliance	—	1	12	(4)	—	—	9	—	—	9
Gross margin	99	104	104	29	57	—	393	(3)	(172)	218
OM&A	10	15	45	17	7	23	117	—	—	117
Taxes, other than income taxes	1	4	4	1	—	—	10	(1)	—	9
Net other operating income	—	(10)	(10)	—	—	—	(20)	—	—	(20)
Reclassifications and adjustments:										
Insurance recovery	—	7	—	—	—	—	7	—	(7)	—
Adjusted net other operating income	—	(3)	(10)	—	—	—	(13)	—	(7)	(20)
Adjusted EBITDA[4]	88	88	65	11	50	(23)	279			
Equity income										2
Finance lease income										6
Depreciation and amortization										(115)
Asset impairment reversal										24
Net interest expense										(62)
Foreign exchange gain										9
Gain on sale of assets and other										2
Loss before income taxes										(22)

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.
(2) Includes the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal.
(3) Includes the segment previously known as Centralia and the coal generation assets from the segment previously known as Alberta Thermal.
(4) Adjusted EBITDA is not defined and has no standardized meaning under IFRS.

The following table reflects adjusted EBITDA by segment and provides reconciliation to earnings before income taxes for the three months ended June 30, 2021:

	Attributable to common shareholders									
	Hydro	Wind & Solar[1]	Gas[2]	Energy Transition[3]	Energy Marketing	Corporate	Total	Equity accounted investments[1]	Reclass Adjustments	IFRS Financials
Revenues	114	79	287	101	38	4	623	(4)	—	619
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	—	(4)	(28)	23	(4)	—	(13)	—	13	—
Realized gain (loss) on closed exchange positions	—	—	1	—	16	—	17	—	(17)	—
Decrease in finance lease receivable	—	—	10	—	—	—	10	—	(10)	—
Finance lease income	—	—	6	—	—	—	6	—	(6)	—
Adjusted revenues	114	75	276	124	50	4	643	(4)	(20)	619
Fuel and purchased power[4]	6	3	110	92	—	4	215	—	—	215
Reclassifications and adjustments:										
Australian interest income	—	—	(1)	—	—	—	(1)	—	1	—
Mine depreciation	—	—	(26)	(24)	—	—	(50)	—	50	—
Coal inventory write-down	—	—	—	(3)	—	—	(3)	—	3	—
Adjusted fuel and purchased power	6	3	83	65	—	4	161	—	54	215
Carbon compliance	—	—	32	10	—	—	42	—	—	42
Gross margin	108	72	161	49	50	—	440	(4)	(74)	362
OM&A[4]	11	15	45	46	7	24	148	—	—	148
Reclassifications and adjustments:										
Parts and materials write-down	—	—	(2)	(23)	—	—	(25)	—	25	—
Adjusted OM&A	11	15	43	23	7	24	123	—	25	148
Taxes, other than income taxes	1	2	4	2	—	—	9	(1)	—	8
Net other operating income	—	—	(10)	(1)	—	—	(11)	—	—	(11)
Adjusted EBITDA[5]	96	55	124	25	43	(24)	319			
Equity income										2
Finance lease income										6
Depreciation and amortization										(123)
Asset impairment charge										(16)
Net interest expense										(60)
Foreign exchange gain										14
Gain on sale of assets and other										32
Earnings before income taxes										72

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.
(2) Includes the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal. Refer to Note 1 for further details.
(3) Includes the segment previously known as Centralia and the coal generation assets from the segment previously known as Alberta Thermal.
(4) During the three months ended June 30, 2021, $3 million related to station service costs for the Hydro segment were reclassified from OM&A to fuel and purchased power for comparative purposes. This did not impact previously reported net earnings.
5) Adjusted EBITDA is not defined and has no standardized meaning under IFRS.

The following table reflects adjusted EBITDA by segment and provides reconciliation to earnings before income taxes for the 6 months ended June 30, 2022:

	Attributable to common shareholders									
	Hydro	**Wind & Solar[1]**	**Gas[2]**	**Energy Transition[3]**	**Energy Marketing**	**Corporate**	**Total**	**Equity accounted investments[1]**	**Reclass Adjustments**	**IFRS Financials**
Revenues	**182**	**191**	**561**	**202**	**62**	**2**	**1,200**	**(7)**	**—**	**1,193**
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	**—**	**28**	**(34)**	**11**	**(46)**	**—**	**(41)**	**—**	**41**	**—**
Realized gain (loss) on closed exchange positions	**—**	**—**	**(7)**	**—**	**65**	**—**	**58**	**—**	**(58)**	**—**
Decrease in finance lease receivable	**—**	**—**	**22**	**—**	**—**	**—**	**22**	**—**	**(22)**	**—**
Finance lease income	**—**	**—**	**11**	**—**	**—**	**—**	**11**		**(11)**	**—**
Adjusted revenues	**182**	**219**	**553**	**213**	**81**	**2**	**1,250**	**(7)**	**(50)**	**1,193**
Fuel and purchased power	**10**	**14**	**278**	**165**	**—**	**2**	**469**	**—**	**—**	**469**
Reclassifications and adjustments:										
Australian interest income	**—**	**—**	**(2)**	**—**	**—**	**—**	**(2)**	**—**	**2**	**—**
Adjusted fuel and purchased power	**10**	**14**	**276**	**165**	**—**	**2**	**467**	**—**	**2**	**469**
Carbon compliance	**—**	**1**	**30**	**(3)**	**—**	**—**	**28**	**—**	**—**	**28**
Gross margin	**172**	**204**	**247**	**51**	**81**	**—**	**755**	**(7)**	**(52)**	**696**
OM&A	**21**	**31**	**89**	**33**	**14**	**41**	**229**	**—**	**—**	**229**
Taxes, other than income taxes	**2**	**6**	**8**	**2**	**—**	**—**	**18**	**(1)**	**—**	**17**
Net other operating income	**—**	**(17)**	**(20)**	**—**	**—**	**—**	**(37)**	**—**	**—**	**(37)**
Reclassifications and adjustments:										
Insurance recovery	**—**	**7**	**—**	**—**	**—**	**—**	**7**	**—**	**(7)**	**—**
Adjusted net other operating income	**—**	**(10)**	**(20)**	**—**	**—**	**—**	**(30)**	**—**	**(7)**	**(37)**
Adjusted EBITDA[4]	**149**	**177**	**170**	**16**	**67**	**(41)**	**538**			
Equity income										**4**
Finance lease income										**11**
Depreciation and amortization										**(232)**
Asset impairment reversal										**66**
Net interest expense										**(129)**
Foreign exchange gain										**11**
Gain on sale of assets and other										**2**
Earnings before income taxes										**220**

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.
(2) Includes the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal.
(3) Includes the segment previously known as Centralia and the coal generation assets from the segment previously known as Alberta Thermal.
(4) Adjusted EBITDA is not defined and has no standardized meaning under IFRS.

The following table reflects adjusted EBITDA by segment and provides reconciliation to earnings before income taxes for the 6 months ended June 30, 2021:

	Attributable to common shareholders									
	Hydro	Wind & Solar(1)	Gas(2)	Energy Transition(3)	Energy Marketing	Corporate	Total	Equity accounted investments(1)	Reclass Adjustments	IFRS Financials
Revenues	203	170	553	240	99	5	1,270	(9)	—	1,261
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	—	1	(51)	29	(12)	—	(33)	—	33	—
Realized gain (loss) on closed exchange positions	—	—	1	—	28	—	29	—	(29)	—
Decrease in finance lease receivable	—	—	20	—	—	—	20	—	(20)	—
Finance lease income	—	—	13	—	—	—	13	—	(13)	—
Adjusted revenues	203	171	536	269	115	5	1,299	(9)	(29)	1,261
Fuel and purchased power(4)	9	7	218	221	—	5	460	—	—	460
Reclassifications and adjustments:										
Australian interest income	—	—	(2)	—	—	—	(2)	—	2	—
Mine depreciation	—	—	(53)	(52)	—	—	(105)	—	105	—
Coal inventory write-down	—	—	—	(11)	—	—	(11)	—	11	—
Adjusted fuel and purchased power	9	7	163	158	—	5	342	—	118	460
Carbon compliance	—	—	71	21	—	—	92	—	—	92
Gross margin	194	164	302	90	115	—	865	(9)	(147)	709
OM&A(4)	19	28	87	69	17	32	252	(1)	—	251
Reclassifications and adjustments:										
Parts and materials write-down	—	—	(2)	(23)	—	—	(25)	—	25	—
Adjusted OM&A	19	28	85	46	17	32	227	(1)	25	251
Taxes, other than income taxes	2	5	7	4	—	—	18	(1)	—	17
Net other operating income	—	—	(20)	(1)	—	—	(21)	—	—	(21)
Adjusted EBITDA(5)	173	131	230	41	98	(32)	641			
Equity income										4
Finance lease income										13
Depreciation and amortization										(272)
Asset impairment charge										(45)
Net interest expense										(123)
Foreign exchange gain										21
Gain on sale of assets and other										33
Earnings before income taxes										93

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.
(2) Includes the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal. Refer to Note 1 for further details.
(3) Includes the segment previously known as Centralia and the coal generation assets from the segment previously known as Alberta Thermal.
(4) During the six months ended June 30, 2021, $5 million related to station service costs for the Hydro segment was reclassified from OM&A to fuel and purchased power for comparative purposes. This did not impact previously reported net earnings.
(5) Adjusted EBITDA is not defined and have no standardized meaning under IFRS.

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

	3 months ended June 30		6 months ended June 30	
	2022	2021	**2022**	2021
Cash flow from operating activities	**(129)**	80	**322**	337
Change in non-cash operating working capital balances	**260**	128	**(24)**	56
Cash flow from operations before changes in working capital	**131**	208	**298**	393
Adjustments				
Share of adjusted FFO from joint venture[1]	**2**	—	**5**	4
Decrease in finance lease receivable	**11**	10	**22**	20
Clean energy transition provisions and adjustments[2]	**8**	28	**8**	36
Realized gain (loss) on closed exchange positions	**65**	17	**58**	29
Other[3]	**3**	4	**8**	8
FFO[4]	**220**	267	**399**	490
Deduct:				
Sustaining capital[1]	**(31)**	(66)	**(48)**	(100)
Productivity capital	**(1)**	(1)	**(2)**	(1)
Dividends paid on preferred shares	**(10)**	(10)	**(20)**	(20)
Distributions paid to subsidiaries' non-controlling interests	**(30)**	(32)	**(72)**	(69)
Principal payments on lease liabilities and other[1]	**(3)**	(3)	**(4)**	(4)
FCF[4]	**145**	155	**253**	296
Weighted average number of common shares outstanding in the period	**271**	270	**271**	271
FFO per share[4]	**0.81**	0.99	**1.47**	1.81
FCF per share[4]	**0.54**	0.57	**0.93**	1.09

(1) Includes our share of amounts for Skookumchuck wind facility, an equity accounted joint venture.
(2) Includes a write-down on parts and material inventory for our coal operations in 2021 to net realizable value.
(3) Other consists of production tax credits which is a reduction to tax equity debt.
(4) 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 bridges our adjusted EBITDA to our FFO and FCF:

	3 months ended June 30		6 months ended June 30	
	2022	2021	**2022**	2021
Adjusted EBITDA[1]	**279**	319	**538**	641
Provisions	**—**	—	**10**	(5)
Interest expense	**(50)**	(48)	**(104)**	(99)
Current income tax expense	**(13)**	(12)	**(25)**	(35)
Realized foreign exchange gain (loss)	**13**	(2)	**15**	(3)
Decommissioning and restoration costs settled	**(7)**	(5)	**(14)**	(8)
Other non-cash items	**(2)**	15	**(21)**	(1)
FFO[3]	**220**	267	**399**	490
Deduct:				
Sustaining capital[2]	**(31)**	(66)	**(48)**	(100)
Productivity capital	**(1)**	(1)	**(2)**	(1)
Dividends paid on preferred shares	**(10)**	(10)	**(20)**	(20)
Distributions paid to subsidiaries' non-controlling interests	**(30)**	(32)	**(72)**	(69)
Principal payments on lease liabilities and other [2]	**(3)**	(3)	**(4)**	(4)
FCF[3]	**145**	155	**253**	296

(1) Adjusted EBITDA is defined in the Additional IFRS Measures and Non-IFRS Measures section and reconciled to earnings (loss) before income taxes above.
(2) Includes our share of amounts for Skookumchuck wind facility, an equity accounted joint venture.
(3) FFO and FCF are defined in the Additional IFRS Measures and Non-IFRS Measures section and reconciled to cash flow from operating activities above.

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 during the period:

	Actual Generation (GWh)		Adjusted EBITDA		Earnings before income taxes	
3 months ended June 30	**2022**	2021	**2022**	2021	**2022**	2021
TransAlta Renewables						
Hydro	**159**	162	**7**	7		
Wind and Solar[(1)]	**1,072**	889	**68**	57		
Gas[(1)]	**734**	755	**56**	38		
Corporate	**—**	—	**(5)**	(5)		
TransAlta Renewables before adjustments	**1,965**	1,806	**126**	97	**18**	28
Less: Proportion of TransAlta Renewables not owned by TransAlta Corporation	**(784)**	(712)	**(50)**	(38)	**(7)**	(11)
Portion of TransAlta Renewables owned by TransAlta Corporation	**1,181**	1,094	**76**	59	**11**	17
Add: TransAlta Corporation's owned assets excluding TransAlta Renewables						
Hydro	**374**	392	**81**	89		
Wind and Solar	**—**	(63)	**20**	(2)		
Gas	**1,832**	2,069	**9**	86		
Energy Transition	**290**	484	**11**	25		
Energy Marketing	**—**	—	**50**	43		
Corporate	**—**	—	**(18)**	(19)		
TransAlta Corporation with Proportionate Share of TransAlta Renewables	**3,677**	3,976	**229**	281	**(29)**	61
Non-controlling interests	**784**	712	**50**	38	**7**	11
TransAlta Consolidated	**4,461**	4,688	**279**	319	**(22)**	72

(1) Wind and Solar and Gas segments include those assets that TransAlta Renewables holds an economic interest in.

6 months ended June 30	Actual Generation (GWh) 2022	2021	Adjusted EBITDA 2022	2021	Earnings before income taxes 2022	2021
TransAlta Renewables						
Hydro	**200**	202	**8**	8		
Wind and Solar[1]	**2,341**	1,958	**156**	132		
Gas[1]	**1,669**	1,513	**112**	91		
Corporate	**—**	**—**	**(11)**	(11)		
TransAlta Renewables before adjustments	**4,210**	3,673	**265**	220	**67**	89
Less: Proportion of TransAlta Renewables not owned by TransAlta Corporation	**(1,680)**	(1,460)	**(106)**	(87)	**(27)**	(35)
Portion of TransAlta Renewables owned by TransAlta Corporation	**2,530**	2,213	**159**	133	**40**	54
Add: TransAlta Corporation's owned assets excluding TransAlta Renewables						
Hydro	**705**	712	**141**	165		
Wind and Solar	**—**	(1)	**21**	(1)		
Gas	**3,562**	3,945	**58**	139		
Energy Transition	**1,343**	1,900	**16**	41		
Energy Marketing	**—**	—	**67**	98		
Corporate	**—**	—	**(30)**	(21)		
TransAlta Corporation with Proportionate Share of TransAlta Renewables	**8,140**	8,769	**432**	554	**193**	58
Non-controlling interests	**1,680**	1,460	**106**	87	**27**	35
TransAlta Consolidated	**9,820**	10,229	**538**	641	**220**	93

(1) Wind and Solar and Gas segments include those assets that TransAlta Renewables holds an economic interest in.

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

	June 30, 2022	Dec. 31, 2021
Period-end long-term debt[1]	**3,179**	3,267
Exchangeable securities	**337**	335
Less: Cash and cash equivalents	**(898)**	(947)
Add: 50 per cent of issued preferred shares and exchangeable preferred shares[2]	**671**	671
Other[3]	**(2)**	(19)
Adjusted net debt[4]	**3,287**	3,307
Adjusted EBITDA[5]	**1,183**	1,286
Adjusted net debt to adjusted EBITDA (times)	**2.8**	2.6

(1) Consists of current and long-term portion of debt, which includes lease liabilities and tax equity financing.
(2) Exchangeable preferred shares are considered equity with dividend payments for credit-rating purposes. For accounting purposes, they are accounted for as debt with interest expense in the unaudited interim condensed consolidated financial statements. For purposes of this ratio, we consider 50 per cent of issued preferred shares, including these, as debt.
(3) Includes principal portion of TransAlta OCP restricted cash (nil for the period ended June 30, 2022) and fair value of hedging instruments on debt (included in risk management assets and/or liabilities on the unaudited interim condensed consolidated statements of financial position).
(4) The tax equity financing for Skookumchuck wind facility, an equity accounted joint venture, is not represented in the amounts. 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. See the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.
(5) 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 assess our ability to pay off debt. Our adjusted net debt to adjusted EBITDA ratio was higher compared to the same period in 2021 as a result of lower adjusted EBITDA in the six months ended June 30, 2022, lower cash and cash equivalents and lower debt repayments.

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 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 June 30, 2022			3 months ended June 30, 2021		
	TransAlta Consolidated	**TransAlta Renewables**	**TransAlta Deconsolidated**	TransAlta Consolidated	TransAlta Renewables	TransAlta Deconsolidated
Hydro	**88**	**7**		96	7	
Wind and Solar	**88**	**68**		55	57	
Gas	**65**	**56**		124	38	
Energy Transition	**11**	**—**		25	—	
Energy Marketing	**50**	**—**		43	—	
Corporate	**(23)**	**(5)**		(24)	(5)	
Adjusted EBITDA	**279**	**126**	**153**	319	97	222
Less: TA Cogen adjusted EBITDA			**(15)**			(38)
Add: Dividend from TransAlta Renewables			**37**			37
Deconsolidated TransAlta adjusted EBITDA(1)			**175**			221

(1) As of the second quarter of 2021, our share of amounts for the Skookumchuck wind equity accounted joint venture is excluded from the TransAlta deconsolidated results due to the sale of an economic interest in the 137 MW Skookumchuck wind facility to TransAlta Renewables.

	6 months ended June 30, 2022			6 months ended June 30, 2021		
	TransAlta Consolidated	**TransAlta Renewables**	**TransAlta Deconsolidated**	TransAlta Consolidated	TransAlta Renewables	TransAlta Deconsolidated
Hydro	**149**	**8**		173	8	
Wind and Solar	**177**	**156**		131	132	
Gas	**170**	**112**		230	91	
Energy Transition	**16**	**—**		41	—	
Energy Marketing	**67**	**—**		98	—	
Corporate	**(41)**	**(11)**		(32)	(11)	
Adjusted EBITDA	**538**	**265**	**273**	641	220	421
Less: TA Cogen adjusted EBITDA			**(29)**			(63)
Less: EBITDA from joint venture investments(1)			**—**			(4)
Add: Dividend from TransAlta Renewables			**75**			75
Add: Dividend from TA Cogen			**10**			3
Deconsolidated TransAlta adjusted EBITDA(1)			**329**			432

(1) As of the second quarter of 2021, our share of amounts for the Skookumchuck wind equity accounted joint venture is excluded from the TransAlta deconsolidated results due to the sale of an economic interest in the 137 MW Skookumchuck wind facility to TransAlta Renewables.

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 and 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 June 30, 2022 and 2021 is detailed below:

	3 months ended June 30, 2022			3 months ended June 30, 2021		
	TransAlta Consolidated	**TransAlta Renewables**	**TransAlta Deconsolidated**	TransAlta Consolidated	TransAlta Renewables	TransAlta Deconsolidated
Cash flow from operating activities	**(129)**	**28**		80	79	
Change in non-cash operating working capital balances	**260**	**19**		128	(19)	
Cash flow from operations before changes in working capital	**131**	**47**		208	60	
Adjustments:						
Decrease in finance lease receivable	**11**	**—**		10	—	
Clean energy transition provisions and adjustments	**8**	**—**		28	—	
Realized gain (loss) on closed exchange positions	**65**	**—**		17	—	
Share of FFO from joint venture(1)	**2**	**—**		—	—	
Finance income - economic interests	**—**	**(3)**		—	(20)	
FFO - economic interests(2)	**—**	**50**		—	44	
Other(3)	**3**	**—**		4	—	
FFO	**220**	**94**	**126**	267	84	183
Dividend from TransAlta Renewables			**37**			37
Distributions to TA Cogen's Partner			**(4)**			(6)
Deconsolidated TransAlta FFO			**159**			214

(1) As of the second quarter of 2021, our share of amounts for the Skookumchuck wind equity accounted joint venture is excluded from the TransAlta deconsolidated results due to the sale of an economic interest in the 137 MW Skookumchuck wind facility to TransAlta Renewables.
(2) FFO - economic interests calculated as Free Cash Flow economic interests plus sustaining capital expenditures economic interests plus/ minus currency adjustment.
(3) Other consists of production tax credits, which is a reduction to tax equity debt, less distributions from equity accounted joint venture.

	6 months ended June 30, 2022			6 months ended June 30, 2021		
	TransAlta Consolidated	**TransAlta Renewables**	**TransAlta Deconsolidated**	TransAlta Consolidated	TransAlta Renewables	TransAlta Deconsolidated
Cash flow from operating activities	**322**	**131**		337	182	
Change in non-cash operating working capital balances	**(24)**	**2**		56	(34)	
Cash flow from operations before changes in working capital	**298**	**133**		393	148	
Adjustments:						
Decrease in finance lease receivable	**22**	**—**		20	—	
Clean energy transition provisions and adjustments	**8**	**—**		36	—	
Realized gain (loss) on closed exchange positions	**58**	**—**		29	—	
Share of FFO from joint venture(1)	**5**	**—**		4		
Finance income - economic interests	**—**	**(22)**		—	(49)	
FFO - economic interests(2)	**—**	**99**		—	85	
Other(3)	**8**	**—**		8	—	
FFO	**399**	**210**	**189**	490	184	306
Dividend from TransAlta Renewables			**75**			75
Distributions to TA Cogen's Partner			**(22)**			(17)
Less: Share of adjusted FFO from joint venture(1)			**—**			(4)
Deconsolidated TransAlta FFO			**242**			360

(1) As of the second quarter of 2021, our share of amounts for the Skookumchuck wind equity accounted joint venture is excluded from the TransAlta deconsolidated results due to the sale of an economic interest in the 137 MW Skookumchuck wind facility to TransAlta Renewables.
(2) FFO - economic interests calculated as Free Cash Flow economic interests plus sustaining capital expenditures economic interests plus/minus currency adjustment.
(3) 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 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.

As at	**June 30, 2022**	Dec. 31, 2021
Adjusted net debt(1)	**3,287**	3,307
Add: TransAlta Renewables cash and cash equivalents	**218**	244
Less: TransAlta Renewables long-term debt	**(785)**	(814)
Less: US tax equity financing and South Hedland debt(2)	**(813)**	(867)
Deconsolidated net debt	**1,907**	1,870
Deconsolidated adjusted EBITDA(3)(5)	**772**	875
Deconsolidated net debt to deconsolidated adjusted EBITDA(4) (times)	**2.5**	2.1

(1) Refer to the Adjusted Net Debt to Adjusted EBITDA calculation under the Key Financial Non-IFRS Ratios section of this MD&A for the reconciliation and composition of Adjusted net debt.
(2) Relates to assets where TransAlta Renewables has economic interests.
(3) Refer to the Deconsolidated Adjusted EBITDA by Segment section of this MD&A for the reconciliation and composition of deconsolidated adjusted EBITDA.
(4) 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.
(5) Last 12 months.

Our deconsolidated net debt to deconsolidated adjusted EBITDA ratio for the six months ended June 30, 2022, increased compared with 2021, due to higher deconsolidated net debt and lower deconsolidated adjusted EBITDA. Higher deconsolidated net debt is a result of lower scheduled repayments on corporate debt and an decrease in cash balances.

Critical Accounting Policies and 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.

Estimates to the extent to which the geopolitical events such as the Russia-Ukraine conflict may, directly or indirectly, impact the Company's operations, financial results and conditions in future periods are also subject to significant uncertainty. Uncertainty related to COVID-19 and the geopolitical events have been considered in our estimates as at and for the period ended June 30, 2022. Refer to the Governance and Risk Management section of this MD&A for further details.

The following were material changes in estimates in the quarter:

Asset Impairments

During the six months ended June 30, 2022, the Company recorded asset impairment charges of $27 million, for three wind assets within the Wind and Solar segment and one of the hydro facilities within the Hydro segment, primarily as a result of increases in the discount rates. Refer to Note 5 of our unaudited interim condensed consolidated financial statements for further details.

Provisions for Decommissioning and Restoration Activities

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. For the six months ended June 30, 2022, the provision for the decommissioning and restoration obligations decreased by $194 million to $599 million as at June 30, 2022, from $793 million as at Dec. 31, 2021, as a result of higher discount rates, largely driven by underlying market benchmark rates. On average, discount rates increased with rates ranging from 6.8 to 9.3 per cent as at June 30, 2022 (Dec. 31, 2021 — 3.6 to 6.5 per cent). Refer to Note 17 of our unaudited interim condensed consolidated financial statements for further details.

Defined Benefit Obligation

The liability for pension and post-employment benefits and associated costs included in compensation expenses are impacted by estimates related to changes in key actuarial assumptions, including discount rates. As a result of increases in discount rates, largely driven by increases in market benchmark rates, the defined benefit obligation decreased by $46 million to $182 million as at June 30, 2022, from $228 million as at Dec. 31, 2021. A 1 per cent increase in discount rates would have a $40 million impact on the defined benefit obligation.

Refer to Note 2(P) of the Company's 2021 audited annual consolidated financial statements for further details on the Significant Accounting Judgments and Key Sources of Estimation Uncertainty.

Accounting Changes

Current Accounting Policy Changes

The accounting policies adopted in the preparation of the unaudited interim condensed consolidated financial statements are consistent with those followed in the preparation of the Company's audited annual consolidated financial statements for the year ended Dec. 31, 2021, except for the adoption of new standards effective as of Jan. 1, 2022.

Amendments to IAS 37 Provisions, Contingent Liabilities and Contingent Assets

On May 14, 2020, the IASB issued Onerous Contracts — Cost of Fulfilling a Contract and amendments to IAS 37 Provisions, Contingent Liabilities and Contingent Assets to specify which costs to include when assessing whether a contract will be loss-making. The amendments are effective for annual periods beginning on or after Jan. 1, 2022 and the Company adopted these amendments as of Jan. 1, 2022. The amendments are effective for contracts for which an entity has not yet fulfilled all its obligations on or after the effective date. No adjustments resulted on adoption of the amendments on Jan 1, 2022.

Future Accounting Policy Changes

Please refer to Note 3 of the audited annual 2021 consolidated financial statements for the future accounting policies impacting the Company. In the three and six months ended June 30, 2022, no additional future accounting policy changes impacting the Company were identified.

Comparative Figures

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

Governance and Risk Management

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

During the three and six months ended June 30, 2022, the global economy continued to recover from the COVID-19 pandemic. The Russian government’s invasion of Ukraine on February 24, 2022 set off historic policy actions and global coordination of sanctions and commitments to reduce dependency on Russian energy including natural gas. This has contributed to global supply chain disruptions, commodity price volatility and potential increases to inherent cybersecurity risk. The Company continues to mitigate inflationary and supply chain risk pertaining to current development projects by locking in the prices of key materials where possible and employing the other supply chain risk mitigation strategies described in our 2021 Annual MD&A. A prolonged Russia-Ukraine conflict and recent inflationary and supply chain dynamics could impact future construction project costs with the risk of rising prices on key materials. The Russia-Ukraine conflict continues to evolve as well as the scope and severity of the economic sanctions. Accordingly, the indirect impacts of the Russia-Ukraine conflict and rising inflation rates in the global markets remains uncertain at this time, but management continues to monitor and assess the resulting impacts.

Interest Rate Risk

Interest rate risk arises as the fair value of future cash flows from a financial instrument fluctuates because of changes in market interest rates. Changes in interest rates can impact our borrowing costs. Changes in our cost of capital may also affect the feasibility of new growth initiatives.

At June 30, 2022, approximately 3 per cent (Dec 31, 2021 – 3 per cent) of our total debt portfolio was subject to changes in floating interest rates through a combination of floating rate debt and interest rate swaps. The Company has US$400 million maturing in November 2022 and we have hedged US$300 million of the underlying to reduce the interest rate risk.

Please refer to the Governance and Risk Management section of our 2021 Annual MD&A and Note 12 of our unaudited interim condensed consolidated financial statements for details on our risks and how we manage them. Our risk management profile and practices have not changed materially from Dec. 31, 2021.

Regulatory Updates

Refer to the Policy and Legal Risks discussion in our 2021 annual MD&A for further details that supplement the recent developments as discussed below:

Canada

Federal

On March 15, 2022, the Government of Canada’s Department of Environment and Climate Change Canada (“ECCC”) released a discussion paper (the “ECCC Paper”) regarding a proposed new Clean Electricity Standard ("CES") to achieve a net-zero electricity sector in Canada by 2035. The ECCC Paper states the government’s intent to institute more stringent regulations on natural gas generation to achieve a net-zero grid by 2035. TransAlta is actively engaging with the federal and provincial governments with a focus on clarifying the implications of the regulatory proposal and emphasizing the important role that our current assets play in delivering reliability, affordability and competitiveness, as well as decarbonization objectives.

On March 29, 2022, the Government of Canada released the 2030 Emissions Reduction Plan ("ERP"). This broad plan includes a broad set of regulatory, policy and funding initiatives designed to achieve Canada's national emissions reduction targets. Notably, the ERP relies heavily on electrification of the economy to reach Canada's national goals. TransAlta engaged the government regarding the design of the plan and will continue to engage on relevant initiatives moving forward.

Both the CES and ERP may create new opportunities for the development of renewables and energy storage projects in Canada.

On June 8, 2022, the Government of Canada published the final regulation creating a federal GHG emissions offset system in the Canada Gazette, Part II-The Canadian Greenhouse Gas Offset Credit System Regulations. This regulation creates a new GHG credit market in Canada. However, TransAlta would not be able to use these credits for compliance under the present provincial regulatory programs nor generate credits from our existing facilities, in the absence of changes in policy and the development of additional federal offset protocols.

The Clean Fuel Regulations ("CFR") were published in the Canada Gazette, Part II on July 6, 2022. The CFRs require producers and importers of liquid fossil fuels, such as gasoline and diesel, to gradually reduce the carbon intensity of these fuels beginning in December 2023. There may be opportunity for TransAlta to contract and build projects that reduce the lifecycle carbon intensity of fossil fuel using renewable electricity at production facilities as a compliance option under the CFRs.

Ontario

On June 2, 2022, Premier Doug Ford was re-elected as the Premier of Ontario with a majority government. Following the election, the government continued working on key files including: the province's Emissions Performance Standards ("EPS") carbon pricing system; the role of natural gas in the electricity sector transition; the development of a voluntary clean energy credit market; and the development and implementation of procurement programs for the electricity sector. TransAlta's Ontario gas-fired thermal assets pass through carbon costs under current contracts, minimizing the impact of any change to the EPS. The Company continues to engage the government on the other relevant policy initiatives to mitigate risk and identify areas of potential opportunity.

In 2022, the IESO moved forward with procurement and planning to meet the upcoming capacity needs in the province in the short, medium and long-term. The IESO is currently conducting a medium-term request for proposals ("RFP") to procure up to 475 MW of capacity from existing generators, with award scheduled for the third quarter of 2022. In addition, the IESO is moving forward with long-term procurement processes to secure up to 3,500 MW of capacity with commercial delivery by 2025-2027. TransAlta continues to participate in these processes.

Alberta

In late 2021, the Alberta Electric System Operator ("AESO") commenced work to assess the system impacts of a net-zero provincial electricity system by 2035, resulting in their first Net-Zero Emissions Electricity Pathways Report (the "Report") on June 27, 2022. The AESO views the Report as the first step in understanding the operational, market and cost implications associated with a future of increased electrification and low-emission supply. TransAlta continues to engage in this work as we seek to understand the challenges and opportunities for the Alberta market in a net-zero future.

The Government of Alberta also launched a consultation on changes to the Technology Innovation and Emissions Reduction ("TIER") Regulation. TIER governs the provinces carbon pricing regime and changes to the system will have implications for TransAlta's thermal generating facilities in the province and the value of emissions credits from our renewables facilities. TransAlta plans to closely engage in the consultations.

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 climate-related impacts over all time horizons, impacts business models and the impact of climate-related events. We anticipate the final rules will face legal challenges. The Company currently provides investors with information regarding our climate governance, risks and performance. We will closely monitor the rule-making and ensure continued alignment with all relevant requirements.

The US mid-term elections will be held on November 8, 2022 and changes in Congress and the Senate could shift the focus of the government, specifically in terms of climate policy and renewable energy. There continues to be the potential for the renewal of the production and investment tax credit supports for wind and solar generation in 2022 and for new tax credits for storage and hydrogen technologies. TransAlta continues to monitor any potential changes for impacts on our growth plans.

Australia

Australia held a national election on May 21, 2022. The Labour Party achieved a majority government. Since forming the Labour Party government, Australia has informed the United Nations that it will increase its Nationally Determined Contribution ("NDC") commitment to increase the country’s 2030 emissions reduction goal from the current 26 to 28 per cent to 43 per cent below 2005 levels. The government also confirmed its intent to boost renewable electricity production to 82 per cent of electricity supply by 2030. We continue to see low policy risk to our existing Australian assets and policy support for continued industrial decarbonization.

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 six months ended June 30, 2022, the majority of our workforce supporting and executing our ICFR and DC&P returned to work and 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 audited annual 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.

In accordance with the provisions of National Instrument 52-109 and consistent with U.S. Securities and Exchange Commission guidance, the scope of the evaluation did not include internal controls over financial reporting of North Carolina Solar, which the Company acquired on Nov. 5, 2021. North Carolina Solar was excluded from management's evaluation of the effectiveness of the Company's internal control over financial reporting as at Dec. 31, 2021, due to the proximity of the acquisition to year-end. Further details related to the acquisition are disclosed in Note 4 to the Company's audited annual consolidated financial statements for the year ended Dec. 31, 2021.

Consistent with the evaluation at Dec. 31, 2021, the scope of the evaluation does not include controls over financial reporting of the assets acquired through the North Carolina Solar acquisition, which the Company acquired on Nov. 5, 2021. North Carolina Solar's total and net assets represented approximately 2 per cent and 3 per cent of the Company's total and net assets and 4 per cent of the Company's total net earnings, respectively, as at June 30, 2022.

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 June 30, 2022, the end of the period covered by this MD&A, our ICFR and DC&P were effective.

Condensed Consolidated Statements of Earnings (Loss)

(in millions of Canadian dollars except per share amounts)

	3 months ended June 30		6 months ended June 30	
Unaudited	**2022**	2021	**2022**	2021
Revenues (Note 3)	**458**	619	**1,193**	1,261
Fuel and purchased power (Note 4)	**231**	215	**469**	460
Carbon compliance (Note 4)	**9**	42	**28**	92
Gross margin	**218**	362	**696**	709
Operations, maintenance and administration (Note 4)	**117**	148	**229**	251
Depreciation and amortization	**115**	123	**232**	272
Asset impairment charge (reversal) (Note 5)	**(24)**	16	**(66)**	45
Taxes, other than income taxes	**9**	8	**17**	17
Net other operating income (Note 6)	**(20)**	(11)	**(37)**	(21)
Operating income	**21**	78	**321**	145
Equity income	**2**	2	**4**	4
Finance lease income	**6**	6	**11**	13
Net interest expense (Note 7)	**(62)**	(60)	**(129)**	(123)
Foreign exchange gain	**9**	14	**11**	21
Gain on the sale of assets and other (Note 14)	**2**	32	**2**	33
Earnings (loss) before income taxes	**(22)**	72	**220**	93
Income tax expense (Note 8)	**37**	44	**73**	64
Net earnings (loss)	**(59)**	28	**147**	29
Net earnings (loss) attributable to:				
TransAlta shareholders	**(70)**	(2)	**116**	(32)
Non-controlling interests (Note 9)	**11**	30	**31**	61
	(59)	28	**147**	29
Net earnings (loss) attributable to TransAlta shareholders	**(70)**	(2)	**116**	(32)
Preferred share dividends (Note 20)	**10**	10	**10**	10
Net earnings (loss) attributable to common shareholders	**(80)**	(12)	**106**	(42)
Weighted average number of common shares outstanding in the period (millions)	**271**	270	**271**	271
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**(0.30)**	(0.04)	**0.39**	(0.16)

See accompanying notes.

Condensed Consolidated Statements of Comprehensive Income (Loss)

(in millions of Canadian dollars)

	3 months ended June 30		6 months ended June 30	
Unaudited	**2022**	2021	**2022**	2021
Net earnings (loss)	**(59)**	28	**147**	29
Other comprehensive income (loss)				
Net actuarial gains on defined benefit plans, net of tax[1]	**18**	1	**36**	38
Gains (losses) on derivatives designated as cash flow hedges, net of tax	**1**	—	**—**	(1)
Total items that will not be reclassified subsequently to net earnings	**19**	1	**36**	37
Gains (losses) on translating net assets of foreign operations, net of tax	**8**	(24)	**(6)**	(37)
Gains (losses) on financial instruments designated as hedges of foreign operations, net of tax	**(13)**	9	**(3)**	14
Losses on derivatives designated as cash flow hedges, net of tax[2]	**(69)**	(108)	**(151)**	(131)
Reclassification of gains on derivatives designated as cash flow hedges to net earnings (loss), net of tax[3]	**(3)**	(8)	**(18)**	(26)
Total items that will be reclassified subsequently to net loss	**(77)**	(131)	**(178)**	(180)
Other comprehensive loss	**(58)**	(130)	**(142)**	(143)
Total comprehensive income (loss)	**(117)**	(102)	**5**	(114)
Total comprehensive income (loss) attributable to:				
TransAlta shareholders	**(102)**	(135)	**44**	(137)
Non-controlling interests (Note 9)	**(15)**	33	**(39)**	23
	(117)	(102)	**5**	(114)

(1) Net of income tax expense of $5 million and $11 million for the three and six months ended June 30, 2022 (June 30, 2021 — nil and $11 million expense).
(2) Net of income tax recovery of $22 million and $44 million for the three and six months ended June 30, 2022 (June 30, 2021 — $28 million and $36 million recovery).
(3) Net of reclassification of income tax expense of $1 million and $5 million for the three and six months ended June 30, 2022 (June 30, 2021 — $2 million and $7 million expense).

See accompanying notes.

Condensed Consolidated Statements of Financial Position

(in millions of Canadian dollars)

Unaudited	**June 30, 2022**	Dec. 31, 2021
Current assets		
Cash and cash equivalents	**898**	947
Restricted cash (Note 18)	**43**	70
Trade and other receivables (Note 10)	**1,027**	651
Prepaid expenses	**61**	29
Risk management assets (Note 11 and 12)	**603**	308
Inventory	**156**	167
Assets held for sale	**27**	25
	2,815	2,197
Non-current assets		
Investments (Note 13)	**117**	105
Long-term portion of finance lease receivables	**158**	185
Risk management assets (Note 11 and 12)	**308**	399
Property, plant and equipment (Note 14)		
Cost	**13,405**	13,389
Accumulated depreciation	**(8,260)**	(8,069)
	5,145	5,320
Right-of-use assets	**96**	95
Intangible assets (Note 15)	**259**	256
Goodwill	**464**	463
Deferred income tax assets	**59**	64
Other assets (Note 16)	**165**	142
Total assets	**9,586**	9,226
Current liabilities		
Accounts payable and accrued liabilities (Note 12)	**1,146**	689
Current portion of decommissioning and other provisions (Note 17)	**39**	48
Risk management liabilities (Note 11 and 12)	**588**	261
Current portion of contract liabilities (Note 21)	**5**	19
Income taxes payable	**9**	8
Dividends payable (Note 19 and 20)	**39**	62
Current portion of long-term debt and lease liabilities (Note 18)	**690**	844
	2,516	1,931
Non-current liabilities		
Credit facilities, long-term debt and lease liabilities (Note 18)	**2,489**	2,423
Exchangeable securities	**737**	735
Decommissioning and other provisions (Note 17)	**588**	779
Deferred income tax liabilities	**353**	354
Risk management liabilities (Note 11 and 12)	**205**	145
Contract liabilities	**12**	13
Defined benefit obligation and other long-term liabilities	**212**	253
Total liabilities	**7,112**	6,633
Equity		
Common shares (Note 19)	**2,893**	2,901
Preferred shares (Note 20)	**942**	942
Contributed surplus	**28**	46
Deficit	**(2,363)**	(2,453)
Accumulated other comprehensive income	**74**	146
Equity attributable to shareholders	**1,574**	1,582
Non-controlling interest (Note 9)	**900**	1,011
Total equity	**2,474**	2,593
Total liabilities and equity	**9,586**	9,226

Commitments and contingencies (Note 21)
See accompanying notes.

Condensed Consolidated Statements of Changes in Equity

(in millions of Canadian dollars)

Unaudited

6 months ended June 30, 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	—	—	—	**116**	—	**116**	**31**	**147**
Other comprehensive income (loss):								
Net losses on translating net assets of foreign operations, net of hedges and tax	—	—	—	—	**(9)**	**(9)**	—	**(9)**
Net losses on derivatives designated as cash flow hedges, net of tax	—	—	—	—	**(169)**	**(169)**	—	**(169)**
Net actuarial gains on defined benefits plans, net of tax	—	—	—	—	**36**	**36**	—	**36**
Intercompany FVOCI investments	—	—	—	—	**70**	**70**	**(70)**	—
Total comprehensive income (loss)	—	—	—	**116**	**(72)**	**44**	**(39)**	**5**
Common share dividends paid	—	—	—	**(13)**	—	**(13)**	—	**(13)**
Preferred share dividends paid	—	—	—	**(10)**	—	**(10)**	—	**(10)**
Shares purchased under normal course issuer bid ("NCIB") program (Note 19)	**(15)**	—	—	**(3)**	—	**(18)**	—	**(18)**
Effect of share-based payment plans	**7**	—	**(18)**	—	—	**(11)**	—	**(11)**
Distributions paid and payable, to non-controlling interests (Note 9)	—	—	—	—	—	—	**(72)**	**(72)**
Balance, June 30, 2022	**2,893**	**942**	**28**	**(2,363)**	**74**	**1,574**	**900**	**2,474**

6 months ended June 30, 2021	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec. 31, 2020	2,896	942	38	(1,826)	302	2,352	1,084	3,436
Net earnings (loss)	—	—	—	(32)	—	(32)	61	29
Other comprehensive income (loss):								
Net losses on translating net assets of foreign operations, net of hedges and tax	—	—	—	—	(23)	(23)	—	(23)
Net losses on derivatives designated as cash flow hedges, net of tax	—	—	—	—	(159)	(159)	1	(158)
Net actuarial gains on defined benefits plans, net of tax	—	—	—	—	38	38	—	38
Intercompany FVOCI investments	—	—	—	—	39	39	(39)	—
Total comprehensive income (loss)	—	—	—	(32)	(105)	(137)	23	(114)
Common share dividends	—	—	—	(12)	—	(12)	—	(12)
Preferred share dividends	—	—	—	(10)	—	(10)	—	(10)
Effect of share-based payment plans	5	—	(5)	—	—	—	—	—
Distributions paid and payable, to non-controlling interests (Note 9)	—	—	—	—	—	—	(67)	(67)
Balance, June 30, 2021	2,901	942	33	(1,880)	197	2,193	1,040	3,233

See accompanying notes.

Condensed Consolidated Statements of Cash Flows

(in millions of Canadian dollars)

	3 months ended June 30		6 months ended June 30	
Unaudited	**2022**	2021	**2022**	2021
Operating activities				
Net earnings (loss)	**(59)**	28	**147**	29
Depreciation and amortization	**115**	173	**232**	377
Gain on sale of assets and other (Note 14)	**(1)**	(32)	**(1)**	(33)
Accretion of provisions (Note 7)	**10**	7	**19**	14
Decommissioning and restoration costs settled (Note 17)	**(7)**	(5)	**(14)**	(8)
Deferred income tax expense (Note 8)	**24**	32	**48**	29
Unrealized loss (gain) from risk management activities	**89**	(13)	**(40)**	(33)
Unrealized foreign exchange loss (gain)	**3**	(16)	**1**	(25)
Provisions	**(1)**	(18)	**4**	(22)
Asset impairment charges (reversals) (Note 5)	**(24)**	16	**(66)**	45
Equity loss (income), net of distributions from investments	**(1)**	1	**(2)**	(1)
Other non-cash items	**(17)**	35	**(30)**	21
Cash flow from operations before changes in working capital	**131**	208	**298**	393
Change in non-cash operating working capital balances	**(260)**	(128)	**24**	(56)
Cash flow (used in) from operating activities	**(129)**	80	**322**	337
Investing activities				
Additions to property, plant and equipment (Note 14)	**(129)**	(119)	**(201)**	(217)
Additions to intangible assets (Note 15)	**(2)**	(2)	**(23)**	(3)
Restricted cash (Note 18)	**3**	(2)	**25**	15
(Advances) repayments in loan receivable (Note 16)	**10**	(2)	**10**	(2)
Proceeds on sale of Pioneer Pipeline (Note 14)	**—**	128	**—**	128
Proceeds on sale of property, plant and equipment	**2**	—	**2**	4
Realized losses on financial instruments	**—**	(1)	**(1)**	(3)
Decrease in finance lease receivable	**11**	10	**22**	20
Other	**(4)**	(13)	**7**	(18)
Change in non-cash investing working capital balances	**15**	(9)	**(7)**	(45)
Cash flow used in investing activities	**(94)**	(10)	**(166)**	(121)
Financing activities				
Net decrease in borrowings under credit facilities	**—**	—	**—**	(114)
Repayment of long-term debt	**(34)**	(27)	**(59)**	(45)
Dividends paid on common shares (Note 19)	**(13)**	(12)	**(27)**	(24)
Dividends paid on preferred shares (Note 20)	**(10)**	(10)	**(20)**	(20)
Repurchase of common shares under NCIB (Note 19)	**(3)**	—	**(18)**	(4)
Proceeds on issuance of common shares	**—**	8	**1**	8
Realized gains on financial instruments	**—**	1	**—**	1
Distributions paid to subsidiaries' non-controlling interests (Note 9)	**(30)**	(30)	**(72)**	(67)
Decrease in lease liabilities	**(3)**	(2)	**(4)**	(4)
Financing fees and other	**(2)**	(1)	**(2)**	(3)
Change in non-cash financing working capital balances	**—**	—	**—**	(1)
Cash flow used in financing activities	**(95)**	(73)	**(201)**	(273)
Cash flow used in operating, investing and financing activities	**(318)**	(3)	**(45)**	(57)
Effect of translation on foreign currency cash	**(5)**	(3)	**(4)**	(4)
Decrease in cash and cash equivalents	**(323)**	(6)	**(49)**	(61)
Cash and cash equivalents, beginning of period	**1,221**	648	**947**	703
Cash and cash equivalents, end of period	**898**	642	**898**	642
Cash taxes paid	**26**	15	**44**	27
Cash interest paid	**60**	61	**107**	112

See accompanying notes.

Notes to 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. Its head office is located in Calgary, Alberta.

Operating Segments

In 2021, the Company realigned its current operating segments to reflect a change in how TransAlta's President and Chief Executive Officer (the chief operating decision maker) ("CODM") reviews financial information in order to allocate resources and assess performance. The primary changes were the elimination of the Alberta Thermal and the Centralia segments, and the reorganization of the North American Gas and Australia Gas segments into a new "Gas" segment. The Alberta Thermal facilities that have been converted to gas have been included in the Gas segment. The remaining assets previously included in Alberta Thermal, including the mining assets and those facilities not converted to gas and the remaining Centralia unit, are included in a new "Energy Transition" segment. No changes were made to the Hydro and Wind and Solar segments. This change better aligns with the Company's long-term strategy and reflects its Clean Electricity Growth Plan. Refer to Note 22 for further details.

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 its 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 August 4, 2022.

C. Use of Estimates and Significant Judgments

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, discount rates, foreign exchange rates, inflation and commodity prices, and changes in economic conditions, legislation and regulations.

During the three and six months ended June 30, 2022, the global economy continued to recover from the COVID-19 pandemic. The Russia-Ukraine conflict has set off historic policy actions and global coordination of sanctions and commitments to reduce dependency on Russian energy including natural gas. This has contributed to global supply chain disruptions, commodity price volatility and potential increases to inherent cybersecurity risk. Energy prices have strengthened due to elevated uncertainty of global oil and natural gas supply given the war in Ukraine. Recent inflationary and supply chain dynamics coupled with rising interest rates and volatility in foreign exchange rates have created an environment that requires close monitoring. Estimates to the extent to which the geopolitical events may, directly or indirectly, impact the Company's operations, financial results and conditions in future periods are also subject to significant uncertainty. Uncertainty related to COVID-19, geopolitical events and Consumer Price Index ("CPI") inflation have been considered in the Company's estimates as at and for the period ended June 30, 2022.

During the three and six months ended, June 30, 2022, there were changes in estimates relating to decommissioning and other provisions (Note 17), asset impairment charge (reversal) (Note 5) and defined benefit obligations.

The liability for pension and post-employment benefits and associated costs included in compensation expenses are impacted by estimates related to changes in key actuarial assumptions, including discount rates. As a result of increases in discount rates, largely driven by increases in market benchmark rates, the defined benefit obligation decreased by $46 million to $182 million as at June 30, 2022 from $228 million as at Dec. 31, 2021. A 1 per cent increase in discount rates would have a $40 million impact on the defined benefit obligation.

Refer to Note 2(P) of the Company's 2021 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, 2021, except for the adoption of new standards effective as of Jan. 1, 2022, the early adoption of standards, and interpretations or amendments that have been issued but are not yet effective.

A. Current Accounting Policy Changes

Amendments to IAS 37 Provisions, Contingent Liabilities and Contingent Assets

On May 14, 2020, the IASB issued Onerous Contracts — Cost of Fulfilling a Contract and amendments to IAS 37 Provisions, Contingent Liabilities and Contingent Assets to specify which costs to include when assessing whether a contract will be loss-making. The amendments are effective for annual periods beginning on or after Jan. 1, 2022 and the Company adopted these amendments as of Jan. 1, 2022. The amendments are effective for contracts for which an entity has not yet fulfilled all its obligations on or after the effective date. No adjustments resulted on adoption of the amendments on Jan 1, 2022.

B. Future Accounting Policy Changes

Please refer to Note 3 of the audited annual 2021 consolidated financial statements for the future accounting policies impacting the Company. In the three and six months ended June 30, 2022, no additional future accounting policy changes impacting the Company were identified.

C. Comparative Figures

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

3. Revenue

A. Disaggregation of Revenue

The majority of the Company's revenues are derived from the sale of physical 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 June 30, 2022	Hydro	Wind and Solar	Gas(1)	Energy Transition(2)	Energy Marketing	Corporate and Other	Total
Revenues from contracts with customers							
Power and other	13	55	112	2	—	—	182
Environmental attributes	—	23	—	—	—	—	23
Revenue from contracts with customers	13	78	112	2	—	—	205
Revenue from leases(3)	—	—	4	—	—	—	4
Revenue from derivatives and other trading activities (4)	—	(13)	(223)	66	36	1	(133)
Revenue from merchant sales	89	22	232	28	—	—	371
Other(5)	3	6	2	—	—	—	11
Total revenue	105	93	127	96	36	1	458
Revenues from contracts with customers							
Timing of revenue recognition							
At a point in time	—	23	—	2	—	—	25
Over time	13	55	112	—	—	—	180
Total revenue from contracts with customers	13	78	112	2	—	—	205

(1) This segment includes the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal. Refer to Note 1 for further details.
(2) This segment includes the segment previously known as Centralia and the facilities not converted to gas previously in the Alberta Thermal segment. Refer to Note 1 for further details.
(3) Total rental income, including contingent rent related to other long-term contracts that meet the criteria of operating leases.
(4) Represents realized and unrealized gains or losses from hedging and derivative positions. Significant volatility and pricing in commodity markets resulted in higher than normal movements in derivative positions.
(5) Includes other miscellaneous revenue.

3 months ended June 30, 2021	Hydro	Wind and Solar	Gas(1)	Energy Transition(2)	Energy Marketing	Corporate and Other	Total
Revenues from contracts with customers							
Power and other	13	49	76	5	—	—	143
Environmental attributes	—	4	—	—	—	—	4
Revenue from contracts with customers	13	53	76	5	—	—	147
Revenue from leases(3)	—	—	5	—	—	—	5
Revenue from derivatives and other trading activities(4)	—	5	(34)	30	38	4	43
Revenue from merchant sales	99	14	240	64	—	—	417
Other(5)	2	3	2	—	—	—	7
Total revenue	114	75	289	99	38	4	619
Revenues from contracts with customers							
Timing of revenue recognition							
At a point in time	—	4	—	5	—	—	9
Over time	13	49	76	—	—	—	138
Total revenue from contracts with customers	13	53	76	5	—	—	147

(1) This segment includes the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal. Refer to Note 1 for further details.
(2) This segment includes the segment previously known as Centralia and the facilities not converted to gas previously in the Alberta Thermal segment. Refer to Note 1 for further details.
(3) Total rental income, including contingent rent and other long-term contracts that meet the criteria of operating leases.
(4) Represents realized and unrealized gains or losses from hedging and derivative positions. Wind and Solar has been revised to present revenue classifications consistent with the current period.
(5) Includes government incentives and other miscellaneous.

6 months ended June 30, 2022	**Hydro**	**Wind and Solar**	**Gas(1)**	**Energy Transition(2)**	**Energy Marketing**	**Corporate and Other**	**Total**
Revenues from contracts with customers							
Power and other	**18**	**118**	**216**	**6**	**—**	**—**	**358**
Environmental attributes	**1**	**30**	**—**	**—**	**—**	**—**	**31**
Revenue from contracts with customers	**19**	**148**	**216**	**6**	**—**	**—**	**389**
Revenue from leases(3)	**—**	**—**	**8**	**—**	**—**	**—**	**8**
Revenue from derivatives and other trading activities(4)	**—**	**(20)**	**(73)**	**114**	**62**	**2**	**85**
Revenue from merchant sales	**159**	**44**	**407**	**82**	**—**	**—**	**692**
Other(5)	**4**	**12**	**3**	**—**	**—**	**—**	**19**
Total revenue	**182**	**184**	**561**	**202**	**62**	**2**	**1,193**
Revenues from contracts with customers							
Timing of revenue recognition							
At a point in time	**1**	**30**	**—**	**6**	**—**	**—**	**37**
Over time	**18**	**118**	**216**	**—**	**—**	**—**	**352**
Total revenue from contracts with customers	**19**	**148**	**216**	**6**	**—**	**—**	**389**

(1) This segment includes the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal. Refer to Note 1 for further details.
(2) This segment includes the segment previously known as Centralia and the facilities not converted to gas previously in the Alberta Thermal segment. Refer to Note 1 for further details.
(3) Total rental income, including contingent rent related to other long-term contracts that meet the criteria of operating leases.
(4) Represents realized and unrealized gains or losses from hedging and derivative positions.
(5) Includes other miscellaneous revenue.

6 months ended June 30, 2021	Hydro	Wind and Solar	Gas(1)	Energy Transition(2)	Energy Marketing	Corporate and Other	Total
Revenues from contracts with customers							
Power and other	13	112	172	10	—	—	307
Environmental attributes	—	9	—	—	—	—	9
Revenue from contracts with customers	13	121	172	10	—	—	316
Revenue from leases(3)	—	—	10	—	—	—	10
Revenue from derivatives and other trading activities(4)	—	3	(57)	63	99	5	113
Revenue from merchant sales	185	29	425	166	—	—	805
Other(5)	5	8	4	—	—	—	17
Total revenue	203	161	554	239	99	5	1,261
Revenues from contracts with customers							
Timing of revenue recognition							
At a point in time	—	9	2	9	—	—	20
Over time	13	112	170	1	—	—	296
Total revenue from contracts with customers	13	121	172	10	—	—	316

(1) This segment includes the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal. Refer to Note 1 for further details.
(2) This segment includes the segment previously known as Centralia and the facilities not converted to gas previously in the Alberta Thermal segment. Refer to Note 1 for further details.
(3) Total rental income, including contingent rent and other long-term contracts that meet the criteria of operating leases.
(4) Represents realized and unrealized gains or losses from hedging and derivative positions. Wind and Solar has been revised to present revenue classifications consistent with the current period.
(5) Includes other miscellaneous revenue.

B. Changes to Revenue Contracts

Gas

During the second quarter of 2022, the Company executed contract extensions for the supply of electricity and/or steam with three of its industrial customers at the Sarnia cogeneration facility. These agreements will extend the delivery term for electricity and/or steam from Dec. 31, 2022 to April 30, 2031, in one case and to Dec. 31, 2032, for the other two, with all agreements being subject to certain conditions, including the Company entering into a new contract with the Ontario Independent Electricity System Operator (the “IESO”). The capacity commitments for the large industrial customers have been extended at rates comparable to current contract rates. The IESO is conducting a medium-term procurement process for capacity for 2026 and beyond for existing generation. The Company has bid into the process and is seeking to secure a contract extension for the Sarnia cogeneration facility following the end of the current IESO contract expiring on Dec. 31, 2025. The Company expects the IESO to announce the successful bids in the third quarter of 2022.

Wind

On June 2, 2022, TransAlta Renewables announced that it amended and extended its current power purchase agreements with New Brunswick Power Corporation ("NB Power") in respect of each of the Kent Hills 1, 2 and 3 wind facilities, representing total generating capacity of 167 MW. The amending agreements provide for a blend-and-extend of the PPAs providing NB Power with an effective 10 per cent reduction to the original contract prices from January 2023 through December 2033 and extend the original contract term for an additional 10-year period through to December 2045.

Refer to Notes 14, 16 and 18 for further discussion related to the Kent Hills wind facilities.

4. Expenses by Nature

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

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

	3 months ended June 30				6 months ended June 30			
	2022		2021		**2022**		2021	
	Fuel and purchased power	**OM&A**	Fuel and purchased power	OM&A	**Fuel and purchased power**	**OM&A**	Fuel and purchased power	OM&A
Gas fuel costs	**135**	**—**	62	—	**257**	**—**	120	—
Coal fuel costs[1]	**9**	**—**	24	—	**48**	**—**	70	—
Royalty, land lease and other direct costs	**5**	**—**	5	—	**12**	**—**	10	—
Purchased power[4]	**80**	**—**	67	—	**149**	**—**	138	—
Mine depreciation[2]	**—**	**—**	50	—	**—**	**—**	105	—
Salaries and benefits	**2**	**56**	7	61	**3**	**114**	17	107
Other operating expenses[3][4]	**—**	**61**	—	87	**—**	**115**	—	144
Total	**231**	**117**	215	148	**469**	**229**	460	251

(1) During the three and six months ended June 30, 2021, $3 million and $11 million, respectively was included in coal fuel costs related to the impairment of coal inventory recorded during 2021.
(2) During the three and six months ended June 30, 2021, $12 million and $29 million, respectively, was included in mine depreciation, related to the impairment of mine depreciation recorded during 2021.
(3) During the second quarter of 2021, OM&A costs included a writedown of $25 million for parts and material inventory related to the Highvale mine and coal operations at our gas converted facilities.
(4) During the three and six months ended June 30, 2021, $3 and $5 million related to station service costs for the Hydro segment was reclassified from OM&A to fuel and purchased power for comparative purposes. This did not impact previously reported net earnings.

B. Carbon Compliance

During the three and six months ended June 30, 2022, the Company utilized 1,169,333 million tonnes of emission credits with a carrying value of $35 million to settle the 2021 carbon compliance obligation of $47 million. The difference of $12 million has been recognized as a reduction in the Company's carbon compliance costs in the current period.

As at June 30, 2022, we currently hold 1,054,604 emission credits in inventory purchased externally with a recorded book value of $34 million (Dec. 31, 2021 — 2,033,752 emission credits with a recorded book value of $55 million). The Company also has approximately 1,678,624 of internally generated eligible emission credits with no recorded book value (Dec. 31, 2021 — 1,922,973). In addition, the Company holds approximately 1,750,000 eligible emission credits generated from assets formerly subject to the Hydro Power Purchase Arrangement ("Hydro PPA") during the period 2018-2020, which also have no recorded book value. Refer to Note 21 for further details.

5. Asset Impairment Charge (Reversal)

The Company has determined that assets at each facility will be grouped together to form a cash generating unit ("CGU") for purposes of impairment testing. Property, Plant and Equipment ("PP&E") and goodwill have been allocated to CGUs to determine the carrying amount.

As part of the Company's monitoring controls, long-range forecasts are prepared for each CGU. The long-range forecast estimates are used to assess the significance of potential indicators of impairment and provide criteria to evaluate adverse changes in operations. The Company also considers the relationship between its market capitalization and its book value, among other factors, when reviewing for indicators of impairment. When indicators of impairment are present, the Company estimates a recoverable amount (the higher of value in use and fair value less costs of disposal) for each CGU by calculating an approximate fair value less costs of disposal using discounted cash flow projections based on the Company's long-range forecasts. The valuations used are subject to measurement uncertainty based on assumptions and inputs to the Company's discount rates, long-range forecast, including changes to fuel costs, operating costs, capital expenditures, external power prices and useful lives of the assets extending to the last planned asset retirement in 2072.

During the period end the Company recognized the following in asset impairment charges (reversals):

	3 months ended June 30		6 months ended June 30	
	2022	2021	**2022**	2021
Kaybob Cogeneration Project	**—**	—	**—**	27
Energy Transition Facilities and Projects[(1)]	**—**	10	**—**	10
Wind	**21**	—	**21**	—
Hydro	**6**	—	**6**	—
Changes in decommissioning and restoration provisions on retired assets[(2)]	**(51)**	6	**(93)**	(6)
Intangible asset impairment - Coal Rights[(3)]	**—**	—	**—**	14
Asset impairment charges (reversals)	**(24)**	16	**(66)**	45

(1) During 2021, certain capital spares and vehicles at the Highvale mine were impaired as they would not be utilized in our converted gas facilities. Carrying amounts have been adjusted to the expected recoverable amount less costs of disposal.
(2) Changes are related to changes in discount rates net of cash flow revisions. Refer to Note 17 for further details.
(3) Impaired to nil in 2021, as no future coal will be extracted from this area of the mine.

2022

Wind

During the second quarter of 2022, the Company recorded an impairment charge on three wind assets within the Wind and Solar segment, primarily as a result of increases in the discount rates. The recoverable amount of $289 million was estimated based on fair value less cost of disposal utilizing a discounted cash flow approach and is categorized as a Level III fair value measurement.

Hydro

During the second quarter of 2022, the Company recorded an impairment on one of the hydro facilities within the Hydro segment, primarily as a result of increases in discount rates. The recoverable amount of $30 million was estimated based on fair value less cost of disposal utilizing a discounted cash flow approach and is categorized as a Level III fair value measurement.

The calculation of fair value less cost of disposal for all of the above facilities is most sensitive to the following assumptions:

As at June 30, 2022	Location of assets	Contract and Merchant discount rates
Wind and Solar	Canada	**6.4 and 7.1 per cent**
	United States ("US")	**6.5 and 7.3 per cent**
Hydro	Canada	**5.9 and 6.4 per cent**

2021

Gas

Energy Transfer Canada, formerly SemCAMS Midstream ULC ("ET Canada") purported to terminate the agreements related to the development and construction of the Kaybob Cogeneration Project. As a result, during the first quarter of 2021, the Company recorded an impairment of $27 million in the Corporate segment as this facility was not yet operational. The recoverable amount was based on estimated fair value less costs of disposal of reselling the equipment purchased to date. TransAlta has commenced an arbitration seeking compensation for ET Canada's wrongful termination of the agreements. ET Canada seeks a declaration that the Agreements were lawfully terminated.

6. Net Other Operating Income

Net other operating income includes the following:

	3 months ended June 30		6 months ended June 30	
	2022	2021	**2022**	2021
Alberta Off-Coal Agreement	**(10)**	(10)	**(20)**	(20)
Liquidated damages recoverable	**(3)**	—	**(10)**	—
Insurance recoveries	**(7)**	(1)	**(7)**	(1)
Net other operating income	**(20)**	(11)	**(37)**	(21)

Alberta Off-Coal Agreement

The Company receives payments from the Government of Alberta for the cessation of coal-fired emissions on or before Dec. 31, 2030. Under the terms of the agreement, the Company receives annual cash payments on or before July 31 of approximately $40 million ($37 million, net of the non-controlling interest related to Sheerness), which commenced Jan. 1, 2017, and will terminate at the end of 2030. Refer to Note 9 in the 2021 audited annual consolidated financial statements for further details.

Liquidated Damages Recoverable

During the three and six months ended June 30, 2022, the Company recorded $3 million and $10 million, respectively, related to requirements to be met by the contractor on turbine availability.

Insurance Recoveries

During the three and six months ending June 30, 2022, the Company recognized insurance proceeds of $7 million related to the replacement costs for the single collapsed tower at the Kent Hills wind facilities.

7. Net Interest Expense

The components of net interest expense are as follows:

	3 months ended June 30		6 months ended June 30	
	2022	2021	**2022**	2021
Interest on debt	**40**	40	**81**	80
Interest on exchangeable debentures	**8**	7	**15**	14
Interest on exchangeable preferred shares	**7**	7	**14**	14
Interest income	**(4)**	(3)	**(7)**	(6)
Capitalized interest (Note 14)	**(3)**	(3)	**(4)**	(8)
Interest on lease liabilities	**2**	2	**3**	4
Credit facility fees, bank charges and other interest	**5**	3	**11**	10
Tax shield on tax equity financing	**(3)**	—	**(3)**	1
Accretion of provisions	**10**	7	**19**	14
Net interest expense	**62**	60	**129**	123

On July 27, 2022, the Company declared a dividend of $7 million in aggregate for Exchangeable Preferred Shares at the fixed rate of 1.745% per cent, per share payable on Aug. 31, 2022. The Exchangeable Preferred Shares are considered debt for accounting purposes and as such, dividends are reported as interest expense.

8. Income Taxes

The components of income tax expense are as follows:

	3 months ended June 30		6 months ended June 30	
	2022	2021	**2022**	2021
Current income tax expense	**13**	12	**25**	35
Deferred income tax expense (recovery) related to the origination and reversal of temporary differences	**(10)**	—	**148**	(19)
Deferred income tax recovery related to temporary difference on investment in subsidiary	**(4)**	—	**(7)**	—
Deferred income tax expense (recovery) arising from the writedown (reversal of write-down) of deferred income tax assets(1)	**38**	32	**(93)**	48
Income tax expense	**37**	44	**73**	64

	3 months ended June 30		6 months ended June 30	
	2022	2021	**2022**	2021
Current income tax expense	**13**	12	**25**	35
Deferred income tax expense	**24**	32	**48**	29
Income tax expense	**37**	44	**73**	64

(1) During the three and six months ended June 30, 2022, the Company recorded a write-down of $38 million and a write-down reversal of deferred tax assets of $93 million respectively (June 30, 2021 — $32 million and $48 million write-down). The deferred income tax assets mainly relate to tax benefits of losses associated with the Company's directly owned US operations and Canadian operations. The write-down of deferred income tax assets related to US operations and Canadian operations arose as it is not considered probable that sufficient future taxable income will be available to utilize the underlying tax losses. The Company evaluates at each period end, whether it is probable that sufficient future taxable income would be available to utilize the underlying tax losses.

9. Non-Controlling Interests

The Company's subsidiaries with significant non-controlling interests are 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 June 30		6 months ended June 30	
	2022	2021	**2022**	2021
Net earnings				
TransAlta Cogeneration L.P.	**6**	19	**13**	31
TransAlta Renewables	**5**	11	**18**	30
	11	30	**31**	61
Total comprehensive income (loss)				
TransAlta Cogeneration L.P.	**6**	19	**13**	31
TransAlta Renewables	**(21)**	14	**(52)**	(8)
	(15)	33	**(39)**	23
Cash distributions paid to non-controlling interests				
TransAlta Cogeneration L.P.	**5**	5	**22**	17
TransAlta Renewables	**25**	25	**50**	50
	30	30	**72**	67

As at	June 30, 2022	Dec. 31, 2021
Equity attributable to non-controlling interests		
TransAlta Cogeneration L.P.	**133**	142
TransAlta Renewables	**767**	869
	900	1,011
Non-controlling interests share (per cent)		
TransAlta Cogeneration L.P.	**49.99**	49.99
TransAlta Renewables	**39.9**	39.9

10. Trade and Other Receivables

As at	June 30, 2022	Dec. 31, 2021
Trade accounts receivable	**548**	499
Collateral paid (Note 12)	**403**	55
Current portion of finance lease receivable	**46**	40
Loan receivable (Note 16)	**13**	55
Income taxes receivable	**17**	2
Trade and other receivables	**1,027**	651

11. Financial Instruments

A. Financial Assets and Liabilities – Measurement

Financial assets and financial liabilities are measured on an ongoing basis at 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.

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, refer to Note 15 of the 2021 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 businesses 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 June 30, 2022, are as follows: Level I — $63 million net asset (Dec. 31, 2021 — $12 million net asset), Level II — $414 million net asset (Dec. 31, 2021 — $122 million net asset) and Level III — $407 million net liability (Dec. 31, 2021 — $159 million net asset).

Significant changes in commodity net risk management assets (liabilities) during the six months ended June 30, 2022, are primarily attributable to volatility in market prices on both existing contracts and new contracts as well as contract settlements.

The following tables summarize the key factors impacting the fair value of the Level III commodity risk management assets and liabilities by classification during the six months ended June 30, 2022 and 2021, respectively:

	6 months ended June 30, 2022			6 months ended June 30, 2021		
	Hedge	**Non-hedge**	**Total**	Hedge	Non-hedge	Total
Opening balance	**285**	**(126)**	**159**	573	9	582
Changes attributable to:						
Market price changes on existing contracts	**(207)**	**(268)**	**(475)**	(142)	(46)	(188)
Market price changes on new contracts	**—**	**(96)**	**(96)**	—	(62)	(62)
Contracts settled	**(52)**	**56**	**4**	(70)	(1)	(71)
Change in foreign exchange rates	**2**	**(1)**	**1**	(17)	1	(16)
Net risk management assets (liabilities) at end of period	**28**	**(435)**	**(407)**	344	(99)	245
Additional Level III information:						
Losses recognized in other comprehensive income	**(205)**	**—**	**(205)**	(160)	—	(160)
Total gains (losses) included in earnings before income taxes	**52**	**(365)**	**(313)**	70	(107)	(37)
Unrealized losses included in earnings before income taxes relating to net assets (liabilities) held at period end	**—**	**(309)**	**(309)**	—	(108)	(108)

As at June 30, 2022, the total Level III risk management asset balance was $42 million (Dec. 31, 2021 — $305 million) and Level III risk management liability balance was $449 million (Dec. 31, 2021 — $146 million). The following information on risk management contracts or groups of risk management contracts that are included in Level III measurements, 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		**June 30, 2022**		
Description	**Sensitivity**	**Valuation technique**	**Unobservable input**	**Reasonable possible change**
Long-term power sale – US	**+25**	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of US$5 or price increase of US$31
	-148			
Coal transportation – US	**+15**	Numerical derivative valuation	Illiquid future power prices (per MWh)	Price decrease of US$5 or price increase of US$31
			Volatility	80% to 120%
	-16		Rail rate escalation	zero to 10%
Full requirements – Eastern US	**+3**	Monte Carlo	Volume	95% to 105%
	-18		Cost of supply	$nil to US$2 per MWh
Long-term wind energy sale – Eastern US	**+18**	Long-term price forecast	Illiquid future power prices (per MWh)	Price increase or decrease of US$6
			Illiquid future REC prices (per unit)	Price decrease of US$2 or increase of US$1
	-15		Wind discounts	zero to 5%
Long-term wind energy sale – Canada	**+26**	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of C$40 or increase of C$4
	-12		Wind discounts	10% decrease or 5% increase
Long-term wind energy sale - Central US	**+52**	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of US$4 or increase of US$5
	-18		Wind discounts	3% decrease or 7% increase
Others	**+8**			
	-9			

As at			Dec. 31, 2021	
Description	**Sensitivity**	**Valuation technique**	**Unobservable input**	**Reasonable possible change**
Long-term power sale – US	+22 -145	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of US$3 or price increase of US$20
Coal transportation – US	+3 -18	Numerical derivative valuation	Illiquid future power prices (per MWh) Volatility Rail rate escalation	Price decrease of US$3 or price increase of US$20 80% to 120% zero to 4%
Full requirements – Eastern US	+9 -9	Monte Carlo	Volume Cost of supply	95% to 105% (+/-) US$1 per MWh
Long-term wind energy sale – Eastern US	+17 -16	Long-term price forecast	Illiquid future power prices (per MWh) Illiquid future REC prices (per unit)	Price increase or decrease of US$6 Price decrease of US$3 or increase of US$2
Long-term wind energy sale – Canada	+21 -11	Long-term price forecast	Illiquid future power prices (per MWh) Wind discounts	Price decrease of C$24 or increase of C$5 5% decrease or 5% increase
Long-term wind energy sale - Central US	+27 -15	Long-term price forecast	Illiquid future power prices (per MWh) Wind discounts	Price decrease of US$2 or increase of US$3 3% decrease or 3% increase
Others	+6 -6			

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 strengthened from Dec. 31, 2021 to June 30, 2022, resulting in an increase in the base fair value and the sensitivity values by approximately nil and $1 million.

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 and independent system operator costs.

iv. Long-Term Wind Energy Sale – Eastern US
In relation to the Big Level wind facility, the Company has a long-term contract for differences whereby the Company receives a fixed price per MWh and pays the prevailing real-time energy market price per MWh as well as the physical delivery of renewable energy credits ("RECs") based on proxy generation. The contract matures in December 2034. The contract is accounted for at fair value through profit or loss.

v. Long-Term Wind Energy Sale – Canada
In relation to the Garden Plain wind project, the Company has entered into two virtual PPAs whereby the Company receives the difference between the fixed contract price per MWh and the Alberta Electric System Operator ("AESO") settled pool price per MWh. Both contracts commence on commercial operation of the facility, which is expected by the second half of 2022 and extend for a weighted average of approximately 17 years. The energy component of the contracts is accounted for at fair value through profit or loss.

In addition to the virtual PPA contracts, the Company has entered into a 'bridge contract' that runs 16-months from Sept. 1, 2021 through Dec. 31, 2022, with the potential for extension at the virtual PPA price, depending on the commencement of commercial operations.

vi. Long-Term Wind Energy Sale – Central US
On Dec. 22, 2021, TransAlta executed two long-term virtual PPAs for the off take of 100 per cent of the generation from its 300 MW White Rock East and White Rock West wind power projects (collectively, the "White Rock Wind projects") to be located in Caddo County, Oklahoma. The Company receives the difference between the fixed contract price per MWh and the settled pool price per MWh. The contracts commence on commercial operation of the facilities, which is expected within the second half of 2023 and extend for greater than 10 years past that date. The energy component of the contracts is accounted for at fair value through profit or loss.

On April 5, 2022, the Company entered into a long-term virtual PPA for the offtake of 100 per cent of the generation from its 200 MW Horizon Hill wind project ("Horizon Hill wind project") to be located in Logan County, Oklahoma. The Company receives the difference between the fixed contract price per MWh and the settled pool price per MWh with the energy component of the contracts accounted for at fair value through profit and loss. The contract commences on commercial operation of the facility, which is expected within the second half of 2023.

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 asset fair value of $48 million as at June 30, 2022 (Dec. 31, 2021 – $8 million net asset) are classified as Level II fair value measurements. The significant changes in other net risk management assets and liabilities during the six months ended June 30, 2022, are primarily attributable to favourable impacts of interest rate increases on existing contracts and favourable foreign exchange rates on new contracts entered into during 2022.

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 - June 30, 2022	**—**	**713**	**—**	**713**	**737**
Long-term debt - June 30, 2022	**—**	**2,781**	**—**	**2,781**	**3,076**
Exchangeable securities - Dec. 31, 2021	—	770	—	770	735
Long-term debt - Dec. 31, 2021	—	3,272	—	3,272	3,167

(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 paid, accounts payable and accrued liabilities, collateral received and dividends payable) approximates fair value due to the liquid nature of the asset or liability. The fair values of the loan receivable and the finance lease receivables approximate the carrying amounts and the amounts receivable represent cash flows from repayments of principal and interest.

C. Inception Gains and Losses

The majority of derivatives traded by the Company are based on adjusted quoted prices on an active exchange or extend beyond the time period for which exchange-based quotes are available. The fair values of these derivatives are determined using inputs that are not readily observable. Refer to section B of this Note 11 above for fair value Level III valuation techniques used. In some instances, a difference may arise between the fair value of a financial instrument at initial recognition (the "transaction price") and the amount calculated through a valuation model. This unrealized gain or loss at inception is recognized in net 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:

	6 months ended June 30	
	2022	2021
Unamortized net loss at beginning of the period	**(102)**	(33)
New inception gains (losses)	**(29)**	15
Change in foreign exchange rates	**(1)**	1
Amortization recorded in net earnings during the period	**(12)**	(7)
Unamortized net loss at end of the period	**(144)**	(24)

12. 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 (loss) 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 16 of the 2021 audited annual consolidated financial statements.

A. Net Risk Management Assets and Liabilities

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

As at June 30, 2022

	Cash flow hedges	**Not designated as a hedge**	**Total**
Commodity risk management			
Current	**(48)**	**18**	**(30)**
Long-term	**76**	**24**	**100**
Net commodity risk management assets	**28**	**42**	**70**
Other			
Current	**38**	**7**	**45**
Long-term	**—**	**3**	**3**
Net other risk management assets	**38**	**10**	**48**
Total net risk management assets	**66**	**52**	**118**

As at Dec. 31, 2021

	Cash flow hedges	Not designated as a hedge	Total
Commodity risk management			
Current	33	12	45
Long-term	252	(4)	248
Net commodity risk management assets	285	8	293
Other			
Current	3	(1)	2
Long-term	—	6	6
Net other risk management assets	3	5	8
Total net risk management assets	288	13	301

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 (loss) in the period that the price changes occur. VaR at June 30, 2022, associated with the Company’s proprietary trading activities was $3 million (Dec. 31, 2021 — $2 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 by products, as considered appropriate. VaR at June 30, 2022, associated with the Company’s commodity derivative instruments used in generation hedging activities was $41 million (Dec. 31, 2021 — $33 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 (loss) in the period in which the price change occurs. VaR at June 30, 2022, associated with these transactions was $60 million (Dec. 31, 2021— $51 million), of which $22 million related to virtual PPAs (Dec. 31, 2021 — $18 million).

iii. Interest Rate Risk

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

The Company's credit facility and the Poplar Creek non-recourse bond are the only debt instruments subject to floating interest rates, which represent 3 per cent of the Company’s debt as at June 30, 2022 (Dec. 31, 2021 – 3 per cent). The Poplar Creek non-recourse bond face value as at June 30, 2022 was $100 million (Dec. 31, 2021 —$104 million), with interest expense based upon the three-month Canadian Dollar Offered Rate, which will be discontinued in 2024.

Interest rate risk is managed with the use of interest rate swap agreements with a notional amount of US$150 million referencing the three-month LIBOR and a notional amount of US$150 million referencing the US Treasury Bond yield, both expected to settle in the third quarter of 2022. The cessation date for three-month LIBOR is June 30, 2023.

The following table outlines the Company's exposure to interest rate risk:

Factor	Increase or decrease (bps)	Approximate impact on net earnings (loss)	Approximate impact on OCI gain(loss)
Interest rate[(1)(2)]	50	nil before tax	$1

(1) These calculations assume an increase in floating interest rates. A decrease in floating interest rates would have the opposite effect.
(2) During 2022, the approximate impact on net earnings (loss) with an increase of 50 bps would result in less than $1 million impact.

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 June 30, 2022:

	Investment grade (Per cent)	Non-investment grade (Per cent)	Total (Per cent)	Total amount
Trade and other receivables[(1,2)]	88	12	100	**1,014**
Long-term finance lease receivables	100	—	100	**158**
Risk management assets[(1)]	86	14	100	**911**
Loan receivable[(2)]	—	100	100	**45**
Total				**2,128**

(1) Letters of credit and cash and cash equivalents are the primary types of collateral held as security related to these amounts.
(2) Includes $45 million loan receivable included within Other Assets with a counterparty that has no external credit rating. The current portion of $13 million was excluded from trade and other receivables as it is included in loan receivable in the table above.

The Company did not have significant expected credit losses as at June 30, 2022.

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 June 30, 2022, was $36 million (Dec. 31, 2021 — $37 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 November 2022. 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:

	2022	2023	2024	2025	2026	2027 and thereafter	Total
Accounts payable and accrued liabilities	1,146	—	—	—	—	—	1,146
Long-term debt(1)	570	169	126	140	143	1,961	3,109
Exchangeable securities(2)	—	—	—	750	—	—	750
Commodity risk management (assets) liabilities	71	(20)	(68)	(52)	5	(6)	(70)
Other risk management assets	(39)	(3)	(5)	—	—	(1)	(48)
Lease liabilities(3)	(3)	—	4	4	3	95	103
Interest on long-term debt and lease liabilities(4)	78	129	125	118	111	809	1,370
Interest on exchangeable securities(2,4)	26	53	62	—	—	—	141
Dividends payable	39	—	—	—	—	—	39
Total	**1,888**	**328**	**244**	**960**	**262**	**2,858**	**6,540**

(1) Excludes impact of hedge accounting and derivatives.
(2) Assumes the exchangeable securities will be exchanged on Jan. 1, 2025.
(3) Lease liabilities includes a lease incentive of $6 million expected to be received in each of 2022 and 2023.
(4) Not recognized as a financial liability on the condensed consolidated Statements of financial position.

C. Collateral and Contingent Features in Derivative Instruments

I. Financial Assets Provided as Collateral

At June 30, 2022, the Company provided $403 million (Dec. 31, 2021 – $55 million) in cash and cash equivalents as collateral to regulated clearing agents as security for commodity trading activities. These funds are held in segregated accounts by the clearing agents. Collateral provided is included in trade and other receivables in the Consolidated Statements of Financial Position.

II. Financial Assets Held as Collateral

At June 30, 2022, the Company held $604 million (Dec. 31, 2021 – $18 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 derivative instruments in a net asset position and is included in accounts payable and accrued liabilities in the Consolidated Statements of Financial Position.

III. Contingent Features in Derivative Instruments

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

As at June 30, 2022, the Company had posted collateral of $562 million (Dec. 31, 2021 – $356 million) in the form of letters of credit on derivative instruments 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 $353 million (Dec. 31, 2021 – $120 million) of collateral to its counterparties.

13. Investments

Energy Impact Partners Investment ("EIP")

On May 6, 2022, the Company entered into a commitment to invest US$25 million over the next four years in EIP's Deep Decarbonization Frontier Fund 1 (the "Frontier Fund"). The investment in the Frontier Fund provides the Company with a portfolio approach to investing in emerging technologies and the opportunity to identify, pilot, commercialize and bring to market emerging technologies that will facilitate the transition to net-zero emissions. During the second quarter of 2022, the Company has made an initial investment of $7 million (US$6 million). The investment will be accounted for at fair value through profit or loss.

Ekona Power Inc.

On February 1, 2022, the Company made an equity investment of $2 million in Ekona Power Inc.'s Class B Preferred Shares. The investment will help support the commercialization of Ekona's novel methane pyrolysis technology platform, which produces cleaner and lower-cost turquoise hydrogen. The investment will be accounted for at fair value through other comprehensive income.

14. Property, Plant and Equipment

Assets under construction

During the three and six months ended June 30, 2022, the Company had additions of $119 million and $191 million, respectively, mainly related to assets under construction for the White Rock Wind projects, Horizon Hill wind project, Northern Goldfields Solar project, the Garden Plain wind project and other planned major maintenance.

During the three and six months ended June 30, 2021, the Company had additions of $119 million and $217 million, respectively. The additions mainly related to assets under construction for the coal-to-gas conversions, Windrise wind project, Sundance Unit 5 repowering project and other planned major maintenance expenditures. During the six months ended June 30, 2021, the Company completed the conversions of Keephills Unit 2, Sheerness Unit 1 and Sundance Unit 6.

During the three and six months ended June 30, 2022, the Company capitalized interest of $3 million and $4 million, respectively, (June 30, 2021 — $3 million and $8 million) to PP&E at a weighted average rate of 6.1 per cent (June 30, 2021 - 6.0 per cent).

Renewable Generation

The Company has begun its rehabilitation plan at the Kent Hills wind facilities which consists of dismantling all 49 remaining turbines, demolishing and removing all existing tower foundations, replacing them with newly-designed foundations, reassembling the wind turbine towers and generators, replacing the wind turbine that collapsed and testing each wind turbine generator before returning it to service. For the three and six months ended June 30, 2022, the Company has capitalized additions of $10 million.

In the first quarter of 2022, $16 million of costs, related to transmission infrastructure at the Windrise wind facility, were reclassified from Property, Plant and Equipment to Other Assets and will be amortized to net earnings (loss) over the useful life of the Windrise wind facility. In accordance with the asset transfer agreement, the ownership of these assets must be transferred to the transmission line owner upon completion of construction of the transmission infrastructure.

Gas Generation

On June 30, 2021, the Company closed the sale of the Pioneer Pipeline to ATCO Gas and Pipelines Ltd. ("ATCO") for the aggregate sale price of $255 million. The net cash proceeds to the Company from the sale of its 50 per cent interest, were approximately $128 million and the Company recognized a gain on sale of $31 million on the statement of earnings. In addition, as part of the transaction, the natural gas transportation agreement with the Pioneer Pipeline Limited Partnership was terminated which resulted in a gain of $2 million.

Energy Transition

During 2021, Keephills Unit 1 and Sundance Unit 5 were retired. Sundance Unit 4 was retired from service effective March 31, 2022.

During the six months ended June 30, 2022, there was a decrease in the decommissioning provision resulting from an increase in discount rates largely driven by increases in market benchmark rates. This resulted in a decrease in the related assets included in property, plant and equipment by $106 million. Refer to Note 17 for further details.

Refer to Note 5 for more details on asset impairments charges and reversals recognized during the three and six months ended June 30, 2022 and 2021.

15. Intangible Assets

The Company acquired a portfolio of wind development projects in the US in 2019. Upon moving forward with any of these projects, additional consideration may be payable on a project-by-project basis in the event a project achieves commercial operations prior to Dec. 31, 2025.

During the six months ended June 30, 2022, the Company recorded $16 million (June 30, 2021 — nil) of contingent consideration relating to US wind development projects. Additionally, the Company reclassified development costs of $3 million from Other Assets to Intangible Assets comprised of initial acquisition costs.

16. Other Assets

Other Assets includes a $45 million (Dec. 31, 2021 - $55 million) unsecured loan related to an advancement by the Company's subsidiary, Kent Hills Wind LP, of the net financing proceeds of the Kent Hills Wind Bond ("KH Bonds"), to its 17 per cent partner. During the second quarter of 2022, the Company received a repayment of $10 million which was required as part of the waiver and amendment made to the KH Bonds. In the second quarter of 2022, the loan receivable agreement was amended and its original maturity date of Oct. 2, 2022 was extended to October 2027, resulting in the classification of a portion of the loan receivable to non-current assets. The remaining terms of the original loan remain unchanged and it continues to bear interest at 4.55 per cent, with interest payable quarterly. No scheduled principal repayments are required until maturity. However, repayments may be required for amounts associated with foundation replacement capital expenditures as outlined in the amendment made to the KH Bonds.

In the first quarter of 2022, $16 million of costs related to transmission infrastructure at the Windrise wind facility were reclassified from Property, Plant and Equipment to Other Assets and will be amortized to net earnings (loss) over the useful life of the Windrise wind facility. Refer to Note 14 for further detail.

17. Decommissioning and Other Provisions

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

	Decommissioning and restoration	Other provisions	Total
Balance, Dec. 31, 2021	793	34	827
Liabilities settled	**(14)**	**(12)**	**(26)**
Accretion	**19**	**—**	**19**
Transfers	**(2)**	**—**	**(2)**
Revisions in estimated cash flows	**12**	**6**	**18**
Revisions in discount rates	**(211)**	**—**	**(211)**
Change in foreign exchange rates	**2**	**—**	**2**
Balance, June 30, 2022	**599**	**28**	**627**

	Decommissioning and restoration	Other provisions	Total
Balance, Dec. 31, 2021	793	34	827
Current portion	35	13	48
Non-current portion	758	21	779
Balance, June 30, 2022	**599**	**28**	**627**
Current portion	**35**	**4**	**39**
Non-current portion	**564**	**24**	**588**

During the three and six months ended June 30, 2022, the decommissioning and restoration provision was impacted as a result of increases in discount rates, largely driven by increases in market benchmark rates. On average, discount rates increased with rates ranging from 6.8 to 9.3 per cent as at June 30, 2022 (Dec. 31, 2021 — 3.6 to 6.5 per cent). Revisions in discount rates and revisions in estimated cash flows within the decommissioning and restoration provision include $106 million related to PP&E assets and $93 million related to retired assets recorded as an asset impairment reversal.

18. Credit Facilities and Long-Term Debt

The Company has $2 billion (Dec. 31, 2021 — $2 billion) of committed syndicated bank facilities and $0.2 billion of committed bilateral credit facilities, of which $1.0 billion was available as at June 30, 2022 (Dec. 31, 2021 — $1.3 billion) including the undrawn letters of credit. During the second quarter of 2022, the committed syndicated credit facilities were extended by one year to June 30, 2026 and the committed bilateral credit facilities were extended by one year to June 30, 2024. The undrawn credit facilities are the primary source for short-term liquidity after the cash flow generated from the Company's business. Interest rates on the credit facilities vary depending on the option selected (Canadian prime, bankers' acceptances, SOFR or US base rate, etc.) in accordance with a pricing grid that is standard for such facilities.

As at June 30, 2022, the Company was in compliance with all debt covenants.

Kent Hills Wind Bonds

In fourth quarter of 2021, the Company disclosed that events of default may have occurred under the trust indenture governing the terms of the KH Bonds. Accordingly, the Company classified the entire carrying value of the bond as current as at Dec. 31, 2021.

During the second quarter of 2022, the Company obtained a waiver and entered into a supplemental indenture that facilitated the rehabilitation of the Kent Hills 1 and 2 wind facilities. Upon obtaining the waiver, the Company has reclassified a portion of the total $212 million carrying value (face value $215 million) outstanding (Dec. 31, 2021 — $221 million) to non-current liabilities, with the exception of the scheduled principal repayments due within the next twelve months from June 30, 2022. 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.

The KH Bonds issued in October 2017, bear interest at 4.45 per cent, with principal and interest payable quarterly in blended payments until maturity on Nov. 30, 2033. The KH Bonds are secured by a first ranking charge over all of the assets of the issuer, Kent Hills Wind LP, which primarily includes the Kent Hills 1, 2 and 3 wind facilities, which at June 30, 2022, had a combined PP&E carrying value of $181 million (Dec. 31, 2021 — $182 million).

Restricted Cash

The Company has nil (Dec. 31, 2021 — $17 million) of restricted cash related to the Company's subsidiary, TransAlta OCP LP bond ("TransAlta OCP bonds"), which was required to be held in a debt service reserve account to fund scheduled debt repayments.

The Company also had $43 million (Dec. 31, 2021 — $53 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.

19. Common Shares

A. Issued and Outstanding

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

	6 months ended June 30			
	2022		2021	
	Common shares (millions)	**Amount**	Common shares (millions)	Amount
Issued and outstanding, beginning of period	**271.0**	**2,901**	269.8	2,896
Purchased and cancelled under the NCIB	**(1.4)**	**(15)**	—	—
Effects of share-based payment plans	**0.9**	**6**	—	(3)
Stock options exercised	**0.2**	**1**	1.2	8
Issued and outstanding, end of period	**270.7**	**2,893**	271.0	2,901

B. Normal Course Issuer Bid Program

On May 24, 2022, the Toronto Stock Exchange (“TSX”) accepted the notice filed by the Company to renew its normal course issuer bid (“NCIB”) for a portion of its common shares. Pursuant to the NCIB, TransAlta may repurchase up to a maximum of 14,000,000 Common Shares, representing approximately 7.16% of its public float of common shares. Any common shares purchased under the NCIB will be cancelled. The period during which TransAlta is authorized to make purchases under the NCIB commences on May 31, 2022 and ends on May 30, 2023.

Shares purchased by the Company 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 deficit.

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

As at		**June 30, 2022**	Dec. 31, 2021
Total shares purchased[(1)]		**1,400,000**	—
Average purchase price per share	**$**	**12.50**	—
Total cost (millions)	**$**	**18**	—
Weighted average book value of shares cancelled	**$**	**15**	—
Amount recorded in deficit	**$**	**3**	—

(1) As of May 25, 2022.

C. Dividends

On April 27, 2022, the Company declared a quarterly dividend of $0.05 per common share, payable on July 1, 2022.

On July 27, 2022, the Company declared a quarterly dividend of $0.05 per common share, payable on Oct. 1, 2022.

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

20. Preferred Shares

A. Issued and Outstanding

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

	June 30, 2022		Dec. 31, 2021	
Series	**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**	11.0	269
Series D	**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

On June 16, 2022, the Company announced that that 1,044,299 of its 11,000,000 currently outstanding Cumulative Redeemable Rate Reset First Preferred Shares, Series C ("Series C Shares") were tendered for conversion, on a one-for-one basis, into Cumulative Redeemable Floating Rate First Preferred Shares, Series D ("Series D Shares") after having taken into account all election notices following the June 15, 2022 conversion deadline.

B. Dividends

On April 27, 2022, the Company declared a quarterly dividend of $0.17981 per share on the Series A preferred shares, $0.16505 per share on the Series B preferred shares, $0.25169 per share on the Series C preferred shares, $0.32463 per share on the Series E preferred shares, and $0.31175 per share on the Series G preferred shares, all payable on June 30, 2022.

On July 27, 2022, the Company declared a quarterly dividend of $0.17981 per share on the Series A preferred shares, $0.22099 per share on the Series B preferred shares, $0.36588 per share on the Series C preferred shares, $0.28841 per share on the Series D preferred shares, $0.32463 per share on the Series E preferred shares and $0.31175 per share on the Series G preferred shares, payable on Sept. 30, 2022.

21. Commitments and Contingencies

A. Commitments

For the significant commitments and contingencies outstanding, refer to Note 36 of the 2021 annual consolidated financial statements. The Company has entered into the following material contractual commitments, as at June 30, 2022:

During the second quarter of 2022, the Company entered into an engineering, procurement and construction agreement for approximately $37 million (AU$41 million) related to the Mount Keith 132kV Expansion Project.

In the second quarter of 2022, the Company entered into agreements for $86 million for the rehabilitation efforts at the Kent hills 1 and 2 wind facilities.

The Company has not incurred any other material contractual commitments, either directly or through its interests in joint operations during 2022.

B. 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 36 of the 2021 audited annual consolidated financial statements. Material changes to the contingencies have been described below.

Hydro Power Purchase Arrangement Emission Performance Credits

The Balancing Pool is claiming entitlement to the emission performance credits ("EPCs") 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 Balancing Pool claims ownership of the EPCs because it believes the change-in-law provisions under the Hydro PPA require the EPCs to be passed through to the Balancing Pool. TransAlta has not received any benefit from the EPCs nor from any purported change in law and believes that the Balancing Pool has no rights to these credits. An arbitration has commenced and the hearing is scheduled for Feb. 6 to 10, 2023. TransAlta holds approximately 1.75 million EPCs with no recorded book value that were created between 2018-2020, which are at risk as a result of the Balancing Pool's claim.

Keephills 1 Stator Force Majeure

The Balancing Pool and ENMAX Energy Corporation ("ENMAX") were seeking to set aside an arbitration award on the basis that they did not receive a fair hearing. The Alberta Court of Queen's Bench dismissed the Balancing Pool and ENMAX's allegations of unfairness on June 26, 2019. The Balancing Pool and ENMAX, appealed this decision to the Court of Appeal, which was heard on Jan. 27, 2022.

On June 9, 2022, the Court of Appeal released a unanimous decision dismissing ENMAX and the Balancing Pool's application. The Court of Appeal upheld the Company's claim of force majeure that arose when its Keephills 1 generating unit tripped offline in 2013. As a result of the decision, the Company's claim of force majeure remains valid and the associated costs of the force majeure event will not be reassessed against TransAlta. ENMAX and the Balancing Pool have until Aug. 8, 2022 to file an application at the Supreme Court of Canada for permission to appeal the Court of Appeal's decision.

Sarnia Outages

The Sarnia cogeneration facility experienced three separate events between May 19, 2021 and June 9, 2021 that resulted in steam interruptions to its industrial customers. As a result, the customers have submitted claims for liquidated damages. Steam supply disruptions of this nature are atypical and infrequent at the Sarnia cogeneration facility. A root cause failure analysis was completed for the three outages, which concluded that all three outages were within TransAlta (SC) LP's control. As such, liquidated damages previously included in contract liabilities in the amount of $12 million have been paid by TransAlta (SC) LP in the second quarter of 2022.

There have been no other material updates to any of the contingencies in the three and six month periods ended June 30, 2022.

22. Segment Disclosures

A. Description of Reportable Segments

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

The following tables provide each segment's results in the format that the CODM reviews the Company's segments to make operating decisions and assess performance. The tables below show the reconciliation of the total segmented results and adjusted EBITDA to the statement of earnings (loss) reported under IFRS. Prior periods have been adjusted for comparable purposes.

For internal reporting purpose, the earnings information from the Company's investment in the Skookumchuck wind facility 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 (Loss) and Segment Assets

Reconciliation of Adjusted EBITDA to Earnings (Loss) Before Income Tax

	Attributable to common shareholders									
3 months ended June 30, 2022	**Hydro**	**Wind & Solar(1)**	**Gas(2)**	**Energy Transition(3)**	**Energy Marketing**	**Corporate**	**Total**	**Equity accounted investments(1)**	**Reclass Adjustments**	**IFRS Financials**
Revenues	105	96	127	96	36	1	461	(3)	—	458
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	—	15	128	—	(56)	—	87	—	(87)	—
Realized gain (loss) on closed exchange positions	—	—	(10)	—	75	—	65	—	(65)	—
Decrease in finance lease receivable	—	—	11	—	—	—	11	—	(11)	—
Finance lease income	—	—	6	—	—	—	6	—	(6)	—
Unrealized foreign exchange (gain) loss on commodity	—	—	—	—	2	—	2	—	(2)	—
Adjusted revenues	105	111	262	96	57	1	632	(3)	(171)	458
Fuel and purchased power	6	6	147	71	—	1	231	—	—	231
Reclassifications and adjustments:										
Australian interest income	—	—	(1)	—	—	—	(1)	—	1	—
Adjusted fuel and purchased power	6	6	146	71	—	1	230	—	1	231
Carbon compliance	—	1	12	(4)	—	—	9	—	—	9
Gross margin	99	104	104	29	57	—	393	(3)	(172)	218
OM&A	10	15	45	17	7	23	117	—	—	117
Taxes, other than income taxes	1	4	4	1	—	—	10	(1)	—	9
Net other operating income	—	(10)	(10)	—	—	—	(20)	—	—	(20)
Reclassifications and adjustments:										
Insurance recovery	—	7	—	—	—	—	7	—	(7)	—
Adjusted net other operating income	—	(3)	(10)	—	—	—	(13)	—	(7)	(20)
Adjusted EBITDA(4)	88	88	65	11	50	(23)	279			
Equity income										2
Finance lease income										6
Depreciation and amortization										(115)
Asset impairment reversal										24
Net interest expense										(62)
Foreign exchange gain										9
Gain on sale of assets and other										2
Loss before income taxes										(22)

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.
(2) Includes the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal.
(3) Includes the segment previously known as Centralia and the coal generation assets from the segment previously known as Alberta Thermal.
(4) Adjusted EBITDA is not defined and have no standardized meaning under IFRS.

3 months ended June 30, 2021	Hydro	Wind & Solar(1)	Gas(2)	Energy Transition(3)	Energy Marketing	Corporate	Total	Equity accounted investments(1)	Reclass Adjustments	IFRS Financials
Revenues	114	79	287	101	38	4	623	(4)	—	619
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	—	(4)	(28)	23	(4)	—	(13)	—	13	—
Realized gain (loss) on closed exchange positions	—	—	1	—	16	—	17	—	(17)	—
Decrease in finance lease receivable	—	—	10	—	—	—	10	—	(10)	—
Finance lease income	—	—	6	—	—	—	6	—	(6)	—
Adjusted revenues	114	75	276	124	50	4	643	(4)	(20)	619
Fuel and purchased power(4)	6	3	110	92	—	4	215	—	—	215
Reclassifications and adjustments:										
Australian interest income	—	—	(1)	—	—	—	(1)	—	1	—
Mine depreciation	—	—	(26)	(24)	—	—	(50)	—	50	—
Coal inventory write-down	—	—	—	(3)	—	—	(3)	—	3	—
Adjusted fuel and purchased power	6	3	83	65	—	4	161	—	54	215
Carbon compliance	—	—	32	10	—	—	42	—	—	42
Gross margin	108	72	161	49	50	—	440	(4)	(74)	362
OM&A(4)	11	15	45	46	7	24	148	—	—	148
Reclassifications and adjustments:										
Parts and materials write-down	—	—	(2)	(23)	—	—	(25)	—	25	—
Adjusted OM&A	11	15	43	23	7	24	123	—	25	148
Taxes, other than income taxes	1	2	4	2	—	—	9	(1)	—	8
Net other operating income	—	—	(10)	(1)	—	—	(11)	—	—	(11)
Adjusted EBITDA(5)	96	55	124	25	43	(24)	319			
Equity income										2
Finance lease income										6
Depreciation and amortization										(123)
Asset impairment charge										(16)
Net interest expense										(60)
Foreign exchange gain										14
Gain on sale of assets and other										32
Earnings before income taxes										72

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.
(2) Includes the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal. Refer to Note 1 for further details.
(3) Includes the segment previously known as Centralia and the coal generation assets from the segment previously known as Alberta Thermal.
(4) During the three months ended June 30, 2021, $3 million related to station service costs for the Hydro segment were reclassified from OM&A to fuel and purchased power for comparative purposes. This did not impact previously reported net earnings.
5) Adjusted EBITDA is not defined and has no standardized meaning under IFRS.

6 months ended June 30, 2022	**Hydro**	**Wind & Solar[1]**	**Gas[2]**	**Energy Transition[3]**	**Energy Marketing**	**Corporate**	**Total**	**Equity accounted investments[1]**	**Reclass Adjustments**	**IFRS Financials**
Revenues	**182**	**191**	**561**	**202**	**62**	**2**	**1,200**	**(7)**	**—**	**1,193**
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	**—**	**28**	**(34)**	**11**	**(46)**	**—**	**(41)**	**—**	**41**	**—**
Realized gain (loss) on closed exchange positions	**—**	**—**	**(7)**	**—**	**65**	**—**	**58**	**—**	**(58)**	**—**
Decrease in finance lease receivable	**—**	**—**	**22**	**—**	**—**	**—**	**22**	**—**	**(22)**	**—**
Finance lease income	**—**	**—**	**11**	**—**	**—**	**—**	**11**		**(11)**	**—**
Adjusted revenues	**182**	**219**	**553**	**213**	**81**	**2**	**1,250**	**(7)**	**(50)**	**1,193**
Fuel and purchased power	**10**	**14**	**278**	**165**	**—**	**2**	**469**	**—**	**—**	**469**
Reclassifications and adjustments:										
Australian interest income	**—**	**—**	**(2)**	**—**	**—**	**—**	**(2)**	**—**	**2**	**—**
Adjusted fuel and purchased power	**10**	**14**	**276**	**165**	**—**	**2**	**467**	**—**	**2**	**469**
Carbon compliance	**—**	**1**	**30**	**(3)**	**—**	**—**	**28**	**—**	**—**	**28**
Gross margin	**172**	**204**	**247**	**51**	**81**	**—**	**755**	**(7)**	**(52)**	**696**
OM&A	**21**	**31**	**89**	**33**	**14**	**41**	**229**	**—**	**—**	**229**
Taxes, other than income taxes	**2**	**6**	**8**	**2**	**—**	**—**	**18**	**(1)**	**—**	**17**
Net other operating income	**—**	**(17)**	**(20)**	**—**	**—**	**—**	**(37)**	**—**	**—**	**(37)**
Reclassifications and adjustments:										
Insurance recovery	**—**	**7**	**—**	**—**	**—**	**—**	**7**	**—**	**(7)**	**—**
Adjusted net other operating income	**—**	**(10)**	**(20)**	**—**	**—**	**—**	**(30)**	**—**	**(7)**	**(37)**
Adjusted EBITDA[4]	**149**	**177**	**170**	**16**	**67**	**(41)**	**538**			
Equity income										**4**
Finance lease income										**11**
Depreciation and amortization										**(232)**
Asset impairment reversal										**66**
Net interest expense										**(129)**
Foreign exchange gain										**11**
Gain on sale of assets and other										**2**
Earnings before income taxes										**220**

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.
(2) Includes the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal.
(3) Includes the segment previously known as Centralia and the coal generation assets from the segment previously known as Alberta Thermal.
(4) Adjusted EBITDA is not defined and have no standardized meaning under IFRS.

6 months ended June 30, 2021	Hydro	Wind & Solar[1]	Gas[2]	Energy Transition[3]	Energy Marketing	Corporate	Total	Equity accounted investments[1]	Reclass Adjustments	IFRS Financials
Revenues	203	170	553	240	99	5	1,270	(9)	—	1,261
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	—	1	(51)	29	(12)	—	(33)	—	33	—
Realized gain (loss) on closed exchange positions	—	—	1	—	28	—	29	—	(29)	—
Decrease in finance lease receivable	—	—	20	—	—	—	20	—	(20)	—
Finance lease income	—	—	13	—	—	—	13	—	(13)	—
Adjusted revenues	203	171	536	269	115	5	1,299	(9)	(29)	1,261
Fuel and purchased power[4]	9	7	218	221	—	5	460	—	—	460
Reclassifications and adjustments:										
Australian interest income	—	—	(2)	—	—	—	(2)	—	2	—
Mine depreciation	—	—	(53)	(52)	—	—	(105)	—	105	—
Coal inventory write-down	—	—	—	(11)	—	—	(11)	—	11	—
Adjusted fuel and purchased power	9	7	163	158	—	5	342	—	118	460
Carbon compliance	—	—	71	21	—	—	92	—	—	92
Gross margin	194	164	302	90	115	—	865	(9)	(147)	709
OM&A[4]	19	28	87	69	17	32	252	(1)	—	251
Reclassifications and adjustments:										
Parts and materials write-down	—	—	(2)	(23)	—	—	(25)	—	25	—
Adjusted OM&A	19	28	85	46	17	32	227	(1)	25	251
Taxes, other than income taxes	2	5	7	4	—	—	18	(1)	—	17
Net other operating income	—	—	(20)	(1)	—	—	(21)	—	—	(21)
Adjusted EBITDA[5]	173	131	230	41	98	(32)	641			
Equity income										4
Finance lease income										13
Depreciation and amortization										(272)
Asset impairment charge										(45)
Net interest expense										(123)
Foreign exchange gain										21
Gain on sale of assets and other										33
Earnings before income taxes										93

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.
(2) Includes the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal. Refer to Note 1 for further details.
(3) Includes the segment previously known as Centralia and the coal generation assets from the segment previously known as Alberta Thermal.
(4) During the three months ended June 30, 2021, $5 million related to station service costs for the Hydro segment were reclassified from OM&A to fuel and purchased power for comparative purposes. This did not impact previously reported net earnings.
5) Adjusted EBITDA is not defined and has no standardized meaning under IFRS.

Depreciation and Amortization on the Condensed Consolidated Statements of Cash Flows

The reconciliation between depreciation and amortization reported on the condensed consolidated statements of earnings (loss) and the condensed consolidated statements of cash flows is presented below:

	3 months ended June 30		6 months ended June 30	
	2022	2021	**2022**	2021
Depreciation and amortization expense on the condensed consolidated statements of earnings (loss)	**115**	123	**232**	272
Depreciation included in fuel and purchased power (Note 4)	**—**	50	**—**	105
Depreciation and amortization on the condensed consolidated statements of cash flows	**115**	173	**232**	377

Glossary of Key Terms

Alberta Electric System Operator ("AESO")
The independent system operator and regulatory 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 Power Purchase Arrangement ("Alberta PPA")
A long-term arrangement established by regulation for the sale of electric energy from formerly regulated generating units to PPA buyers.

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.

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.

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.

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.

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.

Carbon Tax
Sets a carbon price per tonne of Greenhouse Gas emissions related to transportation fuels, heating fuels and other small emission sources.

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

Centralia
The business segment previously disclosed as US Coal has been renamed to reflect the sole asset.

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.

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.

Heating Degree Days (HDD)
A measure designed to quantify the demand for energy needed to heat a building. It is the number of degrees that a day's average temperature is below 65° Fahrenheit (18° Celsius), which is the temperature below which buildings need to be heated.

IFRS
International Financial Reporting Standards.

ICFR
Internal control over financial reporting.

KH Bonds
The Kent Hills Wind LP non-recourse project bonds secured by, among other things, the Kent Hills 1, 2 and 3 wind facilities.

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.

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.

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.

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.

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

TransAlta Corporation
110 - 12th Avenue S.W.
Box 1900, Station “M”
Calgary, Alberta T2P 2M1

Phone
403.267.7110

Website
www.transalta.com

Computershare Trust Company of Canada
Suite 600, 530 - 8th Avenue SW
Calgary, Alberta T2P 3S8

Phone
Toll-free in North America: 1.800.564.6253
Outside North America: 514.982.7555

Fax
Toll-free in North America: 1.800.453.0330
Outside North America: 403.267.6529

Website
www.investorcentre.com

FOR MORE INFORMATION

Investor Inquiries

Phone
Toll-free in North America: 1.800.387.3598
Calgary or Outside North America: 403.267.2520

E-mail
investor_relations@transalta.com

Media Inquiries

Phone
Toll-free 1.855.255.9184
or 403.267.2540

E-mail
TA_Media_Relations@transalta.com