TRANSALTA CORPORATION

Management's Discussion and Analysis

First 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 months ended March 31, 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 March 31, 2022. All tabular amounts in the following discussion are in millions of Canadian dollars unless otherwise noted. This MD&A is dated May 5, 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 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 expected to deliver incremental average annual EBITDA of $250 million; the Company's projects under construction, including the timing of commercial operations 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, and the Garden Plain wind project; the Mount Keith transmission expansion, including the timing of commercial operation and expected annual EBITDA; the effectiveness of the capacity commitments of the industrial customers at 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 reduction of carbon emissions by 75% from 2015 emissions levels by 2026; the remediation of the Kent Hills 1 and Kent Hills 2 wind facilities, including, the timing and cost of such remediation, the ability to secure waivers in respect of the Kent Hills bonds ("KH Bonds") for any potential event of default, and the impact such incident could have on the Company's revenues and contracts; the expectation that agreements will be entered into with New Brunswick Power Corporation and the terms thereof; 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 ability of the Company to realize benefits from Canadian, US and Australian regulatory developments, including receiving funding for clean electricity projects; the potential increase in value of emission reduction credits; the 2022 financial outlook, including adjusted EBITDA, free cash flow ("FCF") and annualized dividend in 2022; sustaining and productivity capital in 2022, including routine capital, planned major maintenance and mine capital; significant planned major outages for 2022 and lost production due to planned major maintenance for 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.

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 the 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; 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; 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/or 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; adverse impacts on our information technology systems and our internal control systems, including increased cyber security 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 and coal, as well as the extent of water, solar or wind resources required to operate our facilities; general economic risks, including deterioration of equity markets, increasing interest rates or rising inflation; failure to meet financial expectations; general domestic and international economic and political developments; armed hostilities, including the war in Ukraine and associated impacts; the threat of terrorism, including cyberattacks, adverse diplomatic developments or other similar events that could adversely affect our business; 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 at the Kent Hills wind facilities is more costly or time consuming than expected; inability to come to a commercial agreement with New Brunswick Power Corporation or enter into a waiver and amendments with the Trustee and holders of the KH Bonds; 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 110 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 following table provides our consolidated ownership of our facilities across the regions in which we operate as at March 31, 2022:

As at March 31, 2022		Hydro	Wind and Solar	Gas[4][5]	Energy Transition[6]	Total
Alberta[4]	Gross installed capacity (MW)[1]	834	636	1,960	113	**3,543**
	Number of facilities	17	13	7	1	**38**
	Weighted average contract life[2][3]	—	7	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**
US	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]	—	—	17	—	**17**
Total	**Gross installed capacity (MW)**[1]	**925**	**1,906**	**3,084**	**784**	**6,699**
	Number of facilities	**26**	**29**	**17**	**3**	**75**
	Weighted average contract life[3]	**1**	**9**	**4**	**3**	**5**

(1) Gross installed capacity for consolidated reporting represents 100 per cent output of a facility. Capacity figures for Wind and Solar includes the 100 per cent of Kent Hills wind facilities; Gas includes 100 per cent of the Ottawa and Windsor facilities, 100 per cent of the Poplar Creek facility, 50 per cent of the Sheerness facility, and 60 per cent of the Fort Saskatchewan facility. On March 31, 2022, Sundance Unit 4 was retired such that, subsequent to March 31, 2022, 113 MW will be excluded from the Energy Transition segment.

(2) The weighted average contract life for Hydro, Gas, Energy Transition and certain wind assets in Alberta are nil as it is 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 gross long-term average gross installed capacity.

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

(5) Gas segment includes the segments previously known as Australian Gas and North American Gas and the coal generation assets converted to gas from the segment previously known as Alberta Thermal.

(6) Energy Transition segment includes the segment previously known as Centralia, the coal generation assets not converted to gas (including Sundance Unit 4) and mining assets from the segment previously known as Alberta Thermal.

Highlights

Unaudited Interim Condensed Consolidated Financial Highlights

	3 months ended March 31	
	2022	2021
Adjusted availability (%)	**89.1**	88.6
Production (GWh)	**5,359**	5,541
Revenues	**735**	642
Fuel and purchased power(1)	**238**	245
Carbon compliance	**19**	50
Operations, maintenance and administration(1)	**112**	103
Adjusted EBITDA(2)	**266**	310
Earnings before income tax	**242**	21
Net earnings (loss) attributable to common shareholders	**186**	(30)
Cash flow from operating activities	**451**	257
Funds from operations(2)	**186**	211
Free cash flow(2)	**115**	129
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**0.69**	(0.11)
Funds from operations per share(2)(3)	**0.69**	0.78
Free cash flow per share(2)(3)	**0.42**	0.48

As at	**March 31, 2022**	Dec. 31, 2021
Total assets	**9,425**	9,226
Total consolidated net debt(4)	**2,342**	2,636
Total long-term liabilities	**4,540**	4,702
Total liabilities	**6,785**	6,633

(1) $2 million related to station service costs for the Hydro segment in the three months ended March 31, 2021 was reclassified from operations, maintenance and administration 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 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) 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 at March 31, 2022 was 271 million shares (March 31, 2021- 270 million shares). Please refer to the Additional IFRS Measures and Non-IFRS Measures section in this MD&A for the purpose of these non-IFRS ratios.

(4) 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 months ended March 31, 2022, results were solid and in line with expectations for all segments with the addition of new contracted assets, namely the Windrise wind facility and North Carolina Solar facility (as defined below) compared to the same period in 2021. The Alberta market pricing was lower in the first quarter of 2022 compared to the same period in 2021 due to fewer planned outages impacting the overall merchant market and no significant weather events.

Adjusted availability for the three months ended March 31, 2022, was 89.1 per cent compared to 88.6 per cent for the same period in 2021. The increase was primarily due to lower planned outages within the Gas segment and Hydro segment. Adjusted availability improved within the Gas segment as there were no planned outages in the current period with the completion of the coal-to-gas conversions in the prior year. These increases in adjusted availability were partially offset by the unplanned outage at the Kent Hills 1 and 2 wind facilities and the early-stage operational issues at the Windrise wind facility in Alberta.

Production for the three months ended March 31, 2022, was 5,359 gigawatt hours ("GWh") compared to 5,541 GWh in the same period in 2021. The decrease in production was primarily due to the retirement of Keephills Unit 1, portfolio optimization activities, 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 adjusted availability, higher wind resources, higher incremental production at our Ada facility within our Gas segment and incremental production from the newly-commissioned Windrise wind facility and the recently acquired 122 MW portfolio of operating solar sites located in North Carolina (collectively, "North Carolina Solar"), in our Wind and Solar segment.

Revenues for the three months ended March 31, 2022, increased by $93 million compared to the same period in 2021, mainly as a result of the Company capturing higher realized prices within the Alberta market through our optimization activities, an increase in revenues within the Wind and Solar segment from higher wind resources, and the addition of the North Carolina Solar facility and the Windrise wind facility. These increases were partially offset by lower production in the Wind and Solar segment and the Energy Transition segment stemming from the unplanned outage at the Kent Hills 1 and 2 Wind facilities and the retirement of Keephills Unit 1.

Fuel and purchased power costs in the three months ended March 31, 2022, decreased by $7 million compared to same period 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 for the three months ended March 31, 2022, decreased by $31 million compared to the same period in 2021, primarily due to lower production and reductions in GHG emissions stemming from changes in the fuel mix ratio, as we now operate on natural gas in Alberta, partially offset by an increase in the carbon price per tonne.

Operations, maintenance and administration ("OM&A") expenses for the three months ended March 31, 2022, increased by $9 million compared to the same period in 2021. Variability caused by the total return swap resulted in a unfavourable period over period change of $8 million compared to the same period in 2021. In addition, during 2021, the Company recognized the Canada Emergency Wage Subsidy ("CEWS") of $8 million. Excluding the impact of the total return swap and the CEWS funding, OM&A expenses were lower for the three months ended March 31, 2022, compared to the same period in 2021, due to lower staffing costs, lower incentive payments and lower legal costs.

Adjusted EBITDA for the three months ended March 31, 2022, decreased by $44 million compared to the same period in 2021, largely due to lower adjusted EBITDA at our Gas, Energy Transition, Hydro, and Energy Marketing segments and higher corporate costs. This was partially offset by higher adjusted EBITDA at our Wind and Solar segment. Significant changes in segmented adjusted EBITDA are highlighted in the Segmented Financial Performance and Operating Results section within this MD&A.

Earnings before income taxes for the three months ended March 31, 2022, increased by $221 million compared to the same period in 2021. **Net earnings attributable to common shareholders** for the three months ended March 31, 2022 was $186 million compared to a loss of $30 million in the same period in 2021. The increase in earnings before income taxes and net earnings attributable to common shareholders in 2022 was largely driven by higher revenues from the Alberta Electricity Portfolio, lower carbon compliance costs and lower depreciation, mainly as a result of the completion of our coal-to-gas conversions and retirement of our coal assets compared to the same period in 2021. In addition, an asset impairment reversal driven by discount rate changes was recognized in 2022 compared to impairment charges in 2021. The higher net earnings attributable to common shareholders was also impacted by higher income tax recoveries in 2022.

Cash flow from operating activities for the three months ended March 31, 2022, increased by $194 million compared to the same period in 2021, primarily due to favourable changes in non-cash working capital and higher revenue attributable to the North American Gas assets, converted gas units and higher revenues in the Wind and Solar segment as well as lower fuel and purchased power and carbon compliance costs as the Company transitioned its units to natural gas.

FCF, one of the Company's key financial metrics, for the three months ended March 31, 2022, totaled $115 million compared to $129 million in the same period in 2021. This represents a decrease of $14 million, driven primarily by lower adjusted EBITDA, higher distributions paid to subsidiaries' non-controlling interests, partially offset by a decrease in sustaining capital spending related to lower planned maintenance turnarounds.

Significant and Subsequent Events

Mount Keith 132kV Transmission Expansion

On May 3, 2022, TransAlta Renewables exercised its option to acquire an economic interest in the expansion of the Mt. 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 approximately AU$50 million to AU$53 million. Southern Cross Energy, a subsidiary of the Company, has entered into an engineering, procurement and construction agreement with ASX-listed GenusPlus Group Ltd 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 EBITDA in the range of AU$6 million to AU$7 million. In addition, the planned completion date should allow at least a portion of the project to qualify for Australia's "Temporary Full Expensing" COVID-19 tax benefit. The project will facilitate the connection of additional generating capacity to our network to support BHP's operations and increase their competitiveness as a supplier of low-carbon nickel.

Sarnia Cogeneration Facility Contract Extensions

The Company recently entered into agreements with three of its large industrial customers at the Sarnia cogeneration facility. The capacity commitments for the large industrial customers have now been extended to 2031, at rates comparable to current contract rates, which, in each case, are subject to the satisfaction of certain conditions, including the Company entering into a new contract with the Ontario Independent Electricity System Operator (the "IESO"). 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.

Executed Long Term PPA for Remaining 30 MW at Garden Plain

The Company has entered into a long term PPA for the remaining 30 MW of renewable electricity and environmental attributes at the Garden Plain wind farm 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 with Pembina Pipeline Corporation, 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

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.

Customer Update at White Rock Wind Facilities

During the second quarter of 2022, TransAlta identified Amazon Energy LLC ("Amazon") as the customer for the 300MW 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

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 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 PPA with a subsidiary of Meta Platforms Inc., formerly known as Facebook, Inc. ("Meta"), 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. 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 at approximately US$290 million to 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 captured under executed turbine supply agreements and engineering, procurement and construction agreements. The project is expected to generate average annual EBITDA of approximately US$27 million to US$30 million inclusive of production tax credits.

Normal Course Issuer Bid

On May 25, 2021, the Toronto Stock Exchange ("TSX") accepted the notice filed by the Company to implement a normal course issuer bid ("NCIB") for a portion of our common shares. During the three months ended March 31, 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.

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 months ended March 31, 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 March 31, 2022	**Hydro**	**Wind and Solar**	**Gas(1)**	**Energy Transition(2)**	**Energy Marketing**	**Corporate and Other**	**Total**
Alberta	**61**	**30**	**44**	**(3)**	**—**	**(18)**	**114**
Canada, Excl. Alberta	**—**	**34**	**22**	**—**	**27**	**—**	**83**
US	**—**	**25**	**2**	**8**	**—**	**—**	**35**
Australia	**—**	**—**	**34**	**—**	**—**	**—**	**34**
Total adjusted EBITDA(3)	**61**	**89**	**102**	**5**	**27**	**(18)**	**266**
Earnings before income taxes							**242**

3 months ended March 31, 2021	Hydro	Wind and Solar	Gas(1)	Energy Transition(2)	Energy Marketing	Corporate and Other	Total
Alberta	77	12	49	4	—	(8)	134
Canada, Excl. Alberta	—	41	22	—	43	—	106
US	—	23	3	12	—	—	38
Australia	—	—	32	—	—	—	32
Total adjusted EBITDA(3)	77	76	106	16	43	(8)	310
Earnings before income taxes							21

(1) Gas segment includes the segments previously known as Australian Gas and North American Gas and the coal generation assets converted to gas from the segment previously known as Alberta Thermal.

(2) Energy Transition segment includes the segment previously known as Centralia and the coal generation assets not converted to gas and mining assets from the segment previously known as Alberta Thermal.

(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 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 53 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 and converted natural gas-fired thermal facilities. Optimization of facilities 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.

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

	2022					2021				
3 months ended March 31	**Hydro**	**Wind & Solar**	**Gas**	**Energy Transition**	**Total**	Hydro	Wind & Solar	Gas	Energy Transition	Total
Total Production (GWh)(1)	**336**	**503**	**1,718**	**19**	**2,576**	327	334	1,830	423	2,914
Revenues(2)	**74**	**35**	**161**	**5**	**275**	87	19	150	45	301
Fuel and purchased power	**4**	**5**	**85**	**4**	**98**	1	1	57	19	78
Carbon compliance	**—**	**—**	**15**	**1**	**16**	—	—	32	11	43
Gross margin(1)	**70**	**30**	**61**	**—**	**161**	86	18	61	15	180

(1) Units in the Gas and Energy Transition segments in prior period operated on coal.
(2) Adjustments to revenues include the impact of unrealized mark-to-market gains or losses.

For the three months ended March 31, 2022, the Alberta Electricity Portfolio generated 2,576 GWh of production, a decrease of 338 GWh compared to the same period in 2021. Production was impacted by dispatch optimization and the retirement of Keephills Unit 1 on Dec. 31, 2021. On March 31, 2022, Sundance Unit 4 was retired, further reducing the Alberta Electricity Portfolio capacity by 113 GWh.

Gross margin for the three months ended March 31, 2022, was $161 million, a decrease of $19 million compared to the same period in 2021. Gross margin was impacted mainly as a result of weaker market conditions in February as compared to the same period in 2021. Ancillary services revenue from the Hydro segment was also lower in February as a result of these market conditions. In addition, the Gas and Energy Transition segment results were impacted by lower production due to higher dispatch optimization in response to market conditions, and higher gas costs, which was partially offset by our gas hedge positions, lower carbon costs, and higher realized prices in Alberta. 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 March 31	
	2022	**2021**
Spot power price average per MWh	**$90**	$95
Natural gas price (AECO) per GJ	**$4.50**	$2.89
Carbon cost per tonne	**$50**	$40
Realized merchant power price per MWh(1)	**$107**	$103
Hydro energy realized power price per MWh	**$108**	$117
Hydro ancillary realized price per MWh	**$45**	$67
Wind energy realized power price per MWh	**$58**	$44
Gas and Energy Transition realized power price per MWh	**$103**	$105
Hedged Volume	**1,738**	1,601
Hedge position (percentage)(2)	**83**	47
Hedged power price average per MWh	**$84**	$64
Fuel and purchased power per MWh(3)	**$56**	$35
Carbon compliance cost per MWh(3)	**$9**	$19

(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 the Gas assets only. The hedge program is focused primarily on generation from the merchant Gas and Energy Transition assets.
(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.

The average pool price decreased from $95/MWh for the three months ending March 31, 2021 to $90/MWh for the same period in 2022. Pool prices were lower on average for the quarter compared to 2021, mainly as a result of fewer Heating degree days ("HDD") as well as fewer planned and unplanned outages across the provincial gas assets.

For the period ended March 31, 2022, the realized power price per MWh of production increased by $4 per MWh, compared with the same period in 2021, primarily due to the optimization of production for our Hydro, Wind, and Gas segments during periods of favourable pricing. The realized prices include gains and losses from hedging positions that are entered into in order to mitigate the impact of unfavourable market pricing.

For the period ended March 31, 2022, the Hydro ancillary realized power price decreased due to lower pool prices and as a result of increased competition within the ancillary services market compared with the same period in 2021.

For the period ended March 31, 2022, the fuel and purchased power cost per MWh of production increased by $21 per MWh compared to the same period in 2021 due to higher natural gas pricing and higher fixed gas transportation costs, partially offset by our hedge positions for gas prices and lower mine depreciation being recognized due to the cessation of mining operations in 2021.

For the period ended March 31, 2022, carbon compliance costs per MWh of production decreased by $10 per MWh compared with the same period in 2021, primarily due to changes in fuel ratios as we increased our natural gas combustion versus coal, as well as lower production, which was partially offset by an increase in carbon tax price from $40 per tonne to $50 per tonne. The shift in fuel ratio effectively lowered our greenhouse gas ("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-centred 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)	
As at March 31,	**2022**	2021	**2022**	2021	**2022**	2021
Hydro	**408**	408	**372**	360	**61**	77
Wind and Solar	**1,453**	1,170	**1,269**	1,131	**89**	76
Renewables	**1,861**	1,578	**1,641**	1,491	**150**	153
Gas			**2,665**	2,635	**102**	106
Energy Transition			**1,053**	1,415	**5**	16
Energy Marketing					**27**	43
Corporate and Other					**(18)**	(8)
Total			**5,359**	5,541	**266**	310
Total earnings before income taxes					**242**	21

(1) Long term average production ("LTA (GWh)") is calculated based on our portfolio as at March 31, 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 (GWh) for Energy Transition is not considered as we are currently transitioning these units completely by the end of 2025 and the LTA (GWh) for Gas is not considered as its is largely dependent on market conditions and merchant demand. LTA (GWh) for the three months ending March 31, 2022, excluding Kent Hills 1 and 2 wind facilities which are currently not in operation, is approximately 1,347 GWh.
(2) Actual production levels are compared against the long-term average to highlight the impact of an important factor that affects the variability in our business results. In the short-term, for each segment for Hydro and Wind and Solar, 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 to 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 March 31	
	2022	2021
Gross installed capacity (MW)	**925**	925
LTA (GWh)	**408**	408
Availability (%)	**96.7**	91.9
Production		
Energy contract		
Other Hydro energy (GWh)(1)	**36**	40
Energy merchant		
Alberta Hydro Assets (GWh)	**336**	320
Total energy production (GWh)	**372**	360
Ancillary service volumes (GWh)(3)	**742**	749
Alberta Hydro Assets(1)	**37**	39
Other Hydro Assets and other revenue(1)(2)	**7**	3
Alberta Hydro Ancillary services(3)	**33**	50
Total gross revenues	**77**	92
Net payment relating to Alberta Hydro PPA(4)	**—**	(3)
Revenues	**77**	89
Fuel and purchased power(5)	**4**	3
Gross margin	**73**	86
Operations, maintenance and administration(5)	**11**	8
Taxes, other than income taxes	**1**	1
Adjusted EBITDA	**61**	77
Supplemental Information:		
Gross Revenues per MWh		
Alberta Hydro Assets energy ($/MWh)	**110**	122
Alberta Hydro Assets ancillary ($/MWh)	**45**	67
Sustaining capital	**6**	5

(1) 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.
(2) 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.
(3) Ancillary services as described in the AESO Consolidated Authoritative Document Glossary.
(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 quarter of 2021 related to adjustments for the final payment under the Alberta PPA.
(5) $2 million related to station service costs for the Hydro segment in the three months ended March 31, 2021 was reclassified from operations, maintenance and administration to fuel and purchased power for comparative purposes. This did not impact previously reported net earnings.

Availability for the three months ended March 31, 2022, increased by 5 per cent compared to the same period in 2021, primarily due to lower planned outages at our Alberta Hydro assets.

Production for the three months ended March 31, 2022, increased by 12 GWh compared to the same period in 2021, mainly due to water resource optimization at our Alberta Hydro assets.

Ancillary service volumes for the three months ended March 31, 2022, were in line with 2021.

Adjusted EBITDA for the three months ended March 31, 2022, decreased by $16 million compared to the same period in 2021, primarily due to lower ancillary service pricing in the Alberta market as well as higher operations, maintenance and administration costs due to increased insurance and additional costs related to asset optimization of the Alberta Hydro Assets in the merchant market. 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 months ended March 31, 2022, were consistent with the same period in 2021.

Wind and Solar

	3 months ended March 31	
	2022	2021
Gross installed capacity (MW)[1]	**1,906**	1,572
LTA (GWh)	**1,453**	1,170
Availability (%)	**78.7**	95.1
Contract production (GWh)	**909**	828
Merchant production (GWh)	**360**	303
Total energy production (GWh)	**1,269**	1,131
Revenues[2]	**108**	96
Fuel and purchased power	**8**	4
Gross margin[2]	**100**	92
Operations, maintenance and administration	**16**	13
Taxes, other than income taxes	**2**	3
Net other operating income	**(7)**	—
Adjusted EBITDA	**89**	76
Supplemental information:		
Sustaining capital	**4**	1

(1) The gross installed capacity first quarter 2022 includes incremental capacity related to new facilities: Windrise wind facility (206 MW), North Carolina Solar facility (122 MW), and Oldman wind facility (4 MW).
(2) For details of the adjustments to revenues included in adjusted EBITDA, refer to the Additional IFRS and Non-IFRS Measures section of this MD&A.

Availability for the three months ended March 31, 2022, decreased by 16 per cent compared to the same period 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.

Production for the three months ended March 31, 2022, increased 138 GWh compared to 2021, primarily due to higher incremental production from the Windrise wind facility and North Carolina Solar facility and higher wind resources, partially offset by lower production due to the extended site outage at Kent Hills 1 and 2 Wind facilities.

Adjusted EBITDA for the three months ended March 31, 2022 increased by $13 million compared to the same period in 2021, primarily due to incremental revenue from the North Carolina Solar facility and the Windrise wind facility and liquidated damages related to turbine performance at the Windrise wind facility, partially offset by lower production due to the extended site outage at the Kent Hills 1 and 2 wind facilities and higher transmission costs experienced in the period. The prior period recognized a reimbursement as a result of the AESO transmission line loss ruling.

Sustaining capital expenditures for the three months ended March 31, 2022 were $3 million higher compared to the same period in 2021, due to higher maintenance on gearbox components in 2022.

Gas

	3 months ended March 31	
	2022	2021
Gross installed capacity (MW)	**3,084**	3,084
Availability (%)	**93.8**	85.0
Contract production (GWh)	**939**	923
Merchant production (GWh)	**1,741**	1,758
Purchased power (GWh)	**(15)**	(46)
Total production (GWh)	**2,665**	2,635
Revenues(1)	**288**	260
Fuel and purchased power(1)	**130**	80
Carbon compliance	**18**	39
Gross margin(1)	**140**	141
Operations, maintenance and administration	**44**	42
Taxes, other than income taxes	**4**	3
Net other operating income	**(10)**	(10)
Adjusted EBITDA	**102**	106
Supplemental information:		
Sustaining capital	**5**	24

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

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. These facilities include Sheerness Units 1 and 2, Keephills Units 2 and 3 and Sundance Unit 6. Previous periods have been adjusted to be comparable to the current period and reflect operations as coal units.

Availability for the three months ended March 31, 2022, increased by 9 per cent compared to the same period in 2021, primarily as a result of lower planned outages with the completion of the coal-to-gas conversions of Keephills Unit 2 and Sheerness Unit 1 and improved performance at Keephills Unit 3 and Sundance Unit 6.

Production for the three months ended March 31, 2022, increased by 30 GWh compared to the same period in 2021, mainly due to incremental production from our Ada cogeneration facility and higher contracted production in Ontario, partially offset by increased dispatch optimization for our Alberta assets.

Adjusted EBITDA for the three months ended March 31, 2022, decreased by $4 million compared to the same period in 2021, mainly due to higher gas prices and natural gas consumption by our converted units in 2022 and increased provisions. This was partially offset by higher realized merchant pricing in the Alberta market, lower carbon costs associated with the change in fuel ratios as we increased our natural gas combustion and eliminated production with coal, and lower legal fees related to the South Hedland PPA contract settlement. Refer to the Alberta Electricity Portfolio section within this MD&A for further details.

Sustaining capital expenditures for the three months ended March 31, 2022, decreased by $19 million compared to the same period in 2021, mainly due to the timing of the Keephills Unit 2 and Sheerness Unit 1 coal to natural gas conversion outages being completed in 2021.

Energy Transition

	3 months ended March 31	
	2022	**2021**
Gross installed capacity (MW)[(1)]	**784**	1,879
Availability (%)	**88.5**	86.8
Adjusted availability (%)[(2)]	**88.5**	86.8
Contract sales volume (GWh)	**820**	820
Merchant sales volume (GWh)	**1,201**	1,573
Purchased power (GWh)	**(968)**	(978)
Total production (GWh)	**1,053**	1,415
Revenues[(3)]	**117**	145
Fuel and purchased power[(3)]	**94**	93
Carbon compliance	**1**	11
Gross margin[(3)]	**22**	41
Operations, maintenance and administration	**16**	23
Taxes, other than income taxes	**1**	2
Adjusted EBITDA	**5**	16
Supplemental information:		
Highvale mine reclamation spend	**2**	1
Centralia mine reclamation spend	**4**	2
Sustaining capital	**—**	2

(1) The gross installed capacity for the first quarter of 2022 excludes Keephills Unit 1 (395 MW retired on Dec. 31, 2021) and Sundance Unit 5 (406 MW) retired in 2021 and reduced capacity for Sundance Unit 4 (293 MW).
(2) Adjusted for dispatch optimization.
(3) For details of the adjustments to revenues and fuel and purchased power included in adjusted EBITDA, refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

The 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. This 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 months ended March 31, 2022, increased by 2 per cent due to lower unplanned outages and derates at Sundance Unit 4 compared to the same period in 2021.

Production decreased by 362 GWh for the three months ended March 31, 2022, compared to the same period in 2021, primarily due the retirement of Keephills Unit 1.

Adjusted EBITDA decreased by $11 million for the three months ended March 31, 2022, compared to the same period in 2021, primarily due to lower production and higher cost of coal at Centralia, partially offset by lower carbon compliance costs and lower operating costs with the retirement of the Alberta coal units.

Mine reclamation spend for the Highvale and Centralia mines for the three months ended March 31, 2022, increased due to advancement of reclamation activities compared to the same period in 2021.

Consistent with the planned retirements and the conversions of coal-to-gas discussed above, the sustaining capital expenditures for the three months ended March 31, 2022, decreased by $2 million compared to the same period in 2021.

Energy Marketing

	3 months ended March 31	
	2022	2021
Revenues[(1)]	**34**	53
Operations, maintenance and administration	**7**	10
Adjusted EBITDA	**27**	43

(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 months ended March 31, 2022, decreased by $16 million compared to the same period in 2021. Results for the quarter were in line with expectations from favourable short-term trading of both physical and financial power and gas products across all North American markets. The higher gross margin for the three months ended March 31, 2021, was due to exceptional short-term volatility in the market. 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.

Corporate

	3 months ended March 31	
	2022	2021
Operations, maintenance, and administration	**18**	8
Adjusted EBITDA	**(18)**	(8)
Adjusted EBITDA	**(18)**	(8)
Total return swap (gains) losses	**1**	(7)
CEWS funding received	**—**	(8)
CEWS funding applied to incremental employment	**1**	—
Adjusted EBITDA excluding impact of total return swap and CEWS	**(16)**	(23)
Supplemental information:		
Total sustaining capital	**2**	2

Corporate overhead costs for the three months ended March 31, 2022, increased by $10 million compared to the same period in 2021. These changes were primarily due to the receipt of CEWS funding in 2021 and realized gains in 2021 from the total return swap on our share-based payment plans.

Adjusted EBITDA after removing the impact of the CEWS funding and total return swap for the three months ended March 31, 2022, decreased by $7 million, compared to the same period in 2021. This is primarily due to lower staffing costs, lower incentive payments and lower legal costs, occurring in the current period compared to the same period in 2021.

For the three months ended March 31, 2022, sustaining capital expenditures were consistent with the same period in 2021.

Strategy and Capability to Deliver Results

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

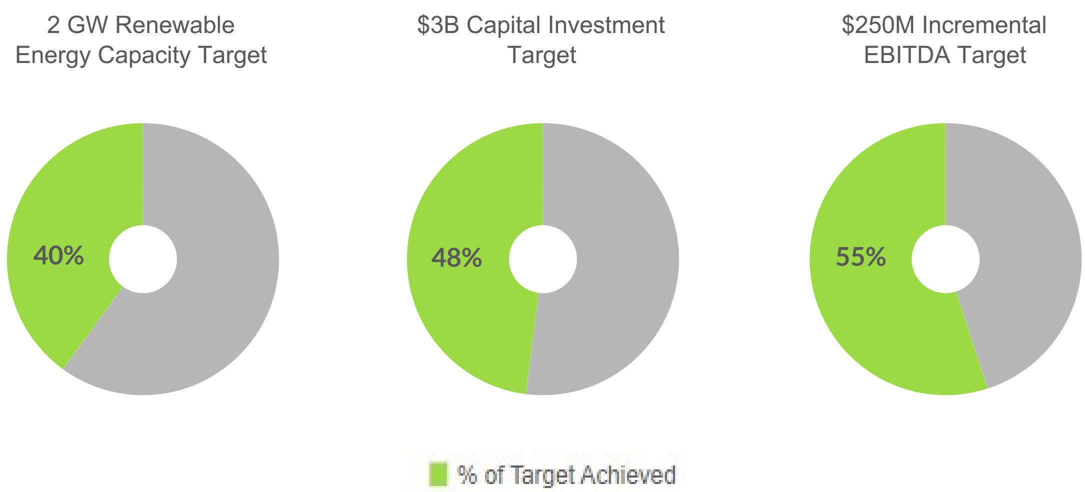
Our goal is to be a leading customer-centred electricity company, committed to a sustainable future, focused on increasing shareholder value by growing our portfolio of high quality generation facilities with stable and predictable cash flows. Our strategy includes meeting our customer needs for clean, 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, and solar 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, announced in the third quarter of 2021, will largely be funded from current cash balances, cash generated from operations, and asset-level financing.

As of May 5, 2022, we have made significant progress in achieving our growth goals. Refer to the Accelerated Clean Electricity Growth Plan in this MD&A for further details.



Our progress towards achieving our strategic targets is summarized below:

Strategic Targets

Goals	Target	Results	Comments
Accelerate Growth in Customer-centred 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 Mt 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 of US$27 - US$30 million and the Mt Keith 132kV transmission project will add incremental EBITDA 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 is evaluating 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.
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 US 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 $2.4 billion as of March 31, 2022. The Company has returned $18 million of share buybacks in the quarter.
Define the Next Generation of Power Solutions and Technologies	Meet the needs of our customers and communities through implementation of innovative power 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. In addition, the Company 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 actively engaged the Government of Canada and Government of Alberta regarding the proposed federal Clean Electricity Standard. Throughout the engagement, TransAlta provided 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*	The Company returned all of its employees to the workplace under a hybrid work model and is guided by local public health authority and government guidelines in all jurisdictions in which it operates 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 2,205 - 2,805 MW from projects in the early stages of development.

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

Projects Under Construction

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

				Total project					
Project	**Type**	**Region**	**MW**	**Estimated spend**	**Spent to date**	**Target completion date(1)**	**PPA Term (2)**	**Average annual EBITDA(3)**	**Status**
Projects Under Construction or Approved for Construction									
Canada									
Garden Plain(4)	Wind	AB	130	$190 — $200	$45	H2 2022	18	$14 - $18	• Secured all required permits and approvals • Fully contracted • Site work commenced • On track to be completed on schedule
United States									
White Rock Wind	Wind	OK	300	US$460 — US$470	US$52	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$26	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$29	H2 2022	16	AU$9 - AU$10	• Full Notice to Proceed issued on Sept. 28, 2021 • Land clearing and preparation underway • On track to be completed on schedule
Mount Keith 132kV Expansion	Transmission	WA	n/a	AU$50 — AU$ 53	AU$—	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 and Horizon Hill wind projects.
(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 PPA is fully contracted, with Pembina Pipeline Corporation ("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	$19 - $20
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
Alberta Solar Opportunities	Solar	Alberta		40
Canadian Wind Opportunities	Wind	Various		250
Brazeau Pumped Hydro	Hydro	Alberta		300 - 900
			Total	**1,290 - 1,890**
US				
Prairie Violet	Wind	Illinois		130
Old Town	Wind	Illinois		185
Big Timber	Wind	Pennsylvania		50
Other US Wind Prospects	Wind	Various		410
			Total	**775**
Australia				
Goldfields Expansions	Gas, Solar, Wind	Western Australia		90
South Hedland Solar	Solar	Western Australia		50
			Total	**140**
Canada, US and Australia			**Total**	**2,205 - 2,805**

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)]	$1,065 million - $1,185 million	$1,263 million
FCF[(1)]	$455 million - $555 million	$562 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.

Range of key 2022 power and gas price assumptions

Market	Original Expectations	Updated Expectations
Alberta Spot ($/MWh)	$80 - $90	$90 - $100
Mid-C Spot (US$/MWh)	US$45 - US$55	US$55 - US$65
AECO Gas Price ($/GJ)	$3.60	$4.50 - $5.50

Other assumptions relevant to the 2022 financial outlook	
Sustaining capital	$150 million - $170 million
Energy Marketing gross margin	$95 million - $115 million

Alberta Hedging

Range of hedging assumptions	Q2 2022	Q3 2022	Q4 2022	Full year 2023
Hedged production (GWh)	1,975	1,581	1,334	3,864
Hedge Price ($/MWh)	74	74	70	70
Hedged gas volumes (GJ)	14 million	13 million	13 million	58 million
Hedge gas prices ($/GJ)	3.11	2.96	2.96	2.28

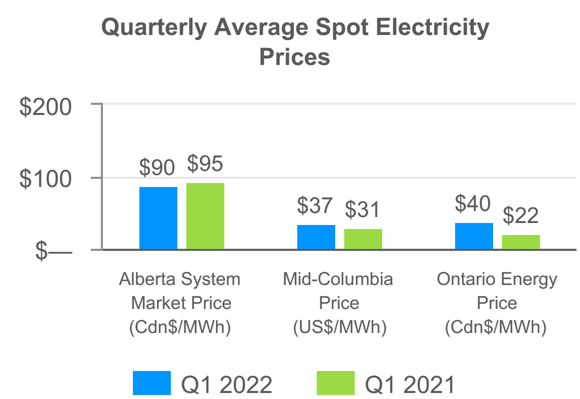
Our overall performance for the first quarter of 2022 is within expectations and the Company continues to track against stated guidance for 2022.

Operations

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

Market Pricing

For 2022, we see 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 similar to last year due to higher natural gas prices, which also raises the cost to import power from the Pacific Northwest offsetting fewer planned outages and the forecasted additions of new wind and solar supply expected to achieve commercial operation in late 2022. A major change in 2022 has been a more than $2/GJ increase in AECO natural gas prices that are supporting higher power prices for the balance of year. Weather and demand are also major factors in actual settled prices. Higher quarter-over-quarter pricing in the Pacific Northwest is being impacted by elevated U.S. natural gas prices and a lower than normal hydro outlook resulting from actual weather and hydrology in the year. Ontario power prices for 2022 are expected to be higher than 2021 due to higher natural gas prices and additional nuclear refurbishment outages.



Kent Hills Wind Facilities Outage

During the first quarter of 2022, the extended outage at Kent Hills 1 and 2 wind facilities continued. Rehabilitation efforts for the foundations are expected to commence during the second quarter of 2022 with the aim of fully returning the wind facility to service during the second half of 2023. The outage is expected to result in foregone revenue of approximately $3.4 million per month on an annualized basis so long as all 50 turbines at 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.

The Kent Hills foundation rehabilitation capital expenditures were originally estimated to range from $75 million to $100 million. The current estimate of net capital expenditures is approximately $120 million, including the cost of replacing the turbine and tower destroyed during the collapse experienced in 2021 and contingency. The cost increase is a result of the adoption of a more robust foundation design, inflationary cost pressures and an accelerated timeline to return the turbines to service ahead of December 2023. We are currently in advanced stages of discussions with New Brunswick Power Corporation and have reached an agreement in principle that provides, among other things, for a term that will now run to Dec. 31, 2045 for each of the existing power purchase agreements. In connection with the potential events of default that may have occurred under the trust indenture governing the terms of the KH Bonds, Kent Hills Wind LP is in active negotiations with the Trustee (as defined below) and the holders of the KH Bonds to obtain a waiver and expects that it will enter into a supplemental indenture during the second quarter of 2022. Refer to the Financial Capital section of this MD&A for further details.

The Company is actively evaluating any options that may be available to recover the rehabilitation costs from third parties and insurance.

Sustaining Capital Expenditures

Our estimate for total sustaining capital is as follows:

Category	Spend as at March 31, 2021	Spend to date as at March 31, 2022	Expected spend in 2022
Total sustaining capital	**34**	**17**	**$150 - $170**

Total sustaining capital expenditures for the three months ended March 31, 2022, were $17 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 and Sheerness Unit 1.

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

Liquidity and Capital Resources

We expect to maintain adequate available liquidity under our committed credit facilities. We currently have access to $2.4 billion in liquidity, including $1.2 billion in cash. We also expect to be well positioned to refinance the upcoming debt maturity in 2022. The funds required for committed growth, sustaining capital and productivity projects are not expected to be significantly impacted by the current economic environment.

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.

	Q2 2021	Q3 2021	Q4 2021	Q1 2022
Revenues	619	850	610	735
Adjusted EBITDA(1)	302	381	270	266
Earnings (loss) before income taxes	72	(441)	(32)	242
Cash flow from operating activities	80	610	54	451
FFO(1)	250	297	213	186
FCF(1)	138	189	106	115
Net earnings (loss) attributable to common shareholders	(12)	(456)	(78)	186
Net earnings (loss) per share attributable to common shareholders, basic and diluted(2)	(0.04)	(1.68)	(0.29)	0.69

	Q2 2020	Q3 2020	Q4 2020	Q1 2021
Revenues	437	514	544	642
Adjusted EBITDA(1)	217	256	234	310
Earnings (loss) before income taxes	(52)	(129)	(168)	21
Cash flow from operating activities	121	257	110	257
FFO(1)	159	193	161	211
FCF(1)	91	106	52	129
Net loss attributable to common shareholders	(60)	(136)	(167)	(30)
Net loss per share attributable to common shareholders, basic and diluted(2)	(0.22)	(0.50)	(0.61)	(0.11)

(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) Basic and diluted earnings per share attributable to common shareholders and adjusted earnings per share are calculated each period using the weighted average common shares outstanding during the period. As a result, the sum of the earnings per share for the four quarters making up the calendar year may sometimes differ from the annual earnings 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 quarter of 2022;
- Liquidated damages receivable related to turbine performance at the Windrise wind facility recorded in the first quarter of 2022;
- Lower carbon costs in the first quarter of 2022 related to going off-coal;
- Keephills Unit 1 was retired in the fourth quarter of 2021;
- Acquisition of the North Carolina Solar facility 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 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 three quarters of 2020;
- Significant foreign exchange gains in the last three quarters of 2020;
- The effects of impairments 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 increased since the fourth quarter of 2020, mainly due to the Energy Marketing's income nearly doubling between 2020 and 2021. Future tax expense increased due to valuation allowances taken on US and Canadian deferred tax assets and removal of existing coal units and impairment of coal related projects that were suspended. In the first quarter of 2022, the current income tax expense decreased due to Energy Marketing not being taxable. Future tax expense increased due to Base Erosion and Anti-Abuse Tax ("BEAT") adjustments, decreasing the non-operating loss pool in US operations and an increase in the Canadian taxable income.

Financial Position

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

Assets	March 31, 2022	Dec. 31, 2021	Increase/(decrease)
Current assets			
Cash and cash equivalents	**1,221**	947	274
Trade and other receivables	**542**	651	(109)
Risk management assets	**514**	308	206
Other current assets(1)	**279**	291	(12)
Total current assets	**2,556**	2,197	359
Non-current assets			
Risk management assets	**375**	399	(24)
Property, plant and equipment, net	**5,191**	5,320	(129)
Other non-current assets(2)	**1,303**	1,310	(7)
Total non-current assets	**6,869**	7,029	(160)
Total assets	**9,425**	9,226	199
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	**841**	689	152
Risk management liabilities	**459**	261	198
Credit facilities, long-term debt and lease liabilities (current)	**832**	844	(12)
Other current liabilities(3)	**113**	137	(24)
Total current liabilities	**2,245**	1,931	314
Non-current liabilities			
Credit facilities, long-term debt and lease liabilities	**2,391**	2,423	(32)
Decommissioning and other provisions (long-term)	**680**	779	(99)
Defined benefit obligation and other long term liabilities	**237**	253	(16)
Other non-current liabilities(4)	**1,232**	1,247	(15)
Total non-current liabilities	**4,540**	4,702	(162)
Total liabilities	**6,785**	6,633	152
Equity			
Equity attributable to shareholders	**1,695**	1,582	113
Non-controlling interests	**945**	1,011	(66)
Total equity	**2,640**	2,593	47
Total liabilities and equity	**9,425**	9,226	199

(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, risk management liabilities (long-term) 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 $311 million as at March 31, 2022 (Dec. 31, 2021 - $266 million). Our working capital increased compared to the previous period mainly due to higher cash and cash equivalents due to cash from operations and collateral received. This was partially offset by a $152 million increase in accounts payable and accrued liabilities and a $109 million decrease in trade and other receivables due to lower production in the Gas and Energy Transition segments.

Current assets increased by $359 million to $2,556 million as at March 31, 2022, from $2,197 million as at Dec. 31, 2021, mainly due to higher cash and cash equivalents and increased risk management assets primarily attributable to volatility in market prices on both existing contracts and new contracts as well as contract settlements. As at March 31, 2022, the Company held $270 million (Dec. 31, 2021 - $18 million) of cash collateral received related to derivative instruments in a net asset position. This was partially offset by reductions in trade and other receivables due to lower production in 2022.

Current liabilities increased by $314 million from $1,931 million as at Dec. 31, 2021 to $2,245 million as at March 31, 2022, mainly due to an increase in risk management liabilities primarily due to volatility in market prices and contract settlements, higher fuel related payables, and higher collateral received for contract positions in accounts payable.

Non-current Assets

Non-current assets at March 31, 2022 are $6,869 million, a decrease of $160 million from $7,029 million as at Dec. 31, 2021. The decrease was primarily due to depreciation, change in estimate of $56 million within PP&E related to increased discount rates on decommissioning and restoration provisions and $14 million unfavourable impact from changes in currency translation. These impacts were partially offset by 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 March 31, 2022 are $4,540 million, a decrease of $162 million from $4,702 million as at Dec. 31, 2021, mainly due to a $101 million decrease to the total decommissioning and restoration provision as a result of increased discount rates, a $32 million decrease in long-term debt and lease liabilities related to scheduled principal repayments on long-term debt and lease liabilities, and a $23 million change in defined benefit obligation due to changes in discount rate assumptions.

Total Equity

As at March 31, 2022, the increase in total equity of $47 million was mainly due to net earnings for the period of $186 million and actuarial gains on defined benefit plans of $18 million, partially offset by net losses on cash flow hedges of $98 million, distributions to non-controlling interests of $42 million, the effect of share-based payment plans of $15 million, and share repurchases under the NCIB of $18 million.

Financial Capital

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

Capital Structure

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

	March 31, 2022		Dec. 31, 2021	
	$	%	$	%
TransAlta Corporation				
Net senior unsecured debt				
Recourse debt - CAD debentures	**251**	**5**	251	4
Recourse debt - US senior notes	**867**	**16**	888	16
Other	**3**	**—**	4	—
Less: cash and cash equivalents	**(943)**	**(18)**	(703)	(12)
Less: other cash and liquid assets[1]	**4**	**—**	(19)	—
Net senior unsecured debt	**182**	**3**	421	8
Other debt liabilities				
Exchangeable debentures	**336**	**6**	335	6
Non-recourse debt				
TAPC Holdings LP bond	**101**	**2**	102	2
OCP bond	**252**	**5**	263	5
Lease liabilities	**77**	**1**	78	1
Total net debt - TransAlta Corporation	**948**	**17**	1,199	22
TransAlta Renewables				
Net TransAlta Renewables reported debt				
Non-recourse debt				
Pingston bond	**45**	**1**	45	1
Melancthon Wolfe Wind bond	**235**	**4**	235	4
New Richmond Wind bond	**120**	**2**	120	2
Kent Hills Wind bond	**218**	**4**	221	4
Windrise Wind bond	**171**	**3**	171	3
Lease liabilities	**22**	**—**	22	—
Less: cash and cash equivalents	**(278)**	**(4)**	(244)	(4)
Debt on TransAlta Renewables Economic Investments				
US tax equity financing[2]	**125**	**2**	135	2
South Hedland non-recourse debt[3]	**736**	**14**	732	13
Total net debt - TransAlta Renewables	**1,394**	**26**	1,437	25
Total consolidated net debt[4][5]	**2,342**	**43**	2,636	47
Non-controlling interests	**945**	**18**	1,011	18
Exchangeable preferred securities[5]	**400**	**7**	400	7
Equity attributable to shareholders				
Common shares	**2,892**	**54**	2,901	51
Preferred shares	**942**	**18**	942	17
Contributed surplus, deficit and accumulated other comprehensive income	**(2,139)**	**(40)**	(2,261)	(40)
Total capital	**5,382**	**100**	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$795 million senior secured notes.
(4) The tax equity financing for Skookumchuck, 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.

Between 2022 and 2024, we have $1,067 million of debt maturing, including $502 million of recourse debt, with the balance mainly related to scheduled non-recourse debt repayments. The Company has classified the entire carrying value outstanding of $218 million for the KH Bonds as a current liability as at March 31, 2022 and upon obtaining a waiver and supplemental indenture, will reclassify to non-current liabilities. We currently expect to refinance the senior notes maturing in 2022.

Credit Facilities

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

As at March 31, 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	658	—	592	Q2 2025
Canadian committed bilateral credit facilities	240	217	—	23	Q2 2023
TransAlta Renewables					
Committed credit facility[2]	700	98	—	602	Q2 2025
Total	**2,190**	**973**	**—**	**1,217**	

(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 March 31, 2022, we provided cash collateral of $20 million.

(2) TransAlta has letters of credit of $184 million and TransAlta Renewables has letters of credit of $98 million issued from uncommitted demand facilities; these obligations are backstopped and reduce the available capacity on the committed credit facilities.

Non-Recourse Debt

The Melancthon Wolfe Wind LP, Pingston Power Inc., TAPC Holdings LP, New Richmond Wind LP, Kent Hills Wind LP, TEC Hedland PTY Ltd notes, Windrise Wind LP and TransAlta OCP LP non-recourse bonds are subject to customary financing conditions and covenants that may restrict the Company's ability to access funds generated by the facilities' operations. Upon meeting certain distribution tests, typically performed once per quarter, the funds are able to be distributed by the subsidiary entities to their respective parent entity. These conditions include meeting a debt service coverage ratio prior to distribution, which was met by these entities in the first quarter of 2022, except in relation to the KH Bonds. The next debt service coverage ratio is calculated in the second quarter of 2022.

Following the foundation issues at Kent Hills 1 and 2 Wind facilities, Kent Hills Wind LP has provided notice to BNY Trust Company of Canada, as trustee (the "Trustee"), for the approximately $218 million outstanding non-recourse KH Bonds secured by, among other things, the Kent Hills 1, 2 and 3 wind facilities, that events of default may have occurred under the trust indenture governing the terms of such bonds. Upon the occurrence of any event of default, holders of more than 50 per cent of the outstanding principal amount of the KH Bonds have the right to direct the Trustee to declare the principal and interest on the KH Bonds and all other amounts due, together with any make-whole amount of $23 million (Dec. 31, 2021 — $39 million), to be immediately due and payable and to direct the Trustee to exercise rights against certain collateral. The Company is in negotiations to obtain a waiver and expects to enter into a supplemental indenture during the second quarter of 2022. The Company continues to work towards bringing the site back to full operations. Refer to the 2022 Financial Outlook section of this MD&A for further details on the Kent Hills wind facilities outage.

Returns to Providers of Capital

Net Interest Expense

The components of net interest expense are shown below:

	3 months ended March 31	
	2022	2021
Interest on debt	**41**	40
Interest on exchangeable debentures	**7**	7
Interest on exchangeable preferred shares	**7**	**7**
Interest income	**(3)**	(3)
Capitalized interest	**(1)**	(5)
Interest on lease liabilities	**1**	2
Credit facility fees, bank charges and other interest	**6**	4
Tax shield on tax equity financing	**—**	1
Other	**—**	3
Accretion of provisions	**9**	7
Net interest expense	**67**	63

Net interest expense for the three months ended March 31, 2022, was consistent with the same period in 2021.

Share Capital

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

As at	**May 5, 2022**	**March 31, 2022**	**Dec. 31, 2021**
	Number of shares *(millions)*		
Common shares issued and outstanding, end of period	**270.6**	**270.6**	269.9
Preferred shares			
Series A	9.6	**9.6**	9.6
Series B	2.4	**2.4**	2.4
Series C	11.0	**11.0**	11.0
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.

Non-Controlling Interests

As at March 31, 2022, the Company owns 60.1 per cent (March 31, 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 (March 31, 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 months ended March 31, 2022, increased by $11 million to $20 million compared to the same period in 2021. Earnings from TA Cogen for the three months ended March 31, 2022, decreased compared with the same period in 2021, mainly due to higher gas commodity price, transportation costs and lower realized power price for our Sheerness units. Earnings increased at TransAlta Renewables in 2022 primarily due to higher revenue from the Windrise wind facility and the recognition of liquidated damages related to turbine performance at the Windrise wind facility. This increase was partially offset by lower finance income and the extended site outage at the Kent Hills 1 and 2 wind facilities (see Note 8 of the unaudited interim condensed consolidated financial statements for further details).

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 not incurred any additional material contractual commitments, either directly or through its interests in joint operations in the three months ended, March 31, 2022.

For the Kent Hills foundation capital expenditures we are now in the final stages of detailed negotiations for all agreements necessary to receive approvals and commence remediation in the second quarter of 2022. We are expecting the rehabilitation of the wind facilities to fully return the wind facilities to service in the second half of 2023. Refer to the 2022 Financial Outlook section for further details.

For updates on 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. There have been no material updates to any of the contingencies in the three month period ended March 31, 2022.

Cash Flows

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

	3 months ended March 31		
	2022	2021	**Increase/ (decrease)**
Cash and cash equivalents, beginning of period	**947**	703	244
Provided by (used in):			
Operating activities	**451**	257	194
Investing activities	**(72)**	(111)	39
Financing activities	**(106)**	(200)	94
Translation of foreign currency cash	**1**	(1)	2
Cash and cash equivalents, end of period	**1,221**	648	573

Cash provided by operating activities for the three months ended March 31, 2022, increased compared with the same period in 2021 primarily due to changes in our non-cash working capital.

Cash used in investing activities for the three months ended March 31, 2022, decreased compared with the same period in 2021, largely due to:

- Decreased cash spend on project construction activities in PP&E ($26 million);
- Lower non-cash working capital related to the timing of construction payables for the assets under construction ($14 million); and
- Higher restricted cash payments related to funding principal debt repayments ($5 million).

Cash used in financing activities for the three months ended March 31, 2022, decreased compared with the same period in 2021, largely due to:

- Lower drawings under the Company's credit facilities ($114 million);
- Partially offset by higher common share repurchases under the NCIB ($11 million);
- Increased distributions paid to subsidiaries' non-controlling interests ($5 million); and
- Higher repayments on long term debt ($7 million).

Financial Instruments

Refer to Note 15 of the notes to the audited annual consolidated financial statements within our 2021 Annual MD&A and Note 9 and 10 of our unaudited interim condensed consolidated financial statements as at and for the three months ended March 31, 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 March 31, 2022, Level III instruments had a net liability carrying value of $203 million (Dec. 31, 2021 - net asset of $159 million).

Please refer to the Critical Accounting Policies and Estimates section of this MD&A for further details regarding valuation techniques. 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 months ended March 31, 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 consolidated financial statements prepared in accordance with IFRS. We believe that these non-IFRS amounts, measures and ratios, read together with our IFRS amounts, provide readers with a better understanding of how management assesses results.

Non-IFRS amounts, measures and ratios do not have standardized meanings under IFRS. They are unlikely to be comparable to similar measures presented by other companies and should not be viewed in isolation from, 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 relabelled 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. 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.

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 by the end of 2021 as 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 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 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 in our total adjusted EBITDA. In addition, in the Wind and Solar adjusted results, we have included our proportionate share of revenues and expenses to reflect the full operational results of this investment. We have not included EMG'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").

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 for the Alberta market. See the Alberta Electricity Portfolio section of this MD&A for additional information.

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

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

	Attributable to common shareholders									
	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity accounted investments[1]	Reclass Adjustments	IFRS Financials
Revenues	77	95	434	106	26	1	739	(4)	—	735
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	—	13	(162)	11	10	—	(128)	—	128	—
Decrease in finance lease receivable	—	—	11	—	—	—	11	—	(11)	—
Finance lease income	—	—	5	—	—	—	5		(5)	—
Unrealized foreign exchange gain on commodity	—	—	—	—	(2)	—	(2)	—	2	—
Adjusted Revenues	77	108	288	117	34	1	625	(4)	114	735
Fuel and purchased power	4	8	131	94	—	1	238	—	—	238
Reclassifications and adjustments:										
Australian interest income	—	—	(1)	—	—	—	(1)	—	1	—
Adjusted fuel and purchased power	4	8	130	94	—	1	237	—	1	238
Carbon compliance	—	—	18	1	—	—	19	—	—	19
Gross margin	73	100	140	22	34	—	369	(4)	113	478
OM&A	11	16	44	16	7	18	112	—	—	112
Taxes, other than income taxes	1	2	4	1	—	—	8	—	—	8
Net other operating income	—	(7)	(10)	—	—	—	(17)	—	—	(17)
Adjusted EBITDA	61	89	102	5	27	(18)	266			
Equity income										2
Finance lease income										5
Depreciation and amortization										(117)
Asset impairment reversal										42
Net interest expense										(67)
Foreign exchange gain and other gains										2
Earnings before income taxes										242

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

The following table reflects adjusted EBITDA by segment and provides reconciliation to earnings (loss) before income taxes for the period ended March 31, 2021:

	Attributable to common shareholders									
	Hydro	Wind & Solar(1)	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity accounted investments(1)	Reclass Adjustments	IFRS Financials
Revenues	89	91	266	139	61	1	647	(5)	—	642
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	—	5	(23)	6	(8)	—	(20)	—	20	—
Decrease in finance lease receivable	—	—	10	—	—	—	10	—	(10)	—
Finance lease income	—	—	7	—	—	—	7	—	(7)	—
Adjusted Revenues	89	96	260	145	53	1	644	(5)	3	642
Fuel and purchased power(2)	3	4	108	129	—	1	245	—	—	245
Reclassifications and adjustments:										
Australian interest income	—	—	(1)	—	—	—	(1)	—	1	—
Mine depreciation	—	—	(27)	(28)	—	—	(55)	—	55	—
Coal inventory write-down	—	—	—	(8)	—	—	(8)	—	8	—
Adjusted fuel and purchased power	3	4	80	93	—	1	181	—	64	245
Carbon compliance			39	11	—	—	50	—	—	50
Gross margin	86	92	141	41	53	—	413	(5)	(61)	347
OM&A(2)	8	13	42	23	10	8	104	(1)	—	103
Taxes, other than income taxes	1	3	3	2	—	—	9	—	—	9
Net other operating income	—	—	(10)	—	—	—	(10)	—	—	(10)
Adjusted EBITDA	77	76	106	16	43	(8)	310			
Equity income										2
Finance lease income										7
Depreciation and amortization										(149)
Asset impairment charge										(29)
Net interest expense										(63)
Foreign exchange gain and other gains										8
Earnings before income taxes										21

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.
(2) $2 million related to station service costs for the Hydro segment in the three months ended March 31, 2021 was reclassified from operations, maintenance and administration to fuel and purchased power for comparative purposes. This did not impact previously reported net earnings.

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

	3 months ended March 31	
	2022	2021
Cash flow from operating activities[1]	**451**	257
Change in non-cash operating working capital balances	**(284)**	(72)
Cash flow from operations before changes in working capital	**167**	185
Adjustments		
Share of adjusted FFO from joint venture[1]	**3**	4
Decrease in finance lease receivable	**11**	10
Clean energy transition provisions and adjustments[2]	**—**	8
Other[3]	**5**	4
FFO[4]	**186**	211
Deduct:		
Sustaining capital[1]	**(17)**	(34)
Productivity capital	**(1)**	—
Dividends paid on preferred shares	**(10)**	(10)
Distributions paid to subsidiaries' non-controlling interests	**(42)**	(37)
Principal payments on lease liabilities[1]	**(1)**	(1)
FCF[4]	**115**	129
Weighted average number of common shares outstanding in the period	**271**	270
FFO per share[4]	**0.69**	0.78
FCF per share[4]	**0.42**	0.48

(1) Includes our share of amounts for Skookumchuck, an equity accounted joint venture.
(2) Includes 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 March 31	
	2022	2021
Adjusted EBITDA[1]	**266**	310
Provisions	**10**	(5)
Interest expense[2]	**(54)**	(51)
Current income tax expense[2]	**(12)**	(23)
Realized foreign exchange gain (loss)	**2**	(1)
Decommissioning and restoration costs settled[2]	**(7)**	(3)
Other non-cash items[3]	**(19)**	(16)
FFO[4]	**186**	211
Deduct:		
Sustaining capital[2]	**(17)**	(34)
Productivity capital	**(1)**	—
Dividends paid on preferred shares	**(10)**	(10)
Distributions paid to subsidiaries' non-controlling interests	**(42)**	(37)
Principal payments on lease liabilities[2]	**(1)**	(1)
FCF[4]	**115**	129

(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, an equity accounted joint venture.
(3) Other consists of production tax credits which is a reduction to tax equity debt.
(4) 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 for the period ended March 31:

	Actual Generation (GWh)		Adjusted EBITDA		Earnings (Loss) before income taxes	
As at March 31	**2022**	2021	**2022**	2021	**2022**	2021
TransAlta Renewables						
Hydro	**41**	40	**1**	1		
Wind and Solar[1]	**1,269**	1,069	**88**	75		
Gas[1]	**935**	758	**56**	53		
Corporate	**—**	—	**(6)**	(6)		
TransAlta Renewables before adjustments	**2,245**	1,867	**139**	123	**49**	61
Less: Proportion of TransAlta Renewables not owned by TransAlta Corporation	**(896)**	(742)	**(55)**	(48)	**(20)**	(24)
Portion of TransAlta Renewables owned by TransAlta Corporation	**1,349**	1,125	**84**	75	**29**	37
Add: TransAlta Corporation's owned assets excluding TransAlta Renewables						
Hydro	**331**	320	**60**	76		
Wind and Solar	**—**	62	**1**	1		
Gas	**1,730**	1,877	**46**	53		
Energy Transition	**1,053**	1,415	**5**	16		
Energy Marketing	**—**	—	**27**	43		
Corporate	**—**	—	**(12)**	(2)		
TransAlta Corporation with Proportionate Share of TransAlta Renewables	**4,463**	4,799	**211**	262	**222**	(3)
Non-controlling interests	**896**	742	**55**	48	**20**	24
TransAlta Consolidated	**5,359**	5,541	**266**	310	**242**	21

(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

As at Dec. 31	March 31, 2022	Dec. 31, 2021
Period-end long-term debt(1)	**3,223**	3,267
Exchangeable securities	**336**	335
Less: Cash and cash equivalents	**(1,221)**	(947)
Add: 50 per cent of issued preferred shares and exchangeable preferred shares(2)	**671**	671
Other(3)	**4**	(19)
Adjusted net debt(4)	**3,013**	3,307
Adjusted EBITDA(5)	**1,219**	1,263
Adjusted net debt to adjusted EBITDA (times)	**2.5**	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 March 31, 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, 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 lower than 2021 as a result of lower adjusted EBITDA in the first quarter of 2022, higher cash and cash equivalents, and 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 March 31, 2022			3 months ended March 31, 2021		
	TransAlta Consolidated	**TransAlta Renewables**	**TransAlta Deconsolidated**	TransAlta Consolidated	TransAlta Renewables	TransAlta Deconsolidated
Hydro	**61**	**1**		77	1	
Wind and Solar	**89**	**88**		76	75	
Gas	**102**	**56**		106	53	
Energy Transition	**5**	**—**		16	—	
Energy Marketing	**27**	**—**		43	—	
Corporate	**(18)**	**(6)**		(8)	(6)	
Adjusted EBITDA	**266**	**139**	**127**	310	123	187
Less: TA Cogen adjusted EBITDA			**(14)**			(25)
Less: EBITDA from joint venture investments(1)			**—**			(4)
Add: Dividend from TransAlta Renewables			**38**			38
Add: Dividend from TA Cogen			**10**			3
Deconsolidated TransAlta adjusted EBITDA			**161**			199

(1) As of the second quarter of 2021, our share of amounts for the Skookumchuck equity accounted joint venture is excluded from the TransAlta deconsolidated results due to the sale of its 100 per cent 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 March 31, 2022 and 2021 is detailed below:

	3 months ended March 31, 2022			3 months ended March 31, 2021		
	TransAlta Consolidated	**TransAlta Renewables**	**TransAlta Deconsolidated**	TransAlta Consolidated	TransAlta Renewables	TransAlta Deconsolidated
Cash flow from operating activities	**451**	**103**		257	103	
Change in non-cash operating working capital balances	**(284)**	**(17)**		(72)	(15)	
Cash flow from operations before changes in working capital	**167**	**86**		185	88	
Adjustments:						
Decrease in finance lease receivable	**11**	**—**		10	—	
Clean energy transition provisions and adjustments	**—**	**—**		8	—	
Share of FFO from joint venture(1)	**3**	**—**		4	—	
Finance income - economic interests	**—**	**(19)**		—	(29)	
FFO - economic interests(2)	**—**	**49**		—	35	
Other(3)	**5**	**—**		4	6	
FFO	**186**	**116**	**70**	211	100	111
Dividend from TransAlta Renewables			**38**			38
Distributions to TA Cogen's Partner			**(18)**			(11)
Less: Share of adjusted FFO from joint venture(1)			**—**			(4)
Deconsolidated TransAlta FFO			**90**			134

(1) As of the second quarter of 2021, our share of amounts for the Skookumchuck equity accounted joint venture is excluded from the TransAlta deconsolidated results due to the sale of its 100 per cent 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 less distributions from equity accounted joint venture .
(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	March 31, 2022	Dec. 31, 2021
Adjusted net debt[1]	**3,013**	3,307
Add: TransAlta Renewables cash and cash equivalents	**278**	244
Less: TransAlta Renewables long-term debt	**(811)**	(814)
Less: US tax equity financing and South Hedland debt[2]	**(861)**	(867)
Deconsolidated net debt	**1,619**	1,870
Deconsolidated adjusted EBITDA[3][5]	**848**	852
Deconsolidated net debt to deconsolidated adjusted EBITDA[4] (times)	**1.9**	2.2

(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 three months ended March 31, 2022 decreased compared with 2021, due to lower deconsolidated net debt and lower deconsolidated adjusted EBITDA. Lower deconsolidated net debt is a result of scheduled repayments on corporate debt and an increase 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. The following were material changes in estimates in the quarter:

During the three months ended March 31, 2022, the global economy continued to recover from the COVID-19 pandemic. Energy prices have strengthened due to elevated uncertainty of global oil and natural gas supply given the war in Ukraine. 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 and the geopolitical events have been considered in our estimates as at and for the period ended March 31, 2022.

Provisions for Decommissioning and Restoration Activities

The Company recognizes provisions for decommissioning and restoration obligations. Initial decommissioning provisions, and subsequent changes thereto, are determined using the Company's best estimate of the required cash expenditures, adjusted to reflect the risks and uncertainties inherent in the timing and amount of settlement. During the first quarter of 2022, the provision for the decommissioning and restoration obligations decreased as a result of higher discount rates, largely driven by underlying market benchmark yields. Refer to Note 13 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 to $205 million as at March 31, 2022 from $228 million as at Dec. 31, 2021.

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 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 consolidated financial statements for the future accounting policies impacting the Company. In the three months ended, March 31, 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.

Governance and Risk Management

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

Please refer to the Governance and Risk Management section of our 2021 Annual MD&A and Note 10 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 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 government 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.

Federal Carbon Pricing on GHG
The Canadian government released an Output-based Pricing System ("OBPS") consultation paper on Dec. 10, 2021, to initiate a 2022 engagement process. TransAlta made a submission regarding the consultation paper and will closely engage governments regarding the review, amendments and regulatory clarification.

Ontario
Ontario will hold a provincial election on or before June 2, 2022. Ahead of the election, the government is engaged in policy development processes regarding the future of the province's Emissions Performance Standards ("EPS") carbon pricing system, a natural gas transition. and development of a voluntary clean energy credit market.

TransAlta's Ontario thermal assets pass through carbon costs under current contracts, minimizing the impact of any change to the EPS. TransAlta continues to engage the government on its other policy initiatives to mitigate risk and identify areas of potential opportunity.

In 2022, the IESO is moving forward with procurement and planning to meet the upcoming capacity needs in the province. The IESO is running a medium-term request for proposals ("RFP") to procure up to 475 MW of capacity from existing generators. This procurement process has been designed to meet the emerging electricity system needs mid-decade. Proposal submissions were due on April 28, 2022, with the RFP awards scheduled for Aug. 26, 2022. The Company is participating in this process. In addition, TransAlta is participating in IESO consultation on the design for a new long-term RFP procurement design for new generation.

United States
On March 21, 2022, the U.S. Securities and Exchange Commission ("SEC") released proposed rules to enhance and standardize climate-related disclosure for investors. The proposed rules cover climate risk governance and risk management, disclosure of material impacts over all time horizons, impacts on business models, and the impact of climate-related events. The SEC invited comments on the proposed rules before finalization and we anticipate the final rules will face legal challenges. TransAlta 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.

Congress continues to consider options for support for renewable energy and energy storage as a part of its broader budget discussions. TransAlta continues to monitor any potential changes for impacts on our growth plans.

Australia
Australia will hold a national election on May 21, 2022. Parties continue to release policy proposals, including policies related to energy and climate. The opposition Labour Party has promised to increase the "AUS 2030" emissions reduction goal and enhance government support for electrification. However, none of the policies proposed to date present significant adverse risks to TransAlta's performance.

Disclosure Controls and Procedures
Management is responsible for establishing and maintaining adequate internal control over financial reporting (“ICFR”) and disclosure controls and procedures (“DC&P”). During the three months ended March 31, 2022, the majority of our workforce supporting and executing our ICFR and DC&P worked remotely. 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 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 NI 52-109 and consistent with U.S. Securities and Exchange Commission guidance, the scope of the evaluation did not include internal controls over financial reporting of North Carolina Solar facility, which the Company acquired on Nov. 5, 2021. The North Carolina Solar facility 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 facility's total and net assets represented approximately 2 per cent and 3 per cent of the Company's total and net assets, respectively, as at March 31, 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 March 31, 2022, the end of the period covered by this MD&A, our ICFR and DC&P were effective.

Condensed Consolidated Statements of Earnings

(in millions of Canadian dollars except per share amounts)

	3 months ended March 31	
Unaudited	**2022**	2021
Revenues (Note 3)	**735**	642
Fuel and purchased power (Note 4)	**238**	245
Carbon compliance	**19**	50
Gross margin	**478**	347
Operations, maintenance and administration (Note 4)	**112**	103
Depreciation and amortization	**117**	149
Asset impairment charge (reversal) (Note 5 and 13)	**(42)**	29
Taxes, other than income taxes	**8**	9
Net other operating income	**(17)**	(10)
Operating income	**300**	67
Equity income	**2**	2
Finance lease income	**5**	7
Net interest expense (Note 6)	**(67)**	(63)
Foreign exchange gain and other gains	**2**	8
Earnings before income taxes	**242**	21
Income tax expense (Note 7)	**36**	20
Net earnings	**206**	1
Net earnings (loss) attributable to:		
TransAlta shareholders	**186**	(30)
Non-controlling interests (Note 8)	**20**	31
	206	1
Weighted average number of common shares outstanding in the period *(millions)*	**271**	270
Net earnings (loss) per share attributable to common shareholders, basic and diluted (Note 15)	**0.69**	(0.11)

See accompanying notes.

Condensed Consolidated Statements of Comprehensive Income (Loss)

(in millions of Canadian dollars)

	3 months ended March 31	
Unaudited	**2022**	2021
Net earnings	**206**	1
Other comprehensive income (loss)		
Net actuarial gains on defined benefit plans, net of tax[1]	**18**	37
Losses on derivatives designated as cash flow hedges, net of tax	**(1)**	(1)
Total items that will not be reclassified subsequently to net earnings	**17**	36
Losses on translating net assets of foreign operations, net of tax	**(14)**	(13)
Gains on financial instruments designated as hedges of foreign operations, net of tax	**10**	5
Losses on derivatives designated as cash flow hedges, net of tax[2]	**(82)**	(23)
Reclassification of gains on derivatives designated as cash flow hedges to net earnings, net of tax[3]	**(15)**	(18)
Total items that will be reclassified subsequently to net earnings	**(101)**	(49)
Other comprehensive loss	**(84)**	(13)
Total comprehensive income (loss)	**122**	(12)

Total comprehensive income (loss) attributable to:		
TransAlta shareholders	**146**	(2)
Non-controlling interests (Note 8)	**(24)**	(10)
	122	(12)

(1) Net of income tax expense of $5 million for the three months ended March 31, 2022 (2021 — $11 million expense).
(2) Net of income tax recovery of $23 million for the three months ended March 31, 2022 (2021 —$8 million recovery).
(3) Net of reclassification of income tax recovery of $4 million for the three months ended March 31, 2022 (2021 —$5 million recovery).

See accompanying notes.

Condensed Consolidated Statements of Financial Position

(in millions of Canadian dollars)

Unaudited	**March 31, 2022**	Dec. 31, 2021
Current assets		
Cash and cash equivalents	**1,221**	947
Restricted cash	**49**	70
Trade and other receivables	**542**	651
Prepaid expenses	**49**	29
Risk management assets (Note 9 and 10)	**514**	308
Inventory	**154**	167
Assets held for sale	**27**	25
	2,556	2,197
Non-current assets		
Investments	**106**	105
Long-term portion of finance lease receivables	**172**	185
Risk management assets (Note 9 and 10)	**375**	399
Property, plant and equipment (Note 11)		
Cost	**13,318**	13,389
Accumulated depreciation	**(8,127)**	(8,069)
	5,191	5,320
Right-of-use assets	**93**	95
Intangible assets	**265**	256
Goodwill	**463**	463
Deferred income tax assets	**57**	64
Other assets	**147**	142
Total assets	**9,425**	9,226
Current liabilities		
Accounts payable and accrued liabilities	**841**	689
Current portion of decommissioning and other provisions (Note 13)	**46**	48
Risk management liabilities (Note 9 and 10)	**459**	261
Current portion of contract liabilities	**16**	19
Income taxes payable	**12**	8
Dividends payable (Note 15 and 16)	**39**	62
Current portion of long-term debt and lease liabilities (Note 14)	**832**	844
	2,245	1,931
Non-current liabilities		
Credit facilities, long-term debt and lease liabilities (Note 14)	**2,391**	2,423
Exchangeable securities	**736**	735
Decommissioning and other provisions (Note 13)	**680**	779
Deferred income tax liabilities	**346**	354
Risk management liabilities (Note 9 and 10)	**138**	145
Contract liabilities	**12**	13
Defined benefit obligation and other long-term liabilities	**237**	253
Total liabilities	**6,785**	6,633
Equity		
Common shares (Note 15)	**2,892**	2,901
Preferred shares (Note 16)	**942**	942
Contributed surplus	**25**	46
Deficit	**(2,270)**	(2,453)
Accumulated other comprehensive income	**106**	146
Equity attributable to shareholders	**1,695**	1,582
Non-controlling interest (Note 8)	**945**	1,011
Total equity	**2,640**	2,593
Total liabilities and equity	**9,425**	9,226

Commitments and contingencies (Note 17)
Subsequent events (Note 19)

See accompanying notes.

Condensed Consolidated Statements of Changes in Equity

(in millions of Canadian dollars)

Unaudited

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

3 months ended March 31, 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)	—	—	—	(30)	—	(30)	31	1
Other comprehensive income (loss):								
Net losses on translating net assets of foreign operations, net of hedges and tax	—	—	—	—	(8)	(8)	—	(8)
Net losses on derivatives designated as cash flow hedges, net of tax	—	—	—	—	(44)	(44)	2	(42)
Net actuarial gains on defined benefits plans, net of tax	—	—	—	—	37	37	—	37
Intercompany FVOCI investments	—	—	—	—	43	43	(43)	—
Total comprehensive income (loss)	—	—	—	(30)	28	(2)	(10)	(12)
Effect of share-based payment plans	(2)	—	(8)	—	—	(10)	—	(10)
Distributions paid, and payable, to non-controlling interests (Note 8)	—	—	—	—	—	—	(37)	(37)
Balance, March 31, 2021	2,894	942	30	(1,856)	330	2,340	1,037	3,377

See accompanying notes.

Condensed Consolidated Statements of Cash Flows

(in millions of Canadian dollars)

	3 months ended March 31	
Unaudited	**2022**	2021
Operating activities		
Net earnings	**206**	1
Depreciation and amortization (Note 18)	**117**	204
Gain on sale of assets	**—**	(1)
Accretion of provisions (Note 13)	**9**	7
Decommissioning and restoration costs settled (Note 13)	**(7)**	(3)
Deferred income tax expense (recovery) (Note 7)	**24**	(3)
Unrealized gain from risk management activities	**(129)**	(20)
Unrealized foreign exchange gain	**(2)**	(9)
Provisions	**5**	(4)
Asset impairment charges (reversals) (Note 5 and 13)	**(42)**	29
Equity income, net of distributions from investments	**(1)**	(2)
Other non-cash items	**(13)**	(14)
Cash flow from operations before changes in working capital	**167**	185
Change in non-cash operating working capital balances	**284**	72
Cash flow from operating activities	**451**	257
Investing activities		
Additions to property, plant, and equipment (Note 11)	**(72)**	(98)
Additions to intangible assets (Note 12)	**(21)**	(1)
Restricted cash	**22**	17
Proceeds on sale of property, plant and equipment	**—**	4
Realized losses on financial instruments	**(1)**	(2)
Decrease in finance lease receivable	**11**	10
Other	**11**	(5)
Change in non-cash investing working capital balances	**(22)**	(36)
Cash flow used in investing activities	**(72)**	(111)
Financing activities		
Net decrease in borrowings under credit facilities	**—**	(114)
Repayment of long-term debt	**(25)**	(18)
Dividends paid on common shares (Note 15)	**(14)**	(12)
Dividends paid on preferred shares (Note 16)	**(10)**	(10)
Repurchase of common shares under NCIB (Note 15)	**(15)**	(4)
Proceeds on issuance of common shares	**1**	—
Distributions paid to subsidiaries' non-controlling interests (Note 8)	**(42)**	(37)
Decrease in lease liabilities	**(1)**	(2)
Financing fees and other	**—**	(2)
Change in non-cash financing working capital balances	**—**	(1)
Cash flow used in financing activities	**(106)**	(200)
Cash flow from (used in) operating, investing and financing activities	**273**	(54)
Effect of translation on foreign currency cash	**1**	(1)
Increase (decrease) in cash and cash equivalents	**274**	(55)
Cash and cash equivalents, beginning of period	**947**	703
Cash and cash equivalents, end of period	**1,221**	648
Cash taxes paid	**18**	12
Cash interest paid	**47**	51

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

During the fourth quarter of 2021, the Company realigned its current operating segments to better 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.

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's and the subsidiaries that it controls.

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

These unaudited interim condensed consolidated financial statements reflect all adjustments which consist of normal recurring adjustments and accruals that are, in the opinion of management, necessary for a fair presentation of results. Interim results will fluctuate due to plant maintenance schedules, the seasonal demands for electricity and changes in energy prices. Consequently, interim condensed results are not necessarily indicative of annual results. TransAlta's results are partly seasonal due to the nature of the electricity market and related fuel costs. Higher maintenance costs are ordinarily incurred in the second and third quarters when electricity prices are expected to be lower, as electricity prices generally increase in the winter months in the Canadian market.

These unaudited interim condensed consolidated financial statements were authorized for issue by the Audit, Finance and Risk Committee on behalf of TransAlta's Board of Directors (the "Board") on May 5, 2022.

C. Use of Estimates and Significant Judgements

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. Refer to Note 2(P) of the Company's most recent audited annual consolidated financial statements for further details. 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.

Changes in Estimates

During the three months ended March 31, 2022, the global economy continued to recover from the COVID-19 pandemic. Energy prices have strengthened due to elevated uncertainty of global oil and natural gas supply given the war in Ukraine. 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 and the geopolitical events have been considered in our estimates as at and for the period ended March 31, 2022.

Provisions for Decommissioning and Restoration Activities

The Company recognizes provisions for decommissioning and restoration obligations. Initial decommissioning provisions, and subsequent changes thereto, are determined using the Company's best estimate of the required cash expenditures, adjusted to reflect the risks and uncertainties inherent in the timing and amount of settlement. During the first quarter of 2022, the provision for the decommissioning and restoration obligations decreased as a result of higher discount rates, largely driven by underlying market benchmark yields. Refer to Note 13 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 to $205 million as at March 31, 2022 from $228 million as at Dec. 31, 2021.

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 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 consolidated financial statements for the future accounting policies impacting the Company. In the three months ended, March 31, 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.

3. Revenue

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 March 31, 2022	Hydro	Wind and Solar	Gas[(1)]	Energy Transition[(2)]	Energy Marketing	Corporate and Other	Total
Revenues from contracts with customers							
Power and other	5	63	104	4	—	—	176
Environmental attributes	1	7	—	—	—	—	8
Revenue from contracts with customers	6	70	104	4	—	—	184
Revenue from leases[(3)]	—	—	4	—	—	—	4
Revenue from derivatives and other trading activities [(4)]	—	(13)	150	48	26	1	212
Revenue from merchant sales	70	22	175	54	—	—	321
Other[(5)]	1	12	1	—	—	—	14
Total revenue	77	91	434	106	26	1	735
Revenues from contracts with customers							
Timing of revenue recognition							
At a point in time	1	7	—	4	—	—	12
Over time	5	63	104	—	—	—	172
Total revenue from contracts with customers	6	70	104	4	—	—	184

(1) 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. 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 government incentives, and other miscellaneous.

3 months ended March 31, 2021	Hydro	Wind and Solar	Gas[1]	Energy Transition[2]	Energy Marketing	Corporate and Other	Total
Revenues from contracts with customers							
Power and other	—	63	97	4	—	—	164
Environmental attributes	—	5	—	—	—	—	5
Revenue from contracts with customers	—	68	97	4	—	—	169
Revenue from leases[3]	—	—	5	—	—	—	5
Revenue from derivatives and other trading activities[4]	—	(4)	(23)	33	61	1	68
Revenue from merchant sales	86	15	185	102	—	—	388
Other[5]	3	7	2	—	—	—	12
Total revenue	89	86	266	139	61	1	642
Revenues from contracts with customers							
Timing of revenue recognition							
At a point in time	—	5	2	4	—	—	11
Over time	—	63	95	—	—	—	158
Total revenue from contracts with customers	—	68	97	4	—	—	169

(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. Refer to Note 1 for further details.
(3) Total rental income, including contingent rent related to certain PPAs and other long-term contracts that meet the criteria of operating leases.
(4) Represents realized and unrealized gains or losses from hedging positions.
(5) Includes government incentives, and other miscellaneous.

4. Expenses by Nature

Fuel and purchased power and operations, maintenance and administrative ("OM&A") expenses classified by nature are as follows:

	3 months ended March 31			
	2022		2021	
	Fuel and purchased power	**OM&A**	Fuel and purchased power	OM&A
Gas fuel costs	**122**	**—**	58	—
Coal fuel costs	**39**	**—**	46	—
Royalty, land lease, other direct costs	**7**	**—**	5	—
Purchased power	**69**	**—**	71	—
Mine depreciation	**—**	**—**	55	—
Salaries and benefits	**1**	**58**	10	46
Other operating expenses	**—**	**54**	—	57
Total	**238**	**112**	245	103

5. Asset Impairment Charge (Reversal)

During the period end the Company recognized the following in impairment charge (reversal):

	3 months ended March 31	
	2022	2021
Property Plant and Equipment Impairments:		
Kaybob Cogeneration Project	—	27
Changes in decommissioning and restoration provisions on retired assets[1]	**(42)**	(12)
Intangible asset impairment - Coal Rights[2]	—	14
Asset impairment charges and reversals	**(42)**	29

(1) Changes are related to changes in discount rates on retired assets. Refer to Note 13 for further details.
(2) Impaired to nil as no future coal will be extracted from this area of the mine.

Kaybob Cogeneration Project

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 Interest Expense

The components of net interest expense are as follows:

	3 months ended March 31	
	2022	2021
Interest on debt	**41**	40
Interest on exchangeable debentures	**7**	7
Interest on exchangeable preferred shares	**7**	7
Interest income	**(3)**	(3)
Capitalized interest (Note 11)	**(1)**	(5)
Interest on lease liabilities	**1**	2
Credit facility fees, bank charges and other interest	**6**	4
Tax shield on tax equity financing	—	1
Other	—	3
Accretion of provisions	**9**	7
Net interest expense	**67**	63

On April 27, 2022, the Company declared a dividend of $7 million in aggregate for Exchangeable Preferred Shares at the fixed rate of 1.726 per cent, per share payable on May 31, 2022. The Exchangeable Preferred Shares are considered debt for accounting purposes, and as such, dividends are reported as interest expense.

7. Income Taxes

The components of income tax expense are as follows:

	3 months ended March 31	
	2022	2021
Current income tax expense	**12**	23
Deferred income tax expense (recovery) related to the origination and reversal of temporary differences	**158**	(19)
Deferred income tax recovery related to temporary difference on investment in subsidiary	**(3)**	—
Deferred income tax expense (recovery) arising from the writedown (reversal of write-down) of unrecognized deferred income tax assets[1]	**(131)**	16
Income tax expense	**36**	20

	2022	2021
Current income tax expense	**12**	23
Deferred income tax expense (recovery)	**24**	(3)
Income tax expense	**36**	20

(1) During the three months ended March 31, 2022, the Company recorded a reversal of write-down of deferred tax assets of $131 million (March 31, 2021 — $16 million write-down). The deferred income tax assets mainly relate to unrecognized tax benefits of losses associated with the Company's directly owned US operations and Canadian operations. 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. The Company wrote these assets off as it is not considered probable that sufficient future taxable income will be available to utilize the underlying tax losses.

8. 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 March 31	
	2022	2021
Net earnings		
TransAlta Cogeneration L.P.	**7**	12
TransAlta Renewables	**13**	19
	20	31
Total comprehensive income (loss)		
TransAlta Cogeneration L.P.	**7**	12
TransAlta Renewables	**(31)**	(22)
	(24)	(10)
Cash distributions paid to non-controlling interests		
TransAlta Cogeneration L.P.	**17**	12
TransAlta Renewables	**25**	25
	42	37

As at	**March 31, 2022**	Dec. 31, 2021
Equity attributable to non-controlling interests		
TransAlta Cogeneration L.P.	**131**	142
TransAlta Renewables	**814**	869
	945	1,011
Non-controlling interests share (per cent)		
TransAlta Cogeneration L.P.	**49.99**	49.99
TransAlta Renewables	**39.9**	39.9

9. 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 March 31, 2022, are as follows: Level I — $26 million net asset (Dec. 31, 2021 — $12 million net asset), Level II — $441 million net asset (Dec. 31, 2021 — $122 million net asset) and Level III — $203 million net liabilities (Dec. 31, 2021 — $159 million net asset).

Significant changes in commodity net risk management assets (liabilities) during the three months ended March 31, 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 three months ended March 31, 2022 and 2021, respectively:

	3 months ended March 31, 2022			3 months ended March 31, 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	**(132)**	**(205)**	**(337)**	(42)	(17)	(59)
Market price changes on new contracts	**—**	**(37)**	**(37)**	—	(7)	(7)
Contracts settled	**(14)**	**29**	**15**	(30)	5	(25)
Change in foreign exchange rates	**(7)**	**4**	**(3)**	(6)	—	(6)
Net risk management assets (liabilities) at end of period	**132**	**(335)**	**(203)**	495	(10)	485
Additional Level III information:						
Losses recognized in other comprehensive income	**(139)**	**—**	**(139)**	(48)	—	(48)
Total gains (losses) included in earnings before income taxes	**14**	**(238)**	**(224)**	30	(24)	6
Unrealized losses included in earnings before income taxes relating to net assets held at period end	**—**	**(209)**	**(209)**	—	(19)	(19)

As at March 31, 2022, the total Level III risk management asset balance was $180 million (Dec. 31, 2021 – $305 million) and Level III risk management liability balance was $383 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	**March 31, 2022**			
Description	**Sensitivity**	**Valuation technique**	**Unobservable input**	**Reasonable possible change**
Long-term power sale – US	+17 -174	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of US$3 or price increase of US$30
Coal transportation – US	+2 -20	Numerical derivative valuation	Illiquid future power prices (per MWh) Volatility Rail rate escalation	Price decrease of US$3 or price increase of US$30 80% to 120% zero to 4%
Full requirements – Eastern US	+9 -9	Historical bootstrap	Volume Cost of supply	95% to 105% (+/-) US$1 per MWh
Long-term wind energy sale – Eastern US	+16 -18	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$2 or increase of US$1
Long-term wind energy sale – Canada	+26 -11	Long-term price forecast	Illiquid future power prices (per MWh) Wind discounts	Price decrease of C$25 or increase of C$4 5% decrease or 5% increase
Long-term wind energy sale - Central US	+29 -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	+5 -5			

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	Historical bootstrap	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 March 31, 2022, resulting in a increase in the base fair value and the sensitivity values by approximately $3 million and $4 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. Commercial operation of the facility was achieved in December 2019, with the contract maturing 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 facility, 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 end of 2022, and extending for a weighted average of approximately 17 years, from commercial operation. The energy component of the contracts is accounted for at fair value through profit or loss.

In addition to the virtual PPA contract, 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.

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 $28 million as at March 31, 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 three months ended March 31, 2022, are primarily attributable to favorable market prices on existing contracts.

IV. Other Financial Assets and Liabilities
The fair value of financial assets and liabilities measured at other than fair value is as follows:

	Fair value(1)				Total carrying value(1)
	Level I	Level II	Level III	Total	
Exchangeable Securities - March 31, 2022	**—**	**739**	**—**	**739**	**736**
Long-term debt - March 31, 2022	**—**	**2,974**	**—**	**2,974**	**3,124**
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 due to the short term nature of these receivables 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 9 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, and a reconciliation of changes is as follows:

	3 months ended March 31	
	2022	2021
Unamortized net loss at beginning of the period	**(102)**	(33)
New inception gains	**9**	2
Change in foreign exchange rates	**3**	—
Amortization recorded in net earnings during the period	**(4)**	(4)
Unamortized net loss at end of the period	**(94)**	(35)

10. Risk Management Activities

The Company is exposed to market risk from changes in commodity prices, foreign exchange rates, interest rates, credit risk and liquidity risk. These risks affect the Company's earnings and the value of associated financial instruments that the Company holds. In certain cases, the Company seeks to minimize the effects of these risks by using derivatives to hedge its risk exposures. The Company's risk management strategy, policies and controls are designed to ensure that the risks it assumes comply with the Company's internal objectives and its risk tolerance. For additional information on the Company's Risk Management Activities please refer to Note 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 March 31, 2022

	Cash flow hedges	**Not designated as a hedge**	**Total**
Commodity risk management			
Current	**(47)**	**86**	**39**
Long-term	**180**	**45**	**225**
Net commodity risk management assets	**133**	**131**	**264**
Other			
Current	**23**	**(7)**	**16**
Long-term	**—**	**12**	**12**
Net other risk management assets	**23**	**5**	**28**
Total net risk management assets	**156**	**136**	**292**

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 in the period that the price changes occur. VaR at March 31, 2022, associated with the Company's proprietary trading activities was $4 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 byproducts, as considered appropriate. VaR at March 31, 2022, associated with the Company's commodity derivative instruments used in generation hedging activities was $32 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 in the period in which the price change occurs. VaR at March 31, 2022, associated with these transactions was $47 million (Dec. 31, 2021— $51 million), of which $15 million related to virtual PPAs (Dec. 31, 2021 — $18 million).

II. Credit Risk

The Company uses external credit ratings, as well as internal ratings in circumstances where external ratings are not available, to establish credit limits for customers and counterparties. The following table outlines the Company's maximum exposure to credit risk without taking into account collateral held, including the distribution of credit ratings, as at March 31, 2022:

	Investment grade *(Per cent)*	**Non-investment grade** *(Per cent)*	**Total** *(Per cent)*	**Total amount**
Trade and other receivables[1,2]	66	34	**100**	**542**
Long-term finance lease receivable	100	—	**100**	**172**
Risk management assets[1]	91	9	**100**	**889**
Total				**1,603**

(1) Letters of credit and cash and cash equivalents are the primary types of collateral held as security related to these amounts.
(2) Includes $55 million loan receivable with a counterparty that has no external credit rating.

The Company did not have significant expected credit losses as at March 31, 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 March 31, 2022, was $50 million (Dec. 31, 2021 — $37 million).

III. Liquidity Risk

TransAlta continues to be in a strong financial position with no liquidity issues. 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	841	—	—	—	—	—	841
Long-term debt[(1)(2)]	797	156	113	127	127	1,836	3,156
Exchangeable securities[(3)]	—	—	—	750	—	—	750
Commodity risk management (assets) liabilities	(14)	(75)	(88)	(80)	(63)	57	(263)
Other risk management assets	(15)	(7)	(5)	—	—	(1)	(28)
Lease liabilities[(4)]	(7)	4	3	3	3	93	99
Interest on long-term debt and lease liabilities[(5)]	118	119	114	108	103	782	1,344
Interest on exchangeable securities[(3, 5)]	53	53	62	—	—	—	168
Dividends payable	39	—	—	—	—	—	39
Total	**1,812**	**250**	**199**	**908**	**170**	**2,767**	**6,106**

(1) Excludes impact of hedge accounting and derivatives.
(2) Non-recourse bonds include $218 million related to Kent Hills Bond classified as current. Refer to Note 14 for further details.
(3) Assumes the exchangeable securities will be exchanged on Jan. 1, 2025.
(4) Lease liabilities include a lease incentive of $9 million expected to be received in 2022.
(5) 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 March 31, 2022, the Company provided $20 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 March 31, 2022, the Company held $270 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 March 31, 2022, the Company had posted collateral of $415 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 $230 million (Dec. 31, 2021 – $120 million) of collateral to its counterparties.

11. Property, Plant and Equipment

During the three months ended March 31, 2022, the Company had additions of $72 million, mainly related to assets under construction for White Rock Wind Project, Horizon Hill wind project, Northern Goldfields Solar Project, Garden Plain wind project and other planned major maintenance. During the three months ended March 31, 2021, the Company had additions of $98 million. The additions mainly related to assets under construction for the Windrise wind project, boiler conversions, Sundance Unit 5 repowering project and other planned major maintenance expenditures.

In the first quarter of 2022, $16 million of costs related to the Windrise transmission infrastructure were reclassified from Property, Plant and Equipment to Other Assets in accordance with the asset transfer agreement, which requires that ownership of these assets be transferred to the transmission line owner.

There was a decrease in the decommissioning provision resulting from an increase in discount rate changes, largely driven by increases in market benchmark rates. This resulted in a decrease in the related assets included in property, plant and equipment by $56 million (March 31, 2021 — $35 million). Refer to Note 13 for further details.

During the three months ended March 31, 2022, the Company capitalized $1 million (March 31, 2021 — $5 million) of interest to PP&E at a weighted average rate of 6.1 per cent (March 31, 2021 —6.1 per cent).

12. 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 only in the event a project achieves commercial operations prior to Dec. 31, 2025.

During the three months ended March 31, 2022, the Company recognized and reclassified to intangible assets $21 million (March 31, 2021 — nil) in project development costs related to various US Wind projects. Contingent consideration of $21 million relating to these projects was also recorded in other long- term liabilities.

13. Decommissioning and Other Provisions

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

	Decommissioning and restoration	Other provisions	Total
Balance, Dec. 31, 2021	793	34	827
Liabilities settled	**(6)**	**(1)**	**(7)**
Accretion	**9**	**—**	**9**
Transfers	**(2)**	**—**	**(2)**
Revisions in estimated cash flows[1]	**1**	**3**	**4**
Revisions in discount rates[1]	**(99)**	**—**	**(99)**
Change in foreign exchange rates	**(6)**	**—**	**(6)**
Balance, March 31, 2022	**690**	**36**	**726**

(1) Revisions in discount rates to the decommissioning and restoration provision include $56 million related to PP&E assets and $42 million related to retired assets recorded as an asset impairment reversal.

	Decommissioning and restoration	Other	Total
Balance, Dec. 31, 2021	793	34	827
Current portion	35	13	48
Non-current portion	758	21	779
Balance, March 31, 2022	**690**	**36**	**726**
Current portion	**35**	**11**	**46**
Non-current portion	**655**	**25**	**680**

A. Decommissioning and Restoration

During the first quarter of 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 5.0 to 7.6 per cent (Dec. 31, 2021 — 3.6 to 6.5 per cent).

B. Other Provisions

Other provisions also include provisions arising from ongoing business activities and include amounts related to commercial disputes between the Company and customers or suppliers. Information about the expected timing of settlement and uncertainties that could impact the amount or timing of settlement has not been provided as this may impact the Company's ability to settle the provisions in the most favourable manner.

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

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 $1.2 billion was available as at March 31, 2022 (Dec. 31, 2021 — $1.3 billion) including the undrawn letters of credit. 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, US LIBOR or US base rate, etc.) in accordance with a pricing grid that is standard for such facilities.

As at March 31, 2022, the Company was in compliance with all debt covenants with the exception of the Kent Hills Bonds ("KH Bonds") as discussed below.

KH Bonds

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 Kent Hills Wind bond is 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 March 31, 2022, had a combined PP&E carrying value of $178 million (Dec. 31, 2021 — $182 million). In the first quarter, the Company repaid $3 million of the principal.

In the fourth quarter of 2021, the Company 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 the bonds. Upon the occurrence of any event of default, holders of more than 50 per cent of the outstanding principal amount of the KH Bonds have the right to direct the Trustee to declare the principal and interest on the KH Bonds and all other amounts due, together with any make-whole amount of $23 million (Dec. 31, 2021 — $39 million), to be immediately due and payable and to direct the Trustee to exercise rights against certain collateral. The Company is in negotiations to obtain a waiver and expects to enter into a supplemental indenture during the second quarter of 2022. The Company continues to work to bring the site back to full operation.

Accordingly, the Company has classified the entire carrying value of $218 million for the KH Bonds as a current liability as at March 31, 2022.

15. Common Shares

A. Issued and Outstanding

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

	3 months ended March 31			
	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**	**5**	—	(2)
Stock options exercised	**0.1**	**1**	0.1	—
Issued and outstanding, end of period	**270.6**	**2,892**	269.9	2,894

B. Normal course issuer bid ("NCIB") Program

On May 25, 2021, the Toronto Stock Exchange ("TSX") accepted the notice filed by the Company to implement a normal course issuer bid for a portion of our 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 18, 2021. 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, 2021 and ends on May 30, 2022.

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	March 31, 2022	Dec. 31, 2021
Total shares purchased	**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**	—

C. Dividends

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

16. Preferred Shares

A. Issued and Outstanding

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

	March 31, 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	**11.0**	**269**	11.0	269
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

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.

17. Commitments and Contingencies

A. Commitments

Other than the commitments disclosed elsewhere in these unaudited interim condensed consolidated financial statements and those disclosed in the 2021 audited annual financial statements, during 2022, the Company has not incurred any additional material contractual commitments, either directly or through its interests in joint operations.

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. There have been no material updates to any of the contingencies in the three month period ended March 31, 2022.

18. 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 Before Income Tax

3 months ended March 31, 2022	Hydro	Wind & Solar[1]	Gas[2]	Energy Transition[3]	Energy Marketing	Corporate	Total	Equity accounted investments[1]	Reclass Adjustments	IFRS Financials
Revenues	77	95	434	106	26	1	739	(4)	—	735
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	—	13	(162)	11	10	—	(128)	—	128	—
Decrease in finance lease receivable	—	—	11	—	—	—	11	—	(11)	—
Finance lease income	—	—	5	—	—	—	5		(5)	—
Unrealized foreign exchange gain on commodity	—	—	—	—	(2)	—	(2)	—	2	—
Adjusted Revenues	77	108	288	117	34	1	625	(4)	114	735
Fuel and purchased power	4	8	131	94	—	1	238	—	—	238
Reclassifications and adjustments:										
Australian interest income	—	—	(1)	—	—	—	(1)	—	1	—
Adjusted fuel and purchased power	4	8	130	94	—	1	237	—	1	238
Carbon compliance	—	—	18	1	—	—	19	—	—	19
Gross margin	73	100	140	22	34	—	369	(4)	113	478
Operations, maintenance and administration	11	16	44	16	7	18	112	—	—	112
Taxes, other than income taxes	1	2	4	1	—	—	8	—	—	8
Net other operating income	—	(7)	(10)	—	—	—	(17)	—	—	(17)
Adjusted EBITDA[4]	61	89	102	5	27	(18)	266			
Equity income										2
Finance lease income										5
Depreciation and amortization										(117)
Asset impairment reversal										42
Net interest expense										(67)
Foreign exchange gain and other gains										2
Earnings before income taxes										242

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.
(2) 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 March 31, 2021	Hydro	Wind & Solar[1]	Gas[2]	Energy Transition[3]	Energy Marketing	Corporate	Total	Equity accounted investments[1]	Reclass Adjustments	IFRS Financials
Revenues	89	91	266	139	61	1	647	(5)	—	642
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	—	5	(23)	6	(8)	—	(20)	—	20	—
Decrease in finance lease receivable	—	—	10	—	—	—	10	—	(10)	—
Finance lease income	—	—	7	—	—	—	7	—	(7)	—
Adjusted Revenues	89	96	260	145	53	1	644	(5)	3	642
Fuel and purchased power[5]	3	4	108	129	—	1	245	—	—	245
Reclassifications and adjustments:										
Australian interest income	—	—	(1)	—	—	—	(1)	—	1	—
Mine depreciation	—	—	(27)	(28)	—	—	(55)	—	55	—
Coal inventory write-down	—	—	—	(8)	—	—	(8)	—	8	—
Adjusted fuel and purchased power	3	4	80	93	—	1	181	—	64	245
Carbon compliance	—	—	39	11	—	—	50	—	—	50
Gross margin	86	92	141	41	53	—	413	(5)	(61)	347
Operations, maintenance and administration[5]	8	13	42	23	10	8	104	(1)	—	103
Taxes, other than income taxes	1	3	3	2	—	—	9	—	—	9
Net other operating income	—	—	(10)	—	—	—	(10)	—	—	(10)
Adjusted EBITDA[4]	77	76	106	16	43	(8)	310			
Equity income										2
Finance lease income from subsidiaries										7
Depreciation and amortization										(149)
Asset impairment charge										(29)
Net interest expense										(63)
Foreign exchange gain and other gains										8
Earnings before income taxes										21

(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) Adjusted EBITDA is not defined and have no standardized meaning under IFRS.
(5) $2 million related to station service costs for the Hydro segment in the three months ended March 31, 2021 was reclassified from operations, maintenance and administration to fuel and purchased power for comparative purposes. This did not impact previously reported net earnings.

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 March 31	
	2022	2021
Depreciation and amortization expense on the condensed consolidated statements of earnings (loss)	**117**	149
Depreciation included in fuel and purchased power (Note 4)	**—**	55
Depreciation and amortization on the condensed consolidated statements of cash flows	**117**	204

19. Subsequent Events

Horizon Hill Wind Project and Fully Executed Corporate PPA with Meta

On April 5, 2022, TransAlta executed a long-term PPA with a subsidiary of Meta Platforms Inc., formerly known as Facebook, Inc. ("Meta"), 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. 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 at approximately US$290 million to 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 captured under executed turbine supply agreements and engineering, procurement and construction agreements.

Mt Keith 132kV Transmission Expansion

On May 3, 2022, TransAlta Renewables exercised its option to acquire an economic interest in the expansion of the Mt. 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 approximately AU$50 million to AU$53 million. Southern Cross Energy, a subsidiary of the Company, has entered into an engineering, procurement and construction agreement with ASX-listed GenusPlus Group Ltd for the expansion. The project is being developed under the existing PPA with BHP, which has a term of 15 years. In addition, the planned completion date should allow at least a portion of the project to qualify for Australia's "Temporary Full Expensing" COVID-19 tax benefit. The project will facilitate the connection of additional generating capacity to our network to support BHP's operations and increase their competitiveness as a supplier of low-carbon nickel.

Sarnia Cogeneration Facility Contract Extensions

The Company recently entered into agreements with three of its large industrial customers at the Sarnia cogeneration facility. The capacity commitments for the large industrial customers have now been extended to 2031, at rates comparable to current contract rates, which, in each case, are subject to the satisfaction of certain conditions, including the Company entering into a new contract with the Ontario Independent Electricity System Operator (the “IESO”). 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.

Energy Impact Partners Investment

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.

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.

Emission 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
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 sites.

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.

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