TRANSALTA CORPORATION

First Quarter Report for 2021

Management's Discussion and Analysis

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

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, 2021 and 2020, and should also be read in conjunction with the audited annual consolidated financial statements and MD&A contained within our 2020 Annual Integrated Report. In this MD&A, unless the context otherwise requires, "we", "our", "us", the "Corporation", 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, 2021. All tabular amounts in the following discussion are in millions of Canadian dollars unless otherwise noted. This MD&A is dated May 12, 2021. Additional information respecting TransAlta, including its Annual Information Form, 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.

Table of Contents

Forward-Looking Statements

This MD&A includes "forward-looking information" within the meaning of applicable Canadian securities laws, and "forward-looking statements" within the meaning of applicable United States securities laws, including the United States Private Securities Litigation Reform Act of 1995 (collectively referred to herein as "forward-looking statements"). All forward-looking statements are based on our beliefs as well as assumptions based on information available at the time the assumption was 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: our conversions to gas, including the conversion of Keephills Unit 2 and Unit 3; the repowering of Sundance Unit 5 into a combined cycle unit, including the timing and cost thereof, the delivery of full notice of proceed, the expected increase to overall output and ability for the repowered unit to provide maximum operating flexibility; the shutting down of the Highvale Mine and eliminating coal as a fuel source in Alberta by the end of 2021; the Garden Plain wind project, including the expected timing and costs thereof; expected increases to our cost per tonne of coal; the growth of the renewables fleet, including the Windrise Wind Project and the timing of commercial operations and total estimated spend in respect of such project; the 2021 financial outlook, including comparable EBITDA, free cash flow and annualized dividend in 2021 and our expectation of achieving the upper end of the 2021 guidance for FCF; sustaining and productivity capital in 2021, including routine capital, planned major maintenance and mine capital; significant planned major outages for 2021; lost production due to planned major maintenance for 2021; expected power prices in Alberta, Ontario and the Pacific Northwest; the cyclicality of the business, including as it relates to maintenance costs, production and loads; expectations regarding refinancing the debt maturing in 2022; certain regulatory developments, including those pertaining to expected changes to climate policies; the satisfaction of the settlement conditions in respect of the dispute with Fortescue Metals Group Ltd. ("FMG"); and the Corporation 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 Corporation, which includes the Corporation being able to continue to operate as an essential service; no significant changes to applicable laws and regulations beyond those that have already been announced, including no material changes to the applicable carbon compliance costs and performance factors; no material adverse impacts to the long-term investment and credit markets; Alberta spot prices of $58/MWh to $68/MWh; Mid-C spot prices of US$25/MWh to US$35/MWh; the Corporation's proportionate ownership of TransAlta Renewables Inc. ("TransAlta Renewables") not changing materially; no decline in the dividends to be received from TransAlta Renewables; the expected life extension of the Alberta Thermal fleet and anticipated financial results generated on conversion or repowering; 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, which cannot currently be predicted, and which present risks including, but not limited to: more restrictive directives of government and public health authorities; reduced labour availability and ability to continue to staff our operations and facilities; disruptions to our supply chains, including our ability to secure necessary equipment and to obtain regulatory approvals on the expected timelines or at all; COVID-19 related force majeure claims; restricted access to capital and increased borrowing costs; a further decrease in short-term and/or long-term electricity demand and lower merchant pricing in Alberta and Mid-Columbia; further reductions in production; increased costs resulting from our efforts to mitigate the impact of COVID-19; deterioration of worldwide credit and financial markets; a higher rate of losses on our accounts receivable due to credit defaults; impairments and/or write-downs of assets; and adverse impacts on our information technology systems and our internal control systems, including increased cyber security threats. The forward-looking statements are also subject to other risk factors that include, but are not limited to: fluctuations in market prices; commodity risk management and energy trading risks, including the effectiveness of the Corporation's risk management tools associated with hedging and trading procedures to protect against significant losses, including the effect of unforeseen price variances from historical behavior; 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 at such facilities; 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; disruptions in the source of fuels, including natural gas required for the converted or repowered generating units, as well as the extent of water, solar or wind resources required to operate our facilities; failure to meet financial expectations; the threat of terrorism, including cyberattacks; equipment failure and our ability to carry out or have completed the repairs in a cost-effective manner or timely manner or at all; industry risk and competition; fluctuations in the value of foreign currencies and foreign political risks; structural subordination of securities; counterparty credit risk; changes to our relationship with, or ownership of, TransAlta Renewables; changes in the payment 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 or delays in the closing of acquisitions; increased costs or delays in the conversion of coal-fired generating units to gas-fired generating units; increased costs or delays in the construction or commissioning of pipelines to converted units; inadequacy or unavailability of insurance coverage; our provision for income taxes; legal, regulatory and contractual disputes and proceedings involving the Corporation; reliance on key personnel; and labour relations matters. The foregoing risk factors, among others, are described in further detail in the other risks and uncertainties contained in the Corporation's Annual Information Form and Management's Discussion and Analysis for the year ended Dec. 31, 2020, filed under the Corporation's profile with the Canadian securities regulators on www.sedar.com and the US Securities and Exchange Commission ("SEC") on www.sec.gov.

Readers are urged to consider these factors carefully in evaluating the forward-looking statements and are cautioned not to place undue reliance on them, which reflect the Corporation's expectations only as of the date hereof. The purpose of the financial outlooks contained herein are 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 and is given as of the date of this presentation. 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. 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.

Highlights

	3 months ended March 31	
	2021	2020
Comparable EBITDA[1,2]	**310**	220
Free cash flow[1]	**129**	109
Adjusted availability (%)	**88.6**	92.8
Production (GWh)	**5,541**	6,486
Revenues	**642**	606
Fuel and purchased power[3]	**243**	193
Carbon compliance[3]	**50**	45
Operations, maintenance and administration	**105**	128
Net earnings (loss) attributable to common shareholders	**(30)**	27
Cash flow from operating activities	**257**	214
Funds from operations[1]	**211**	172
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**(0.11)**	0.10
Funds from operations per share[1]	**0.78**	0.62
Free cash flow per share[1]	**0.48**	0.39
Dividends declared per common share	**—**	0.0425
Dividends declared per preferred share[4]	**—**	0.2562

As at	**March 31, 2021**	Dec. 31, 2020
Total assets	**9,419**	9,747
Total consolidated net debt[1,5]	**2,889**	2,975
Total long-term liabilities	**5,106**	5,376

(1) These items are not defined and have no standardized meaning under IFRS. Presenting these items from period to period provides management and investors with the ability to evaluate earnings trends more readily in comparison with prior periods' results. Refer to the Reconciliation of Non-IFRS Measures section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS. See also the Additional IFRS measures and Non-IFRS Measures section of this MD&A.
(2) Comparable earnings before interest, taxes, depreciation and amortization ("comparable EBITDA").
(3) In the first quarter of 2021, carbon compliance costs have been reclassified from fuel and purchase power costs and disclosed separately. Prior periods have been adjusted for comparative purposes.
(4) Weighted average of the Series A, B, C, E and G preferred share dividends declared. Dividends declared vary year over year due to timing of dividend declarations.
(5) Total consolidated net debt includes long-term debt, including current portion, amounts due under credit facilities, exchangeable debentures, US tax equity financing and lease liabilities, net of available cash and cash equivalents, the principal portion of restricted cash in TransAlta OCP LP ("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.

Comparable EBITDA for the three months ended March 31, 2021, increased by $90 million, compared with the same period in 2020, largely due to higher comparable EBITDA at our Hydro and Energy Marketing segments and lower corporate costs. This was partially offset by lower performance at the Centralia segment. Significant changes in segmented comparable EBITDA are highlighted in the Segmented Comparable Results within this MD&A.

Free cash flow ("FCF"), one of the Corporation's key financial metrics, totaled $129 million for the three months ended March 31, 2021. This represents an increase of $20 million compared to the same period in 2020, driven primarily by the higher comparable EBITDA noted above. FCF reflects the after tax performance as well as the impact of the settlement of provisions and higher distributions paid to subsidiaries' non-controlling interests. Segmented cash flows for the three months ended March 31, 2021, are $79 million higher, compared to the same period in 2020 primarily due to higher performance in our Hydro, North American Gas, Australian Gas, Energy Marketing and Corporate segments.

Adjusted availability for the three months ended March 31, 2021, was 88.6 per cent compared to 92.8 per cent, for the same period in 2020. The decrease was primarily due to the planned outage for the Keephills 2 boiler conversion, a delay in the completion of the Sundance 6 boiler conversion and an increase in outages and derates within the Alberta Thermal and Centralia segments.

Production for the three months ended March 31, 2021 was 5,541 GWh compared to 6,486 GWh for the same period in 2020. The decrease in production was primarily due to portfolio optimization, lower adjusted availability and the retirement of Unit 1 in the Centralia segment.

Revenues for the three months ended March 31, 2021, increased $36 million, compared to the same period in 2020, mainly as a result of the Corporation capturing higher realized prices within the Alberta market as the hydro and thermal assets are no longer under Alberta PPAs and the elimination of the net payment obligations under the Alberta PPAs in the prior period, strong performance from Energy Marketing and an increase in revenues within the North American Gas segment from the addition of the Ada Facility. These increases were offset by lower production in the Alberta Thermal and Centralia segments.

Fuel and purchased power costs increased by $50 million in the three months ended March 31, 2021, compared to the same period in 2020. In our Alberta Thermal segment, higher coal mine depreciation and a coal inventory write-downs at the Highvale mine contributed to higher fuel costs. In addition, in the Centralia segment, our margins declined compared to 2020 as we acquired higher priced power to fulfil our contractual obligations during an unplanned outage during a period of higher merchant pricing.

Carbon compliance costs increased by $5 million in the three months ended March 31, 2021, compared to the same period in 2020 due to an increase in carbon costs per tonne, partially offset by lower production and reductions in greenhouse gas ("GHG") emissions stemming from changes in the fuel mix ratio as we operate more on natural gas and less on coal. Operating with natural gas reduces compliance costs as we produce fewer GHG emissions than when we operate using coal combustion.

Operations, maintenance and administration ("OM&A") expenses for the three months ended March 31, 2021, decreased by $23 million compared to the same period in 2020. Variability caused by the total return swap resulted in a favourable year-over-year change of $18 million and we received a Canada Emergency Wage Subsidy ("CEWS") of $8 million. Excluding the impact of the total return swap and CEWS funding, OM&A expenses were slightly higher for the three months ended March 31, 2021, compared to the same period in 2020, due to increased staffing costs for growth and strategy initiatives, settlement of provisions and higher insurance premiums.

Net loss attributable to common shareholders for the three months ended March 31, 2021, was $30 million, compared to net earnings of $27 million in the same period in 2020. The decrease was largely due to higher fuel and purchased power costs, asset impairments, increase in tax expense and higher earnings related to non-controlling interests. This decrease was partially offset by higher revenues, favourable changes in foreign exchange rates and lower OM&A.

Alberta Electricity Portfolio

On Dec. 31, 2020, the power purchase arrangements for many of our Alberta hydro facilities and the Keephills 1 and 2 units expired and, effective Jan. 1, 2021, these facilities began operating on a fully merchant basis in the Alberta market and form a core part of our Alberta electricity portfolio optimization activities. The variability in production by facility is driven by the diversity in our fuel types, which enables portfolio management, and allows for maximization of operating margins. The Alberta portfolio includes hydro, wind, energy storage and thermal units. A portion of the baseload generation in the portfolio has been hedged to provide cash flow certainty.

During the first quarter of 2021, we completed the conversion to gas at Sundance Unit 6 and it is now running solely on gas. The conversion to gas at Keephills Unit 2 is currently underway with completion expected during the second quarter of 2021, as planned. The Keephills Unit 3 conversion to gas is planned to begin at the end of the third quarter of 2021. We continue to progress our clean energy plan and are on track to eliminate coal as a fuel source by the end of 2021.

The Alberta spot price averaged $95 per MWh in the first quarter of 2021, compared to $67 per MWh in 2020. The increase in the spot prices in the first quarter of 2021 reflect strong prices in periods of scarce supply driven by cold weather events and lower wind generation overlapping several planned maintenance outages in the province.

During the first quarter, our Alberta hydro, thermal, wind, battery storage and gas assets generated 2,738 GWh of production and $284 million of revenue from energy and ancillary services. In the three months ended March 31, 2021, the Hydro and Alberta Thermal segments achieved realized power prices of $122/MWh and $87/MWh respectively, as the Corporation was able to benefit during higher-priced periods by optimizing dispatch in the Hydro segment while our hedging positions at Alberta Thermal minimized unfavourable market pricing during lower priced hours in the first quarter. Of the total thermal generation for the quarter, approximately 60 per cent was hedged at the beginning of the quarter through forward sales.

The Corporation was able to benefit from higher-priced periods by optimizing dispatch in the Hydro segment and at Alberta Thermal, while our hedging positions minimize unfavourable market pricing during lower priced hours in the quarter.

Corporate Strategy

The Corporate strategy remains unchanged from that disclosed in the 2020 Annual MD&A.

Garden Plain Wind Project

On May 3, 2021, the Corporation announced that it entered into a long-term power purchase agreement ("PPA") with Pembina Pipeline Corporation ("Pembina") pursuant to which Pembina has contracted for the renewable electricity and environmental credits of 100 MWs of the 130 MW Garden Plain wind project ("Garden Plain"). Under this 18-year agreement, Pembina has the option to purchase a 37.7 per cent interest in the project (49 per cent of the power purchase agreement). The option must be exercised no later than 30 days after commercial operational date. TransAlta would remain the operator of the facility and earn a service fee if Pembina exercises this option. Garden Plain will be located approximately 30 km north of Hanna, Alberta. Construction activities are scheduled to start in fall 2021 with completion of the project expected in the second half of 2022. Total construction capital of the project is estimated at approximately $195 million.

Other Activities

In addition, during the first three months of 2021, the following developments have occurred:

- On Feb. 1, 2021, we announced the completion of the conversion to gas of Sundance Unit 6.
- The Sheerness Unit 1 conversion to gas was completed and returned to service on March 31, 2021.
- Windrise construction advanced significantly, with procedures in place to protect the construction team during the COVID-19 pandemic. The bulk of the major equipment has been delivered to site and turbine erection activities have commenced. In addition, the main transmission line is progressing well and remains on track for energization during the second quarter. As at March 31, 2021, the project is approximately 84 per cent complete and is on track to be completed during the second half of 2021.
- The conversion to gas of Keephills Unit 2 is currently in progress with expected completion during the second quarter.
- During the quarter, we advanced the planning, detailed engineering design, and contractual negotiations for the Sundance 5 repowering project. As as result of the detailed design review, we have increased steam production resulting in slightly higher overall MW output and made the decision to upgrade the high pressure turbine as part of the repowering scope to allow for maximum operating flexibility in the unit going forward. Project costs have increased to account for changes in final design. TransAlta expects to issue full notice to proceed later this year and the target completion date for Sundance 5 is estimated for the first half of 2024.

The following is a list of the projects under construction in our Clean Energy Investment Plan, as previously disclosed in the Corporate Strategy section in the 2020 Annual MD&A, and their status:

	Total project				
Project	**Estimated spend**	**Spent to date(1)**	**Remaining estimated spend in 2021**	**Target completion date(2)**	**Details**
Windrise wind project(3)	270 — 285	230	50	H2 2021	207 MW wind project with a 20-year Renewable Electricity Support Agreement with AESO
Boiler conversions	120 — 200	82	37	2020 to 2022	Conversion to gas at Alberta Thermal
Repowering	900 — 950	138	222	H1 2024	Repower Sundance Unit 5 to a combined cycle design (746 MW)
Total	**1,290 — 1,435**	**450**	**309**		

(1) Represents cumulative amounts spent as of March 31, 2021.
(2) H1 is defined as the first half of the year and H2 is defined as the second half of the year.
(3 Windrise wind development project was sold to TransAlta Renewables on Feb. 26, 2021.

The Corporation will not be proceeding with the Kaybob cogeneration facility as a result of Energy Transfer Canada ULC's ("ET Canada"), formerly known as SemCAMS Midstream ULC, purported termination of the agreements to develop, construct and operate the 40 MW cogeneration facility at the Kaybob South No. 3 sour gas processing plant. As a result, the Corporation has recorded an impairment of $27 million in the first quarter of 2021. TransAlta has commenced an arbitration, seeking full compensation for ET Canada's wrongful termination of the agreements. ET Canada seeks a declaration that the agreements were lawfully terminated. A hearing for this matter has not yet been scheduled.

Significant and Subsequent Events

Updates and developments impacting the Clean Energy Investment Plan can be found in the Corporate Strategy section of this MD&A.

Sarnia Cogeneration Facility Contract Extension

On May 12, 2021, the Corporation executed an Amended and Restated Energy Supply Agreement with one of its large industrial customers at the Sarnia cogeneration facility which provides for the supply of electricity and steam. This agreement will extend the term of the original agreement from Dec. 31, 2022 to Dec. 31, 2032. However, if the Corporation is unable to enter into a new contract with the Ontario Independent Electricity System Operator ("IESO") or enter into agreements with its other industrial customers at the Sarnia cogeneration facility that extend past Dec. 31, 2025, then this agreement will automatically terminate on Dec. 31, 2025. The current contract with the IESO in respect of the Sarnia cogeneration facility expires on Dec. 31, 2025. The Corporation is in active discussions with the three other existing industrial off-takers regarding extensions to their supply of electricity and steam from the Sarnia cogeneration facility on comparable terms.

Equity, Diversity and Inclusion Program

On May 3, 2021, TransAlta announced that it had received certification from Diversio, a technology company setting the global standard for diversity and inclusion, for its continued commitment to and meaningful performance on equity, diversity, and inclusion ("E,D&I") in the workplace. TransAlta is the first publicly traded energy company to be certified. Diversio's award-winning artificial intelligence technology has helped hundreds of organizations and investors to collect data, gain insights, and implement solutions to make meaningful progress on E,D&I. Each certified organization must uphold standards of E,D&I, action that not only makes their companies more attractive to new talent but also makes them more successful. The certification is endorsed by several leading organizations and signals to investors, employees, customers, and other stakeholders that the organization is setting an example of the importance of shifting from words to actions in order to move the dial on E,D&I.

Sustainability Linked Loan

In March 2021, TransAlta extended its $1.25 billion Syndicated Credit facility to June 30, 2025 and converted the facility into a Sustainability Linked Loan ("SLL"). The facility's financing terms will align the cost of borrowing to TransAlta's GHG emission reductions and gender diversity targets, which are part of the Corporation's overall environment, economic, social, and governance strategy, or E^2SG. The SLL will have a cumulative pricing adjustment to the borrowing costs on the facilities and a corresponding adjustment to the standby fee (the "Sustainability Adjustment"). Depending on performance against interim targets that have been set for each year of the credit facility term, the Sustainability Adjustment is structured as a two-way mechanic and could move either up, down or remain unchanged for each sustainability performance target based on performance. The SLL further underscores TransAlta's dedication to sustainability, including E,D&I and responsible growth.

Mangrove Claim

On April 23, 2019, The Mangrove Partners Master Fund Ltd. ("Mangrove") commenced an action in the Ontario Superior Court of Justice naming TransAlta Corporation, the incumbent members of the Board of Directors of TransAlta Corporation on such date, and Brookfield BRP Holdings (Canada) as defendants. Mangrove was seeking to set aside the 2019 Brookfield transaction. The parties reached a confidential settlement and the action was discontinued in the Ontario Superior Court of Justice on April 30, 2021.

Keephills 1 Superheater Force Majeure

Keephills Unit 1 was taken offline from March 17, 2015 to May 17, 2015 as a result of a large leak in the secondary superheater. TransAlta claimed force majeure under the PPA. ENMAX Energy Corporation, the purchaser under the PPA at the time, did not dispute the force majeure but the Balancing Pool attempted to do so, seeking to recover $12 million in capacity payment charges it paid to TransAlta while the unit was offline. The parties reached a confidential settlement on April 21, 2021 and this matter is now resolved.

TransAlta Renewables Acquisitions

The Corporation completed the sale of its 100 per cent direct interest in the 207 MW Windrise wind project ("Windrise") to TransAlta Renewables Inc. ("TransAlta Renewables"), a subsidiary of the Corporation, on Feb. 26, 2021 for $213 million. The remaining construction costs for Windrise will be paid by TransAlta Renewables. Windrise is expected to commence commercial operation in the second half of 2021.

On April 1, 2021, the Corporation also completed the sale of its 100 per cent economic interest in the 29 MW Ada cogeneration facility ("Ada") and its 49 per cent economic interest in the 137 MW Skookumchuck wind facility ("Skookumchuck") to TransAlta Renewables for $43 million and $103 million, respectively. Both facilities are fully operational. Pursuant to the transaction, a TransAlta subsidiary owns Ada and Skookumchuck directly and has issued to TransAlta Renewables tracking preferred shares reflecting its economic interest in the facilities. The Ada cogeneration facility is under a PPA until 2026. The Skookumchuck wind facility is contracted under a PPA until 2040 with an investment grade counterparty.

Management Changes

On March 31, 2021, Dawn Farrell, President and Chief Executive Officer, retired from the Corporation and the Board after leading the Corporation for almost a decade. John Kousinioris succeeded Ms. Farrell as President and Chief Executive Officer and joined the Board on April 1, 2021. Prior to his appointment as Chief Executive Officer of TransAlta, Mr. Kousinioris held the roles of Chief Operating Officer, Chief Growth Officer and Chief Legal and Compliance Officer and Corporate Secretary at TransAlta.

Effective April 30, 2021, Brett Gellner, our Chief Development Officer, retired after almost 13 years with TransAlta. During this time at the Corporation, he has fulfilled multiple roles in commercial, finance, growth and strategy and served as our Chief Financial Officer.

Board of Director Changes

On May 4, 2021, we announced that the Board of Directors (the "Board") elected four new directors: Ms. Laura W. Folse, Ms. Sarah Slusser, Mr. Thomas O'Flynn and Mr. Jim Reid, who each bring diverse expertise and new perspectives to the Board.

Mrs. Georgia Nelson, Mr. Richard Legault and Mr. Yakout Mansour did not stand for re-election and retired from the Board immediately following the annual shareholder meeting on May 4, 2021. TransAlta acknowledges with gratitude the many contributions that each of Mr. Legault, Mr. Mansour and Mrs. Nelson have made to the Corporation.

COVID-19

The World Health Organization declared a Public Health Emergency of International Concern relating to COVID-19 on Jan. 30, 2020, which they subsequently declared, on March 11, 2020, as a global pandemic.

The Corporation continues to operate under its business continuity plan, which focused on ensuring that: (i) employees who can work remotely do so; and (ii) employees who operate and maintain our facilities, and who are not able to work remotely, are able to work safely and in a manner that ensures they remain healthy. During the second and third quarters of 2020, the Corporation successfully brought employees who were working remotely back to the office without compromising health and safety standards. In December 2020, as a result of rising COVID-19 case counts in the Province of Alberta and in light of office attendance restrictions eventually imposed by the Government of Alberta, staff at TransAlta's head office returned to remote work protocols. All of TransAlta's offices and sites follow strict health screening and social distancing protocols with personal protective equipment readily available and in use. Further, TransAlta maintains travel bans aligned to local jurisdictional guidance, enhanced cleaning procedures, revised work schedules, contingent work teams and the reorganization of processes and procedures to limit contact with other employees and contractors on-site.

All of our facilities continue to remain fully operational and are capable of meeting our customers' needs. The Corporation continues to work and serve all of our customers and counterparties under the terms of their contracts. We have not experienced interruptions to service requirements. Electricity and steam supply continue to remain a critical service requirement to all of our customers and have been deemed an essential service in our jurisdictions.

The Corporation continues to maintain a strong financial position due in part to its long-term contracts and hedged positions and its ample financial liquidity.

The Board and management have been monitoring the evolution of the pandemic and are continually assessing its impact to the safety of the Corporation's employees, operations, supply chains and customers as well as, more generally, to the business and affairs of the Corporation and our existing capital projects. Potential impacts of the pandemic on the business and affairs of the Corporation include, but are not limited to: potential interruptions of production, supply chain disruptions, unavailability of employees, potential delays in capital projects, increased credit risk with counterparties and increased volatility in commodity prices as well as the valuation of financial instruments. In addition, the broader impacts to the global economy and financial markets could have potential adverse impacts on the availability of capital for investment and the demand for power and commodity pricing.

Refer to Note 4 of the audited annual 2020 consolidated financial statements within our 2020 Annual Integrated Report and Note 3 of our unaudited interim condensed consolidated financial statements for the three months ended March 31, 2021, for significant events impacting both prior and current year results.

2021 Financial Outlook

Refer to the 2021 Financial Outlook section in our 2020 Annual Integrated Report for full details on our 2021 Financial Outlook and related assumptions.

The following table outlines our expectations on key financial targets and related assumptions for 2021:

Measure	**Target**
Comparable EBITDA[1]	$960 million - $1,080 million
FCF[1]	$340 million - $440 million
Dividend	$0.18 per share annualized

(1) These items are not defined and have no standardized meaning under IFRS. Presenting these items from period to period provides management and investors with the ability to evaluate earnings trends more readily in comparison with prior periods' results. 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 power price assumptions	**January 2021 Outlook**
Market	**Power Prices ($/MWh)**
Alberta Spot	$58 - $68
Mid-C Spot (US$)	US$25 - US$35

Other assumptions relevant to the 2021 financial outlook	
Sustaining capital	$175 million - $210 million

Our overall performance for the first quarter of 2021 is ahead of expectations. As a result, the Corporation is tracking to the upper end of the range for comparable EBITDA as we have experienced higher power prices in the Alberta power market. The Corporation is also tracking to the upper end of the 2021 guidance for FCF based on continuing high prices in the Alberta electricity market.

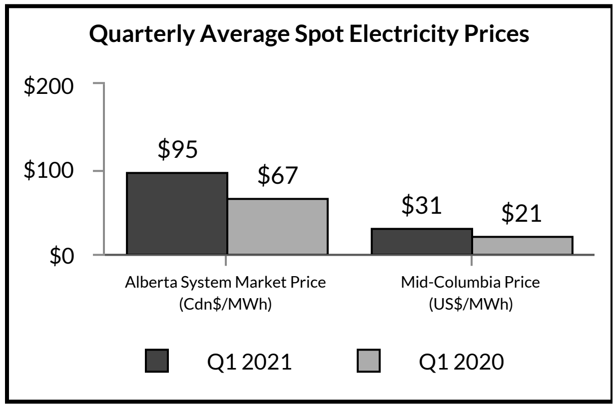
Operations

The following provides updates to our original assumptions included in the 2021 Financial Outlook.

Market Pricing

Power prices were higher in Alberta in the three months ended March 31, 2021, compared to the same period in 2020. This resulted from commercial offer behavior following the expiry of the Alberta PPAs with the Balancing Pool on Dec. 31, 2020, higher carbon compliance costs, and tighter market conditions during periods of cold weather in addition to planned outages. Alberta power prices for the remainder of 2021 are expected to continue to be higher than in 2020 as a result of the factors discussed above.

Power prices were also higher in the Pacific Northwest in the three months ended March 31, 2021, compared to the same period in 2020, mainly due to lower hydro generation. Comparable or higher prices are expected in the Pacific Northwest for the remainder of 2021 compared to 2020.



Sustaining and Productivity Capital Expenditures

Our estimate for total sustaining and productivity capital is allocated among the following:

Category	Description	Spent to date[1]	Expected spend in 2021		
Routine capital[2]	Capital required to maintain our existing generating capacity	**7**	44	—	54
Planned major maintenance	Regularly scheduled major maintenance	**27**	130	—	154
Mine capital	Capital related to mining equipment and land purchases	**—**	1	—	2
Total sustaining capital		**34**	**175**	**—**	**210**
Productivity capital	Projects to improve power production efficiency and corporate improvement initiatives	**—**	3	—	7
Total sustaining and productivity capital		**34**	**178**	**—**	**217**

(1) As at March 31, 2021.
(2) Includes hydro life extension expenditures.

Significant planned major outages at TransAlta's operated units for the remainder of 2021 include the following:

- Major maintenance turnaround at Keephills Units 2 is currently in progress with planned completion during the second quarter;
- Major maintenance turnaround at Keephills Unit 3 is planned to begin at the end of the third quarter;
- Major maintenance turnaround at Centralia is planned to commence and end in second quarter;
- Distributed planned maintenance expenditures across the entire hydro fleet; and
- Distributed expenditures across our wind fleet, focusing on planned component replacements.

A conversion to gas outage at our non-operated unit, Sheerness Unit 1, was completed in first quarter of 2021.

Lost production as a result of planned major maintenance, excluding planned major maintenance for Centralia, which is scheduled during a period of dispatch optimization, is estimated as follows for 2021:

	Alberta Thermal and Centralia	Gas and renewables	Lost to date[1]
GWh lost	1,700-1,800	500-600	406

(1) As at March 31, 2021.

Segmented Comparable Results

Segmented cash flow generated by the business measures the net cash generated by each of our segments after sustaining and productivity capital expenditures, reclamation costs, payments on lease liabilities and provisions. This is the cash flow available to pay our interest and cash taxes, make distributions to our non-controlling partners and pay dividends to our preferred shareholders, grow the business, pay down debt and return capital to our shareholders.

The table below shows the segmented cash flow generated by each of our segments:

	3 months ended March 31	
	2021	2020
Segmented cash flow[1]		
Hydro	**72**	23
Wind and Solar	**69**	72
North American Gas[2]	**33**	29
Australian Gas	**32**	28
Alberta Thermal[3]	**17**	22
Centralia[3]	**9**	28
Generation segmented cash flow	**232**	202
Energy Marketing	**45**	18
Corporate[4]	**(11)**	(33)
Total segmented cash flow	**266**	187

(1) Segmented cash flow is a non-IFRS measure and has no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section for further details.
(2) This segment was previously known as the Canadian Gas segment but renamed with the acquisition of the US cogeneration facility in the second quarter of 2020.
(3) The Canadian Coal segment was renamed Alberta Thermal and US Coal segment was renamed Centralia in the third quarter of 2020.
(4) Includes gains and losses on the total return swap.

Segmented cash flow generated by the business for the three months ended March 31, 2021 increased by $79 million, compared to the same period in 2020. The increase was largely due to strong results from our Hydro segment optimizing water flow during periods of high realized pricing in Alberta, favourable short-term trading within Energy Marketing and lower corporate costs as a result of $8 million of CEWS funding and realized gains on the total return swap. In the three months ended March 31, 2021, we realized a net gain of $7 million from the total return swap on our share-based payment plans, whereas in the same period last year we realized a net loss of $11 million. This was offset by lower results in Centralia from an unplanned outage during periods of higher pricing, the settlement of provisions for the line loss rule proceeding in the Wind and Solar segment and increased capital expenditures for planned major maintenance in Alberta Thermal. In the three months ended March 31, 2021, approximately 60 per cent of our generation segmented cash flows are generated by renewable resources, compared to 47 per cent for the same period in 2020.

Hydro

	3 months ended March 31	
	2021	2020
Gross installed capacity (MW)	**926**	926
Availability (%)	**91.9**	93.9
Alberta Hydro Assets (GWh)[1]	**320**	306
Other Hydro Assets (GWh)[1]	**40**	37
Total energy production (GWh)	**360**	343
Ancillary service volumes (GWh)[2]	**749**	872
Revenues		
Alberta Hydro Assets[1]	**39**	25
Other Hydro Assets[1]	**3**	3
Capacity payments[3]	**—**	15
Alberta Hydro Ancillary services and other[2]	**50**	38
Total gross revenues	**92**	81
Net payment relating to Alberta Hydro PPA[4]	**(3)**	(43)
Total Revenues	**89**	38
Fuel and purchased power	**1**	2
Comparable gross margin	**88**	36
Operations, maintenance and administration	**10**	9
Taxes, other than income taxes	**1**	1
Comparable EBITDA	**77**	26
Deduct:		
Sustaining capital:		
Routine capital	**1**	1
Planned major maintenance	**4**	2
Total sustaining capital expenditures	**5**	3
Hydro cash flow	**72**	23

(1) Alberta Hydro Assets include 13 hydro facilities on the Bow and North Saskatchewan river systems in Alberta that are not owned by TransAlta Renewables. Other Hydro Assets include our hydro facilities in BC, Ontario and the hydro facilities in Alberta owned by TransAlta Renewables.
(2) Ancillary Services as described in the AESO Consolidated Authoritative Document Glossary.
(3) Capacity payments include the annual capacity charge as described in the Power Purchase Arrangements Determination Regulation AR 175/2000, available from Alberta Queen's Printer. The Alberta Hydro PPA expired on Dec. 31, 2020.
(4) The net payment relating to the Alberta Hydro PPA represents the Corporation'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 Hydro PPA.

Availability for the three months ended March 31, 2021, decreased compared to the the same period in 2020, primarily due to unplanned outages at our Horseshoe and Kananaskis facilities and an extended planned outage at our Rundle facility.

Production for the three months ended March 31, 2021, increased by 17 GWh, compared to the same period in 2020, mainly due to higher water flow in response to strong prices in the Alberta market.

Ancillary service volumes for the three months ended March 31, 2021, decreased 123 GWh, compared to the the same period in 2020. This was primarily due to extended icing events at our Bighorn facility and a planned outage at our Rundle facility.

	3 months ended March 31	
	2021	2020
Gross Revenues per MWh		
Alberta Hydro Assets ($/MWh)	**$122**	$82
Alberta Hydro ancillary services ($/MWh)	**$67**	$44

In the three months ended March 31, 2021, Alberta Hydro Assets revenue per MWh and Alberta Hydro ancillary revenue per MWh of production increased by approximately $40 per MWh and approximately $23 per MWh, respectively, compared to the same period in 2020 as result of higher merchant prices in Alberta. For further discussion on the market conditions and pricing, refer to the 2021 Financial Outlook section and Alberta Electricity Portfolio section of this MD&A.

Comparable EBITDA for the three months ended March 31, 2021, increased by $51 million, compared with the same period in 2020. On Dec. 31, 2020, the PPA for many of our Alberta hydro facilities expired and, effective Jan. 1, 2021, these facilities began operating on a merchant basis in the Alberta power market. The Corporation was able to optimize revenues on the merchant facilities through increased water flow during periods of higher realized prices in the Alberta market and benefited from the elimination of net payment obligations under the Alberta PPAs. This was partially offset by lower ancillary service volumes.

Sustaining capital expenditures for the three months ended March 31, 2021, increased by $2 million compared to the same period in 2020, due to a greater number of outages.

Hydro's cash flow for the three months ended March 31, 2021, increased by $49 million, compared with the same period in 2020, mainly due to higher comparable EBITDA.

Wind and Solar

	3 months ended March 31	
	2021	2020
Gross installed capacity (MW)[(1)]	**1,572**	1,495
Availability (%)	**95.1**	95.3
Contract production (GWh)	**828**	795
Merchant production (GWh)	**303**	341
Total production (GWh)	**1,131**	1,136
Revenues	**96**	94
Fuel and purchased power	**4**	5
Comparable gross margin	**92**	89
Operations, maintenance and administration	**13**	13
Taxes, other than income taxes	**3**	2
Comparable EBITDA	**76**	74
Deduct:		
Sustaining capital:		
Planned major maintenance	**1**	2
Total sustaining capital expenditures	**1**	2
Provisions	**6**	—
Wind and Solar cash flow	**69**	72

(1) The 2021 gross installed capacity includes the addition of the WindCharger battery storage facility and our proportionate share of the Skookumchuck wind facility, which were added in the fourth quarter of 2020.

Availability and production for the three months ended March 31, 2021, were consistent with the same period in 2020. Production was down slightly due to lower wind resources in the West and to a lesser extent in the East, but was offset by higher production from the new Skookumchuck facility.

Comparable EBITDA for the three months ended March 31, 2021, increased by $2 million compared with the same period in 2020, primarily due to the new Skookumchuck facility and higher pricing in Alberta, which was partially offset by lower production from the balance of the fleet.

Sustaining capital expenditures for the three months ended March 31, 2021, were consistent with the same period in 2020, which was in line with expectations.

Wind and Solar's cash flow for the three months ended March 31, 2021, decreased $3 million, compared to the the same period in 2020, mainly due to settlements of prior provisions related to the transmission line loss rule proceeding, partially offset by higher comparable EBITDA.

North American Gas(1)

	3 months ended March 31	
	2021	2020
Gross installed capacity (MW)(2)	**974**	945
Availability (%)	**100.1**	101.3
Contract production (GWh)	**503**	457
Merchant production (GWh)(3)	**69**	20
Purchased power (GWh)(3)	**(46)**	(20)
Total production (GWh)	**526**	457
Revenues	**78**	56
Fuel and purchased power	**24**	13
Carbon compliance	**7**	1
Comparable gross margin	**47**	42
Operations, maintenance and administration	**12**	12
Taxes, other than income taxes	**—**	1
Comparable EBITDA	**35**	29
Deduct:		
Sustaining capital:		
Routine capital	**1**	—
Planned major maintenance	**1**	—
Total sustaining capital expenditures	**2**	—
North American Gas cash flow	**33**	29

(1) This segment was previously known as the Canadian Gas segment but was renamed with the acquisition of the Ada facility in the second quarter of 2020.
(2) 2021 includes 29 MW from the acquisition of the Ada facility in the second quarter of 2020.
(3) Purchased power used for dispatch optimization has been separated from merchant production in the current year. Comparable periods have been adjusted to reflect this change.

Availability for the three months ended March 31, 2021, was consistent with the same period in 2020. We were able to achieve higher than 100 per cent availability due to colder weather, which allows the facilities to produce at greater levels than the nameplate capacity.

Production for the three months ended March 31, 2021, increased by 69 GWh compared to the same period in 2020, mainly due to the Ada facility acquired in May 2020 and higher merchant production at Sarnia.

Comparable EBITDA for the three months ended March 31, 2021, increased by $6 million, compared with the same period in 2020, primarily due to the acquisition of the Ada facility and higher realized pricing in Alberta.

Sustaining capital expenditures for the three months ended March 31, 2021, increased by $2 million, compared with the same period in 2020, mainly due to planned major maintenance at the Ada facility.

North American Gas' cash flow for the three months ended March 31, 2021, increased by $4 million compared to the same period in 2020, due to higher comparable EBITDA, which was partially offset by higher capital expenditures at the Ada facility.

Australian Gas

	3 months ended March 31	
	2021	2020
Gross installed capacity (MW)	**450**	450
Availability (%)	**91.0**	91.9
Contract production (GWh)	**424**	471
Revenues	**43**	39
Fuel and purchased power	**1**	2
Comparable gross margin	**42**	37
Operations, maintenance and administration	**10**	7
Comparable EBITDA	**32**	30
Deduct:		
Sustaining capital:		
Planned major maintenance	**—**	2
Total sustaining capital expenditures	**—**	2
Australian Gas cash flow	**32**	28

Availability for the three months ended March 31, 2021, decreased slightly compared to the same period in 2020, mainly due to unplanned outages.

Production for the three months ended March 31, 2021, decreased compared with the same period in 2020, mainly due to a change in customer loads. Changes in production do not have a significant financial impact as our contracts are structured as capacity payments with customer supplied fuel or a passthrough of fuel costs.

Comparable EBITDA for the three months ended March 31, 2021, increased by $2 million, compared with the same period in 2020. The increase was mainly due to the timing of legal fees and the strengthening of the Australian dollar relative to the Canadian dollar.

Sustaining capital expenditures for the three months ended March 31, 2021 decreased by $2 million, compared with the same period in 2020. The decrease was mainly due to timing of planned major maintenance.

Australian Gas' cash flow for the three months ended March 31, 2021, increased by $4 million, compared with the same period in 2020, mainly due to higher comparable EBITDA and lower sustaining capital expenditures.

Alberta Thermal[1]

	3 months ended March 31	
	2021	2020
Gross installed capacity (MW)[2]	**2,866**	3,229
Availability (%)	**79.9**	88.8
Contract production (GWh)	**—**	1,538
Merchant production (GWh)	**2,108**	1,435
Total production (GWh)	**2,108**	2,973
Revenues	**184**	192
Fuel and purchased power	**74**	77
Carbon compliance	**43**	44
Comparable gross margin	**67**	71
Operations, maintenance and administration	**30**	33
Taxes, other than income taxes	**4**	4
Net other operating income	**(10)**	(10)
Comparable EBITDA	**43**	44
Deduct:		
Sustaining capital:		
Routine capital	**3**	1
Mine capital	**—**	1
Planned major maintenance	**20**	14
Total sustaining capital expenditures	**23**	16
Provisions	**1**	—
Principal payments on lease liabilities	**1**	4
Decommissioning and restoration costs settled	**1**	2
Alberta Thermal cash flow	**17**	22

(1) The Canadian Coal segment was renamed Alberta Thermal in the third quarter of 2020.
(2) All periods include 406 MW for Sundance Unit 5, which is temporarily mothballed. Sheerness Unit 2's capacity was increased in 2020 following a generator rewind and final testing. Sundance Unit 3's 368 MW was included in 2020's gross installed capacity until it was retired in the third quarter of 2020.

Availability for the three months ended March 31, 2021 decreased compared with the same period in 2020, as a result of the delayed completion of the Sundance Unit 6 conversion outage and the planned Keephills 2 conversion. Additionally, the fleet experienced derates and an unplanned outage at Keephills 3 and unplanned outages at Sundance 4 and Sundance 6.

Production for the three months ended March 31, 2021, decreased by 865 GWh, compared to the same period in 2020, mainly due to lower availability and portfolio optimization.

Revenue for the three months ended March 31, 2021, decreased by $8 million, compared to the same period in 2020, mainly due to lower production, partially offset by higher realized prices within the Alberta market.

	3 months ended March 31	
	2021	2020
Hedge position (percentage)[1]	**60**	91
Spot power price average per MWh	**$95**	$67
Realized power prices per MWh[2]	**$87**	$65
Natural gas price (AECO) per GJ[3]	**$2.96**	$1.93
Fuel and purchased power per MWh	**$35**	$26
Carbon compliance per MWh	**$20**	$15

(1) Represents the percentage of production sold forward at the beginning of the reporting period for the Alberta Thermal segment.
(2) Realized power price is the average price realized as a result of the Corporation's commercial contracted sales and portfolio optimization activities.
(3) AECO refers to the NGX Physical AECO Same Day 5a Index for delivery at NIT (NOVA Inventory Transfer).

In the three months ended March 31, 2021, the realized power prices per MWh of production increased by $22 per MWh, compared with the same period in 2020, primarily due to optimizing production during periods of favourable pricing. The realized prices include gains or losses from hedging positions that are entered into to mitigate the impact of unfavourable market pricing.

In the three months ended March 31, 2021, the fuel and purchased power costs per MWh of production increased by $9 per MWh, compared the same period in 2020. The final invoice for the transmission line loss rule proceeding was received in the quarter, increasing fuel costs by $5 million. Costs per MWh increased due to fixed coal costs and higher transmission line costs spread over less volumes resulting in increased costs per MWh.

In the three months ended March 31, 2021, carbon compliance costs per MWh of production increased by $5 per MWh, compared with the same period in 2020, primarily due to an increase in carbon costs from $30/tonne to $40/tonne, partially offset by changes in fuel ratios as we increase our natural gas combustion versus coal. This effectively lowers our fuel and GHG compliance costs as natural gas combustion produces fewer GHG emissions than coal combustion.

OM&A costs for the three months ended March 31, 2021, were $3 million lower compared with the same period in 2020, due to planned reductions at coal fired facilities, Keephills Unit 1 and Sundance Unit 4, and planned reductions following the conversion to gas at Sundance Unit 6.

Comparable EBITDA for the three months ended March 31, 2021, was consistent with the same period in 2020. Higher Alberta pricing was offset by lower production and higher fuel and carbon compliance costs.

For the three months ended March 31, 2021, sustaining and productivity capital expenditures increased by $7 million, compared to the same period in 2020, mainly due to timing of conversion to gas outages at our coal facilities.

Alberta Thermal's cash flow for the three months ended March 31, 2021, decreased by $5 million, compared to the same period in 2020, mainly due to higher sustaining capital expenditures, which were partially offset by lower lease payments.

Centralia(1)

	3 months ended March 31	
	2021	2020
Gross installed capacity (MW) (2)	**670**	1,340
Availability (%)	**86.7**	76.2
Adjusted availability (%)(3)	**86.7**	93.2
Contract sales volume (GWh)	**820**	830
Merchant sales volume (GWh)	**1,150**	1,271
Purchased power (GWh)	**(978)**	(995)
Total production (GWh)	**992**	1,106
Revenues	**100**	118
Fuel and purchased power	**74**	68
Comparable gross margin	**26**	50
Operations, maintenance and administration	**13**	16
Taxes, other than income taxes	**1**	1
Comparable EBITDA	**12**	33
Deduct:		
Sustaining capital:		
Routine capital	**—**	1
Planned major maintenance	**1**	2
Total sustaining capital expenditures	**1**	3
Decommissioning and restoration costs settled	**2**	2
Centralia cash flow	**9**	28

(1) The US Coal segment was renamed Centralia in the third quarter of 2020.
(2) Centralia Unit 1 was retired from services in the first quarter of 2021.
(3) Adjusted for dispatch optimization.

Adjusted availability for the three months ended March 31, 2021, decreased compared to the same period in 2020, due to higher unplanned outages.

Production for the three months ended March 31, 2021, decreased by 114 GWh, compared to the same period in 2020. This was largely a result of the retirement of Centralia Unit 1, which was partially offset by a decrease in dispatch optimization.

Fuel and purchased power increased $6 million during the quarter due to an unplanned outage necessitating power purchases during high merchant pricing, which was partially offset by lower fuel costs.

OM&A costs for the three months ended March 31, 2021, decreased $3 million, compared with the same period in 2020, due to strong cost controls and the retirement of Centralia Unit 1.

Comparable EBITDA for the three months ended March 31, 2021 decreased by $21 million compared to the same period in 2020, primarily due to an outage occurring during a period of higher merchant pricing in the first quarter of 2021.

Sustaining capital expenditures for the three months ended March 31, 2021, were $2 million lower compared with the same period in 2020, mainly due to timing of planned major maintenance.

Centralia's cash flow for the three months ended March 31, 2021, decreased by $19 million, compared to the the same period in 2020, mainly due to lower comparable EBITDA, partially offset by timing of sustaining capital expenditures.

Energy Marketing

	3 months ended March 31	
	2021	2020
Revenues and comparable gross margin	**53**	22
Operations, maintenance and administration	**10**	9
Comparable EBITDA	**43**	13
Deduct:		
Provisions and other	**(2)**	(5)
Energy Marketing cash flow	**45**	18

Comparable EBITDA for the three months ended March 31, 2021, increased by $30 million, compared to the same period in 2020, resulting from favourable short-term trading of both physical and financial power and gas products across all North American markets.

Energy Marketing's cash flow for the three months ended March 31, 2021, increased by $27 million, compared to the the same period in 2020, mainly due to higher comparable EBITDA, which was partially offset by changes in emissions obligations and prepaid balances for transmission rights.

Corporate

	3 months ended March 31	
	2021	2020
Operations, maintenance, and administration	**8**	29
Comparable EBITDA	**(8)**	(29)
Deduct:		
Sustaining capital:		
Routine capital	**2**	3
Total sustaining capital expenditures	**2**	3
Principal payments on lease liabilities	**1**	1
Corporate cash flow	**(11)**	(33)

Corporate overhead costs for the three months ended March 31, 2021, decreased by $21 million compared to the same period in 2020. These changes were primarily due to the receipt of CEWS funding and realized gains from the total return swap. A portion of the settlement cost of our employee share-based payment plans is hedged by entering into total return swaps, which are cash settled every quarter.

	3 months ended March 31	
Supplemental disclosure	**2021**	2020
Corporate cash flow	**(11)**	(33)
Total return swap (gains) losses	**(7)**	11
CEWS	**(8)**	—
Adjusted Corporate cash flow	**(26)**	(22)

Adjusted Corporate overhead costs for the three months ended March 31, 2021, increased by $4 million, compared to the same period in 2020, due to increased staffing costs, higher insurance premiums and additional legal fees as we progress the settlement of outstanding legal issues. Staffing costs increased due to additional headcount and staff reorganization to centralize services to support growth initiatives and the portfolio management of our operating in the Alberta electricity market in order to maximize our overall return on these assets.

Additional IFRS Measures and Non-IFRS Measures

An additional IFRS measure is a line item, heading or subtotal that is relevant to an understanding of the consolidated financial statements but is not a minimum line item mandated under IFRS, or the presentation of a financial measure that is relevant to an understanding of the consolidated financial statements but is not presented elsewhere in the consolidated financial statements. We have included line items entitled gross margin and operating income (loss) in our unaudited interim condensed consolidated statements of earnings (loss) for the three months ended March 31, 2021 and 2020. Presenting these line items provides management and investors with a measurement of ongoing operating performance that is readily comparable from period to period.

We evaluate our performance and the performance of our business segments using a variety of measures to provide management and investors with an understanding of our financial position and results. Certain financial measures discussed in this MD&A are not defined under IFRS, are not standard measures under IFRS and, therefore, should not be considered in isolation or as an alternative to, or to be more meaningful than, net earnings attributable to common shareholders or cash flow from operating activities, as determined in accordance with IFRS when assessing our financial performance or liquidity. These measures may not be comparable to similar measures presented by other issuers and should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. Comparable EBITDA, deconsolidated comparable EBITDA, deconsolidated comparable EBITDA by segment, FFO, deconsolidated FFO, FCF, total net debt, total consolidated net debt, adjusted net debt, deconsolidated net debt and segmented cash flow generated by the business, all as defined below, are non-IFRS measures that are presented in this MD&A. See the Reconciliation of Non-IFRS Measures, Segmented Comparable Results, Selected Quarterly Information, Key Financial Ratios and Financial Capital sections of this MD&A for additional information, including a reconciliation of such non-IFRS measures to the most comparable IFRS measure.

Reconciliation of Non-IFRS Measures

Each business segment assumes responsibility for its operating results measured to comparable EBITDA and cash flows generated by the business. Gross margin is also a useful measure as it provides management and investors with a measurement of operating performance that is readily comparable from period to period.

Comparable EBITDA

EBITDA is a widely adopted valuation metric and 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, under comparable EBITDA we reclassify certain transactions to facilitate the discussion of the performance of our business:

- Comparable EBITDA is adjusted to exclude the impact of unrealized mark-to-market gains or losses.
- Any gains or losses on asset sales or foreign exchange gains or losses are not included as these are not part of operating income.
- 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.
- We also reclassify the depreciation on our mining equipment from fuel, carbon compliance and purchased power to reflect the actual cash cost of our business in our comparable EBITDA.
- The writedown of coal inventory has been removed from the calculation as it distorts the comparability of comparable EBITDA. Coal inventory writedowns are adjustments that are not reflective of our core on-going business results upon conversion to gas. To accelerate our conversion to gas, a decision was made to accelerate the mine shut-down to the end of 2021.
- 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.
- Asset impairments (reversals) are removed to calculate comparable EBITDA as these are accounting adjustments that impact depreciation and amortization and do not reflect business performance.
- 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 comparable EBITDA of Skookumchuck in our total comparable EBITDA. In addition, in the Wind and Solar comparable results, we have included our proportionate share of revenues and expenses to reflect the full operational results of this investment. We have not included EMG International, LLC's comparable EBITDA in our total comparable EBITDA as it does not represent our regular power-generating operations.

A reconciliation of net earnings (loss) attributable to common shareholders to comparable EBITDA results is set out below:

	3 months ended March 31	
	2021	2020
Net earnings (loss) attributable to common shareholders	**(30)**	27
Net earnings attributable to non-controlling interests	**31**	7
Preferred share dividends	**—**	10
Net earnings	**1**	44
Adjustments to reconcile net income to comparable EBITDA		
Income tax expense	**20**	2
Other gains	**(1)**	—
Foreign exchange (gain) loss	**(7)**	19
Net interest expense	**63**	62
Equity income	**(2)**	—
Depreciation and amortization	**149**	156
Comparable reclassifications		
Decrease in finance lease receivables	**10**	4
Mine depreciation included in fuel cost	**55**	28
Australian interest income	**1**	1
Unrealized mark-to-market gains	**(20)**	(55)
Adjustments to earnings to arrive at comparable EBITDA		
Coal inventory write-down	**8**	—
Asset impairment (reversal)(1)	**29**	(41)
Share of adjusted EBITDA from Joint venture(2)	**4**	—
Comparable EBITDA	**310**	220

(1) The asset impairment for the three months ended March 31, 2021 of $29 million, mainly relates to the impairment of the Kaybob project and coal rights, offset by changes in the decommissioning and restoration liability at the Centralia mine and Sundance 1 & 2 units. The asset impairment reversal for the same period in 2020, primarily includes the $41 million decrease for the decommissioning and restoration liability at the Centralia mine and Sundance Units 1 & 2 as a result of a substantial increase in TransAlta's credit spread due to the COVID-19 crisis causing increased credit spreads across most entities, which was partially offset by decreases in the benchmark rates.
(2) Includes our share of amounts for Skookumchuck, an equity accounted joint venture.

Funds from Operations and Free Cash Flow

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. FCF is a key 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. FFO per share and FCF per share are calculated using the weighted average number of common shares outstanding during the period.

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

	3 months ended March 31	
	2021	2020
Cash flow from operating activities[1]	**257**	214
Change in non-cash operating working capital balances	**(72)**	(50)
Cash flow from operations before changes in working capital	**185**	164
Adjustments		
Share of adjusted FFO from joint venture[1]	**4**	—
Decrease in finance lease receivable	**10**	4
Coal inventory write-down	**8**	—
Other	**4**	4
FFO	**211**	172
Deduct:		
Sustaining capital	**(34)**	(29)
Dividends paid on preferred shares	**(10)**	(10)
Distributions paid to subsidiaries' non-controlling interests	**(37)**	(19)
Principal payments on lease liabilities	**(2)**	(5)
Other	**1**	—
FCF	**129**	109
Weighted average number of common shares outstanding in the period	**270**	277
FFO per share	**0.78**	0.62
FCF per share	**0.48**	0.39

(1) Includes our share of amounts for Skookumchuck, an equity accounted joint venture.

The table below bridges our comparable EBITDA to our FFO and FCF:

	3 months ended March 31	
	2021	2020
Comparable EBITDA[1]	**310**	220
Provisions and other	**(5)**	5
Interest expense	**(51)**	(47)
Current income tax expense	**(23)**	(9)
Realized foreign exchange gain (loss)	**(1)**	15
Decommissioning and restoration costs settled	**(3)**	(4)
Other cash and non-cash items	**(16)**	(8)
FFO	**211**	172
Deduct:		
Sustaining capital	**(34)**	(29)
Dividends paid on preferred shares	**(10)**	(10)
Distributions paid to subsidiaries' non-controlling interests	**(37)**	(19)
Principal payments on lease liabilities	**(2)**	(5)
Other	**1**	—
FCF	**129**	109

(1) Includes our share of amounts for Skookumchuck, an equity accounted joint venture.

The table below bridges our reported EBITDA of our owned assets to our comparable EBITDA:

3 months ended March 31, 2021	Reported	Adjustments[1]	Joint venture investment[2]	Comparable total
Revenues	642	(3)	5	**644**
Fuel, carbon compliance and purchased power	243	(64)	—	**179**
Carbon compliance	50	—	—	**50**
Gross margin	349	61	5	**415**
Operations, maintenance and administration	105	—	1	**106**
Asset impairment	29	(29)	—	**—**
Taxes, other than income taxes	9	—	—	**9**
Net other operating income	(10)	—	—	**(10)**
Comparable EBITDA	216	90	4	**310**

(1) Refer to the reconciliation of net earnings (loss) attributable to common shareholders to comparable EBITDA table above for details of all adjustments.
(2) Includes our share of amounts for Skookumchuck, an equity accounted joint venture which was acquired in the fourth quarter of 2020 .

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, hydro 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 2020	Q3 2020	Q4 2020	**Q1 2021**
Revenues	437	514	544	**642**
Comparable EBITDA	217	256	234	**310**
FFO	159	193	161	**211**
Net earnings (loss) attributable to common shareholders	(60)	(136)	(167)	**(30)**
Net earnings (loss) per share attributable to common shareholders, basic and diluted[1]	(0.22)	(0.50)	(0.61)	**(0.11)**

	Q2 2019	Q3 2019	Q4 2019	Q1 2020
Revenues	497	593	609	606
Comparable EBITDA	215	305	243	220
FFO	155	244	189	172
Net earnings (loss) attributable to common shareholders	—	51	66	27
Net earnings (loss) per share attributable to common shareholders, basic and diluted[1]	—	0.18	0.24	0.10

(1) Basic and diluted earnings per share attributable to common shareholders and comparable 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.

Reported net earnings, comparable EBITDA and FFO are generally higher in the first and fourth quarters due to higher demand associated with the cold winter months in the markets in which we operate and lower planned outages.

Net earnings attributable to common shareholders has also been impacted by the following variations and events:

- Effective Jan. 1, 2021, many of our Alberta hydro facilities, Keephills 1 and 2 units and Sheerness began operating on a merchant basis in the Alberta market.
- Revenues declined due to weaker market conditions during the last three quarters of 2020 as a result of COVID-19 pandemic and low oil prices;
- Impact of Sheerness going off-coal, which has 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;
- Coal inventory writedowns in the first quarter of 2021 and third and fourth quarters of 2020;
- Impact of the updated provision estimates for the 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, which more than offset foreign exchange losses experienced during the first quarter of 2020;
- Gains relating to the Keephills 3 and Genesee 3 swap in the fourth quarter of 2019;
- Effects of impairments and reversals during the first quarter of 2021, second, third and fourth quarters of 2020 and the third and fourth quarters of 2019;
- Effects of changes in decommissioning and restoration provision in the first quarter of 2020, third quarter of 2020 and third quarter of 2019;
- Effects of changes in useful lives of certain assets during the third quarter of 2020 and third quarter of 2019;
- Current tax expense increased since the first quarter of 2020, mainly due to the Energy Marketing segment becoming taxable, increased valuation allowances taken on US deferred tax assets, offset by an increased deferred tax recovery mainly due to decreased revenues compared to Q1 2020; and
- Recognition of $56 million received on winning the arbitration against the Balancing Pool in the third quarter of 2019.

Key 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 Comparable EBITDA

As at	**March 31, 2021**	Dec. 31, 2020
Period-end long-term debt(1)	**3,206**	3,361
Exchangeable debentures	**331**	330
Less: Cash and cash equivalents	**(648)**	(703)
Add: 50 per cent of issued preferred shares and exchangeable preferred shares(2)	**671**	671
Other(3)	**—**	(13)
Adjusted net debt(4)	**3,560**	3,646
Comparable EBITDA(5)	**1,017**	927
Adjusted net debt to comparable EBITDA (times)	**3.5**	3.9

(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 purposes. For accounting purposes, they are accounted for as debt with interest expense in the consolidated financial statements.
(3) Includes fair value asset of hedging instruments on debt included in risk management assets and/or liabilities and the principal portion of OCP restricted cash included in restricted cash on the consolidated financial statements as at March 31, 2021 and Dec. 31, 2020.
(4) The interest on the tax equity financing for Skookumchuck, an equity accounted joint venture, is not represented in the amounts.
(5) Last 12 months.

We continue to actively reduce our net senior unsecured debt levels to achieve a lower adjusted net debt to adjusted comparable EBITDA. Our adjusted net debt to adjusted comparable EBITDA ratio was lower than 2020 as a result of strong comparable EBITDA in the first quarter of 2021.

Deconsolidated Net Debt to Deconsolidated Comparable EBITDA

In addition to reviewing fully consolidated ratios and results, management reviews net debt to comparable EBITDA on a deconsolidated basis to highlight TransAlta's financial flexibility, balance sheet strength and leverage, excluding the portion of TransAlta Renewables and TransAlta Cogeneration L.P. ("TA Cogen") that are not owned by TransAlta. These metrics and ratios are not defined under IFRS, and may not be comparable to those used by other entities or by rating agencies. See also the IFRS Measures and Non-IFRS Measures section of this MD&A for further details.

As at	March 31, 2021	Dec. 31, 2020
Period-end long-term debt[1]	**3,206**	3,361
Exchangeable debentures	**331**	330
Less: Cash and cash equivalents	**(648)**	(703)
Add: TransAlta Renewables cash and cash equivalents	**407**	582
Add: 50 per cent of issued preferred shares and exchangeable preferred shares[2]	**671**	671
Other[3]	**—**	(13)
Less: TransAlta Renewables long-term debt	**(692)**	(692)
Less: US tax equity financing and South Hedland debt[4]	**(893)**	(905)
Deconsolidated net debt	**2,382**	2,631
Comparable EBITDA[5][6]	**1,017**	927
Less: TransAlta Renewables comparable EBITDA[5]	**(467)**	(462)
Less: TA Cogen comparable EBITDA[5]	**(67)**	(54)
Less: comparable EBITDA from equity accounted investments[5][6]	**(7)**	(3)
Add: Dividend from TransAlta Renewables[5]	**151**	151
Add: Dividend from TA Cogen[5]	**19**	17
Deconsolidated comparable EBITDA[5]	**646**	576
Deconsolidated net debt to deconsolidated comparable EBITDA[5] (times)	**3.7**	4.6

(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 purposes. For accounting purposes, they are accounted for as debt with interest expense in the consolidated financial statements.
(3) Includes fair value asset of hedging instruments on debt included in risk management assets and/or liabilities and the principal portion of OCP restricted cash included in restricted cash on the consolidated financial statements as at March 31, 2021 and Dec. 31, 2020.
(4) Relates to assets where TransAlta Renewables has economic interests.
(5) Last 12 months.
(6) Comparable EBITDA includes our share of amounts for Skookumchuck, an equity accounted joint venture.

We continue to actively reduce our net senior unsecured debt levels to achieve a lower adjusted net debt to adjusted comparable EBITDA. Our deconsolidated net debt to deconsolidated comparable EBITDA ratio decreased compared with 2020, mainly as a result lower debt balances and stronger comparable EBITDA in the period.

Deconsolidated Comparable EBITDA by Segment
Comparable 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 comparable EBITDA to deconsolidated comparable EBITDA by segment results is set out below:

	3 months ended March 31, 2021			3 months ended March 31, 2020		
	TransAlta Consolidated	**TransAlta Renewables**	**TransAlta Deconsolidated**	TransAlta Consolidated	TransAlta Renewables	TransAlta Deconsolidated
Hydro	**77**	**1**		26	—	
Wind and Solar	**76**	**75**		74	74	
North American Gas	**35**	**21**		29	19	
Australian Gas	**32**	**32**		30	30	
Alberta Thermal	**43**	**—**		44	—	
Centralia	**12**	**—**		33	—	
Energy Marketing	**43**	**—**		13	—	
Corporate	**(8)**	**(6)**		(29)	(5)	
Comparable EBITDA	**310**	**123**	**187**	220	118	102
Less: TA Cogen comparable EBITDA			**(25)**			(12)
Less: EBITDA from joint venture investments[1]			**(4)**			—
Add: Dividend from TransAlta Renewables			**38**			38
Add: Dividend from TA Cogen			**3**			1
Deconsolidated TransAlta comparable EBITDA			**199**			129

(1) Represents our share of amounts for Skookumchuck, an equity accounted joint venture.

Deconsolidated FFO

The Corporation has set a target to return 10 to 15 per cent of TransAlta's deconsolidated FFO to shareholders as it aligns shareholder returns to the assets held directly at TransAlta. This metric 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 IFRS Measures and Non-IFRS Measures section of this MD&A for further details.

	3 months ended March 31, 2021			3 months ended March 31, 2020		
	TransAlta Consolidated	**TransAlta Renewables**	**TransAlta Deconsolidated**	TransAlta Consolidated	TransAlta Renewables	TransAlta Deconsolidated
Cash flow from operating activities	**257**	**103**		214	82	
Change in non-cash operating working capital balances	**(72)**	**(15)**		(50)	(18)	
Cash flow from operations before changes in working capital	**185**	**88**		164	64	
Adjustments:						
Decrease in finance lease receivable	**10**	**—**		4	—	
Coal inventory write-down	**8**	**—**		—	—	
Share of FFO from joint venture[(1)]	**4**	**—**		—	—	
Finance and interest income - economic interests	**—**	**(29)**		—	(8)	
AFFO - economic interests	**—**	**35**		—	40	
Sustaining capital expenditures - economic interests[(2)]	**—**	**—**		—	3	
Tax equity distributions - economic interests[(2)]	**—**	**6**		—	6	
Other	**4**	**—**		4	—	
FFO	**211**	**100**	**111**	172	105	67
Dividend from TransAlta Renewables			**38**			38
Distributions to TA Cogen's Partner			**(11)**			(1)
Less: Share of adjusted FFO from joint venture			**(4)**			—
Deconsolidated TransAlta FFO			**134**			104

(1) Represents our share of amounts for Skookumchuck, an equity accounted joint venture.
(2) During the first quarter of 2021, sustaining capital expenditures and tax equity distributions for TransAlta Renewables' economic interests have been added back to the AFFO to align with the Corporation's calculation of FFO. Prior comparative periods have been adjusted.

Financial Position

The following table provides a summary of account balances derived from the unaudited interim condensed consolidated statements of financial position as at March 31, 2021 and Dec. 31, 2020:

As at	March 31, 2021	Dec. 31, 2020	Increase (decrease)
Assets			
Cash and cash equivalents	**648**	703	(55)
Risk management assets (current and long-term)	**649**	692	(43)
Property, plant, and equipment, net	**5,658**	5,822	(164)
Intangible assets	**286**	313	(27)
Others(1)	**2,178**	2,217	(39)
Total assets	**9,419**	9,747	(328)
Liabilities and equity			
Credit facilities, long-term debt and lease liabilities (current and long-term)	**3,206**	3,361	(155)
Decommissioning and other provisions (current and long-term)	**601**	673	(72)
Defined benefit obligation and other long-term liabilities	**251**	298	(47)
Equity attributable to shareholders	**2,340**	2,352	(12)
Non-controlling interests	**1,037**	1,084	(47)
Others(2)	**1,984**	1,979	5
Total liabilities and equity	**9,419**	9,747	(328)

(1) Includes restricted cash, trade and other receivables, prepaid expenses, inventory, assets held for sale, investments, long-term portion of finance lease receivable, right-of-use assets, goodwill, deferred income tax assets and other assets.
(2) Includes accounts payable and accrued liabilities, income taxes payable, dividends payable, deferred income tax liabilities, contract liabilities, risk management liabilities and exchangeable securities.

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

- See the cash flow section of this MD&A for details on the change in cash during the period.
- Risk management assets, net of liabilities, decreased primarily due to unfavourable changes in market prices and contract settlements.
- Property, plant and equipment ("PP&E") decreased due to depreciation ($183 million), asset impairments ($27 million), which was partially offset by additions ($98 million) relating to assets under construction for the Windrise wind project, boiler conversions, Sundance Unit 5 repowering project and other planned major maintenance expenditures. Our PP&E also decreased due to changes in foreign exchange rates ($13 million decrease) and revisions to decommissioning provisions as a result of changes in discount rates ($35 million).
- Intangible assets decreased due to a $14 million impairment of coal rights and depreciation expense of $13 million.
- Credit facilities, long-term debt and lease liabilities decreased due to lower drawings on the credit facilities ($114 million) and debt repayments ($18 million), partially offset by changes in outstanding balances as a result of the weakening of the US dollar ($11 million).
- Decommissioning and other provisions have decreased mainly due to revisions in discount rates ($45 million) and the settlement of provisions resulted in a decrease of $32 million.
- Defined benefit obligation and other long-term liabilities decreased due to net actuarial gains resulting from increases in actuarial discount rates.
- Equity attributable to shareholders decreased mainly due to net losses for the period ($30 million), net losses on translating net assets of foreign operations ($8 million), net losses on cash flow hedges ($44 million) and the effect of share-based payment plans ($10 million), partially offset by changes in fair value investments ($43 million), actuarial gains on defined benefit plans ($37 million).
- Non-controlling interests decreased mainly due to distributions ($37 million) and fair value investment losses on intercompany fair value through other comprehensive income ("FVOCI") investments ($43 million), partially offset by net earnings attributable to non-controlling interests ($31 million).

Cash Flows

The following reconciles TransAlta's opening cash and cash equivalents to closing cash and cash equivalents:

	3 months ended March 31		
	2021	2020	Increase (decrease)
Cash and cash equivalents, beginning of period	**703**	411	292
Provided by (used in):			
Operating activities	**257**	214	43
Investing activities	**(111)**	(95)	(16)
Financing activities	**(200)**	(196)	(4)
Translation of foreign currency cash	**(1)**	4	(5)
Cash and cash equivalents, end of period	**648**	338	310

Cash provided by operating activities for the three months ended March 31, 2021, was higher compared with the same period in 2020 primarily from higher revenues being realized in Alberta on the merchant assets.

Cash used in investing activities for the three months ended March 31, 2021, increased compared with the same period in 2020, largely due to:

- increased cash spent on construction activities ($26 million);
- lower non-cash working capital related to the timing of construction payables for the assets under construction ($12 million);
- offset by an increase in the amount collected on finance lease receivables ($6 million).

Cash used in financing activities for the three months ended March 31, 2021, increased compared with the same period in 2020, largely due to:

- decrease on amounts outstanding under the credit facilities and long-term debt ($14 million);
- increase in distributions paid to subsidiaries' non-controlling interests ($18 million);
- offset by realized gains ($10 million) recognized in the same period of the prior year and changes in working capital of related to financing activities ($13 million).

Financial Capital

Capital Structure

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

As at	March 31, 2021		Dec. 31, 2020	
	$	**%**	$	%
TransAlta Corporation				
Net senior unsecured debt				
Recourse debt - CAD debentures	**250**	**4**	249	3
Recourse debt - US senior notes	**877**	**13**	886	13
Credit facilities	**—**	**—**	114	2
Other	**5**	**—**	7	—
Less: cash and cash equivalents	**(241)**	**(4)**	(121)	(2)
Less: Other cash and liquid assets[1]	**—**	**—**	(13)	—
Net senior unsecured debt	**891**	**13**	1,122	16
Other debt liabilities				
Exchangeable debentures	**331**	**5**	330	5
Non-recourse debt	**383**	**6**	385	6
Lease liabilities	**106**	**2**	112	2
Total net debt - TransAlta Corporation	**1,711**	**26**	1,949	29
TransAlta Renewables				
Net TransAlta Renewables reported debt				
Non-recourse debt	**668**	**10**	670	10
Lease liabilities	**24**	**—**	22	—
Less: cash and cash equivalents	**(407)**	**(6)**	(582)	(9)
Debt on TransAlta Renewables Economic Investments				
US tax equity financing[2]	**131**	**2**	134	2
Non-recourse debt[3]	**762**	**11**	782	11
Total net debt - TransAlta Renewables	**1,178**	**17**	1,026	14
Total consolidated net debt[4]	**2,889**	**43**	2,975	43
Non-controlling interests	**1,037**	**16**	1,084	16
Exchangeable preferred securities[5]	**400**	**6**	400	6
Equity attributable to shareholders				
Common shares	**2,894**	**43**	2,896	43
Preferred shares	**942**	**14**	942	14
Contributed surplus, deficit and accumulated other comprehensive income	**(1,496)**	**(22)**	(1,486)	(22)
Total capital	**6,666**	**100**	6,811	100

(1) Includes principal portion of OCP restricted cash and fair value asset 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$800 million senior secured notes.
(4) The tax equity financing for Skookumchuck, an equity accounted joint venture, is not represented in these amounts.
(5) Exchangeable preferred securities are considered equity with dividend payments for credit purposes. For accounting purposes, they are accounted for as debt with interest expense in the Consolidated Financial Statements.

The Corporation continues to maintain a strong financial position in part due to our long-term contracts and hedged positions. At quarter end we had access to $2.1 billion in liquidity including $648 million in cash and cash equivalents.

We have access to additional capital through potential project financing of existing assets that are currently unencumbered. Between 2021 and 2023, we have $860 million of debt maturing, including $511 million of recourse debt, with the balance mainly related to scheduled non-recourse debt repayments. We currently expect to refinance the senior notes maturing in 2022.

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

As at March 31, 2021	Facility size	Utilized: Outstanding letters of credit[1]	Utilized: Actual drawings	Available capacity	Maturity date
TransAlta Corporation					
Committed syndicated bank facility[2]	1,250	400	—	850	Q2 2025
Canadian committed bilateral credit facilities	240	160	—	80	Q2 2023
TransAlta Renewables					
Committed credit facility[2]	700	95	—	605	Q2 2025
Total	**2,190**	**655**	**—**	**1,535**	

(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. As at March 31, 2021, we provided cash collateral of $20 million.

(2) TransAlta has letters of credit of $97 million and TransAlta Renewables has letters of credit of $95 million issued from uncommitted demand facilities, these obligations are backstopped and reduce the available capacity on the committed credit facilities.

Share Capital

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

As at	May 12, 2021	March 31, 2021	Dec. 31, 2020
	Number of shares *(millions)*		
Common shares issued and outstanding, end of period	**269.9**	**269.9**	269.8
Preferred shares			
Series A[1]	9.6	**9.6**	10.2
Series B[1]	2.4	**2.4**	1.8
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[2]	**0.4**	**0.4**	0.4
Preferred shares issued and outstanding, end of period	**39.0**	**39.0**	39.0

(1) On March 18, 2021, the Corporation announced that 1,417,338 of its 10.2 million Series A Cumulative Fixed Redeemable Rate Reset Preferred Shares ("Series A Shares") and 871,871 of its 1.8 million Series B Cumulative Redeemable Floating Rate Preferred Shares ("Series B Shares") were tendered for conversion, on a one-for-one basis, into Series B Shares and Series A Shares, respectively after having taken into account all election notices. As a result of the conversion, the Corporation had 9.6 million Series A shares and 2.4 million Series B Shares issued and outstanding as at March 31, 2021.

(2) Brookfield invested $400 million in consideration for redeemable, retractable, first preferred shares on Oct. 30, 2020. For accounting purposes, these preferred share are considered debt and disclosed as such in the consolidated financial statements.9.6 million Series A shares and 2.4 million Series B Shares issued and outstanding as at March 31, 2021.

Non-Controlling Interests

As at March 31, 2021, we own 60.1 per cent (March 31, 2020 – 60.3 per cent) of TransAlta Renewables. Our ownership percent decreased due to common shares issued under TransAlta Renewables' Dividend Reinvestment Plan ("DRIP"). We do not participate in this plan. In the fourth quarter of 2020, TransAlta Renewables suspended the DRIP in respect of any future declared dividends. Any future dividends will only be paid only in cash.

We also own 50.01 per cent of TA Cogen (March 31, 2020 - 50.01 per cent), which owns, operates or has an interest in three natural-gas-fired facilities (Ottawa, Windsor and Fort Saskatchewan) and one dual-fuel generating facility (Sheerness).

Reported earnings attributable to non-controlling interests for the three months ended March 31, 2021 was $31 million, an increase of $24 million compared to the same period in 2020. Earnings increased at TransAlta Renewables mainly due to higher finance income and foreign exchange gains resulting from the strengthening Australian dollar relative to the Canadian dollar. Earnings from TA Cogen for the three months ended March 31, 2021, also increased compared with the same period in 2020, due to higher prices in the Alberta market partially offset by lower production.

Returns to Providers of Capital

Net Interest Expense

The components of net interest expense are shown below:

	3 months ended March 31	
	2021	2020
Interest on debt	**40**	43
Interest on exchangeable securities	**14**	7
Interest income	**(3)**	(3)
Capitalized interest	**(5)**	(1)
Interest on lease liabilities	**2**	2
Credit facility fees, bank charges, and other interest	**4**	4
Tax shield on tax equity financing	**1**	—
Other	**3**	1
Accretion of provisions	**7**	9
Net interest expense	**63**	62

Net interest expense for the three months ended March 31, 2021, was consistent with March 31, 2020. Interest increased in the first quarter of 2021 on the exchangeable securities issued in the fourth quarter of 2020 and was offset by an increase in capitalized interest on development projects and lower interest on other debt balances.

Regulatory Updates

Refer to the Policy and Legal Risks discussion in our 2020 annual MD&A for further details that supplement the recent developments as discussed below:

Federal Climate Plan

On Dec. 11, 2020, the Government of Canada released its "*A Healthy Environment and a Healthy Economy*" climate plan that outlines how the federal government intends to use policies, regulations and funding to achieve Canada's Paris Agreement emissions reduction target of 30 per cent reduction from 2005 greenhouse gas emission levels. The three major aspects of the plan include increased carbon prices and obligations, increased funding for clean technology and the implementation of the Clean Fuel Regulation ("CFR"). The 2021 federal budget proposed significant spending to undertake the elements of the climate plan as well as additional measures, including a potential tax credit for carbon capture, utilization and storage ("CCUS"). On April 22, 2021, during a climate summit hosted by President Biden, Prime Minister Trudeau increased Canada's greenhouse gas reduction target from 40 to 45 per cent below 2005 levels by 2030. The government stated that it will consult with provinces and industry regarding many elements of the plan so significant uncertainty remains regarding the final form of the related regulations and other initiatives. TransAlta continues to engage with governments to mitigate risks and identify opportunities within the new federal plan.

Clean Fuel Regulation

On Dec. 19, 2020, the Canadian federal government published its draft version of the CFR. This started a 75-day obligatory public consultation period that ended on March 4, 2021 where the public was able to submit comments. The federal government also announced the CFR would only regulate liquid transportation fuels, removing gaseous and solid fuels from regulation thereby limiting the impact on the electricity sector. The CFR is scheduled to be finalized in December 2021 and come into force on Dec. 1, 2022.

Federal Carbon Pricing on GHG

On June 21, 2018, the Canadian federal *Greenhouse Gas Pollution Pricing Act* ("GGPPA") came into force. Under the GGPPA, the federal government implemented a national price on GHG emissions. On Jan. 1, 2019, the GGPPA's backstop mechanisms came into force in provinces and territories that did not have an independent carbon pricing program or where the existing program was not deemed equivalent to the federal system. The backstop mechanism has two components: a carbon levy for small emitters ("Carbon Tax") and regulation for large emitters called the Output-Based Pricing Standard ("OBPS"). The Carbon Tax sets a carbon price per tonne of GHG emissions related to transportation fuels, heating fuels and other small emission sources. The carbon price is also the OBPS compliance price for carbon obligations.

On Feb. 12, 2021, the federal government began planning for a 2022 review of the OBPS and other aspects of the GGPPA. TransAlta will actively engage in this process as any changes to the OBPS will likely influence provincial carbon pricing systems in the future.

Ontario Transition to Provincial Emission Performance Standard ("EPS")
In the fall of 2020, the federal government confirmed the EPS met the requirements of the GGPPA permitting Ontario to transition from the OBPS to the EPS. The Ontario government initially planned to transition to the EPS on Jan. 1, 2021. This implementation has been delayed until Jan. 1, 2022. The eventual transition to the EPS represents no material risk to TransAlta's business in Ontario. TransAlta will continue to submit compliance reports to the federal government under the OBPS until the implementation of the EPS .

Supreme Court Ruling on Federal Carbon Tax Constitutionality
On March 25, 2021, in a six to three decision, the Supreme Court of Canada ruled the GGPPA was constitutional. The Court found the "evidence clearly shows that establishing minimum national standards of GHG price stringency to reduce GHG emissions is of concern to Canada" and that the federal law is "critical to our response to an existential threat to human life in Canada and around the world." As a result, provincial governments will need to continue to impose their own carbon costs on greenhouse gas emissions in line with federal GGPPA regulations or the federal government will impose its own OBPS and/or Carbon Tax.

President Biden's American Jobs Plan
On March 31, 2021, President Biden announced his American Jobs Plan (the "Plan") which is heavily focused on climate change. The Plan proposes to spend $2 trillion over the next decade to rebuild transportation infrastructure, make existing and new infrastructure climate change resilient, create cleaner energy systems, support the deployment of electric vehicles and ensure the job growth particularly for low income and communities of colour. The Plan requires passage in the House and the Senate so the details are likely to change in the coming months as Congress develops enacting legislation. Given the narrow Democratic control in both chambers, passage is not guaranteed.

The proposed Made in America Tax Plan would pay for the Plan's costs over 15 years by setting the corporate tax at 28 per cent, reducing the ability of corporations to avoid paying taxes in the US, and seeking agreements to establish a global minimum corporate tax.

The Plan's proposed policy of relevance to TransAlta's are:
- $175 billion investment in electric vehicles;
- 100 per cent carbon free electricity sector by 2035;
- Extension of investment credits to support further renewable project development;
- Federal Grid Deployment Authority to support development of 20 gigawatts of new transmission;
- $180 billion in research and development funding for new energy technology such as storage technologies;
- 45Q tax credit expansion to support increased carbon capture use and storage installation; and,
- $35 billion in research and development support for carbon capture technologies.

President Biden's Updated 2030 Emissions Reduction Commitment
On April 22, 2021, during a climate summit hosted by President Biden, the President committed to reduce U.S. greenhouse gas emissions by 50 to 52 per cent below 2005 levels by 2030.

Other Consolidated Analysis

Commitments

Certain commitments disclosed in the Other Consolidated Analysis section of the 2020 Annual Integrated Report are based on variable pricing and any material updates to contracts containing variable pricing are discussed below. Please also refer to our Other Consolidated Analysis section of the 2020 Annual Integrated Report for a complete listing of commitments we have incurred either directly or through interests in joint operations.

Natural Gas and Transportation Contracts
These contracts include fixed volume commitments for natural gas. As of March 31, 2021 and Dec. 31, 2020, the Corporation had supply agreements for variable price natural gas commodity contracts for 139 TJ per day until 2034 based on Alberta Energy Company (AECO) pricing. As a result of changes in variable gas pricing, the total commitment for natural gas commodity contracts increased by $308 million to $2.0 billion as at March 31, 2021 (Dec. 31, 2020 - $1.7 billion).

Contingencies

For the current significant outstanding contingencies, refer to the Other Consolidated Analysis section of the 2020 Annual MD&A included in the 2020 Annual Integrated Report. Changes to these contingencies during the three months ended March 31, 2021, are included with the Significant and Subsequent Events section of the MD&A and below:

I. Transmission Line Loss Rule Proceeding

The Corporation has been participating in a transmission line loss rule proceeding before the Alberta Utilities Commission ("AUC"). The AUC determined that it has the ability to retroactively adjust line loss charges going back to 2006 and directed the AESO to recalculate loss factors for 2006 to 2016. The first two invoices were received during 2020 for a cumulative amount of $17 million and have been settled. The third and final invoice for $11 million was received in the first quarter of 2021 and will be paid by the payment deadline of May 31, 2021.

II. Kaybob 3 Cogeneration Dispute

The Corporation is engaged in a dispute with Energy Transfer Canada ULC, formerly SemCAMS Midstream ULC ("ET Canada") as a result of ET Canada's purported termination of agreements between the parties to develop, construct and operate a 40 MW cogeneration facility at the Kaybob South No. 3 sour gas processing plant. TransAlta has commenced an arbitration seeking full compensation for ET Canada's wrongful termination of the agreements. ET Canada seeks a declaration that the agreements were lawfully terminated. A hearing has not yet been scheduled.

III. FMG Dispute

The Corporation is currently engaged in a dispute with FMG as a result of FMG's purported termination of the South Hedland PPA. TransAlta sued FMG, seeking payments of amounts invoiced and not paid under the South Hedland PPA, as well as a declaration that the PPA is valid and in force. FMG, on the other hand, seeks a declaration that the PPA was lawfully terminated. The trial for this matter was set to start on May 3, 2021 but on May 2, 2021 the Corporation entered into a conditional settlement with FMG. The trial has been adjourned pending satisfaction of the settlement conditions.

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. There were no material changes in estimates in the quarter.

Accounting Changes

Current Accounting Changes

The accounting policies adopted in the preparation of the unaudited interim condensed consolidated financial statements are consistent with those followed in the preparation of the Corporation's annual consolidated financial statements for the year ended Dec. 31, 2020, except for the adoption of new standards effective as of Jan. 1, 2021 and the early adoption of standards, interpretations or amendment that has been issued but is not yet effective.

I. Amendments to IAS 16 *Property, Plant and Equipment*: Proceeds before Intended Use

Effective Jan. 1, 2021, the Corporation early adopted amendments to IAS 16 *Property plant and equipment* ("IAS 16 Amendments"), in advance of its mandatory effective date of Jan. 1, 2022. The Corporation adopted the IAS 16 Amendments retroactively. No cumulative effect of initially applying the guidance arose. The IAS 16 Amendments prohibit deducting from the cost of an item of property, plant and equipment any proceeds from selling items produced while bringing that asset to the location and condition necessary for it to be capable of operating in a manner intended by management. Instead, an entity recognizes the proceeds from selling such items, and the cost of producing those items, in profit or loss. No adjustments resulted from early adopting the amendment.

II. IFRS 7 *Financial Instruments:* Disclosures — Interest Rate Benchmark Reform

London Interbank Offered Rate ("LIBOR") is scheduled to be phased out as an interest rate index readily used by corporations for financial instruments by the end of 2021. The IASB issued Interest Rate Benchmark Reform — Phase 2 in August 2020, which amends IFRS 9 *Financial Instruments*, IAS 39 *Financial instruments: Recognition and Measurement*, IFRS 7 *Financial Instruments: Disclosures* and IFRS 16 *Leases*. The amendments were effective Jan. 1, 2021, and were adopted by the Corporation on Jan. 1, 2021.

The credit facility references US LIBOR for US-dollar drawings and the Canadian Dollar Offered Rate for Canadian drawings, and includes appropriate fallback language to replace these benchmark rates if a benchmark transition event were to occur. There was no financial impact upon adoption. As at March 31, 2021, there were no drawings under the credit facility. The Corporation is monitoring the reform and does not expect any material impact.

Future Accounting Policy Changes

Amendments to IAS 1 *Presentation of Financial Statements*: Material Accounting Policies

On Feb. 12, 2021, the IASB issued amendments to IAS 1 *Presentation of Financial Statements* to require entities to disclose their material accounting policy information rather than their significant accounting policies. The amendments are effective for annual periods beginning on or after Jan. 1, 2023, but the Corporation plans to early adopt these amendments for the 2021 annual financial statements.

For further details and changes in estimates relating to prior years, refer to Note 3 of the audited annual consolidated financial statements and Note 2 of the unaudited interim condensed consolidated financial statements.

Financial Instruments

Refer to Note 15 of the notes to the audited annual consolidated financial statements within our 2020 Annual Integrated Report and Note 10 and 11 of our unaudited interim condensed consolidated financial statements as at and for the three months ended March 31, 2021, 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, 2021, Level III instruments had a net asset carrying value of $485 million (Dec. 31, 2020 - $582 million). The decrease during the period is primarily attributable to unfavourable market prices and contract settlements. Our risk management profile and practices have not changed materially from Dec. 31, 2020.

Governance and Risk Management

Refer to the Governance and Risk Management section of our 2020 Annual Integrated Report and Note 11 of our unaudited interim condensed consolidated financial statements for details on our risks and how we manage them. Our risk management profile and practices have not changed materially from Dec. 31, 2020. The following factors may contribute to those risks and uncertainties:

COVID-19 Global Pandemic

During the quarter, TransAlta has maintained a number of risk mitigation measures introduced in 2020 in response to the COVID-19 pandemic to keep our people safe and to ensure we are able to remain fully operational and capable of meeting our customer needs.

Overall, we continue to actively monitor the situation and advice from public health officials with a view to responding to changing recommendations and adapting our response and approach as necessary.

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, 2021, 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. Management has reviewed the changes as a result of changes implemented in response to COVID-19 and is reasonably assured that adjustments to process have not materially affected, or are reasonably likely to materially affect, our ICFR or DC&P.

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 Corporation's ICFR.

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

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

Management has evaluated, with the participation of our Chief Executive Officer and Chief Financial Officer, the effectiveness of our ICFR and DC&P as of the end of the period covered by this MD&A. Based on the foregoing evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as at March 31, 2021, the end of the period covered by this MD&A, our ICFR and DC&P were effective.

Condensed Consolidated Statements of Earnings (Loss)

(in millions of Canadian dollars except per share amounts)

	3 months ended March 31	
Unaudited	**2021**	2020
Revenues (Note 4)	**642**	606
Fuel and purchased power (Note 5)	**243**	193
Carbon compliance	**50**	45
Gross margin	**349**	368
Operations, maintenance and administration (Note 5)	**105**	128
Depreciation and amortization	**149**	156
Asset impairment (reversal) (Note 6)	**29**	(41)
Taxes, other than income taxes	**9**	9
Net other operating income	**(10)**	(10)
Operating income	**67**	**126**
Equity income	**2**	—
Finance lease income	**7**	1
Net interest expense (Note 7)	**(63)**	(62)
Foreign exchange gain (loss)	**7**	(19)
Other gains	**1**	—
Earnings before income taxes	**21**	46
Income tax expense (Note 8)	**20**	2
Net earnings	**1**	44
Net earnings (loss) attributable to:		
TransAlta shareholders	**(30)**	37
Non-controlling interests (Note 9)	**31**	7
	1	44
Net earnings (loss) attributable to TransAlta shareholders	**(30)**	37
Preferred share dividends (Note 17)	**—**	10
Net earnings (loss) attributable to common shareholders	**(30)**	27
Weighted average number of common shares outstanding in the period *(millions)*	**270**	277
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**(0.11)**	0.10

See accompanying notes.

Condensed Consolidated Statements of Comprehensive Income (Loss)

(in millions of Canadian dollars)

	3 months ended March 31	
Unaudited	**2021**	2020
Net earnings	**1**	44
Other comprehensive income (loss)		
Net actuarial gains on defined benefit plans, net of tax (Note 1B)[1]	**37**	6
Gains (losses) on derivatives designated as cash flow hedges, net of tax[2]	**(1)**	9
Total items that will not be reclassified subsequently to net earnings	**36**	15
Gains (losses) on translating net assets of foreign operations, net of tax	**(13)**	96
Gains (losses) on financial instruments designated as hedges of foreign operations, net of tax	**5**	(41)
Gains (losses) on derivatives designated as cash flow hedges, net of tax[3]	**(23)**	14
Reclassification of gains on derivatives designated as cash flow hedges to net earnings, net of tax[4]	**(18)**	(25)
Total items that will be reclassified subsequently to net earnings	**(49)**	44
Other comprehensive income (loss)	**(13)**	59
Total comprehensive income (loss)	**(12)**	103

Total comprehensive income (loss) attributable to:		
TransAlta shareholders	**(2)**	78
Non-controlling interests (Note 9)	**(10)**	25
	(12)	103

(1) Net of income tax expense of $11 million for the three months ended March 31, 2021 (2020 - $2 million expense).
(2) Net of income tax expense of nil for the three months ended March 31, 2021 (2020 - $1 million expense).
(3) Net of income tax recovery of $8 million for the three months ended March 31, 2021 (2020 - $5 million expense).
(4) Net of reclassification of income tax expense of $5 million for the three months ended March 31, 2021 (2020 - $7 million expense).

See accompanying notes.

Condensed Consolidated Statements of Financial Position

(in millions of Canadian dollars)

Unaudited	**March 31, 2021**	Dec. 31, 2020
Cash and cash equivalents	**648**	703
Restricted cash	**53**	71
Trade and other receivables	**568**	583
Prepaid expenses	**55**	31
Risk management assets (Note 10 and 11)	**164**	171
Inventory (Note 12)	**216**	238
Assets held for sale	**105**	105
	1,809	1,902
Investments	**102**	100
Long-term portion of finance lease receivables	**215**	228
Risk management assets (Note 10 and 11)	**485**	521
Property, plant and equipment (Note 13)		
Cost	**13,395**	13,398
Accumulated depreciation	**(7,737)**	(7,576)
	5,658	5,822
Right of use assets	**132**	141
Intangible assets	**286**	313
Goodwill	**463**	463
Deferred income tax assets	**59**	51
Other assets	**210**	206
Total assets	**9,419**	9,747
Accounts payable and accrued liabilities	**625**	599
Current portion of decommissioning and other provisions	**47**	59
Risk management liabilities (Note 10 and 11)	**93**	94
Current portion of contract liabilities	**2**	1
Income taxes payable	**21**	18
Dividends payable (Note 16 and 17)	**37**	59
Current portion of long-term debt and lease liabilities (Note 14)	**111**	105
	936	935
Credit facilities, long-term debt and lease liabilities (Note 14)	**3,095**	3,256
Exchangeable securities (Note 15)	**731**	730
Decommissioning and other provisions	**554**	614
Deferred income tax liabilities	**399**	396
Risk management liabilities (Note 10 and 11)	**63**	68
Contract liabilities	**13**	14
Defined benefit obligation and other long-term liabilities (Note 1B)	**251**	298
Equity		
Common shares (Note 16)	**2,894**	2,896
Preferred shares	**942**	942
Contributed surplus	**30**	38
Deficit	**(1,856)**	(1,826)
Accumulated other comprehensive income	**330**	302
Equity attributable to shareholders	**2,340**	2,352
Non-controlling interests (Note 9)	**1,037**	1,084
Total equity	**3,377**	3,436
Total liabilities and equity	**9,419**	9,747

Significant and subsequent events (Note 3)
Commitments and contingencies (Note 18)

See accompanying notes.

Condensed Consolidated Statements of Changes in Equity

(in millions of Canadian dollars)

Unaudited

3 months ended March 31, 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 of 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 9)	—	—	—	—	—	—	**(37)**	**(37)**
Balance, March 31, 2021	**2,894**	**942**	**30**	**(1,856)**	**330**	**2,340**	**1,037**	**3,377**

3 months ended March 31, 2020	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec. 31, 2019	2,978	942	42	(1,455)	454	2,961	1,101	4,062
Net earnings	—	—	—	37	—	37	7	44
Other comprehensive income (loss):								
Net gains on translating net assets of foreign operations, net of hedges and tax	—	—	—	—	55	55	—	55
Net losses on derivatives designated as cash flow hedges, net of tax	—	—	—	—	(2)	(2)	—	(2)
Net actuarial gains on defined benefits plans, net of tax	—	—	—	—	6	6	—	6
Intercompany FVOCI investments	—	—	—	—	(18)	(18)	18	—
Total comprehensive income (loss)	—	—	—	37	41	78	25	103
Common share dividends	—	—	—	(12)	—	(12)	—	(12)
Preferred share dividends	—	—	—	(10)	—	(10)	—	(10)
Shares purchased under NCIB	(14)	—	—	5	—	(9)	—	(9)
Changes in non-controlling interests in TransAlta Renewables (Note 9)	—	—	—	2	—	2	5	7
Effect of share-based payment plans	(4)	—	(14)	—	—	(18)	—	(18)
Distributions paid, and payable, to non-controlling interests (Note 9)	—	—	—	—	—	—	(26)	(26)
Balance, March 31, 2020	2,960	942	28	(1,433)	495	2,992	1,105	4,097

See accompanying notes.

Condensed Consolidated Statements of Cash Flows

(in millions of Canadian dollars)

	3 months ended March 31	
Unaudited	**2021**	2020
Operating activities		
Net earnings	**1**	44
Depreciation and amortization (Note 19)	**204**	184
(Gain) loss on sale of assets	**(1)**	—
Accretion of provisions (Note 7)	**7**	9
Decommissioning and restoration costs settled	**(3)**	(4)
Deferred income tax recovery (Note 8)	**(3)**	(7)
Unrealized (gain) loss from risk management activities	**(20)**	(53)
Unrealized foreign exchange (gains) losses	**(9)**	26
Provisions	**(4)**	—
Asset impairment (reversal) (Note 6)	**29**	(41)
Equity income, net of distributions from Joint Ventures	**(2)**	—
Other non-cash items	**(14)**	6
Cash flow from operations before changes in working capital	**185**	164
Change in non-cash operating working capital balances	**72**	50
Cash flow from operating activities	**257**	214
Investing activities		
Additions to property, plant and equipment (Note 13)	**(98)**	(72)
Additions to intangibles	**(1)**	(2)
Restricted cash	**17**	17
Proceeds on sale of property, plant and equipment	**4**	—
Realized gains (losses) on financial instruments	**(2)**	3
Decrease in finance lease receivable	**10**	4
Other	**(5)**	3
Change in non-cash investing working capital balances	**(36)**	(48)
Cash flow used in investing activities	**(111)**	(95)
Financing activities		
Net decrease in borrowings under credit facilities (Note 14)	**(114)**	(101)
Repayment of long-term debt (Note 14)	**(18)**	(17)
Dividends paid on common shares (Note 16)	**(12)**	(11)
Dividends paid on preferred shares (Note 17)	**(10)**	(10)
Repurchase of common shares under NCIB (Note 16)	**(4)**	(9)
Realized (gains) losses on financial instruments	**—**	(10)
Distributions paid to subsidiaries' non-controlling interests (Note 9)	**(37)**	(19)
Repayment of lease liabilities (Note 14)	**(2)**	(5)
Other	**(2)**	—
Change in non-cash financing working capital balances	**(1)**	(14)
Cash flow used in financing activities	**(200)**	(196)
Cash flow used in operating, investing, and financing activities	**(54)**	(77)
Effect of translation on foreign currency cash	**(1)**	4
Decrease in cash and cash equivalents	**(55)**	(73)
Cash and cash equivalents, beginning of period	**703**	411
Cash and cash equivalents, end of period	**648**	338
Cash income taxes paid	**12**	12
Cash interest paid	**51**	39

See accompanying notes.

Notes to Condensed Consolidated Financial Statements

(Unaudited)

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

1. Accounting Policies

A. 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 TransAlta Corporation's ("TransAlta" or the "Corporation") most recent 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 Corporation's annual consolidated financial statements. Accordingly, they should be read in conjunction with the Corporation's most recent 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 Corporation 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. 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 the Board of Directors on May 12, 2021.

B. Use of Estimates and Significant Judgments

The preparation of these unaudited interim condensed consolidated financial statements in accordance with IAS 34 requires management to use judgment and make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and disclosures of contingent assets and liabilities. These estimates are subject to uncertainty. Refer to Note 2(Z) of the Corporation's most recent 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.

Change in Estimates

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 $233 million as at March 31, 2021 from $282 million as at Dec. 31, 2020.

2. Significant Accounting Policies

A. Current Accounting Changes

The accounting policies adopted in the preparation of the unaudited interim condensed consolidated financial statements are consistent with those followed in the preparation of the Corporation's annual consolidated financial statements for the year ended Dec. 31, 2020, except for the adoption of new standards effective as of Jan. 1, 2021 and the early adoption of standards, interpretations or amendments that have been issued but are not yet effective.

I. Amendments to IAS 16 *Property, Plant and Equipment*: Proceeds before Intended Use

Effective Jan. 1, 2021, the Corporation early adopted amendments to IAS 16 *Property plant and equipment* ("IAS 16 Amendments"), in advance of its mandatory effective date of Jan. 1, 2022. The Corporation adopted the IAS 16 Amendments retroactively. No cumulative effect of initially applying the guidance arose. The IAS 16 Amendments prohibit deducting from the cost of an item of property, plant and equipment any proceeds from selling items produced while bringing that asset to the location and condition necessary for it to be capable of operating in a manner intended by management. Instead, an entity recognizes the proceeds from selling such items, and the cost of producing those items, in profit or loss. No adjustments resulted from early adopting the amendment.

II. IFRS 7 *Financial Instruments:* Disclosures — Interest Rate Benchmark Reform
London Interbank Offered Rate ("LIBOR") is scheduled to be phased out as an interest rate index readily used by corporations for financial instruments by the end of 2021. The IASB issued Interest Rate Benchmark Reform — Phase 2 in August 2020, which amends IFRS 9 *Financial Instruments*, IAS 39 *Financial instruments: Recognition and Measurement*, IFRS 7 *Financial Instruments: Disclosures* and IFRS 16 *Leases*. The amendments were effective Jan. 1, 2021, and were adopted by the Corporation on Jan. 1, 2021.

The credit facility references US LIBOR for US-dollar drawings and the Canadian Dollar Offered Rate for Canadian drawings, and includes appropriate fallback language to replace these benchmark rates if a benchmark transition event were to occur. There was no financial impact upon adoption. As at March 31, 2021, there were no drawings under the credit facility. The Corporation is monitoring the reform and does not expect any material impact.

B. Future Accounting Policy Changes

Amendments to IAS 1 *Presentation of Financial Statements*: Material Accounting Policies
On Feb. 12, 2021, the IASB issued amendments to IAS 1 *Presentation of Financial Statements* to require entities to disclose their material accounting policy information rather than their significant accounting policies. The amendments are effective for annual periods beginning on or after Jan. 1, 2023, but the Corporation plans to early adopt these amendments for the 2021 annual financial statements.

C. Comparative Figures

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

3. Significant and Subsequent Events

A. Sarnia Cogeneration Facility Contract Extension

On May 12, 2021, the Corporation executed an Amended and Restated Energy Supply Agreement with one of its large industrial customers at the Sarnia cogeneration facility which provides for the supply of electricity and steam. This agreement will extend the term of the original agreement from Dec. 31, 2022 to Dec. 31, 2032. However, if the Corporation is unable to enter into a new contract with the Ontario Independent Electricity System Operator ("IESO") or enter into agreements with its other industrial customers at the Sarnia cogeneration facility that extend past Dec. 31, 2025, then this agreement will automatically terminate on Dec. 31, 2025. The current contract with the IESO in respect of the Sarnia cogeneration facility expires on Dec. 31, 2025. The Corporation is in active discussions with the three other existing industrial off-takers regarding extensions to their supply of electricity and steam from the Sarnia cogeneration facility on comparable terms.

B. Garden Plain Wind Project

On May 3, 2021, the Corporation announced that it entered into a long-term power purchase agreement ("PPA") with Pembina Pipeline Corporation ("Pembina") pursuant to which Pembina has contracted for the renewable electricity and environmental credits of 100 MWs of the 130 MW Garden Plain wind project ("Garden Plain"). Under this 18-year agreement, Pembina has the option to purchase a 37.7 per cent interest in the project (49 per cent of the power purchase agreement). The option must be exercised no later than 30 days after commercial operational date. TransAlta would remain the operator of the facility and earn a service fee if Pembina exercises this option. Garden Plain will be located approximately 30 km north of Hanna, Alberta. Construction activities are scheduled to start in fall 2021 with completion of the project expected in the second half of 2022. Total construction capital of the project is estimated at approximately $195 million.

C. Mangrove Claim

On April 23, 2019, The Mangrove Partners Master Fund Ltd. ("Mangrove") commenced an action in the Ontario Superior Court of Justice naming TransAlta Corporation, the incumbent members of the Board of Directors of TransAlta Corporation on such date, and Brookfield BRP Holdings (Canada) as defendants. Mangrove was seeking to set aside the 2019 Brookfield transaction. The parties reached a confidential settlement and the action was discontinued in the Ontario Superior Court of Justice on April 30, 2021.

D. Keephills 1 Superheater Force Majeure
Keephills Unit 1 was taken offline from March 17, 2015 to May 17, 2015 as a result of a large leak in the secondary superheater. TransAlta claimed force majeure under the PPA. ENMAX Energy Corporation, the purchaser under the PPA at the time, did not dispute the force majeure but the Balancing Pool attempted to do so, seeking to recover $12 million in capacity payment charges it paid to TransAlta while the unit was offline. The parties reached a confidential settlement on April 21, 2021 and this matter is now resolved.

E. TransAlta Renewables Acquisitions
The Corporation completed the sale of its 100 per cent direct interest in the 207 MW Windrise wind project ("Windrise") to TransAlta Renewables Inc. ("TransAlta Renewables"), a subsidiary of the Corporation, on Feb. 26, 2021 for $213 million. The remaining construction costs for Windrise will be paid by TransAlta Renewables. Windrise is expected to commence commercial operation in the second half of 2021.

On April 1, 2021, the Corporation also completed the sale of its 100 per cent economic interest in the 29 MW Ada cogeneration facility ("Ada") and its 49 per cent economic interest in the 137 MW Skookumchuck wind facility ("Skookumchuck") to TransAlta Renewables for $43 million and $103 million, respectively. Both facilities are fully operational. Pursuant to the transaction, a TransAlta subsidiary owns Ada and Skookumchuck directly and has issued to TransAlta Renewables tracking preferred shares reflecting its economic interest in the facilities. The Ada cogeneration facility is under a PPA until 2026. The Skookumchuck wind facility is contracted under a PPA until 2040 with an investment grade counterparty.

F. Normal Course Issuer Bid
On May 26, 2020, The Corporation announced that the TSX accepted the notice filed by the Corporation to implement a Normal Course Issuer Bid ("NCIB") for a portion of its common shares. During the three months ended March 31, 2021, no common share were purchased and cancelled under the NCIB. For the three months ended March 31, 2020, the Corporation purchased and cancelled a total of 1,297,000 common shares at an average price of $6.73 per common share, for a total cost of $9 million.

G. Global Pandemic
The World Health Organization declared a Public Health Emergency of International Concern relating to COVID-19 on Jan. 30, 2020, which they subsequently declared, on March 11, 2020, as a global pandemic.

All of our facilities continue to remain fully operational and capable of meeting our customers' needs. The Corporation continues to work and serve all of our customers and counterparties under the terms of their contracts. We have not experienced interruptions to service requirements. Electricity and steam supply continue to remain a critical service requirement to all of our customers and have been deemed an essential service in our jurisdictions.

The Corporation continues to maintain a strong financial position due in part to the long-term contracts and hedged positions. At the end of the first quarter, we had access to $2.1 billion in liquidity including $648 million in cash and cash equivalents.

4. Revenue

A. Disaggregation of Revenue

The majority of the Corporation'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 Corporation disaggregates into the following groups for the purpose of determining how economic factors affect the recognition of revenue.

3 months ended March 31, 2021	Hydro	Wind and Solar	North American Gas	Australian Gas	Alberta Thermal	Centralia	Energy Marketing	Corporate	Total
Revenue from contracts with customers									
Power and other	—	63	64	29	6	2	—	—	164
Environmental credits	—	5	—	—	—	—	—	—	5
Revenue from contracts with customers	—	68	64	29	6	2	—	—	169
Revenue from leases(1)	—	—	5	—	—	—	—	—	5
Revenue from derivatives and other trading activities(2)	—	(4)	1	—	(41)	50	61	1	68
Merchant revenue and other	89	22	4	2	241	42	—	—	400
Total revenue	89	86	74	31	206	94	61	1	642
Revenue from contracts with customers									
Timing of revenue recognition									
At a point in time	—	5	—	—	4	2	—	—	11
Over time	—	63	64	29	2	—	—	—	158
Total revenue from contracts with customers	—	68	64	29	6	2	—	—	169

(1) Total rental income, including contingent rent related to certain PPAs and other long-term contracts that meet the criteria of operating leases.
(2) Represents realized and unrealized gains or losses from hedging positions.

3 months ended March 31, 2020	Hydro	Wind and Solar	North American Gas(1)	Australian Gas	Alberta Thermal(2)	Centralia(2)	Energy Marketing	Corporate	Total
Revenue from contracts with customers									
Power and other(3)	36	61	44	21	77	4	—	—	243
Environmental credits(4)	—	8	—	—	—	—	—	(5)	3
Total revenue from contracts with customers	36	69	44	21	77	4	—	(5)	246
Revenue from leases(5)	—	—	4	15	13	—	—	—	32
Revenue from derivatives and other trading activities	—	11	1	—	2	99	28	2	143
Merchant revenue and other	2	25	2	3	114	39	—	—	185
Total revenue	**38**	**105**	**51**	**39**	**206**	**142**	**28**	**(3)**	**606**
Revenue from contracts with customers									
Timing of revenue recognition									
At a point in time	—	4	—	—	5	4	—	—	13
Over time	36	65	44	21	72	—	—	(5)	233
Total revenue from contracts with customers	**36**	**69**	**44**	**21**	**77**	**4**	**—**	**(5)**	**246**

(1) This segment was previously known as the Canadian Gas segment but renamed with the acquisition of the US cogeneration facility in the second quarter of 2020.
(2) The Canadian Coal segment was renamed Alberta Thermal and US Coal segment was renamed Centralia in the third quarter of 2020.
(3) Certain contract balances within the Wind and Solar segment and North American Gas Segments have been reclassified from revenue from contracts with customers to revenue from other or revenue from leases.
(4) Environmental credit revenue includes inter-segment revenues generated by the Wind and Solar and Hydro segments. Revenues are recognized as emission credits and are used to offset environmental obligations. Elimination of these revenues are reflected at the Corporate segment.
(5) Total rental income, including contingent rent related to certain PPAs and other long-term contracts that meet the criteria of operating leases.

5. 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			
	2021		2020	
	Fuel and purchased power	**OM&A**	Fuel and purchased power	OM&A
Gas fuel costs(1)	**58**	**—**	40	—
Coal fuel costs(1)(2)	**46**	**—**	69	—
Royalty, land lease, other direct costs	**5**	**—**	5	—
Purchased power	**69**	**—**	39	—
Mine depreciation(2)	**55**	**—**	28	—
Salaries and benefits	**10**	**46**	12	67
Other operating expenses	**—**	**59**	—	61
Total	**243**	**105**	193	128

(1) In the first quarter of 2021, fuel costs have been split to show gas and coal fuel costs separately within the above table and carbon compliance costs have been reclassified from fuel and purchased power to a separate line called carbon compliance costs on the condensed consolidated statements of earnings (loss). Prior periods have been adjusted to reflect these reclassifications.
(2) Included in coal fuel costs and mine depreciation is $25 million related to impairment of coal inventory which was recorded in the first quarter of 2021.

6. Asset Impairment Charges and Reversals

	3 months ended March 31	
	2021	2020
PP&E impairment - Kaybob Cogeneration Project	**27**	—
Intangible asset impairment - Coal Rights[(1)]	**14**	—
Changes in decommissioning and restoration provisions for retired assets[(2)]	**(12)**	(41)
Asset impairment (reversal)	**29**	(41)

(1) Impaired to nil as no future coal will be extracted from this area of the mine.
(2) Change primarily due to increases in discount rates. On average, excluding short term rate decreases for retirements in the next 5 years, these discount rates increased by approximately 0.2 to 0.4 per cent with rates ranging from 3.6 per cent to 7.2 percent (Dec. 31, 2020 - range of 3.6 per cent to 6.9 percent).

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 Corporation 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. Please refer to Note 18 for further details.

7. Net Interest Expense

The components of net interest expense are as follows:

	3 months ended March 31	
	2021	2020
Interest on debt	**40**	43
Interest on exchangeable securities	**14**	7
Interest income	**(3)**	(3)
Capitalized interest	**(5)**	(1)
Interest on lease liabilities	**2**	2
Credit facility fees, bank charges and other interest	**4**	4
Tax shield on tax equity financing	**1**	—
Other	**3**	1
Accretion of provisions	**7**	9
Net interest expense	**63**	62

8. Income Taxes

The components of income tax expense are as follows:

	3 months ended March 31	
	2021	2020
Current income tax expense	**23**	9
Deferred income tax recovery related to the origination and reversal of temporary differences	**(19)**	(10)
Deferred income tax expense arising from the writedown of deferred income tax assets(1)	**16**	3
Income tax expense	**20**	2

	3 months ended March 31	
	2021	2020
Current income tax expense	**23**	9
Deferred income tax recovery	**(3)**	(7)
Income tax expense	**20**	2

(1) During the three months ended March 31, 2021, the Corporation recorded a writedown on deferred tax assets of $16 million (March 31, 2020 - $3 million write down). The deferred income tax assets mainly relate to the tax benefits of losses associated with the Corporation's directly owned US operations. The Corporation evaluates at each period end, whether it is probable that sufficient future taxable income would be available from the Corporation's directly owned US operations to utilize the underlying tax losses. The Corporation wrote these assets off as it is not considered probable that sufficient future taxable income will be available from the Corporation's directly owned US operations to utilize the underlying tax losses.

9. Non-Controlling Interests

The Corporation'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	
	2021	2020
Net earnings		
TransAlta Cogeneration L.P.	**12**	3
TransAlta Renewables	**19**	4
	31	7
Total comprehensive income (loss)		
TransAlta Cogeneration L.P.	**12**	3
TransAlta Renewables	**(22)**	22
	(10)	25
Cash distributions paid to non-controlling interests		
TransAlta Cogeneration L.P.	**12**	1
TransAlta Renewables	**25**	18
	37	19

As at	**March 31, 2021**	Dec. 31, 2020
Equity attributable to non-controlling interests		
TransAlta Cogeneration L.P.	**137**	136
TransAlta Renewables	**900**	948
	1,037	1,084
Non-controlling interests share (per cent)		
TransAlta Cogeneration L.P.	**49.99**	49.99
TransAlta Renewables	**39.9**	39.9

10. 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 Corporation 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 Corporation 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.

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 Corporation 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 Corporation'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 2020 audited annual consolidated financial statements.

Information on risk management contracts or groups of risk management contracts that are included in Level III measurements and the related unobservable inputs and sensitivities, is as follows, and excludes the effects on fair value of certain unobservable inputs such as liquidity and credit discount (described as "base fair values"), as well as inception gains or losses. 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, commodity volatility and correlations, delivery volumes, escalation rates and cost of supply.

As at	March 31, 2021					
Description	**Base fair value**	**Sensitivity**	**Valuation technique**	**Unobservable input**	**Range**	**Reasonable possible change**
Long-term power sale – US	**517**	+31 -52	Long-term price forecast	Illiquid future power prices (per MWh)	US$26 to US$29	Price decrease of US$3 or price increase of US$5
Coal transportation - US	**(19)**	+2 -4	Numerical derivation valuation	Illiquid future power prices (per MWh)	US$26 to US$29	Price decrease of US$3 or price increase of US$5
				Volatility	21% to 43%	80% to 120%
				Rail rate escalation	$21 to $24	zero to 4%
Full requirements - Eastern US	**—**	+4 -4	Historical bootstrap	Volume		95% to 105%
				Cost of supply		(+/-) US$1 per MWh
Long-term wind energy sale – Eastern US	**(25)**	+22 -21	Long-term price forecast	Illiquid future power prices (per MWh)	US$35 to US$51	Price increase or decrease of US$6
				Illiquid future REC prices (per unit)	US$2 to US$16	Price decrease of US$3 or price increase of US$2
Others	**(3)**	+3 -4				

As at	Dec. 31, 2020					
Description	Base fair value	Sensitivity	Valuation technique	Unobservable input	Range	Reasonable possible change
Long-term power sale – US	598	+35 -59	Long-term price forecast	Illiquid future power prices (per MWh)	US$24 to US$32	Price decrease of US$3 or a price increase of US$5
Coal transportation - US	(16)	+3 -5	Numerical derivative valuation	Illiquid future power prices (per MWh)	US$24 to US$32	Price decrease of US$3 or a price increase of US$5
				Volatility	15% to 40%	80% to 120%
				Rail rate escalation	US$21 to US$24	zero to 4%
Full requirements - Eastern US	11	+3 -3	Historical bootstrap	Volume		95% to 105%
				Cost of supply		(+/-) US$1 per MWh
Long-term wind energy sale – Eastern US	(29)	+22 -22	Long-term price forecast	Illiquid future power prices (per MWh)	US$35 to US$52	Price increase or decrease of US$6
				Illiquid future REC prices (per unit)	US$11	Price increase or decrease of US$1
Others	(4)	+5 -5				

i. Long-Term Power Sale – US

The Corporation 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. With the weakening of the US dollar relative to the Canadian dollar from Dec. 31, 2020 to March 31, 2021, the base fair value and the sensitivity values have decreased by approximately $6 million and $1 million, respectively.

ii. Coal Transportation - US

The Corporation has a coal rail transport agreement that includes an upside sharing mechanism to the benefit of the supplier, with a contract start date of Jan. 1, 2021, and extending until Dec. 31, 2025. Option pricing techniques have been utilized to value the obligation associated with this component of the deal.

iii. Full Requirements – Eastern US

The Corporation has a portfolio of full requirement service contracts, whereby the Corporation 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 Corporation has a long-term contract for differences whereby the Corporation 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 commencing on July 1, 2019, and extending for 15 years after the commercial operation date. The contract is accounted for at fair value through profit or loss.

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, 2021, are as follows: Level I - $1 million net liability (Dec. 31, 2020 – $13 million net liability), Level II – nil (Dec. 31, 2020 – $27 million net liability) and Level III – $485 million net asset (Dec. 31, 2020 – $582 million net asset).

Significant changes in commodity net risk management assets and liabilities during the three months ended March 31, 2021, are primarily attributable to unfavourable market prices and 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 level during the three months ended March 31, 2021 and 2020, respectively:

	3 months ended March 31, 2021			3 months ended March 31, 2020		
	Hedge	**Non-hedge**	**Total**	Hedge	Non-hedge	Total
Opening balance	**573**	**9**	**582**	678	8	686
Changes attributable to:						
Market price changes on existing contracts	**(42)**	**(17)**	**(59)**	18	22	40
Market price changes on new contracts	**—**	**(7)**	**(7)**	—	5	5
Contracts settled	**(30)**	**5**	**(25)**	(23)	—	(23)
Change in foreign exchange rates	**(6)**	**—**	**(6)**	57	(1)	56
Net risk management assets (liabilities), end of period	**495**	**(10)**	**485**	730	34	764
Additional Level III information:						
Gains (losses) recognized in other comprehensive income	**(48)**	**—**	**(48)**	75	—	75
Total gains (losses) included in earnings before income taxes	**30**	**(24)**	**6**	23	26	49
Unrealized gains (losses) included in earnings before income taxes relating to net assets held at period end	**—**	**(19)**	**(19)**	—	26	26

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 $9 million as at March 31, 2021 (Dec. 31, 2020 – $12 million net liability) are classified as Level II fair value measurements. The significant changes in other net risk management assets during the three months ended March 31, 2021, are primarily attributable to favourable changes in interest and foreign exchange rates.

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**
	Level I	**Level II**	**Level III**	**Total**	**value(1)**
Exchangeable securities - March 31, 2021	**—**	**774**	**—**	**774**	**731**
Long-term debt - March 31, 2021	**—**	**3,188**	**—**	**3,188**	**3,076**
Exchangeable securities - Dec. 31, 2020	—	769	—	769	730
Long-term debt - Dec. 31, 2020	—	3,480	—	3,480	3,227

(1) Includes current portion.

The fair values of the Corporation'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 recorded in other assets and the finance lease receivables approximate the carrying amounts.

C. Inception Gains and Losses

The majority of derivatives traded by the Corporation are based on adjusted quoted prices on an active exchange or extend beyond the time period for which exchange-based quotes are available. For derivatives that extend beyond the time period for which exchange-based quotes are available, the fair values of these derivatives are determined using inputs that are not readily observable. Refer to section B of this Note 10 above for fair value Level III valuation techniques used. In some instances, a difference may arise between the fair value of a financial instrument at initial recognition (the “Transaction Price”) and the amount calculated through a valuation model. This unrealized gain or loss at inception is recognized in net earnings (loss) only if the fair value of the instrument is evidenced by a quoted market price in an active market, observable current market transactions that are substantially the same, or a valuation technique that uses observable market inputs. Where these criteria are not met, the difference is deferred on the condensed consolidated statements of financial position in risk management assets or liabilities, and is recognized in net earnings (loss) over the term of the related contract. The difference between the Transaction Price and the fair value determined using a valuation model, yet to be recognized in net earnings, and a reconciliation of changes is as follows:

	3 months ended March 31	
	2021	2020
Unamortized net gain (loss) at beginning of period	**(33)**	9
New inception gains	**2**	2
Amortization recorded in net earnings during the period	**(4)**	(4)
Unamortized net gain (loss) at end of period[(1)]	**(35)**	7

(1) In the third quarter of 2020, the net inception gain on the long-term fixed price power sale contract in the US changed to a loss position based on the day 1 forward price curve at inception of the contract.

11. Risk Management Activities

The Corporation is exposed to market risk from changes in commodity prices, foreign exchange rates, interest rates, credit risk and liquidity risk. These risks affect the Corporation's earnings and the value of associated financial instruments that the Corporation holds. The Corporation's risk management strategy, policies and controls are designed to ensure that the risk it assumes comply with the Corporation's internal objectives and its risk tolerance. For additional information on the Corporation's Risk Management Activities refer to Note 16 of the 2020 audited annual consolidated financial statements.

A. Net Risk Management Assets and Liabilities

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

As at March 31, 2021

	Cash flow hedges	**Not designated as a hedge**	**Total**
Commodity risk management			
Current	**65**	**—**	**65**
Long-term	**429**	**(10)**	**419**
Net commodity risk management assets (liabilities)	**494**	**(10)**	**484**
Other			
Current	**8**	**(2)**	**6**
Long-term	**—**	**3**	**3**
Net other risk management assets	**8**	**1**	**9**
Total net risk management assets (liabilities)	**502**	**(9)**	**493**

As at Dec. 31, 2020

	Cash flow hedges	Not designated as a hedge	Total
Commodity risk management			
Current	101	(11)	90
Long-term	471	(19)	452
Net commodity risk management assets (liabilities)	572	(30)	542
Other			
Current	(9)	(4)	(13)
Long-term	—	1	1
Net other risk management liabilities	(9)	(3)	(12)
Total net risk management assets (liabilities)	563	(33)	530

B. Nature and Extent of Risks Arising from Financial Instruments

I. Market Risk

i. Commodity Price Risk Management – Proprietary Trading

The Corporation'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 Corporation'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, 2021, associated with the Corporation's proprietary trading activities was $1 million (Dec. 31, 2020 - $1 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, 2021, associated with the Corporation's commodity derivative instruments used in generation hedging activities was $17 million (Dec. 31, 2020 - $12 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, 2021, associated with these transactions was $9 million (Dec. 31, 2020 - $15 million).

II. Credit Risk

The Corporation 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 Corporation's maximum exposure to credit risk without taking into account collateral held, including the distribution of credit ratings, as at March 31, 2021:

	Investment grade *(Per cent)*	**Non-investment grade** *(Per cent)*	**Total** *(Per cent)*	**Total amount**
Trade and other receivables[1]	90	10	**100**	**568**
Long-term finance lease receivable	100	—	**100**	**215**
Risk management assets[1]	95	5	**100**	**649**
Loan receivable[2]	—	100	**100**	**52**
Total				**1,484**

(1) Letters of credit and cash and cash equivalents are the primary types of collateral held as security related to these amounts.
(2) The counterparty has no external credit rating.

The maximum credit exposure to any one customer for commodity trading operations and hedging, including the fair value of open trades, net of any collateral held, at March 31, 2021, was $16 million (Dec. 31, 2020 - $22 million). TransAlta has implemented additional monitoring and risk mitigation measures to address the on-going impacts from the COVID-19 pandemic.

III. Liquidity Risk

TransAlta continues to be in a strong financial position with no liquidity issues. The Corporation 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 Corporation'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 Corporation'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:

	2021	2022	2023	2024	2025	2026 and thereafter	Total
Accounts payable and accrued liabilities	625	—	—	—	—	—	625
Long-term debt(1)	77	620	163	118	135	1,998	3,111
Exchangeable securities(2)	—	—	—	—	750	—	750
Commodity risk management assets	(44)	(82)	(128)	(129)	(99)	(2)	(484)
Other risk management assets	(6)	—	(1)	(2)	—	—	(9)
Lease liabilities(3)	6	(5)	6	5	5	113	130
Interest on long-term debt and lease obligations(4)	123	156	124	118	112	878	1,511
Interest on exchangeable securities(2,4)	39	53	53	53	—	—	198
Dividends payable	37	—	—	—	—	—	37
Total	**857**	**742**	**217**	**163**	**903**	**2,987**	**5,869**

(1) Excludes impact of hedge accounting and derivatives.
(2) Assumes the debentures will be exchanged on Jan. 1, 2025. Refer to Note 15 for further details.
(3) Lease liabilities include a lease incentive of $13 million, expected to be received in 2022.
(4) Not recognized as a financial liability on the condensed consolidated statements of financial position.

C. Collateral and Contingent Features in Derivative Instruments

Collateral is posted in the normal course of business based on the Corporation's senior unsecured credit rating as determined by certain major credit rating agencies. Certain of the Corporation'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, 2021, the Corporation had posted collateral of $176 million (Dec. 31, 2020 – $163 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 Corporation having to post an additional $117 million (Dec. 31, 2020 – $85 million) of collateral to its counterparties.

12. Inventory

The cost of coal from the Highvale mine continues to increase as a result of the Corporation's decision to convert coal fired facilities to natural gas. The cost of coal is not expected to be recovered based on current power pricing. For the three months ended March 31, 2021, the Corporation recorded a $25 million write-down on its internally produced coal inventory to its net realizable value, of which $17 million relates to increased depreciation from the accelerated closure of the mine.

The components of inventory are as follows:

As at	**March 31, 2021**	Dec. 31, 2020
Parts and materials	**108**	**107**
Coal	**69**	**83**
Deferred stripping costs	**4**	**8**
Natural gas	**1**	**2**
Purchased emission credits	**34**	**38**
Total	**216**	**238**

Carbon compliance costs are regulated costs that the business incurs as a result of greenhouse gases emission generated from our operating units. TransAlta's exposure to carbon compliance costs is mitigated through the use of eligible emission credits generated from the Corporation's Wind and Solar and Hydro segments, as well as, purchasing emission credits from the market at prices lower than the regulated compliance price of carbon. Emission credits generated from our Alberta business have no recorded book value but are expected to be used to offset emission obligations from our Alberta Thermal and North American Gas segments in the future when the compliance price of carbon is expected to increase, resulting in a reduced cash cost for carbon compliance. At March 31, 2021, we currently hold 1,340,096 credits of inventory purchased externally with a recorded book value of $34 million (Dec. 31, 2020 — 1,434,761 credits with a recorded book value of $38 million). The Corporation has approximately 762,963 (Dec. 31, 2020 — 502,653) of internally generated eligible emission credits with no recorded book value.

13. Property, Plant and Equipment

During the three months ended March 31, 2021, the Corporation 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. During the three months ended March 31, 2020, the Corporation had additions of $72 million mainly relating to assets under construction for the conversion of coal fired facilities to gas, the Windrise wind facility, the Kaybob cogeneration facility, land and planned major maintenance expenditures.

As at March 31, 2021, there was a substantial 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 $35 million.

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

The amounts outstanding are as follows:

As at	**March 31, 2021**			Dec. 31, 2020		
	Carrying value	**Face value**	**Interest**(1)	Carrying value	Face value	Interest(1)
Credit facilities(2)	**—**	**—**	**—%**	114	114	2.7%
Debentures	**250**	**251**	**7.1%**	249	251	7.1%
Senior notes(3)	**877**	**884**	**5.4%**	886	894	5.4%
Non-recourse(4)	**1,813**	**1,833**	**4.1%**	1,837	1,858	4.1%
Other(5)	**136**	**143**	**7.1%**	141	147	7.1%
	3,076	**3,111**		3,227	3,264	
Lease liabilities	**130**			134		
	3,206			3,361		
Less: current portion of long-term debt	**(103)**			(97)		
Less: current portion of lease liabilities	**(8)**			(8)		
Total current long-term debt and lease liabilities	**(111)**			(105)		
Total credit facilities, long-term debt and lease liabilities	**3,095**			3,256		

(1) Interest is an average rate weighted by principal amounts outstanding before the effect of hedging.
(2) Composed of bankers' acceptances and other commercial borrowings under long-term committed credit facilities.
(3) US face value at March 31, 2021 - US$700 million (Dec. 31, 2020 - US$700 million).
(4) Includes AU$800 million (Dec 31, 2020 - AU$800 million) senior secured note offering by TEC Hedland Pty Ltd., a subsidiary of the Corporation.
(5) Includes US$109 million at March 31, 2021 (Dec. 31, 2020 - US$110 million) of tax equity financing.

The Corporation has $2.0 billion of committed syndicated credit facilities, of which $1.5 billion was available as at March 31, 2021 (Dec. 31, 2020 – $2.0 billion) including the undrawn letters of credit. On March 30, 2021, the credit facilities were amended to extend to June 30, 2025, of which $1.25 billion has been converted into a facility with a Sustainability Linked Loan ("SLL"). The facility's financing terms will align the cost of borrowing to TransAlta's greenhouse gas emission reduction and gender diversity targets, which are part of the Corporation's overall environment, economic, social and governance, or E^2SG. The SLL will have a cumulative pricing adjustment to the borrowing costs on the facilities and a corresponding adjustment to the standby fee (the "Sustainability Adjustment"). Depending on performance against interim targets that have been set for each year of the credit facility term, the Sustainability Adjustment is structured as a two-way mechanic and could move either up, down or remain unchanged for each sustainability performance target based on performance. In addition, the Corporation's committed bilateral credit facilities were also extended to June 30, 2023.

As at March 31, 2021, the Corporation was in compliance with all debt covenants.

15. Exchangeable Securities

A. $750 Million Exchangeable Securities

As at	March 31, 2021			Dec. 31, 2020		
	Carrying value	**Face value**	**Interest**	Carrying value	Face value	Interest
Exchangeable debentures – due May 1, 2039	**331**	**350**	**7 %**	330	350	7 %
Exchangeable preferred shares[1]	**400**	**400**	**7 %**	400	400	7 %
Total Exchangeable Securities	**731**	**750**		**730**	**750**	

(1) Exchangeable preferred share dividends are reported as interest expense.

On May 3, 2021, the Corporation declared a dividend of $7 million in aggregate for the issued and outstanding Cumulative Redeemable Rate Reset First Preferred Share, Series I ("Exchangeable Preferred Shares") at the fixed rate of 1.726 per cent per Share. The dividend is payable May 31, 2021. The Exchangeable Preferred Shares are considered debt for accounting purposes, and as such, dividends are reported as interest expense (Note 7).

B. Option to Exchange

As at	March 31, 2021		Dec. 31, 2020	
Description	**Base fair value**	**Sensitivity**	Base fair value	Sensitivity
Option to exchange – embedded derivative	—	nil -39	—	nil -33

The Corporation entered into an investment agreement whereby Brookfield Renewable Partners or its affiliates (collectively "Brookfield") agreed to invest $750 million in the Corporation through the purchase of exchangeable securities.

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

Sensitivity ranges for the base fair value are determined using reasonably possible alternative assumptions for key unobservable inputs, which is mainly the change in the implied discount rate of the future cash flow. The sensitivity analysis has been prepared using the Corporation's assessment that a change in the implied discount rate of the future cash flow of 1 per cent is a reasonably possible change.

16. 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			
	2021		2020	
	Common shares *(millions)*	**Amount**	Common shares *(millions)*	Amount
Issued and outstanding, beginning of period	**269.8**	**2,896**	277.0	2,978
Effect of share-based payment plans	**—**	**(2)**	—	(4)
Purchased and cancelled under the NCIB	**—**	**—**	(1.3)	(14)
Stock options exercised	**0.1**	**—**	—	—
Issued and outstanding, end of period	**269.9**	**2,894**	275.7	2,960

B. Dividends

On Dec. 23, 2020, the Corporation declared a quarterly dividend of $0.045 per common share, paid on April 1, 2021. On May 3, 2021, the Corporation declared a quarterly dividend of $0.045 per common share, payable on July 1, 2021.

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

C. Stock Options

On May 4, 2021, the Corporation approved amendments to the Stock Option Plan to reduce the total aggregate number of common shares held in reserve for issuance under this program. The amendments reduce the aggregate total number of shares reserved for issuance to 14,500,000 common shares as at March 31, 2021 (Dec. 31, 2020 - 16,500,000 common shares).

17. 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, 2021		Dec. 31, 2020	
Series	**Number of shares** *(millions)*	**Amount**	Number of shares (millions)	Amount
Series A	**9.6**	**235**	10.2	248
Series B	**2.4**	**58**	1.8	45
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

On March 18, 2021, the Corporation announced that 1,417,338 of its 10.2 million Series A Cumulative Fixed Redeemable Rate Reset Preferred Shares ("Series A Shares") and 871,871 of its 1.8 million Series B Cumulative Redeemable Floating Rate Preferred Shares ("Series B Shares") were tendered for conversion, on a one-for-one basis, into Series B Shares and Series A Shares, respectively after having taken into account all election notices. As a result of the conversion, the Corporation had 9.6 million Series A shares and 2.4 million Series B Shares issued and outstanding as at March 31, 2021.

B. Dividends

The following table summarizes the value of preferred share dividends declared during the three months ended March 31, 2021 and 2020:

		3 months ended March 31	
Series	**Quarterly amounts per share**	**2021(1)**	2020
A	0.16931	—	2
B(2)	0.13186	—	—
C	0.25169	—	3
E	0.32463	—	3
G	0.31175	—	2
Total for the period		**—**	**10**

(1) No dividends were declared in the first quarter of 2021 as the quarterly dividend related to the period covering the first quarter of 2021 was declared in December 2020.
(2) Series B Preferred Shares pay quarterly dividends at a floating rate based on the 90-day Government of Canada Treasury Bill rate, plus 2.103 per cent.

On May 3, 2021, the Corporation declared a quarterly dividend of $0.17981 per share on the Series A preferred shares, $0.13108 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, 2021.

18. Commitments and Contingencies

A. Commitments

Certain commitments disclosed in the 2020 annual audited financial statements are based on variable pricing. Any material updates to contracts containing variable pricing are discussed below. Please also refer to our 2020 annual audited financial statements for a complete listing of commitments we have incurred either directly or through interests in joint operations.

Natural Gas and Transportation Contracts

These contracts include fixed volume commitments for natural gas. As of March 31, 2021 and Dec. 31, 2020, the Corporation had supply agreements for variable price natural gas commodity contracts for 139 TJ per day until 2034 based on Alberta Energy Company (AECO) pricing. As a result of changes in variable gas pricing, the total commitment for natural gas commodity contracts increased by $308 million to $2.0 billion as at March 31, 2021 (Dec. 31, 2020 - $1.7 billion).

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 Corporation'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 Corporation responds as required. For the current significant outstanding contingencies, refer to Note 36 of the annual audited consolidated financial statements. The changes to these contingencies during the three months ended March 31, 2021 are included below:

I. Transmission Line Loss Rule Proceeding

The Corporation has been participating in a transmission line loss rule proceeding before the Alberta Utilities Commission ("AUC"). The AUC determined that it has the ability to retroactively adjust line loss charges going back to 2006 and directed the AESO to recalculate loss factors for 2006 to 2016. The first two invoices were received during 2020 for a cumulative amount of $17 million and have been settled. The third and final invoice for $11 million was received in the first quarter of 2021 and will be paid by the payment deadline of May 31, 2021.

II. Kaybob 3 Cogeneration Dispute

The Corporation is engaged in a dispute with Energy Transfer Canada ULC, formerly SemCAMS Midstream ULC ("ET Canada") as a result of ET Canada's purported termination of agreements between the parties to develop, construct and operate a 40 MW cogeneration facility at the Kaybob South No. 3 sour gas processing plant. TransAlta has commenced an arbitration seeking full compensation for ET Canada's wrongful termination of the agreements. ET Canada seeks a declaration that the agreements were lawfully terminated. A hearing has not yet been scheduled.

III. FMG Dispute

The Corporation is currently engaged in a dispute with Fortescue Metals Group Ltd. ("FMG") as a result of FMG's purported termination of the South Hedland PPA. TransAlta sued FMG, seeking payments of amounts invoiced and not paid under the South Hedland PPA, as well as a declaration that the PPA is valid and in force. FMG, on the other hand, seeks a declaration that the PPA was lawfully terminated. The trial for this matter was set to start on May 3, 2021 but on May 2, 2021 the Corporation entered into a conditional settlement with FMG. The trial has been adjourned pending satisfaction of the settlement conditions.

19. Segment Disclosures

A. Reported Segment Earnings (Loss)

3 months ended March 31, 2021	Hydro	Wind and Solar	North American Gas	Australian Gas	Alberta Thermal	Centralia	Energy Marketing	Corporate	Total	Equity accounted investments[1]	IFRS Financials
Revenues	89	91	74	31	206	94	61	1	647	(5)	642
Fuel and purchased power[2]	1	4	24	2	137	74	—	1	243	—	243
Carbon compliance[2]	—	—	7	—	43	—	—	—	50	—	50
Gross margin	88	87	43	29	26	20	61	—	354	(5)	349
Operations, maintenance, and administration	10	13	12	10	30	13	10	8	106	(1)	105
Depreciation and amortization	4	35	12	7	72	15	—	6	151	(2)	149
Asset impairment	—	—	—	—	6	(4)	—	27	29	—	29
Taxes, other than income taxes	1	3	—	—	4	1	—	—	9	—	9
Net other operating income	—	—	—	—	(10)	—	—	—	(10)	—	(10)
Operating income (loss)	73	36	19	12	(76)	(5)	51	(41)	69	(2)	67
Equity income from associate	—	—	—	—	—	—	—	—	—	2	2
Finance lease income	—	—	1	6	—	—	—	—	7	—	7
Net interest expense									(63)	—	(63)
Foreign exchange gain									7	—	7
Gain on sale of assets									1	—	1
Earnings before income taxes									21	—	21

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

(2) In the first quarter of 2021, carbon compliance costs have been reclassified from fuel and purchase power costs and disclosed separately. Prior periods have been adjusted for comparative purposes.

3 months ended March 31, 2020	Hydro	Wind and Solar	North American Gas[1]	Australian Gas	Alberta Thermal[2]	Centralia[2]	Energy Marketing	Corporate	Total
Revenues	38	105	51	39	206	142	28	(3)	606
Fuel and purchased power[3]	2	5	13	3	105	68	—	(3)	193
Carbon compliance[3]	—	—	1	—	44	—	—	—	45
Gross margin	36	100	37	36	57	74	28	—	368
Operations, maintenance, and administration	9	13	12	7	33	16	9	29	128
Depreciation and amortization	6	33	11	11	67	22	—	6	156
Asset impairment reversal	—	—	—	—	(4)	(37)	—	—	(41)
Taxes, other than income taxes	1	2	1	—	4	1	—	—	9
Net other operating income	—	—	—	—	(10)	—	—	—	(10)
Operating income (loss)	20	52	13	18	(33)	72	19	(35)	126
Finance lease income	—	—	1	—	—	—	—	—	1
Net interest expense									(62)
Foreign exchange loss									(19)
Earnings before income taxes									46

(1) This segment was previously known as the Canadian Gas segment but renamed with the acquisition of the US cogeneration facility in the second quarter of 2020.
(2) The Canadian Coal segment was renamed Alberta Thermal and US Coal segment was renamed Centralia in the third quarter of 2020.
(3) In the first quarter of 2021, carbon compliance costs have been reclassified from fuel and purchase power costs and disclosed separately. Prior periods have been adjusted.

B. 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	
	2021	2020
Depreciation and amortization expense on the condensed consolidated statements of earnings (loss)	**149**	156
Depreciation included in fuel and purchased power (Note 5)	**55**	28
Depreciation and amortization on the condensed consolidated statements of cash flows	**204**	184

Exhibit 1

(Unaudited)

The information set out below is referred to as “unaudited” as a means of clarifying that it is not covered by the audit opinion of the independent registered public accounting firm that has audited and reported on the annual audited consolidated financial statements.

To the Financial Statements of TransAlta Corporation

EARNINGS COVERAGE RATIO

The following selected financial ratio is calculated for the twelve months ended March 31, 2021:

Earnings coverage on long-term debt supporting the Corporation’s Shelf Prospectus

(0.7) times

Earnings coverage on long-term debt on a net earnings basis is equal to net earnings before interest expense and income taxes, divided by interest expense including capitalized interest.

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 Corporation'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.

AUC
Alberta Utilities Commission.

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. Their 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.

Boiler
A device for generating steam for power, processing or heating purposes, or for producing hot water for heating purposes or hot water supply. Heat from an external combustion source is transmitted to a fluid contained within the tubes of the boiler shell.

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.

Combined cycle
An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

Derate
To lower the rated electrical capability of a power generating facility or unit.

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 Corporation 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 Corporation 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 Corporation through its operations (cash from operations) minus the funds used by the Corporation for the purchase improvement, or maintenance of the long-term assets to improve the efficiency or capacity of the Corporation (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 Corporation believes are not representative of ongoing cash flows from operations.

FVOCI
Fair value through other comprehensive income; where fair value accounting adjustments are recorded through the statement other comprehensive income.

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.

IFRS
International Financial Reporting Standards.

ICFR
Internal control over financial reporting.

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 Corporation'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.

Terajoule (TJ)
A metric unit of energy commonly used in the energy industry. One TJ equals 1,000 GJ or one trillion joules. One TJ is also equal to 277,778 kilowatt hours ("kWh").

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

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

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

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

Phone
403.267.7110

Website
www.transalta.com

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

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

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

Website
www.investorcentre.com

FOR MORE INFORMATION

Investor Inquiries

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

E-mail
investor_relations@transalta.com

Media Inquiries

Phone
Toll-free 1.855.255.9184
or 403.267.2540

E-mail
TA_Media_Relations@transalta.com