TRANSALTA CORPORATION

Second Quarter Report for 2020

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 and six months ended June 30, 2020 and 2019, and should also be read in conjunction with the audited annual consolidated financial statements and MD&A contained within our 2019 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 June 30, 2020. All tabular amounts in the following discussion are in millions of Canadian dollars unless otherwise noted. This MD&A is dated July 30, 2020. 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.

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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: the Corporation's ongoing protocols and procedures relating to the novel coronavirus ("COVID-19") pandemic; our coal-to-gas conversion projects, including the completion of the conversion of Sundance Unit 6 by the second half of 2020, the conversion of Keephills Unit 2 and Unit 3 in 2021, the repowering of Sundance Unit 5 and Keephills Unit 1 into combined cycle units and the expected commercial operation date for the repowering of Sundance Unit 5; the asset impairment in the third quarter due to the retirement of Sundance Unit 3; the sale of the Pioneer Pipeline to NOVA Gas Transmission Ltd. ("NGTL") and the anticipated benefits of such sale, including access to NGTL's highly liquid natural gas network and gas trading hub and additional flexibility for natural gas delivery; utilizing the proceeds from the sale of the Pioneer Pipeline to fund the Corporation's Clean Energy Investment Plan; entering into long-term delivery transportation agreements with NGTL to bring the total new and existing natural gas pipeline transportation service to 400 TJ per day by 2023; the growth of the renewables fleet, including the WindCharger Project, Windrise Wind Project and Skookumchuck Wind Project, including the timing of commercial operations; expansion of the on-site generation and cogeneration business, including achieving commercial operations of the Kaybob Cogeneration Project in the second half of 2021; growth and coal-to-gas conversion expenditures under the Clean Energy Investment Plan, including the total estimated spend and target completion dates; the 2020 financial outlook, including comparable EBITDA, free cash flow and annualized dividend in 2020; Alberta spot and Mid-C spot power prices; sustaining and productivity capital in 2020, including routine capital, planned major maintenance and mine capital; lost production due to planned major maintenance; forecasted reduction in Alberta power demand and merchant power prices during 2020; expected impact on power prices in Alberta, Ontario and the Pacific Northwest due to COVID-19 and the collapse in oil prices; the cyclicality of the business, including maintenance costs, production, electricity prices and loads; our financial capital, including closing the second tranche of the $400 million investment by Brookfield; utilizing existing cash and credit facilities to repay the debt maturing in 2020; refinancing the debt maturing in 2022; Alberta market design and that no changes are expected after our Alberta PPAs expire at the end of 2020; the impact of COVID-19 on regulatory and environmental processes; the trial dates for the disputes with Fortescue Metals Group Ltd. and Mangrove Partners Master Fund Ltd. ("Mangrove"); the appeal of the Keephills 1 stator force majeure claim; the estimated exposure relating to the transmission line loss rule proceeding; potential impacts of COVID-19 on the business and affairs of the Corporation, and actions to be taken in response to the pandemic; and the Corporation continuing to maintain a strong financial position and significant liquidity with our existing committed credit facilities.

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, including any tax and regulatory changes in the markets in which we operate; no material adverse impacts to the long-term investment and credit markets; Alberta spot power prices being equal to $45 to $53 per megawatt hour ("MWh") in 2020; Mid-C spot power prices being equal to US$25 to US$35 per MWh in 2020; sustaining capital in 2020 being between $155 million and $185 million; productivity capital of $5 million to $10 million; discount rates; our 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 coal fleet and anticipated financial results generated on conversion or repowering; assumptions regarding the ability of the converted units to successfully compete in the Alberta energy market; and assumptions regarding our current strategy and priorities, including as it pertains to our current priorities relating to the coal-to-gas conversions, growing TransAlta Renewables and being able to realize the full economic benefit from the capacity, energy and Ancillary Services from our Alberta hydro assets once the applicable PPA has expired; our being successful in defending against the claims alleged by Mangrove; the second $400 million tranche of the Brookfield investment closing as anticipated in the fourth quarter of 2020; and the Brookfield investment and its related arrangements having the expected benefits to the Corporation. Forward-looking statements are subject to a number of significant risks, uncertainties and assumptions 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, the general economic decline and the collapse of the oil and gas market, the impact of which on the Corporation will largely depend on the overall severity and duration of COVID-19 and the general economic downturn, 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; successful completion of our growth and expansion projects, including our ability to secure necessary equipment and to obtain regulatory approvals on the expected timelines or at all; our ability to maintain our credit ratings; our ability to maintain adequate internal controls in the event that our employees are restricted from accessing our regular offices for a significant period of time; 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-C; further reductions in production; increased costs resulting from our efforts to mitigate the impact of COVID-19; deterioration of worldwide credit and financial markets that could limit our ability to obtain external financing to fund our operations and growth expenditures; a higher rate of losses on our accounts receivable due to credit defaults; further disruptions to our supply chain; impairments and/or write-downs of assets; and adverse impacts on our information technology systems and our internal control systems as a result of the need to increase remote work arrangements, 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; 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; changes in general economic or market conditions including interest rates; operational risks involving our facilities, including unplanned outages at such facilities; disruptions in the transmission and distribution of electricity; the effects of weather and other climate-change related risks; unexpected increases in cost structure; disruptions in the source of fuels, including natural gas required for the conversions and repowering, as well as the extent of water, solar or wind resources required to operate our facilities; failure to meet financial expectations; natural and man-made disasters, including those resulting in dam or dyke failures; the threat of domestic terrorism and 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; 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; impact of unavailability or disruption of power transmission or commodity transportation facilities; industry risk and competition; the need to engage or rely on certain stakeholder groups and third parties; fluctuations in the value of foreign currencies and foreign political risks; the need for and availability of additional financing; structural subordination of securities; counterparty credit risk; changes in credit and market conditions; changes to our relationship with, or ownership of, 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; changes in expectations in the payment of future dividends, including from TransAlta Renewables; inadequacy or unavailability of insurance coverage; downgrades in credit ratings; our provision for income taxes; legal, regulatory and contractual disputes and proceedings involving the Corporation, including in relation to the litigation with FMG and Mangrove; 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 Management Proxy Circular dated March 9, 2020 and its Annual Information Form and Management's Discussion and Analysis for the year ended Dec. 31, 2019, 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 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 June 30		6 months ended June 30	
	2020	2019	**2020**	2019
Revenues	**437**	497	**1,043**	1,145
Fuel, carbon compliance and purchased power	**151**	177	**389**	543
Operations, maintenance and administration	**112**	130	**240**	234
Net loss attributable to common shareholders	**(60)**	—	**(33)**	(65)
Cash flow from operating activities	**121**	258	**335**	340
Comparable EBITDA(1,2)	**217**	215	**437**	436
Funds from operations(1)	**159**	155	**331**	324
Free cash flow(1)	**91**	49	**200**	144
Net loss per share attributable to common shareholders, basic and diluted	**(0.22)**	—	**(0.12)**	(0.23)
Funds from operations per share(1)	**0.58**	0.55	**1.20**	1.14
Free cash flow per share(1)	**0.33**	0.17	**0.72**	0.51
Dividends declared per common share	**0.0425**	0.04	**0.085**	0.04
Dividends declared per preferred share(3)	**0.2533**	0.2591	**0.5123**	0.2591

As at	**June 30, 2020**	Dec. 31, 2019
Total assets	**9,370**	9,508
Total consolidated net debt(1,4)	**3,168**	3,110
Total long-term liabilities	**4,229**	4,329

(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 Discussion of Consolidated Financial Results section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS. See also the Additional IFRS measures and Non-IFRS Measures section of this MD&A.
(2) Comparable earnings before interest, taxes, depreciation and amortization ("comparable EBITDA").
(3) 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.
(4) Total consolidated net debt includes long-term debt, including current portion, amounts due under credit facilities, exchangeable securities, US tax equity financing and lease obligations, net of available cash and cash equivalents, the principal portion of restricted cash in TransAlta OCP LP 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.

Free cash flow ("FCF"), one of the Corporation's key financial metrics, totalled $91 million and $200 million for the three and six months ended June 30, 2020, respectively. FCF for the three and six months ended June 30, 2020, increased by $42 million and $56 million, respectively, compared to the same periods in 2019. The increase was driven primarily by strong segmented cash flows, realized foreign exchange gains, lower sustaining capital expenditures and lower distributions paid to subsidiaries' non-controlling interests. Segmented cash flows generated by the business are $47 million and $48 million dollars higher for the second quarter and year-to-date periods in 2020, respectively, compared with 2019, due to higher performance in our US Coal, North American Gas, Wind and Solar and Energy Marketing segments that more than offset lower results in the Canadian Coal and Hydro segments.

Adjusted availability for the three and six months ended June 30, 2020, was 90.7 per cent and 91.7 per cent, respectively, compared to 83.8 per cent and 86.7 per cent, respectively, for the same periods in 2019. This increase was largely due to fewer planned and unplanned outages and derates within the generation segments, partially offset by the planned outage at Canadian Coal for the Sheerness dual-fuel conversion.

Production for the three and six months ended June 30, 2020, was 4,607 gigawatt hours ("GWh") and 11,093 GWh, respectively, compared to 5,235 GWh and 13,360 GWh, respectively, for the same periods in 2019. This decrease in production was primarily due to the planned outage at Sheerness, curtailments for our Canadian Coal contracted facilities and lower merchant demand at Canadian Coal and a significantly lower price environment in the Pacific Northwest during the first half of 2020, which resulted in power purchases to meet contractual obligations at US Coal. These decreases were partially offset by higher production at Wind and Solar due to the addition of the Big Level and Antrim facilities in late 2019 and high water resources at Hydro during the quarter.

Revenues for the three and six months ended June 30, 2020, decreased by $60 million and $102 million, respectively, compared to the same periods in 2019, mainly as a result of lower production and power prices at our Canadian Coal and US Coal segments. Production was down due to the planned outage at Sheerness and lower demand resulting from the COVID-19 pandemic and the impact of low oil prices on the Alberta economy. This was partially offset by higher revenues from our Wind and Solar segment as a result of higher wind resources and Big Level and Antrim commencing operations in December 2019.

Fuel, carbon compliance and purchased power costs decreased by $26 million and $154 million in the three and six months ended June 30, 2020, respectively, compared to the same periods in 2019. In the US Coal segment, we improved our margins through purchasing low priced power to fulfill our contractual obligations compared to 2019. In our Canadian Coal segment, lower production and our ability to co-fire with natural gas reduced fuel costs. Co-firing allows us to produce fewer greenhouse gas ("GHG") emissions than coal combustion, which lowers our GHG compliance costs. In addition, our North American Gas segment had lower costs due to lower merchant production.

Operations, maintenance and administration ("OM&A") expense for the three and six months ended June 30, 2020, decreased by $18 million and increased by $6 million, respectively, compared to the same periods in 2019. Variability caused by the total return swap resulted in a decrease of $7 million and an increase of $17 million for the three month and six months ended June 30, 2020, respectively. Excluding the impact of the total return swap, OM&A decreased by $11 million in both periods, due to tighter cost controls, lower labor costs across multiple segments and lower legal fees.

Comparable EBITDA for the three and six months ended June 30, 2020, increased by $2 million and $1 million, respectively, compared with the same periods in 2019, largely due to strong performance at the US Coal, Wind and Solar and Energy Marketing segments offset by lower comparable EBITDA at the Canadian Coal, North American Gas and Hydro segments as well as higher Corporate costs. Significant changes in segmented comparable EBITDA are highlighted in the Segmented Comparable Results within this MD&A.

Net loss attributable to common shareholders for the three months ended June 30, 2020, was $60 million compared to nil in the same period in the prior year. The decrease is largely due to lower revenues, higher depreciation, asset impairment and lower income tax recoveries partially offset by lower OM&A and foreign exchange gains. Net loss attributable to common shareholders for the six months ended June 30, 2020, was $33 million, compared to a loss of $65 million in the same period in 2019, an improvement of $32 million. Stronger earnings from our US Coal and Wind and Solar segments, foreign exchange gains and a reduction in the Centralia mine decommissioning provision due to changes in discount rates resulting in an asset impairment reversal were partially offset by higher depreciation, higher interest expense and lower income tax recoveries.

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.

COVID-19

The World Health Organization ("WHO") 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 outbreak of COVID-19 has resulted in governments worldwide enacting emergency measures to constrain the spread of the virus. These measures, which include the implementation of travel bans, self-imposed quarantine periods, self-isolation, physical and social distancing and the closure of non-essential business, have caused significant disruption to businesses globally which has resulted in an uncertain and challenging economic environment.

The Corporation formally implemented its business continuity plan on March 9, 2020, which focused on ensuring that: (i) employees that could work remotely did so; and (ii) employees that operate and maintain our facilities, and who were not able to work remotely, were able to work safely and in a manner that ensured they remained healthy. During the second quarter of 2020, the Corporation began a staggered approach to bring employees that were working remotely back to the office. All of TransAlta's offices and sites follow strict health screening and social distancing protocols with personal protective equipment readily available. 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.

While our results have been impacted by price and demand as a result of COVID-19, all of our facilities continue to remain fully operational and capable of meeting our customers' needs. We have modified our operating procedures and implemented safety protocols that are allowing all office employees to now return to sites across the fleet by the end of July. 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.

Normal Course Issuer Bid

On May 26, 2020, the Corporation announced that the Toronto Stock Exchange ("TSX") accepted the notice filed by the Corporation to implement a Normal Course Issuer Bid ("NCIB") for a portion of its common shares. Pursuant to the NCIB, TransAlta may repurchase up to a maximum of 14,000,000 common shares, representing approximately 7.02 per cent of its public float of common shares as at May 25, 2020. Purchases under the NCIB may be made through open market transactions on the TSX and any alternative Canadian trading platforms on which the common shares are traded, based on the prevailing market price. Any common shares purchased under the NCIB will be cancelled.

The period during which TransAlta is authorized to make purchases under the NCIB commenced on May 29, 2020 and ends on May 28, 2021 or such earlier date on which the maximum number of common shares are purchased under the NCIB or the NCIB is terminated at the Corporation's election.

Under TSX rules, not more than 228,157 common shares (being 25 per cent of the average daily trading volume on the TSX of 912,630 common shares for the six months ended April 30, 2020) can be purchased on the TSX on any single trading day under the NCIB, with the exception that one block purchase in excess of the daily maximum is permitted per calendar week.

During the six months ended June 30, 2020, under the current and previous NCIB, the Corporation purchased and cancelled a total of 2,849,400 common shares at an average price of $7.51 per common share, for a total cost of $21 million.

Board of Director Changes

On April 21, 2020, we announced that the Board appointed John P. Dielwart as Chair of the Board, upon his re-election as an independent director at TransAlta's annual shareholder meeting. As previously announced, Ambassador Gordon Giffin, the previous Chair of the Board, retired from the Board after serving as Chair since 2011.

Mr. Dielwart has served as an independent director on the Board since 2014, and has served as the Chair of the Governance, Safety and Sustainability Committee. He previously served on the Investment Performance Committee and the Audit, Finance and Risk Committee of the Board. Mr. Dielwart is a founder and director of ARC Resources Ltd. from 1996 to present and served as Chief Executive Officer of ARC Resources Ltd. from 2001 to 2013. Mr. Dielwart earned a Bachelor of Science (Distinction) in Civil Engineering from the University of Calgary, is a member of the Association of Professional Engineers and Geoscientists of Alberta and a Past-Chairman of the Board of Governors of the Canadian Association of Petroleum Producers. Mr. Dielwart is also a director and former Co-Chair of the Calgary and Area Child Advocacy Centre. In 2015, Mr. Dielwart was inducted into the Calgary Business Hall of Fame.

On July 30, 2020, Robert Flexon delivered to the Corporation his resignation from the Board, which is to be effective Aug. 1, 2020. Mr. Flexon recently assumed the role of Chair of the Board of Directors of PG&E Corporation ("PG&E") and is resigning from the Board due only to the potential for perceived conflicts of interests between PG&E and the Corporation.

Refer to Note 4 of the audited annual 2019 consolidated financial statements within our 2019 Annual Integrated Report and Note 3 of our unaudited interim condensed consolidated financial statements for the three and six months ended June 30, 2020, for significant events impacting both prior and current year results.

Corporate Strategy

Our corporate strategy continues to focus on investing in a range of clean and renewable technologies such as wind, hydro, solar, battery and thermal (natural gas-fired and cogeneration) that produce electricity for industrial customers and communities to deliver returns to our shareholders. On Sept. 16, 2019, TransAlta announced its Clean Energy Investment Plan to further its strategy and announced near-term objectives on Jan. 16, 2020. During the first half of 2020, the following developments have occurred impacting those objectives:

Successfully execute our coal-to-gas conversions. We continued to advance our coal-to-gas conversion projects. We are on-track to complete the conversion of Sundance Unit 6 in the second half of 2020. The Corporation continues to advance conversion of its Keephills Unit 2 and Unit 3 for completion in 2021 and have issued FNTP for both units. During the first quarter of 2020, we received regulatory approval from the Alberta Utilities Commission for the repowering of Sundance Unit 5 and Keephills Unit 1 into combined cycle units. The Corporation is still waiting for approval from Alberta Environment and Parks. We are on track to issue full notice to proceed in 2021 for Sundance Unit 5, with an expected commercial operation date in 2023.

On July 22, 2020, the Corporation announced that we gave notice to the Alberta Electric System Operator ("AESO") of our intention to retire the currently mothballed coal-fired Sundance Unit 3 effective July 31, 2020. The retirement decision was largely driven by TransAlta's assessment of future market conditions, the age and condition of the unit and our ability to supply energy and capacity from our generation portfolio in Alberta. This decision advances our transition to 100 per cent clean electricity by 2025. An asset impairment of approximately $69 million ($52 million after-tax) will be recorded in the third quarter of 2020.

During the second quarter of 2020, TransAlta entered into a definitive Purchase and Sale Agreement with respect to the previously announced sale of its 50 per cent interest in the Pioneer Pipeline to NOVA Gas Transmission Ltd. ("NGTL"), a wholly-owned subsidiary of TC Energy (the "Transaction"). The purchase price of $255 million represents both TransAlta's and Tidewater Midstream & Infrastructure Ltd.'s ("Tidewater") interests. As part of the Transaction, NGTL intends to integrate the Pioneer Pipeline into its natural gas pipeline infrastructure in Alberta. The completion of this Transaction will provide TransAlta with access to NGTL's highly liquid natural gas network and gas trading hubs, a broad and diversified group of gas producers and resource basins, additional flexibility for natural gas delivery to the Corporation's power stations and cash proceeds that can be used to fund the Clean Energy Investment Plan.

As part of the Transaction, TransAlta entered into incremental long-term firm natural gas delivery transportation agreements with NGTL for 275 TJ per day, bringing the total long-term firm natural gas transportation contracts to 400 TJ per day by 2023. TransAlta's current commitments, including its 139 TJ per day supply arrangement with Tidewater, will remain in place until the closing of the Transaction. The Transaction is subject to customary regulatory approvals, which is anticipated to occur in the second half of 2021.

Expand our renewables fleet. We continue to expand our renewables platform and were able to advance the WindCharger Battery Project and the Windrise Wind Project into construction in early 2020. The following significant developments on our renewables projects occurred during the first half of 2020:

- WindCharger construction started in late March 2020 after TransAlta put in place the necessary safety procedures to protect the construction team during the COVID-19 pandemic. The project will achieve a commercial operations date ("COD") in August 2020.
- Construction activities on the Windrise Wind Project continue to advance with all appropriate procedures in place to protect the construction team during the COVID-19 pandemic. The TransAlta project team has modified the construction schedule to reflect a COVID-19 related delay in the delivery of the wind turbine components and plans to complete Windrise construction and commissioning in second half of 2021.
- The AESO and TransAlta concluded discussions that resulted in an amendment to the Renewable Electricity Support Agreement ("RESA"), which extended the Commencement of Construction Longstop Date, Target COD and COD Longstop Date by twelve months due to probable project delays caused by the COVID-19 pandemic. As a result of the amendment, the Commencement of Construction Longstop Date and Target COD have been extended to June 30, 2022 and the COD Longstop Date[1] to Dec. 31, 2023. TransAlta's completion and commissioning of the Windrise Wind Project is expected to occur well within these amended timelines.
- The Skookumchuck Wind Project remains under construction and TransAlta's option to purchase occurs at the COD. The project owner has notified TransAlta that construction has been delayed due to weather and other factors and, as a result, the project is expected to be completed and reach full COD in the second half of 2020.

[1] *Capitalized terms as defined within AESO's RESA.*

Advance and expand our on-site generation and cogeneration business and expand our presence in the US renewables market. As part of our business strategy, we are focused on growing our on-site generation and cogeneration asset base. On May 19, 2020, we closed the acquisition of a contracted cogeneration asset from two private companies for a purchase price of approximately US$27 million, subject to working capital adjustments. The asset is a 29 MW cogeneration facility ("Ada") in Michigan which is contracted under a long-term power purchase agreement ("PPA") and steam sale agreement for approximately six years with Consumers Energy and Amway. Ada has been included in the North American Gas segment results, which was previously known as the Canadian Gas segment.

The Corporation continues to advance the Kaybob Cogeneration Project with commercial operations scheduled to commence in the second half of 2021; however, the Corporation continues to monitor COVID-19 and market conditions to determine if any adjustments to plans are necessary. During the first half of 2020, we executed agreements for the purchase of the reciprocating engine generator, generator step up transformers, electrical building and switchgear. The project has secured a municipal development permit in March 2020 and Alberta Energy Regulator permit approval in early April 2020.

Growth and coal-to-gas conversion expenditures

TransAlta announced our Clean Energy Investment Plan at our 2019 Investor Day and we now have the activities supporting that plan fully underway. In addition to the $337 million spent on the Big Level and Antrim wind projects and the $105 million spent on the Pioneer Pipeline, the following major projects are in progress and represent our remaining spend under our Clean Energy Investment Plan:

	Total project		Remaining estimated spend in 2020	Target completion date[2]	Details
	Estimated spend	**Spent to date[1]**			
Project					
Skookumchuck wind project[3,4]	150 - 160	—	84	H2 2020	Option to purchase a 49 per cent ownership in the 136.8 MW wind project with a 20-year PPA
Windrise wind project[4]	270 - 285	75	170	H2 2021	207 MW wind project with a 20-year Renewable Electricity Support Agreement with AESO
WindCharger battery[4,5]	7 - 8	6	2	H2 2020	10 MW/20 MWh utility-scale storage project
Boiler conversions[6]	120 - 200	37	46	2020 to 2023	Coal-to-gas conversions at Canadian Coal
Repowering	750 - 770	88	25	2023	Repower Sundance Unit 5 to a combined cycle design
Kaybob cogeneration project[4]	105 - 115	30	35	H2 2021	40 MW cogeneration project with SemCAMS under a 13-year fixed price contract
Total	**1,402 - 1,538**	**236**	**362**		

(1) Represents cumulative amounts spent as of June 30, 2020.
(2) H2 is defined as the second half of the year.
(3) The estimated spend in 2020 assumes the project will receive tax equity financing for the remainder of the total project spend.
(4) These projects could potentially be dropped down to TransAlta Renewables Inc.
(5) Net of expected government reimbursements.
(6) Total estimated spend includes the Sheerness dual-fuel conversion.

For full details on the Clean Energy Investment Plan, refer to our 2019 annual MD&A within our 2019 Annual Integrated Report.

2020 Financial Outlook

Refer to the 2020 Financial Outlook section in our 2019 annual MD&A within our 2019 Annual Integrated Report for full details on our 2020 Financial Outlook and related assumptions.

The following table outlines our expectations on key financial targets and related assumptions for 2020:

Measure	Target
Comparable EBITDA[1]	$925 million to $1,000 million
FCF[1]	$325 million to $375 million
Dividend	$0.17 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 Discussion of Consolidated Financial Results section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS. See also the Additional IFRS measures and Non-IFRS Measures section of this MD&A.

Range of key power price assumptions Market	Original Expectations Power Prices ($/MWh)	Updated Expectations Power Prices ($/MWh)
Alberta Spot	$53 to $63	$45 to $53
Mid-C Spot (US$)	$25 to $35	No change

Other assumptions relevant to the 2020 financial outlook		
Sustaining capital	$170 million to $200 million	$155 million to $185 million

Our overall performance for the first half of 2020 is in line with expectations. The Corporation is currently tracking to the lower end of the range for comparable EBITDA as we are expecting lower power prices to persist in Alberta given the continuing impacts on demand from COVID-19 and low oil prices, which are expected to continue for the balance of the year. However, the Corporation continues to track to the mid-point of the guidance for FCF provided above, as we have been able to respond with our hedging activities and adjustments in our capital investment plans. Our current forecast includes a reduction in Alberta power demand and expectations of a corresponding drop in the merchant power price from our initial forecasts.

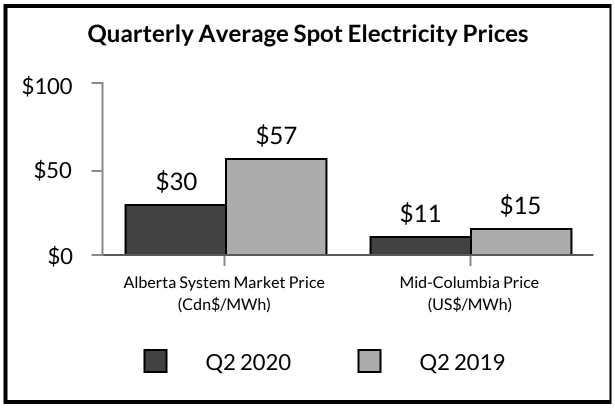
Operations

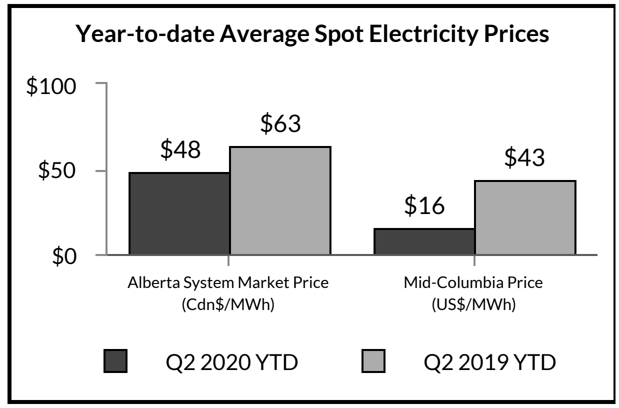
The following provides updates to our original assumptions included in the 2020 Financial Outlook.

Market Pricing

For the three and six months ended June 30, 2020, the average spot electricity price in Alberta decreased compared to the same periods in 2019. In 2020, a combination of fewer planned outages, strong hydro generation in the Pacific Northwest and demand losses from COVID-19 and low oil prices resulted in lower prices for the first half of 2020 compared with the same period in 2019. For the remainder of 2020, power prices in Alberta remain at risk for being lower than 2019, due to lower demand resulting from the impacts of the COVID-19 pandemic and the collapse in oil prices.

Power prices were significantly lower in the Pacific Northwest in the three and six months ended June 30, 2020 compared to the same periods in 2019, mainly due to extremely high power prices in February and March of 2019 and stronger hydro generation during the second quarter of 2020, which resulted in lower prices compared to the prior year. Pacific Northwest power prices for the remainder of 2020 are at risk of being lower than 2019 if impacts on demand from COVID-19 continue into the summer. Similarly, Ontario power prices are now expected to be lower than 2019 prices due to the impact related to COVID-19.





Energy Marketing

EBITDA from our Energy Marketing segment is affected by prices and volatility in the market, overall strategies adopted, and changes in regulation and legislation. We continuously monitor both the market and our exposure to maximize earnings while still maintaining an acceptable risk profile. Our 2020 EBITDA forecast for Energy Marketing increased from a range of $75 million to $85 million and the segment is now expected to contribute between $85 million to $95 million in gross margin for the year.

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 2020
Routine capital[2]	Capital required to maintain our existing generating capacity	**16**	55 - 65
Planned major maintenance	Regularly scheduled major maintenance	**37**	95 - 110
Mine capital	Capital related to mining equipment and land purchases	**2**	5 - 10
Total sustaining capital		**55**	**155 - 185**
Productivity capital	Projects to improve power production efficiency and corporate improvement initiatives	**1**	5 - 10
Total sustaining and productivity capital		**56**	**160 - 195**

(1) As at June 30, 2020.
(2) Includes hydro life extension expenditures.

Significant planned major outages at TransAlta's operated units for the remainder of 2020 include the following:

- One outage for major maintenance at Sundance Unit 6 within our Canadian Coal segment during the third and fourth quarters of 2020. This work will be undertaken in parallel with the coal-to-gas conversion of this unit;
- Distributed planned maintenance expenditures across the entire hydro fleet; and
- Distributed expenditures across our wind fleet, focusing on planned component replacements.

Lost production as a result of planned major maintenance, excluding planned major maintenance for US Coal, which is scheduled during a period of dispatch optimization, is estimated as follows for 2020:

	Coal	Gas and renewables	Total	Lost to date[1]
GWh lost	700 - 800	250 - 300	950 - 1,100	284

(1) As at June 30, 2020.

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 Consolidated Statements of Earnings (Loss) for the three and six months ended June 30, 2020 and 2019. 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, Funds from Operations ("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 Discussion of Consolidated Financial Results, 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.

Discussion of Consolidated Financial Results

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:

- To be more comparable with other companies in the industry, 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 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 depreciate these assets over their expected lives.
- 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.
- 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.

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

	3 months ended June 30		6 months ended June 30	
	2020	2019	**2020**	2019
Net earnings (loss) attributable to common shareholders	**(60)**	—	**(33)**	(65)
Net earnings attributable to non-controlling interests	**15**	16	**22**	51
Preferred share dividends	**10**	10	**20**	10
Net earnings (loss)	**(35)**	26	**9**	(4)
Adjustments to reconcile net income to comparable EBITDA				
Income tax expense	**(17)**	(50)	**(15)**	(33)
Other losses	**—**	12	**—**	12
Foreign exchange (gain) loss	**(23)**	8	**(4)**	9
Net interest expense	**57**	56	**119**	106
Depreciation and amortization	**163**	143	**319**	288
Comparable reclassifications				
Decrease in finance lease receivables	**4**	6	**8**	12
Mine depreciation included in fuel cost	**26**	31	**54**	60
Australian interest income	**1**	1	**2**	2
Unrealized mark-to-market (gains) losses	**9**	(18)	**(46)**	(16)
Adjustments to earnings to arrive at comparable EBITDA				
Asset impairment (reversal)(1)	**32**	—	**(9)**	—
Comparable EBITDA	**217**	215	**437**	436

(1) The asset impairment (reversal) for the three and six months ended June 30, 2020 of $32 million and $9 million, respectively, relates to changes in the decommissioning and restoration liability at the Centralia mine and Sundance Units 1 & 2 as a result of changes in the discount rates due to volatility in the current market. For further details, refer to the Critical Accounting Estimates section of this MD&A.

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 an important metric as it represents the amount of cash that is available to invest in growth initiatives, make scheduled principal repayments on debt, repay maturing debt, pay common share dividends or repurchase common shares. Changes in working capital are excluded so FFO and FCF are not distorted by changes that we consider temporary in nature, reflecting, among other things, the impact of seasonal factors and timing of receipts and payments. 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 June 30		6 months ended June 30	
	2020	2019	**2020**	2019
Cash flow from operating activities	**121**	258	**335**	340
Change in non-cash operating working capital balances	**30**	(110)	**(20)**	(30)
Cash flow from operations before changes in working capital	**151**	148	**315**	310
Adjustments				
Decrease in finance lease receivable	**4**	6	**8**	12
Other	**4**	1	**8**	2
FFO	**159**	155	**331**	324
Deduct:				
Sustaining capital	**(26)**	(61)	**(55)**	(86)
Productivity capital	**(1)**	(1)	**(1)**	(3)
Dividends paid on preferred shares(1)	**(10)**	(10)	**(20)**	(20)
Distributions paid to subsidiaries' non-controlling interests	**(26)**	(27)	**(45)**	(59)
Payments on lease obligations	**(5)**	(6)	**(10)**	(11)
Other	**—**	(1)	**—**	(1)
FCF	**91**	49	**200**	144
Weighted average number of common shares outstanding in the period	**276**	284	**276**	284
FFO per share	**0.58**	0.55	**1.20**	1.14
FCF per share	**0.33**	0.17	**0.72**	0.51

(1) Dividends paid on preferred shares for the three months ended June 30, 2019 have been adjusted to include dividends payable in the second quarter of 2019.

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

	3 months ended June 30		6 months ended June 30	
	2020	2019	**2020**	2019
Comparable EBITDA	**217**	215	**437**	436
Provisions and other	**10**	7	**15**	11
Interest expense	**(45)**	(46)	**(92)**	(88)
Current income tax expense	**(12)**	(7)	**(21)**	(14)
Realized foreign exchange gain (loss)	**(6)**	(2)	**9**	(7)
Decommissioning and restoration costs settled	**(4)**	(8)	**(8)**	(15)
Other cash and non-cash items	**(1)**	(4)	**(9)**	1
FFO	**159**	155	**331**	324
Deduct:				
Sustaining capital	**(26)**	(61)	**(55)**	(86)
Productivity capital	**(1)**	(1)	**(1)**	(3)
Dividends paid on preferred shares(1)	**(10)**	(10)	**(20)**	(20)
Distributions paid to subsidiaries' non-controlling interests	**(26)**	(27)	**(45)**	(59)
Payments on lease obligations	**(5)**	(6)	**(10)**	(11)
Other	**—**	(1)	**—**	(1)
FCF	**91**	49	**200**	144

(1) Dividends paid on preferred shares for the three months ended June 30, 2019 have been adjusted to include dividends payable in the second quarter of 2019.

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 obligations 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 the business by each of our segments:

	3 months ended June 30		6 months ended June 30	
	2020	2019	**2020**	2019
Segmented cash flow[1]				
Canadian Coal	**21**	19	**43**	60
US Coal	**20**	11	**48**	(1)
North American Gas[2]	**25**	24	**54**	48
Australian Gas	**29**	29	**57**	59
Wind and Solar	**57**	39	**129**	105
Hydro	**27**	32	**50**	56
Generation segmented cash flow	**179**	154	**381**	327
Energy Marketing	**30**	20	**48**	44
Corporate[3]	**(18)**	(30)	**(51)**	(41)
Total segmented cash flow	**191**	144	**378**	330

(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. See the Corporate Strategy section of this MD&A and Note 3 of the interim condensed consolidated financial statements for further details.
(3) Includes gains and losses on the total return swap.

Segmented cash flow generated by the business increased by $47 million and $48 million in the three and six months ended June 30, 2020, respectively, compared to the same periods in 2019, mainly due to strong results from our US Coal, North American Gas, Wind and Solar and Energy Marketing segments, partially offset by the planned outage at Canadian Coal in the first quarter of 2020, lower demand impacting our Canadian Coal and Hydro segments and the impact of the realized gains and losses on the total return swap in the Corporate segment. In the six months ended June 30, 2020, we realized a net loss of $8 million from the total return swap on our share-based payment plans, whereas in the same period last year we realized a net gain of $9 million.

Canadian Coal

	3 months ended June 30		6 months ended June 30	
	2020	2019	**2020**	2019
Availability (%)	**91.3**	80.3	**90.1**	85.7
Contract production (GWh)	**1,302**	1,424	**2,840**	3,486
Merchant production (GWh)	**849**	1,365	**2,284**	3,022
Total production (GWh)	**2,151**	2,789	**5,124**	6,508
Gross installed capacity (MW)(1)	**3,229**	3,231	**3,229**	3,231
Revenues	**141**	186	**333**	421
Fuel, carbon compliance and purchased power	**85**	91	**206**	237
Comparable gross margin	**56**	95	**127**	184
Operations, maintenance and administration	**33**	35	**66**	68
Taxes, other than income taxes	**3**	4	**7**	7
Net other operating income	**(10)**	(10)	**(20)**	(20)
Comparable EBITDA	**30**	66	**74**	129
Deduct:				
Sustaining capital:				
Routine capital	**3**	4	**4**	7
Mine capital	**1**	5	**2**	10
Planned major maintenance	**6**	29	**20**	32
Total sustaining capital expenditures	**10**	38	**26**	49
Productivity capital	**1**	1	**1**	3
Total sustaining and productivity capital	**11**	39	**27**	52
Provisions	**(8)**	—	**(8)**	1
Payments on lease obligations	**3**	4	**7**	8
Decommissioning and restoration costs settled	**3**	4	**5**	8
Canadian Coal cash flow	**21**	19	**43**	60

(1) 2019 & 2020 - includes 774 MW for Sundance Units 3 and 5, which are temporarily mothballed. In addition, the Keephills 3 and Genesee 3 asset swap resulted in a net 2 MW reduction of capacity that occurred in the fourth quarter of 2019.

Availability for the three and six months ended June 30, 2020, was higher compared to the same periods in 2019, mainly due to lower planned outages.

Production for the three and six months ended June 30, 2020, decreased 638 and 1,384 GWh, respectively, compared to the same periods in 2019. This was largely as a result of curtailments and dispatch optimization resulting in lower merchant production in the coal fleet due to lower demand due to COVID-19 and reduced oil production in the province.

Revenue for the three and six months ended June 30, 2020, decreased by $45 million and $88 million, respectively, compared to the same periods in 2019, mainly due to lower merchant production.

In the three and six months ended June 30, 2020, revenue per MWh of production remained fairly consistent at approximately $66 per MWh and $65 per MWh, respectively, compared with $67 per MWh and $65 per MWh, respectively, for the same periods in 2019, primarily due to higher realized prices as a result of hedges and fixed capacity revenues with lower contracted production.

In the three and six months ended June 30, 2020, fuel, carbon compliance and purchased power costs per MWh of production increased to approximately $40 per MWh for both periods, compared with $33 per MWh and $36 per MWh, respectively, for the same periods in 2019. This increase was partially due to the $7 million increase in the provision for the transmission line loss relating to prior years, representing $3 per MWh and $1 per MWh of fuel, carbon compliance and purchased power costs for the three and six months ended June 30, 2020, respectively (refer to the Other Consolidated Analysis section of this MD&A for further details). Costs per MWh also increased due to higher gas prices and fixed coal costs spread over less volume resulting in increased costs per MWh. Consequently, comparable gross margin per MWh for the three and six months ended June 30, 2020, was $8 per MWh and $4 per MWh lower, respectively, compared with the same periods in 2019.

We continued to co-fire with natural gas, when economical. Natural gas combustion produces fewer GHG emissions than coal combustion, which lowers our overall fuel and GHG compliance costs.

OM&A costs for the three and six months ended June 30, 2020, were $2 million lower in both periods compared with the same periods in 2019, due to strong cost controls.

Comparable EBITDA for the three and six months ended June 30, 2020, decreased $36 million and $55 million, respectively, compared to the same periods in 2019. This largely reflects the weaker power demand conditions driving lower Alberta wholesale power prices and resulting in lower merchant production as well as the increase to the transmission line loss provision.

For the three and six months ended June 30, 2020, sustaining and productivity capital expenditures decreased by $28 million and $25 million, respectively, compared to the same periods in 2019, mainly due to less planned major maintenance outages in the first half of 2020. In 2019, there were more planned major outages, while during 2020 there was only the one planned outage for the dual-fuel conversion at the Sheerness plant.

Canadian Coal's cash flow for the three months ended June 30, 2020, increased by $2 million compared to the same period in 2019, mainly due to lower sustaining capital spend offsetting the reduction in comparable EBITDA. For the six months ended June 30, 2020, cash flow decreased by $17 million, compared to the same period in 2019, mainly due to lower merchant production and pricing, partially offset by lower sustaining capital expenditures.

US Coal

	3 months ended June 30		6 months ended June 30	
	2020	2019	**2020**	2019
Availability (%)	**44.6**	35.2	**60.4**	55.9
Adjusted availability (%)[1]	**79.1**	73.6	**86.1**	75.2
Contract sales volume (GWh)	**829**	830	**1,659**	1,650
Merchant sales volume (GWh)	**—**	397	**1,271**	2,571
Purchased power (GWh)	**(829)**	(881)	**(1,824)**	(1,850)
Total production (GWh)	**—**	346	**1,106**	2,371
Gross installed capacity (MW)	**1,340**	1,340	**1,340**	1,340
Revenues	**61**	72	**179**	231
Fuel and purchased power	**17**	34	**85**	188
Comparable gross margin	**44**	38	**94**	43
Operations, maintenance and administration	**15**	18	**31**	32
Taxes, other than income taxes	**2**	1	**3**	2
Comparable EBITDA	**27**	19	**60**	9
Deduct:				
Sustaining capital:				
Routine capital	**1**	1	**2**	1
Planned major maintenance	**5**	4	**7**	4
Total sustaining capital expenditures	**6**	5	**9**	5
Decommissioning and restoration costs settled	**1**	3	**3**	5
US Coal cash flow	**20**	11	**48**	(1)

(1) Adjusted for dispatch optimization.

Adjusted availability for the three months ended June 30, 2020, increased compared to the same period in 2019 due to lower planned outages and increased dispatch optimization. Adjusted availability for the six months ended June 30, 2020, increased compared to the same period in 2019 due to lower derates in 2020. In the first quarter of 2019, Centralia operated with a derate due to blocked precipitator hoppers.

There was no production in the three months ended June 30, 2020, compared to 346 GWh of production in the same period in 2019, due to units undergoing planned maintenance and remaining on reserve shutdown during the quarter. Production decreased by 1,265 GWh in the six months ended June 30, 2020, compared to the same period in 2019, due mainly to lower merchant pricing in the first quarter of 2020 and timing of dispatch optimization. In 2019, both Centralia units remained in service into April due to higher prices in the Pacific Northwest, whereas in 2020, due to seasonally lower prices, both Centralia units were taken out of service throughout February and March and for the entire second quarter of 2020.

OM&A costs for the three months ended June 30, 2020, were $3 million lower compared with the same period in 2019, mainly due to the units remaining on reserve shutdown. OM&A costs for the six months ended June 30, 2020, were consistent with the same period in 2019 and in line with expectations.

Comparable EBITDA returned to normalized levels in 2020 and for the three months ended June 30, 2020, increased by $8 million compared to the same period in 2019, primarily due to low priced power purchases and favourable foreign exchange rates. For the six months ended June 30, 2020, comparable EBITDA increased by $51 million compared to the same period in 2019, primarily due to the impacts of an isolated and extreme pricing event in March 2019 during which Centralia was unable to commit one of its units to physical production for day-ahead supply due to an unplanned forced outage repair. In addition, comparable EBITDA in the first half of 2020 benefited from low priced power purchases and the strengthening of the US dollar relative to the Canadian dollar.

For the three and six months ended June 30, 2020, sustaining capital expenditures were $1 million and $4 million higher, respectively, than the same periods in 2019, mainly due to increased planned outage work in 2020 during the reserve shutdown.

US Coal's cash flow for the three and six months ended June 30, 2020, increased by $9 million and $49 million, respectively, compared to the the same periods in 2019, mainly due to higher comparable EBITDA, partially offset by higher sustaining capital spend.

North American Gas[(1)]

	3 months ended June 30		6 months ended June 30	
	2020	2019	**2020**	2019
Availability (%)	**95.8**	89.2	**98.6**	94.3
Contract production (GWh)	**452**	423	**909**	860
Merchant production (GWh)[(2)]	**(51)**	(59)	**(51)**	100
Total production (GWh)	**401**	364	**858**	960
Gross installed capacity (MW)[(3)]	**974**	945	**974**	945
Revenues	**53**	55	**109**	127
Fuel and purchased power	**14**	12	**28**	43
Comparable gross margin	**39**	43	**81**	84
Operations, maintenance and administration	**12**	11	**24**	22
Taxes, other than income taxes	**—**	1	**1**	1
Comparable EBITDA	**27**	31	**56**	61
Deduct:				
Sustaining capital:				
Routine capital	**2**	3	**2**	8
Planned major maintenance	**—**	4	**—**	5
Total sustaining capital expenditures	**2**	7	**2**	13
North American Gas cash flow	**25**	24	**54**	48

(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. See the Corporate Strategy section of this MD&A and Note 3 of the interim condensed consolidated financial statements for further details.
(2) Includes purchased power, which is used for dispatch optimization, when economical.
(3) 2020 includes 29 MW for the acquisition of the Ada facility in the second quarter of 2020. Both years include production capacity for the Fort Saskatchewan facility, which prior to November 2019 was accounted for as a finance lease and include the portion we own of the Poplar Creek facility as a part of gross capacity measures.

Availability for the three and six months ended June 30, 2020, increased compared to the same periods in 2019, primarily due to lower planned and unplanned outages at our Sarnia and Ottawa facilities.

Production for the three months ended June 30, 2020, increased by 37 GWh compared to the same period in 2019, mainly due to the new Ada facility and higher customer demand partially offset by lower market demand for our Sarnia facility. Production for the six months ended June 30, 2020, decreased by 102 GWh compared to the same period in 2019, mainly due to lower Ontario market demand in the first quarter of 2020, which was partially offset by the new Ada facility. Due to the nature of our contracts, 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.

OM&A costs for the three and six months ended June 30, 2020, were $1 million and $2 million higher, respectively, compared with the same periods in 2019, due to the renegotiation of the Fort Saskatchewan maintenance agreement, where we no longer have pass-through provisions.

Comparable EBITDA for the three and six months ended June 30, 2020, decreased by $4 million and $5 million, respectively, compared with the same periods in 2019, due to lower power prices in Alberta and Ontario.

Sustaining capital expenditures for the three and six months ended June 30, 2020, decreased by $5 million and $11 million, respectively, compared with the same periods in 2019, mainly due to lower planned outages.

North American Gas' cash flow for the three and six months ended June 30, 2020, increased by $1 million and $6 million, respectively, compared to the the same periods in 2019, as lower capital expenditures were partially offset by lower comparable EBITDA.

Australian Gas

	3 months ended June 30		**6 months ended June 30**	
	2020	2019	**2020**	2019
Availability (%)	**94.3**	90.6	**93.1**	86.0
Contract production (GWh)	**448**	453	**919**	919
Gross installed capacity (MW)	**450**	450	**450**	450
Revenues	**39**	40	**78**	81
Fuel and purchased power	**1**	1	**3**	2
Comparable gross margin	**38**	39	**75**	79
Operations, maintenance and administration	**9**	8	**16**	18
Comparable EBITDA	**29**	31	**59**	61
Deduct:				
Sustaining capital:				
Planned major maintenance	**—**	2	**2**	2
Total sustaining capital expenditures	**—**	2	**2**	2
Australian Gas cash flow	**29**	29	**57**	59

Availability for the three and six months ended June 30, 2020, increased compared to the same periods in 2019, mainly due to unplanned outages in 2019.

Production for the three and six months ended June 30, 2020, was consistent with the same periods in 2019. Due to the nature of our contracts, 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 and six months ended June 30, 2020, decreased by $2 million for both periods compared with the same periods in 2019, mainly due to the weakening of the Australian dollar relative to the Canadian dollar.

Sustaining capital expenditures for the three months ended June 30, 2020, were $2 million lower than the same period in 2019, mainly due to planned major maintenance at our Southern Cross facility. For the six months ended June 30, 2020, sustaining capital expenditures were consistent with the same period in 2019, which was in line with expectations.

Australian Gas' cash flow for the three months ended June 30, 2020, was consistent with the same period in 2019, and for the six months ended June 30, 2020, cash flow decreased by $2 million, mainly due to the weakening of the Australian dollar relative to the Canadian dollar.

Wind and Solar

	3 months ended June 30		6 months ended June 30	
	2020	2019	**2020**	2019
Availability (%)	**96.3**	95.2	**95.8**	95.1
Contract production (GWh)	**677**	518	**1,472**	1,275
Merchant production (GWh)	**260**	190	**601**	404
Total production (GWh)	**937**	708	**2,073**	1,679
Gross installed capacity (MW)(1)	**1,495**	1,382	**1,495**	1,382
Revenues	**80**	61	**174**	148
Fuel and purchased power	**4**	3	**9**	7
Comparable gross margin	**76**	58	**165**	141
Operations, maintenance and administration	**13**	13	**26**	25
Taxes, other than income taxes	**2**	2	**4**	4
Net other operating income	**—**	(4)	**—**	(4)
Comparable EBITDA	**61**	47	**135**	116
Deduct:				
Sustaining capital:				
Planned major maintenance	**3**	3	**5**	5
Total sustaining capital expenditures	**3**	3	**5**	5
Payments on lease obligations	**1**	1	**1**	1
Decommissioning and restoration costs settled	**—**	—	**—**	1
Other	**—**	4	**—**	4
Wind and Solar cash flow	**57**	39	**129**	105

(1) The 2020 gross installed capacity includes the addition of Big Level and Antrim in late December, partially offset by the reduction of wind turbines due to tower fires at Wyoming Wind and Summerview.

Availability for the three and six months ended June 30, 2020, increased compared to the same periods in 2019, due to lower planned and unplanned outages.

Production for the three and six months ended June 30, 2020, increased by 229 GWh and 394 GWh, respectively, compared to the same periods in 2019, mainly due to the Big Level and Antrim wind facilities commencing commercial operations in December 2019, higher wind resources and higher availability.

Comparable EBITDA for the three and six months ended June 30, 2020, increased by $14 million and $19 million, respectively, compared with the same periods in 2019, primarily due to higher production related to the Big Level and Antrim wind facilities, which were commissioned in December of 2019, partially offset by insurance proceeds received in 2019.

Sustaining capital expenditures for the three and six months ended June 30, 2020, were consistent with the same periods in 2019, which was expected.

Wind and Solar's cash flow for the three and six months ended June 30, 2020, increased by $18 million and $24 million, respectively, compared to the the same periods in 2019, mainly due to higher comparable EBITDA.

Hydro

	3 months ended June 30		6 months ended June 30	
	2020	2019	**2020**	2019
Production				
Energy contracted				
Alberta Hydro PPA assets (GWh)(1)	**508**	417	**814**	735
Other hydro energy (GWh)(1)	**135**	133	**167**	160
Energy merchant				
Other hydro energy (GWh)	**26**	25	**31**	28
Total energy production (GWh)	**669**	575	**1,012**	923
Ancillary service volumes (GWh)(2)	**717**	788	**1,589**	1,569
Gross installed capacity (MW)	**925**	926	**925**	926
Revenues				
Alberta Hydro PPA assets energy	**16**	27	**40**	56
Alberta Hydro PPA assets ancillary	**8**	28	**44**	57
Capacity payments received under Alberta Hydro PPA(3)	**15**	14	**30**	28
Other revenue(4)	**17**	18	**23**	23
Total gross revenues	**56**	87	**137**	164
Net payment relating to Alberta Hydro PPA(5)	**(14)**	(38)	**(57)**	(78)
Revenues	**42**	49	**80**	86
Fuel and purchased power	**2**	2	**4**	3
Comparable gross margin	**40**	47	**76**	83
Operations, maintenance and administration	**10**	10	**19**	18
Taxes, other than income taxes	**1**	—	**2**	1
Comparable EBITDA	**29**	37	**55**	64
Deduct:				
Sustaining capital:				
Routine capital	**1**	1	**2**	2
Planned major maintenance	**1**	3	**3**	5
Total sustaining capital expenditures	**2**	4	**5**	7
Decommissioning and restoration costs settled	**—**	1	**—**	1
Hydro cash flow	**27**	32	**50**	56

(1) Alberta Hydro PPA assets include 13 hydro facilities on the Bow and North Saskatchewan river systems included under the PPA legislation. Other hydro facilities include our hydro facilities in BC, Ontario and the hydro facilities in Alberta not included in the legislated PPA.
(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 expires on Dec. 31, 2020.
(4) Other revenue includes revenues from our non-PPA hydro facilities, our transmission business and other contractual arrangements including the flood mitigation agreement with the Alberta government and black start services.
(5) 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 which expires on Dec. 31, 2020.

Production for the three and six months ended June 30, 2020, increased by 94 GWh and 89 GWh, respectively, compared to the same periods in 2019, mainly due to by higher water resources.

Total gross revenues for the three and six months ended June 30, 2020, decreased by $31 million and $27 million, respectively, compared to the same periods in 2019, as lower energy and ancillary services revenues were impacted by lower Alberta pricing, which was partially offset by higher production.

In the three and six months ended June 30, 2020, Alberta Hydro PPA assets energy revenue per MWh of production decreased to approximately $31 per MWh and $49 per MWh, respectively, compared with $65 per MWh and $76 per MWh, respectively, for the same periods in 2019. Similarly, in the three and six months ended June 30, 2020, Alberta Hydro PPA assets ancillary revenue per MWh of production decreased to approximately $11 per MWh and $28 per MWh, respectively, compared with $36 per MWh for both periods in 2019. Lower realized prices are primarily due to the market conditions in Alberta in 2020, for further discussion on the market conditions and pricing, refer to the 2020 Financial Outlook section of this MD&A.

Comparable EBITDA for the three and six months ended June 30, 2020, decreased by $8 million and $9 million, respectively, compared with the same periods in 2019, as lower energy and ancillary services revenues were impacted by lower Alberta pricing, which was partially offset by higher production.

Sustaining capital expenditures for the three and six months ended June 30, 2020, decreased by $2 million for both periods, compared with the same periods in 2019, due to lower planned outages.

Hydro's cash flow for the three and six months ended June 30, 2020, decreased by $5 million and $6 million, respectively, compared with the same periods in 2019, mainly due to lower comparable EBITDA partially offset by lower sustaining capital expenditures.

Energy Marketing

	3 months ended June 30		6 months ended June 30	
	2020	2019	**2020**	2019
Revenues and comparable gross margin	**34**	21	**56**	49
Operations, maintenance and administration	**6**	8	**15**	17
Comparable EBITDA	**28**	13	**41**	32
Deduct:				
Provisions and other	**(2)**	(7)	**(7)**	(12)
Energy Marketing cash flow	**30**	20	**48**	44

Comparable EBITDA for the three and six months ended June 30, 2020, increased by $15 million and $9 million, respectively, compared to the same periods in 2019. Results were primarily attained from short-term strategies across various geographic regions in both the power and natural gas markets.

Energy Marketing's cash flow for the three and six months ended June 30, 2020, increased by $10 million and $4 million, respectively, compared to the the same periods in 2019, mainly due to higher comparable EBITDA.

Corporate

	3 months ended June 30		6 months ended June 30	
	2020	2019	**2020**	2019
Operations, maintenance, and administration	14	27	**43**	34
Net other operating loss	—	2	—	2
Comparable EBITDA	**(14)**	(29)	**(43)**	(36)
Deduct:				
Sustaining capital:				
Routine capital	**3**	2	**6**	5
Total sustaining capital expenditures	**3**	2	**6**	5
Payments on lease obligations	**1**	1	**2**	2
Other	—	(2)	—	(2)
Corporate cash flow	**(18)**	(30)	**(51)**	(41)

Our Corporate overhead costs for the three months ended June 30, 2020, decreased by $15 million and for the six months ended June 30, 2020, increased by $7 million compared to the same periods in 2019. These changes were primarily due to realized gains and losses from the total return swap. A portion of the settlement cost of our share-based payment plans is fixed by entering into total return swaps, which are cash settled every quarter.

Supplemental disclosure	3 months ended June 30 2020	2019	6 months ended June 30 2020	2019
Corporate cash flow	**(18)**	(30)	**(51)**	(41)
Total return swap (gains) losses	**(3)**	4	**8**	(9)
Adjusted Corporate cash flow	**(21)**	(26)	**(43)**	(50)

Excluding the impact of the total return swap, Corporate costs for the three and six months ended June 30, 2020 have decreased by $5 million and $7 million, respectively, mainly due to lower legal and labour costs.

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 US Coal. 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.

	Q3 2019	Q4 2019	Q1 2020	**Q2 2020**
Revenues	593	609	606	**437**
Comparable EBITDA	305	243	220	**217**
FFO	244	189	172	**159**
Net earnings (loss) attributable to common shareholders	51	66	27	**(60)**
Net earnings (loss) per share attributable to common shareholders, basic and diluted(1)	0.18	0.24	0.10	**(0.22)**
	Q3 2018	Q4 2018	Q1 2019	Q2 2019
Revenues	593	622	648	497
Comparable EBITDA	252	265	221	215
FFO	204	217	169	155
Net earnings (loss) attributable to common shareholders	(86)	(122)	(65)	—
Net earnings (loss) per share attributable to common shareholders, basic and diluted(1)	(0.30)	(0.43)	(0.23)	—

(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:

- Revenues declined due to weaker market conditions in the first and second quarters of 2020 as a result of COVID-19 and low oil prices;
- Significant foreign exchange losses in the first quarter of 2020 and foreign exchange gains in the second quarter of 2020;
- Gains relating to the Keephills 3 and Genesee 3 swap in the fourth quarter of 2019;
- Effects of asset impairments and reversals during the first and second quarters of 2020 (due to changes in discount rates), third and fourth quarters of 2019 and asset impairments during the third and fourth quarters of 2018;
- Effects of changes in useful lives of certain assets during the third quarter of 2019;
- Change in income tax rates in Alberta in the second quarter of 2019;
- Lower scheduled payments commencing in January 2019 from the Poplar Creek finance lease; and
- Recognition of the $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.

Funds from Operations before Interest to Adjusted Interest Coverage

For the twelve months ended	June 30, 2020	Dec. 31, 2019
FFO[1]	**764**	757
Less: PPA Termination Payments	**(56)**	(56)
Add: Interest on debt, exchangeable securities and leases, net of interest income and capitalized interest	**177**	166
FFO before interest	**885**	867
Interest on debt, exchangeable securities and leases, net of interest income	**183**	172
Add: 50 per cent of dividends paid on preferred shares	**20**	20
Adjusted interest	**203**	192
FFO before interest to adjusted interest coverage (times)	**4.4**	4.5

(1) See the Discussion of Consolidated Financial Results section in this MD&A for the reconciliation of cash flow from operating activities to FFO for the six months ended June 30, 2020 and 2019. These amounts are used to calculate the twelve months ended FFO by taking the current year-to-date FFO plus the 2019 FFO minus the prior year-to-date FFO. See also the IFRS Measures and Non-IFRS Measures section for further details.

Our target for FFO before interest to adjusted interest coverage is four to five times. While both periods are within our target range, the ratio decreased slightly in 2020 compared to 2019, mainly due to higher adjusted interest.

Adjusted FFO to Adjusted Net Debt

As at	June 30, 2020	Dec. 31, 2019
FFO[1, 2]	**764**	757
Less: PPA Termination Payments[1]	**(56)**	(56)
Less: 50 per cent of dividends paid on preferred shares[1]	**(20)**	(20)
Adjusted FFO[1]	**688**	681
Period-end long-term debt[3]	**3,113**	3,212
Exchangeable securities	**328**	326
Less: Cash and cash equivalents	**(257)**	(411)
Less: Principal portion of TransAlta OCP restricted cash	**—**	(10)
Add: 50 per cent of issued preferred shares	**471**	471
Fair value asset of hedging instruments on debt[4]	**(16)**	(7)
Adjusted net debt	**3,639**	3,581
Adjusted FFO to adjusted net debt (%)	**18.9**	19.0

(1) Last 12 months.
(2) Refer to the Discussion of Consolidated Financial Results section of this MD&A for the the reconciliation of cash flow from operating activities to FFO for the six months ended June 30, 2020 and 2019. These amounts are used to calculate the twelve months ended FFO by taking the current year-to-date FFO plus the 2019 FFO minus the prior year-to-date FFO. See also the IFRS Measures and Non-IFRS Measures section for further details.
(3) Includes lease obligations and tax equity financing.
(4) Included in risk management assets and/or liabilities on the consolidated financial statements as at June 30, 2020 and Dec. 31, 2019.

Our target range for adjusted FFO to adjusted net debt is 20 to 25 per cent. Our adjusted FFO to adjusted net debt declined due to higher adjusted net debt compared with 2019.

Adjusted Net Debt to Comparable EBITDA

As at	June 30, 2020	Dec. 31, 2019
Adjusted net debt	**3,639**	3,581
Comparable EBITDA(1)	**985**	984
Less: PPA Termination Payments(1)	**(56)**	(56)
Adjusted comparable EBITDA(1)	**929**	928
Adjusted net debt to adjusted comparable EBITDA (times)	**3.9**	3.9

(1) Last 12 months.

Our target for adjusted net debt to comparable EBITDA is 3.0 to 3.5 times. Our adjusted net debt to comparable EBITDA ratio was consistent with 2019, which was expected.

Deconsolidated Net Debt to Deconsolidated Comparable EBITDA

In addition to reviewing fully consolidated ratios and results, management reviews net debt to adjusted comparable EBITDA on a deconsolidated basis to highlight TransAlta's financial flexibility, balance sheet strength and leverage excluding the portion of TransAlta Renewables and 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	June 30, 2020	Dec. 31, 2019
Period-end long-term debt(1)	**3,113**	3,212
Exchangeable securities	**328**	326
Less: Cash and cash equivalents	**(257)**	(411)
Add: TransAlta Renewables cash and cash equivalents(2)	**29**	63
Less: Principal portion of TransAlta OCP restricted cash	**—**	(10)
Add: 50 per cent of issued preferred shares	**471**	471
Less: Fair value asset of hedging instruments on debt(3)	**(16)**	(7)
Less: TransAlta Renewables long-term debt	**(825)**	(961)
Less: US tax equity financing(4)	**(145)**	(145)
Deconsolidated net debt	**2,698**	2,538
Comparable EBITDA(5)	**985**	984
Less: PPA Termination Payments(5)	**(56)**	(56)
Less: TransAlta Renewables comparable EBITDA(5)	**(444)**	(438)
Less: TA Cogen comparable EBITDA(5)	**(60)**	(80)
Add: Dividend from TransAlta Renewables(5)	**151**	151
Add: Dividend from TA Cogen(5)	**20**	37
Deconsolidated comparable EBITDA (5)	**596**	598
Deconsolidated net debt to deconsolidated comparable EBITDA(5) (times)	**4.5**	4.2

(1) Includes lease obligations and tax equity financing.
(2) In the second quarter of 2020, we adjusted the calculation to remove the portion of cash relating to TransAlta Renewables' cash and cash equivalents to reflect deconsolidated cash. Prior periods have also been updated.
(3) Included in risk management assets and/or liabilities on the consolidated financial statements as at June 30, 2020 and Dec. 31, 2019.
(4) Relates to assets where TransAlta Renewables has economic interests.
(5) Last 12 months.

Our target for deconsolidated net debt to deconsolidated comparable EBITDA is 2.5 to 3.0 times. Our deconsolidated net debt to deconsolidated comparable EBITDA ratio increased compared with 2019, mainly as a result of lower cash balances and foreign exchange impacts on our US-denominated debt.

Deconsolidated FFO

The Corporation has a dividend policy that aims 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 June 30, 2020			3 months ended June 30, 2019		
	TransAlta Consolidated	**TransAlta Renewables**	**TransAlta Deconsolidated**	TransAlta Consolidated	TransAlta Renewables	TransAlta Deconsolidated
Cash flow from operating activities	**121**	**71**		258	52	
Change in non-cash operating working capital balances	**30**	**(5)**		(110)	19	
Cash flow from operations before changes in working capital	**151**	**66**		148	71	
Adjustments:						
Decrease in finance lease receivable	**4**	**—**		6	—	
Finance and interest income - economic interests	**—**	**(10)**		—	(13)	
Adjusted FFO - economic interests	**—**	**42**		—	36	
Other	**4**	**—**		1	—	
FFO	**159**	**98**	**61**	155	94	61
Dividend from TransAlta Renewables			**37**			37
Distributions to TA Cogen's Partner			**(3)**			(6)
Deconsolidated TransAlta FFO			**95**			92

	6 months ended June 30, 2020			6 months ended June 30, 2019		
	TransAlta Consolidated	**TransAlta Renewables**	**TransAlta Deconsolidated**	TransAlta Consolidated	TransAlta Renewables	TransAlta Deconsolidated
Cash flow from operating activities	**335**	**153**		340	183	
Change in non-cash operating working capital balances	**(20)**	**(23)**		(30)	(22)	
Cash flow from operations before changes in working capital	**315**	**130**		310	161	
Adjustments:						
Decrease in finance lease receivable	**8**	**—**		12	—	
Finance and interest income - economic interests	**—**	**(18)**		—	(39)	
Adjusted FFO - economic interests	**—**	**82**		—	73	
Other	**8**	**—**		2	—	
FFO	**331**	**194**	**137**	324	195	129
Dividend from TransAlta Renewables			**75**			75
Distributions to TA Cogen's Partner			**(4)**			(21)
Deconsolidated TransAlta FFO			**208**			183

Financial Position

The following table provides a summary of account balances derived from the unaudited interim condensed consolidated statements of financial position as at June 30, 2020 and Dec. 31, 2019:

As at	June 30, 2020	Dec. 31, 2019	Increase (decrease)
Assets			
Cash and cash equivalents	**257**	411	(154)
Trade and other receivables	**428**	462	(34)
Inventory	**297**	251	46
Risk management assets (current and long-term)	**939**	806	133
Assets held for sale	**97**	—	97
Property, plant, and equipment, net	**5,936**	6,207	(271)
Intangible assets	**341**	318	23
Others(1)	**1,075**	1,053	22
Total assets	**9,370**	9,508	(138)
Liabilities and equity			
Credit facilities, long-term debt and lease obligations (current and long-term)	**3,113**	3,212	(99)
Decommissioning and other provisions (current and long-term)	**528**	546	(18)
Risk management liabilities (current and long-term)	**165**	110	55
Equity attributable to shareholders	**2,923**	2,961	(38)
Others(2)	**2,641**	2,679	(38)
Total liabilities and equity	**9,370**	9,508	(138)

(1) Includes restricted cash, prepaid expenses, long-term portion of finance lease receivables, right of use assets, goodwill, deferred income tax assets and other assets.
(2) Includes accounts payable and accrued liabilities, income taxes payable, dividends payable, exchangeable securities, contract liabilities, defined benefit obligation and other long-term liabilities, deferred income tax liabilities and non-controlling interests.

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.
- Trade and other receivables decreased largely due to lower collateral payments and timing of customer receipts.
- Inventory increased mainly due to higher tonnes of coal at Centralia resulting from dispatch optimization beginning as early as February in 2020 ($34 million) as well as higher emission credits inventory ($15 million).
- Risk management assets, net of liabilities increased primarily due to changes in market prices and foreign exchange rates, partially offset by contract settlements.
- Assets held for sale relate to the sale of the Pioneer Pipeline (refer to the Corporate Strategy section of this MD&A for further details).
- Property, plant and equipment ("PP&E") decreased due to depreciation ($336 million) and revisions to decommissioning provisions as a result of changes in discount rates ($41 million), which was partially offset by additions ($147 million) relating to assets under construction for the coal-to-gas conversions, the Windrise wind facility, the Kaybob cogeneration facility, land and planned major maintenance expenditures. Our PP&E was also impacted significantly due to changes in foreign exchange rates ($54 million).
- Intangible assets increased due to the Ada acquisition ($37 million) and additions ($5 million), partially offset by depreciation ($23 million).
- Credit facilities, long-term debt and lease obligations decreased due to lower drawings on the credit facilities ($109 million) and debt repayments ($44 million), partially offset by changes in outstanding balances as a result of the strengthening of the US dollar ($50 million).
- Decommissioning and other provisions have decreased mainly due to changes in discount rates ($50 million), partially offset by accretion ($15 million) and the strengthening of the US dollar ($13 million).
- Equity attributable to shareholders decreased mainly due to common and preferred share dividend payments ($43 million), the share repurchases under the NCIB ($21 million) and the effect of share-based payment plans ($14 million), partially offset by net gains on translating net assets of foreign operations ($44 million).

Cash Flows

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

	6 months ended June 30		
	2020	2019	Increase (decrease)
Cash and cash equivalents, beginning of period	**411**	89	322
Provided by (used in):			
Operating activities	**335**	340	(5)
Investing activities	**(204)**	(230)	26
Financing activities	**(290)**	10	(300)
Translation of foreign currency cash	**5**	(1)	6
Cash and cash equivalents, end of period	**257**	208	49

Cash provided by operating activities for the six months ended June 30, 2020, was consistent with the same period in 2019.

Cash used in investing activities for the six months ended June 30, 2020, decreased compared with the same period in 2019, largely due to:

- less cash spent on acquisitions, in 2020 TransAlta acquired Ada ($37 million) whereas in 2019, we acquired Antrim ($32 million) and the Pioneer Pipeline ($83 million);
- Offset by lower changes in our restricted cash ($19 million) and lower non-cash working capital related to the timing of construction payables for the assets under construction ($24 million).

Cash from financing activities for the six months ended June 30, 2020, decreased compared with the same period in 2019, largely due to:

- $350 million was provided in 2019 on issuance of the exchangeable securities;
- Offset by lower debt repayments ($40 million) as a result of lower payments on the credit facilities ($30 million) and lower scheduled principal repayments on project debt ($10 million); and
- $14 million in lower distributions paid to the non-controlling shareholders.

Financial Capital

Capital Structure

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

As at	June 30, 2020		Dec. 31, 2019	
	$	%	$	%
TransAlta Corporation				
Recourse debt - CAD debentures	**648**	**9**	647	9
Recourse debt - US senior notes	**949**	**13**	905	13
Exchangeable securities	**328**	**5**	326	5
Other	**8**	**—**	9	—
Less: cash and cash equivalents	**(228)**	**(3)**	(348)	(5)
Less: principal portion of restricted cash on TransAlta OCP	**—**	**—**	(10)	—
Less: fair value asset of economic hedging instruments on debt	**(16)**	**(1)**	(7)	—
Net recourse debt, excluding US tax equity financing	**1,689**	**23**	1,522	22
US tax equity financing	**145**	**2**	145	2
Non-recourse debt	**413**	**6**	426	6
Lease obligations	**125**	**2**	119	2
Total net debt - TransAlta Corporation	**2,372**	**33**	2,212	32
TransAlta Renewables				
Credit facility	**111**	**1**	220	3
Less: cash and cash equivalents	**(29)**	**—**	(63)	(1)
Net recourse debt	**82**	**1**	157	2
Non-recourse debt	**692**	**10**	718	10
Lease obligations	**22**	**—**	23	—
Total net debt - TransAlta Renewables	**796**	**11**	898	12
Total consolidated net debt	**3,168**	**44**	3,110	44
Non-controlling interests	**1,068**	**15**	1,101	15
Equity attributable to shareholders				
Common shares	**2,944**	**41**	2,978	42
Preferred shares	**942**	**13**	942	13
Contributed surplus, deficit and accumulated other comprehensive income	**(963)**	**(13)**	(959)	(14)
Total capital	**7,159**	**100**	7,172	100

The Corporation continues to maintain a strong financial position in part due to our long-term contracts and hedged positions. The Corporation is scheduled to receive $400 million from the second tranche of financing from the Brookfield investment in the fourth quarter of 2020 and we have access to additional capital through potential project financing of existing assets that are currently unencumbered. Between 2020 and 2022, we have $1,197 million of debt maturing, comprised of approximately $947 million of recourse debt, with the balance mainly related to scheduled non-recourse debt repayments. For the debt maturing in 2020, we expect to utilize our existing cash and credit facilities and we expect to refinance the debt maturing in 2022. We currently have access to $1.6 billion in liquidity including $257 million in cash and cash equivalents.

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

As at June 30, 2020	Facility size	Utilized: Outstanding letters of credit[1]	Utilized: Actual drawings	Available capacity	Maturity date
TransAlta Corporation					
Committed syndicated bank facility [2]	1,250	393	—	857	Q2 2023
Canadian committed bilateral credit facilities[3]	240	233	—	7	Q2 2022
TransAlta Renewables					
Committed credit facility[2]	700	92	110	498	Q2 2023
Total	**2,190**	**718**	**110**	**1,362**	

(1) We have obligations to issue letters of credit and cash collateral to secure potential liabilities to certain parties, including those related to potential environmental obligations, commodity risk management and hedging activities, pension plan obligations, construction projects and purchase obligations. At June 30, 2020, we provided cash collateral of $15 million.

(2) TransAlta has letters of credit of $110 million and TransAlta Renewables has letters of credit of $91 million issued from uncommitted demand facilities, these obligations are backstopped and reduce the available capacity on the committed credit facilities.

(3) One of the bilateral $80 million credit facilities has a maturity date of Q2 2021.

The strengthening of the US dollar has increased our long-term debt balances by $50 million as at June 30, 2020. Almost all our US-denominated debt is hedged either through financial contracts or net investments in our US operations. During the period, these changes in our US-denominated debt were offset as follows:

	June 30, 2020
Effects of foreign exchange on carrying amounts of US operations (net investment hedge)	**23**
Foreign currency economic cash flow hedges on debt	**9**
Economic hedges and other	**11**
Unhedged	**7**
Total	**50**

Share Capital

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

As at	July 30, 2020	June 30, 2020	Dec. 31, 2019
	Number of shares *(millions)*		
Common shares issued and outstanding, end of period	**274.2**	**274.2**	277.0
Preferred shares			
Series A	10.2	**10.2**	10.2
Series B	1.8	**1.8**	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, end of period	**38.6**	**38.6**	38.6

Non-Controlling Interests

As of June 30, 2020, we own 60.2% per cent (June 30, 2019 – 60.6 per cent) of TransAlta Renewables. Our ownership percent decreased due to common shares issued under TransAlta Renewables' Dividend Reinvestment Plan. We do not participate in this plan.

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

Reported earnings attributable to non-controlling interests for the three months ended June 30, 2020, remained fairly consistent with the same period in 2019. Reported earnings attributable to non-controlling interests for the six months ended June 30, 2020, decreased by $29 million to $22 million compared to the same period in 2019. Earnings decreased at TransAlta Renewables for the six months ended June 30, 2020 compared to the same period in 2019, mainly due to the change in the fair value of investments in subsidiaries of TransAlta, lower revenue due to low Alberta pricing and lower finance income from subsidiaries of TransAlta, partially offset by foreign exchange gains. Earnings from TA Cogen for the six months ended June 30, 2020, also decreased compared with the same period in 2019, mainly due to lower gross margin as a result of the planned outage for the dual-fuel conversion at the Sheerness plant and low Alberta prices.

Returns to Providers of Capital

Net Interest Expense

The components of net interest expense are shown below:

	3 months ended June 30		6 months ended June 30	
	2020	2019	**2020**	2019
Interest on debt	**39**	42	**82**	83
Interest on exchangeable securities	**8**	5	**15**	5
Interest income	**(2)**	(3)	**(5)**	(5)
Capitalized interest	**(1)**	(1)	**(2)**	(2)
Interest on lease obligations	**2**	1	**4**	2
Credit facility fees, bank charges, and other interest	**5**	4	**9**	7
Other	**—**	2	**1**	4
Accretion of provisions	**6**	6	**15**	12
Net interest expense	**57**	56	**119**	106

Net interest expense was higher in the three and six months ended June 30, 2020, primarily due to interest on the exchangeable securities, higher interest on lease obligations due to leases recognized in the fourth quarter of 2019 and higher accretion of provisions due to changes in the estimated decommissioning provision which occurred in the second half of 2019. For further details on the change in estimate for the decommissioning provision refer to Note 3(A)(IV) of the 2019 audited annual consolidated financial statements.

Regulatory Updates

Refer to the Policy and Legal Risks discussion in our 2019 annual MD&A for further details that supplement the recent developments as discussed below:

Post-PPA Alberta Electricity Market

The Alberta government concluded its review of the market power mitigation measures in Alberta's electricity market and determined that no additional mitigation is required to be introduced into Alberta's existing market design. The government's announcement reduces regulatory uncertainty and provides additional market clarity for new investment as the PPAs expire at the end of 2020.

COVID-19 Impact on Regulatory Processes and Environmental Reporting

As a result of COVID-19, all North American integrated electricity market system operators and the Federal Energy Regulatory Commission have moved staff to work from home structures with the exception of their system operations staff. Planned in-person consultation processes have been cancelled and these and other stakeholder processes have been rescheduled to telephone or virtual formats and/or delayed. These actions are expected to result in delays or potential cancellation of regulatory changes and other market operation working groups' activities. Standard market activities have not been impacted. Consultations and related activities now take place virtually and are starting to form a new normal whereby work and decision-making is getting back to pre-COVID-19 timelines.

Due to COVID-19, the Alberta and Canadian federal government provided options to delay environmental reporting, including options to delay compliance reporting for their respective large GHG emitters programs. Facilities were still able to submit reports on the regular compliance dates. As the economies have opened up, some governments have restarted environmental reporting requirements. However, reporting deadlines for large emitter GHG programs will remain delayed for this compliance year as these delays were enacted through temporary changes to regulations.

Other Consolidated Analysis

Commitments

In addition to the commitments disclosed elsewhere in the financial statements and those disclosed in the 2019 annual audited financial statements, during 2020, the Corporation has incurred the following additional contractual commitments, either directly or through its interests in joint operations. Approximate future payments under these agreements are as follows:

	2020	2021	2022	2023	2024	2025 and thereafter	Total
Natural gas and transportation contracts	—	3	12	5	3	1	**24**
Transmission	—	3	5	5	5	7	**25**
Total	**—**	**6**	**17**	**10**	**8**	**8**	**49**

Natural Gas and Transportation Contracts

Includes the incremental change in fixed price or volume natural gas purchase and transportation contracts, as compared to the amounts disclosed in the 2019 annual audited consolidated financial statements. In addition to the commitments shown above, upon closing the sale of the Pioneer Pipeline, a 15-year transportation agreement will provide 275 TJ per day of natural gas on a firm basis by 2023, bringing the total firm natural gas transportation contracts to 400 TJ per day. This agreement would replace the Corporation's existing 15-year commitment to purchase 139 TJ per day of natural gas on the Pioneer Pipeline.

Transmission

Includes the incremental change in transmission agreements, as compared to the amounts disclosed in the 2019 annual audited consolidated financial statements.The Corporation has several agreements to purchase transmission network capacity in the Pacific Northwest. Provided certain conditions for delivering the service are met, the Corporation is committed to the transmission at the supplier's tariff rate whether it is awarded immediately or delivered in the future after additional facilities are constructed.

Contingencies

For the current significant outstanding contingencies, refer to the Other Consolidated Analysis section of the 2019 Annual MD&A included in the 2019 Annual Integrated Report. Changes to these contingencies during the six months ended June 30, 2020 are included below:

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 and issue a single invoice charging or crediting market participants for the difference in losses charges. A decision by the AUC determined the methodology to be used retroactively, which made it possible for the Corporation to estimate the total retroactive potential exposure faced by the Corporation for its non-PPA power generation. The single invoice for the historical adjustments was expected to be issued in April 2021, with cash settlement expected in June 2021. The previous provision, which was based on known data, was approximately $12 million.

The AESO requested the AUC approve a pay-as-you-go settlement, instead of issuing a single invoice, which request the Corporation challenged. This form of settlement would permit the AESO to issue an invoice for each historical year as the line loss factors are recalculated, advancing some charges into 2020. Based on the recently published AESO loss factors for the period of 2014 to 2016, using the AUC-approved methodology, the provision has increased to $20 million mainly due to higher loss factors for Keephills 3 and Poplar Creek.

The AUC recently ruled on the AESO's request and approved an invoice settlement process that instead will be broken down into three periods (2014 to 2016, 2010 to 2013 and 2006 to 2009) with the first invoice for line losses issued in 2020. The first invoice that will be payable in 2020 is estimated to be approximately $6 million, with the other two invoices payable in 2021. It is important to note that the estimated amounts continue to be uncertain and the AESO's recalculated loss factors remain subject to further review and change. TransAlta will continue to participate in the proceeding and carefully review all calculations to help ensure that the invoices are accurate and reflect the decisions of the AUC.

FMG Disputes
The Corporation is currently engaged in two disputes with Fortescue Metals Group Ltd. ("FMG"). The first arose as a result of FMG's purported termination of the South Hedland PPA. TransAlta sued FMG, seeking payment 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. This matter has been re-scheduled to proceed to trial beginning May 3, 2021, instead of June 15, 2020, but it may be delayed further, depending on the extent of continued restrictions arising from the COVID-19 pandemic.

The second dispute involves FMG's claims against TransAlta related to the transfer of the Solomon facility to FMG. FMG claims certain amounts related to the condition of the facility while TransAlta claims certain outstanding costs that should be reimbursed. A trial date for this matter has not yet been scheduled but it will not occur until 2021 at the earliest.

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 is seeking to set aside the 2019 Brookfield transaction. TransAlta believes the claim is wholly lacking in merit and is taking all steps to defend against the allegations. The two week trial of this matter has been rescheduled to begin on April 19, 2021, instead of September 2020, but it may be delayed further, depending on the extent of restrictions arising from the COVID-19 pandemic.

Keephills 1 Stator Force Majeure
The Balancing Pool and ENMAX Energy Corporation ("ENMAX") are seeking to set aside an arbitration award on the basis that they did not receive a fair hearing. The Alberta Court of Queen's Bench ("ABQB") dismissed the Balancing Pool and ENMAX's allegations of unfairness on June 26, 2019. The Balancing Pool and ENMAX, however, sought leave to appeal the ABQB's decision at the Court of Appeal, which was granted on Feb. 13, 2020. The appeal is scheduled to be heard on April 8, 2021. TransAlta believes that the Court of Appeal will affirm the ABQB decision that the arbitration proceeding was not unfair.

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 those estimates due to factors such as fluctuations in interest rates, foreign exchange rates, inflation and commodity prices, and changes in economic conditions, legislation and regulations.

The duration and impact of the COVID-19 pandemic are unknown at this time. Estimates to the extent to which the COVID-19 pandemic may, directly or indirectly impact the Corporation's operations, financial results and conditions in future periods are also subject to significant uncertainty. For a description of additional risks identified as a result of the pandemic, refer to Note 10 of the unaudited interim condensed consolidated financial statements as at and for the three and six months ended June 30, 2020.

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
Decommissioning and other provisions
During the first half of 2020, there was significant volatility in the discount rates used for the decommissioning provision mainly due to an increase in TransAlta's credit spread due to the COVID-19 crisis, which has caused increased credit spreads for most entities. This increase in the credit spreads in the first quarter was partially offset by decreases in the benchmark rates. As a result, during the first quarter, the Corporation decreased the decommissioning provision by $125 million, of which $84 million decreased the related assets included in property, plant and equipment and $41 million was reflected as an asset impairment reversal. During the second quarter, the discount rates used for the decommissioning provision decreased due to the reduction in TransAlta's credit spreads, resulting in a partial reversal of $75 million, of which $43 million increased the related assets in property, plant and equipment and $32 million was reflected as an asset impairment. On a year-to-date basis, the decommissioning provision decreased by $50 million, of which $41 million decreased the related assets included in property, plant and equipment and $9 million was reflected as an asset impairment reversal on the statement of earnings as it relates to the Centralia mine and Sundance Units 1 & 2, which are no longer operating and reached the end of their useful lives.

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, 2019, except for the adoption of new standards effective as of Jan. 1, 2020. The Corporation has not early adopted any standard, interpretation or amendment that has been issued but is not yet effective.

I. Amendments to IAS 1 and IAS 8 *Definition of Material*

The Corporation adopted the amendments to IAS 1 and IAS 8 as of Jan. 1, 2020. The amendments provide a new definition of material that states "information is material if omitting, misstating or obscuring it could reasonably be expected to influence decisions that the primary users of general purpose financial statements make on the basis of those financial statements, which provide financial information about a specific reporting entity."

The amendments clarify that materiality will depend on the nature or magnitude of information, either individually or in combination with other information, in the context of the financial statements. A misstatement of information is material if it could reasonably be expected to influence decisions made by the primary users. These amendments had no impact on the consolidated financial statements of, nor is there expected to be any future impact to the Corporation.

II. Amendments to IFRS 7 and 9 *Interest Rate Benchmark Reform*

In September 2019, the IASB issued *Interest Rate Benchmark Reform* - Amendments to IFRS 9, IAS 39 and IFRS 7. These amendments provide temporary relief during the period of uncertainty from applying specific hedge accounting requirements to hedging relationships directly affected by the on-going interest rate benchmark reforms. These amendments are mandatory for annual periods beginning on or after Jan. 1, 2020. The Corporation adopted these amendments as of Jan. 1, 2020. There were no hedging relationships that were directly affected on Jan. 1, 2020.

During the first quarter of 2020, the Corporation entered into cash flow hedges of interest rate risk associated with a future forecasted debt issuance using London Interbank Offered Rate ("LIBOR") based derivative instruments. As a temporary relief, provided by the IFRS 9 amendments, the Corporation has assumed that the LIBOR interest rate on which the cash flows of the interest rate swaps are based is not altered by interbank offered rates ("IBOR") reform when assessing if the hedge is highly effective.

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 14 of the notes to the audited annual consolidated financial statements within our 2019 Annual Integrated Report and Note 9 and 10 of our unaudited interim condensed consolidated financial statements as at and for the three and six months ended June 30, 2020 for details on Financial Instruments.

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

At June 30, 2020, Level III instruments had a net asset carrying value of $759 million (Dec. 31, 2019 - $686 million). The increase during the period is primarily attributable to changes in market prices and foreign exchange rates, partially offset by contract settlements. Our risk management profile and practices have not changed materially from Dec. 31, 2019.

Governance and Risk Management

Refer to the Governance and Risk Management section of our 2019 Annual Integrated Report and Note 10 of our unaudited interim condensed consolidated financial statements for details on our risks and how we manage them. Our risk management profile and practices have not changed materially from Dec. 31, 2019.

We have adopted a number of risk mitigation measures in response to the COVID-19 pandemic, including the formal implementation of TransAlta's business continuity plan on March 9, 2020. The Board and management have been monitoring the development of the outbreak and are continually assessing its impact on the Corporation's operations, supply chains and customers as well as, more generally, to the business and affairs of the Corporation. 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 at TransAlta, potential delays in growth projects, increased credit risk with counterparties and increased volatility in commodity prices as well as valuations 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.

To manage the risks resulting from COVID-19, we have taken a number of steps in furtherance of the Corporation's business continuity efforts:

Management Responses
- Formed a COVID-19 emergency team run by our Chief Operating Officer, reporting to our Chief Executive Officer;
- Regularly communicating with the Board of Directors and employees in regards to the Corporation's response to COVID-19;
- Created a team to develop, implement and update COVID-19 safety protocols, including a back to office and site strategy which will remain in place until a vaccination or cure has been distributed;
- Established a committee to consider and respond to any claims of force majeure that may be received as a result of COVID-19;
- Developed leadership plans, including contingent authorities;

Policy Changes
- Aligned all non-essential travel and quarantine requirements with local jurisdictional guidance for all TransAlta employees and contractors returning from air, bus, train or ship travel for all jurisdictions in which we operate;

Employee Changes
- Provided assurances to employees that their employment with TransAlta would not be impacted by the COVID-19 pandemic;
- Developed and implemented COVID-19 specific back to office protocols to ensure all TransAlta locations remain safe;
- Requested and received an essential workers quarantine exemption approval from Alberta Health to minimize disruptions in the event international technical assistance is required for our Alberta assets;
- Implemented health screening procedures (i.e., questionnaires and temperature tests), enhanced cleaning measures and strict work protocols at the Corporation's offices and facilities in accordance with our back to office and site strategy;

Operational Changes
- Modified our operating procedures and implemented restrictions to non-essential access to our facilities to support continued operations through the pandemic;
- Reviewed the supply chain risk associated with all key power generation process inputs and implemented weekly monitoring for changes in risk;
- Reached out to key supply chain contacts to determine strategies and contingencies to ensure we are able to continue to progress our growth projects, wherever possible;
- Identified new cybersecurity risks associated with phishing emails and enhanced security protocols and increased awareness of potential threats;

Financial Oversight

- Maintained our hedge positions in Alberta, where we have 75 per cent of our thermal baseload merchant generation hedged at approximately $53 per MWh for the remainder of 2020;
- Continued to monitor counterparties for changes in creditworthiness as well as monitor their ability to meet obligations; and
- Continued to monitor the situation and communicate with our key lenders on any foreseeable impacts and on our response to the crisis. We maintain a strong financial position and significant liquidity with our existing committed credit facilities.

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 and six months ended June 30, 2020, 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 report. Based on the foregoing evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as at June 30, 2020, the end of the period covered by this report, our ICFR and DC&P were effective.

Condensed Consolidated Statements of Earnings (Loss)

(in millions of Canadian dollars except per share amounts)

	3 months ended June 30		6 months ended June 30	
Unaudited	**2020**	2019	**2020**	2019
Revenues (Note 4)	**437**	497	**1,043**	1,145
Fuel, carbon compliance and purchased power (Note 5)	**151**	177	**389**	543
Gross margin	**286**	320	**654**	602
Operations, maintenance and administration (Note 5)	**112**	130	**240**	234
Depreciation and amortization	**163**	143	**319**	288
Asset impairment (reversal) (Note 1B)	**32**	—	**(9)**	—
Taxes, other than income taxes	**8**	8	**17**	15
Net other operating income	**(10)**	(12)	**(20)**	(22)
Operating income (loss)	**(19)**	51	**107**	87
Finance lease income	**1**	1	**2**	3
Net interest expense (Note 6)	**(57)**	(56)	**(119)**	(106)
Foreign exchange gain (loss)	**23**	(8)	**4**	(9)
Other losses	**—**	(12)	**—**	(12)
Loss before income taxes	**(52)**	(24)	**(6)**	(37)
Income tax recovery (Note 7)	**(17)**	(50)	**(15)**	(33)
Net earnings (loss)	**(35)**	26	**9**	(4)
Net earnings (loss) attributable to:				
TransAlta shareholders	**(50)**	10	**(13)**	(55)
Non-controlling interests (Note 8)	**15**	16	**22**	51
	(35)	26	**9**	(4)
Net earnings (loss) attributable to TransAlta shareholders	**(50)**	10	**(13)**	(55)
Preferred share dividends (Note 16)	**10**	10	**20**	10
Net loss attributable to common shareholders	**(60)**	—	**(33)**	(65)
Weighted average number of common shares outstanding in the period *(millions)*	**276**	284	**276**	284
Net loss per share attributable to common shareholders, basic and diluted	**(0.22)**	—	**(0.12)**	(0.23)

See accompanying notes.

Condensed Consolidated Statements of Comprehensive Income (Loss)

(in millions of Canadian dollars)

	3 months ended June 30		6 months ended June 30	
Unaudited	**2020**	2019	**2020**	2019
Net earnings (loss)	**(35)**	26	**9**	(4)
Other comprehensive income (loss)				
Net actuarial losses on defined benefit plans, net of tax(1)	**(21)**	(17)	**(15)**	(36)
Gains (losses) on derivatives designated as cash flow hedges, net of tax(2)	**(4)**	(3)	**5**	—
Total items that will not be reclassified subsequently to net earnings	**(25)**	(20)	**(10)**	(36)
Gains (losses) on translating net assets of foreign operations, net of tax(3)	**(29)**	(33)	**67**	(54)
Gains (losses) on financial instruments designated as hedges of foreign operations, net of tax(3)	**18**	12	**(23)**	20
Gains (losses) on derivatives designated as cash flow hedges, net of tax(4)	**41**	46	**55**	(5)
Reclassification of gains on derivatives designated as cash flow hedges to net earnings, net of tax(5)	**(24)**	(29)	**(49)**	(8)
Total items that will be reclassified subsequently to net earnings	**6**	(4)	**50**	(47)
Other comprehensive income (loss)	**(19)**	(24)	**40**	(83)
Total comprehensive income (loss)	**(54)**	2	**49**	(87)
Total comprehensive income (loss) attributable to:				
TransAlta shareholders	**(41)**	22	**37**	(103)
Non-controlling interests (Note 8)	**(13)**	(20)	**12**	16
	(54)	2	**49**	(87)

(1) Net of income tax recovery of $7 million and $5 million for the three and six months ended June 30, 2020 (2019 - $1 million and $8 million recovery).
(2) Net of income tax expense of nil and $1 million for the three and six months ended June 30, 2020 (2019 - $1 million and $1 million expense).
(3) No income tax expense was recorded for the three and six months ended June 30, 2020 or 2019.
(4) Net of income tax expense of $11 million and $16 million for the three and six months ended June 30, 2020 (2019 - $13 million expense and $1 million recovery).
(5) Net of reclassification of income tax expense of $6 million and $13 million for the three and six months ended June 30, 2020 (2019 - $8 million and $2 million expense).

See accompanying notes.

Condensed Consolidated Statements of Financial Position

(in millions of Canadian dollars)

Unaudited	**June 30, 2020**	Dec. 31, 2019
Cash and cash equivalents	**257**	411
Restricted cash	**16**	32
Trade and other receivables	**428**	462
Prepaid expenses	**48**	19
Risk management assets (Note 9 and 10)	**275**	166
Inventory (Note 11)	**297**	251
	1,321	1,341
Assets held for sale (Note 3D)	**97**	—
Long-term portion of finance lease receivables	**168**	176
Risk management assets (Note 9 and 10)	**664**	640
Property, plant and equipment (Note 12)		
Cost	**13,526**	13,395
Accumulated depreciation	**(7,590)**	(7,188)
	5,936	6,207
Right of use assets	**151**	146
Intangible assets (Note 3C)	**341**	318
Goodwill	**465**	464
Deferred income tax assets	**34**	18
Other assets	**193**	198
Total assets	**9,370**	9,508
Accounts payable and accrued liabilities	**401**	413
Current portion of decommissioning and other provisions	**67**	58
Risk management liabilities (Note 9 and 10)	**109**	81
Current portion of contract liabilities	**1**	1
Income taxes payable	**21**	14
Dividends payable (Note 15 and 16)	**38**	37
Current portion of long-term debt and lease obligations (Note 13)	**513**	513
	1,150	1,117
Credit facilities, long-term debt and lease obligations (Note 13)	**2,600**	2,699
Exchangeable securities (Note 14)	**328**	326
Decommissioning and other provisions (Note 1B)	**461**	488
Deferred income tax liabilities	**451**	472
Risk management liabilities (Note 9 and 10)	**56**	29
Contract liabilities	**14**	14
Defined benefit obligation and other long-term liabilities	**319**	301
Equity		
Common shares (Note 15)	**2,944**	2,978
Preferred shares	**942**	942
Contributed surplus	**32**	42
Deficit	**(1,499)**	(1,455)
Accumulated other comprehensive income	**504**	454
Equity attributable to shareholders	**2,923**	2,961
Non-controlling interests (Note 8)	**1,068**	1,101
Total equity	**3,991**	4,062
Total liabilities and equity	**9,370**	9,508

Significant and subsequent events (Note 3)
Commitments and contingencies (Note 17)
See accompanying notes.

Condensed Consolidated Statements of Changes in Equity

(in millions of Canadian dollars)

Unaudited

6 months ended June 30, 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 (loss)	—	—	—	**(13)**	—	**(13)**	**22**	**9**
Other comprehensive income (loss):								
Net gains on translating net assets of foreign operations, net of hedges and of tax	—	—	—	—	**44**	**44**	—	**44**
Net gains on derivatives designated as cash flow hedges, net of tax	—	—	—	—	**11**	**11**	—	**11**
Net actuarial losses on defined benefits plans, net of tax	—	—	—	—	**(15)**	**(15)**	—	**(15)**
Intercompany FVOCI investments	—	—	—	—	**10**	**10**	**(10)**	—
Total comprehensive income (loss)	—	—	—	**(13)**	**50**	**37**	**12**	**49**
Common share dividends	—	—	—	**(23)**	—	**(23)**	—	**(23)**
Preferred share dividends	—	—	—	**(20)**	—	**(20)**	—	**(20)**
Shares purchased under NCIB	**(30)**	—	—	**9**	—	**(21)**	—	**(21)**
Changes in non-controlling interests in TransAlta Renewables (Note 8)	—	—	—	**3**	—	**3**	**9**	**12**
Effect of share-based payment plans	**(4)**	—	**(10)**	—	—	**(14)**	—	**(14)**
Distributions paid, and payable, to non-controlling interests (Note 8)	—	—	—	—	—	—	**(54)**	**(54)**
Balance, June 30, 2020	**2,944**	**942**	**32**	**(1,499)**	**504**	**2,923**	**1,068**	**3,991**

6 months ended June 30, 2019	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive	Attributable to shareholders	Attributable to non-	Total
Balance, Dec. 31, 2018	3,059	942	11	(1,496)	481	2,997	1,137	4,134
Impact of change in accounting policy	—	—	—	3	—	3	—	3
Adjusted balance as at Jan. 1, 2019	3,059	942	11	(1,493)	481	3,000	1,137	4,137
Net earnings (loss)	—	—	—	(55)	—	(55)	51	(4)
Other comprehensive income (loss):								
Net losses on translating net assets of foreign operations, net of hedges and tax	—	—	—	—	(34)	(34)	—	(34)
Net losses on derivatives designated as cash flow hedges, net of tax	—	—	—	—	(13)	(13)	—	(13)
Net actuarial losses on defined benefits plans, net of tax	—	—	—	—	(36)	(36)	—	(36)
Intercompany FVOCI investments	—	—	—	—	35	35	(35)	—
Total comprehensive income (loss)	—	—	—	(55)	(48)	(103)	16	(87)
Common share dividends	—	—	—	(11)	—	(11)	—	(11)
Preferred share dividends	—	—	—	(10)	—	(10)	—	(10)
Shares purchased under NCIB	(26)	—	—	5	—	(21)	—	(21)
Changes in non-controlling interests in TransAlta Renewables (Note 8)	—	—	—	2	—	2	12	14
Effect of share-based payment plans	1	—	1	—	—	2	—	2
Distributions paid, and payable, to non-controlling interests (Note 8)	—	—	—	—	—	—	(70)	(70)
Balance, June 30, 2019	3,034	942	12	(1,562)	433	2,859	1,095	3,954

See accompanying notes.

Condensed Consolidated Statements of Cash Flows

(in millions of Canadian dollars)

	3 months ended June 30		6 months ended June 30	
Unaudited	**2020**	2019	**2020**	2019
Operating activities				
Net earnings (loss)	**(35)**	26	**9**	(4)
Depreciation and amortization (Note 18)	**188**	173	**372**	347
Loss on sale of assets	**—**	17	**—**	17
Accretion of provisions	**6**	6	**15**	12
Decommissioning and restoration costs settled	**(4)**	(8)	**(8)**	(15)
Deferred income tax recovery (Note 7)	**(29)**	(57)	**(36)**	(47)
Unrealized (gain) loss from risk management activities	**7**	(18)	**(46)**	(16)
Unrealized foreign exchange (gains) losses	**(24)**	6	**2**	5
Provisions	**9**	2	**9**	4
Asset impairment (reversal) (Note 1B)	**32**	—	**(9)**	—
Other non-cash items	**1**	1	**7**	7
Cash flow from operations before changes in working capital	**151**	148	**315**	310
Change in non-cash operating working capital balances	**(30)**	110	**20**	30
Cash flow from operating activities	**121**	258	**335**	340
Investing activities				
Additions to property, plant and equipment (Note 12)	**(75)**	(110)	**(147)**	(144)
Additions to intangibles	**(3)**	(3)	**(5)**	(6)
Restricted cash	**(1)**	—	**16**	35
Acquisitions, net of cash acquired	**(37)**	—	**(37)**	(32)
Investment in the Pioneer Pipeline	**—**	(33)	**—**	(83)
Proceeds on sale of property, plant and equipment	**1**	1	**1**	2
Realized gains on financial instruments	**3**	—	**6**	3
Decrease in finance lease receivable	**4**	6	**8**	12
Increase in loan receivable	**(3)**	(4)	**(3)**	(4)
Other	**1**	11	**4**	10
Change in non-cash investing working capital balances	**1**	(45)	**(47)**	(23)
Cash flow used in investing activities	**(109)**	(177)	**(204)**	(230)
Financing activities				
Net decrease in borrowings under credit facilities (Note 13)	**(8)**	(210)	**(109)**	(139)
Repayment of long-term debt (Note 13)	**(27)**	(25)	**(44)**	(54)
Issuance of exchangeable securities (Note 14)	**—**	350	**—**	350
Dividends paid on common shares (Note 15)	**(12)**	(12)	**(23)**	(23)
Dividends paid on preferred shares (Note 16)	**(10)**	(10)	**(20)**	(10)
Repurchase of common shares under NCIB (Note 15)	**(10)**	(18)	**(19)**	(18)
Realized (gains) losses on financial instruments	**3**	—	**(7)**	—
Distributions paid to subsidiaries' non-controlling interests (Note 8)	**(23)**	(24)	**(42)**	(56)
Repayment of lease obligations (Note 13)	**(5)**	(6)	**(10)**	(11)
Other	**(2)**	—	**(2)**	—
Financing fees	**—**	(28)	**—**	(28)
Change in non-cash investing working capital balances	**—**	2	**(14)**	(1)
Cash flow from (used in) financing activities	**(94)**	19	**(290)**	10
Cash flow from (used in) operating, investing, and financing activities	**(82)**	100	**(159)**	120
Effect of translation on foreign currency cash	**1**	(1)	**5**	(1)
Increase (decrease) in cash and cash equivalents	**(81)**	99	**(154)**	119
Cash and cash equivalents, beginning of period	**338**	109	**411**	89
Cash and cash equivalents, end of period	**257**	208	**257**	208
Cash income taxes paid	**8**	7	**20**	15
Cash interest paid	**60**	53	**99**	85

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 accordance 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 July 30, 2020.

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(Y) of the Corporation's most recent annual consolidated financial statements for further details.

The outbreak of the novel strain of coronavirus ("COVID-19") has resulted in governments worldwide enacting emergency measures to constrain the spread of the virus. These measures, which include the implementation of travel bans, self-imposed quarantine periods, self-isolation, physical and social distancing and the closure of non-essential business, have caused significant disruption to businesses globally which has resulted in an uncertain and challenging economic environment. The duration and impact of the COVID-19 pandemic are unknown at this time. Estimates to the extent to which the COVID-19 pandemic may, directly or indirectly impact the Corporation's operations, financial results and conditions in future periods are also subject to significant uncertainty. For a description of additional risks identified as a result of the pandemic, refer to Note 10.

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

Decommissioning and other provisions

During the first half of 2020, there was significant volatility in the discount rates used for the decommissioning provision mainly due to an increase in TransAlta's credit spread due to the COVID-19 crisis, which has caused increased credit spreads for most entities. This increase in the credit spreads in the first quarter was partially offset by decreases in the benchmark rates. As a result, during the first quarter, the Corporation decreased the decommissioning provision by $125 million, of which $84 million decreased the related assets included in property, plant and equipment and $41 million was reflected as an asset impairment reversal. During the second quarter, the discount rates used for the decommissioning provision decreased due to the reduction in TransAlta's credit spreads, resulting in a partial reversal of $75 million, of which $43 million increased the related assets in property, plant and equipment and $32 million was reflected as an asset impairment. On a year-to-date basis, the decommissioning provision decreased by $50 million, of which $41 million decreased the related assets included in property, plant and equipment and $9 million was reflected as an asset impairment reversal on the statement of earnings as it relates to the Centralia mine and Sundance Units 1 & 2, which are no longer operating and reached the end of their useful lives.

2. Significant Accounting Policies

A. Current Accounting Changes

The accounting policies adopted in the preparation of the 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, 2019, except for the adoption of new standards effective as of Jan. 1, 2020. The Corporation has not early adopted any standard, interpretation or amendment that has been issued but is not yet effective.

I. Amendments to IAS 1 and IAS 8 *Definition of Material*

The Corporation adopted the amendments to IAS 1 and IAS 8 as of Jan. 1, 2020. The amendments provide a new definition of material that states “information is material if omitting, misstating or obscuring it could reasonably be expected to influence decisions that the primary users of general purpose financial statements make on the basis of those financial statements, which provide financial information about a specific reporting entity.”

The amendments clarify that materiality will depend on the nature or magnitude of information, either individually or in combination with other information, in the context of the financial statements. A misstatement of information is material if it could reasonably be expected to influence decisions made by the primary users. These amendments had no impact on the consolidated financial statements of, nor is there expected to be any future impact to the Corporation.

II. Amendments to IFRS 7 and 9 *Interest Rate Benchmark Reform*

In September 2019, the International Accounting Standards Board issued amendments to International Financial Reporting Standards ("IFRS") relating to *Interest Rate Benchmark Reform* - amending IFRS 9, IAS 39 and IFRS 7. These amendments provide temporary relief during the period of uncertainty from applying specific hedge accounting requirements to hedging relationships directly affected by the on-going interest rate benchmark reforms. These amendments are mandatory for annual periods beginning on or after Jan. 1, 2020. The Corporation adopted these amendments as of Jan. 1, 2020. There were no hedging relationships that were directly affected on Jan. 1, 2020.

During the first quarter of 2020, the Corporation entered into cash flow hedges of interest rate risk associated with a future forecasted debt issuance using London Interbank Offered Rate ("LIBOR") based derivative instruments. As a temporary relief, provided by the IFRS 9 amendments, the Corporation has assumed that the LIBOR interest rate on which the cash flows of the interest rate swaps are based is not altered by interbank offered rates ("IBOR") reform when assessing if the hedge is highly effective.

B. 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. Global Pandemic

The World Health Organization ("WHO") 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 formally implemented its business continuity plan on March 9, 2020, which focused on ensuring that: (i) employees that could work remotely did so; and (ii) employees that operate and maintain our facilities, who were not able to work remotely, were able to work safely and in a manner that ensured they remained healthy. During the second quarter of 2020, the Corporation began a staggered approach to bring employees that were working remotely back to the office. All of TransAlta's offices and sites follow strict health screening and social distancing protocols with personal protective equipment readily available. 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 capable of meeting our customers' needs. We have modified our operating procedures and implemented safety protocols that are allowing all office employees to now return to sites across the fleet by the end of July. 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. The Corporation is scheduled to receive $400 million from the second tranche of financing from Brookfield in the fourth quarter of 2020 and the Corporation has access to additional capital through the potential project financing of existing assets that are currently unencumbered. We currently have access to $1.6 billion in liquidity including $257 million in cash and have sufficient liquidity to meet the upcoming debt maturity due November 2020. The next major debt repayment is scheduled for November 2022.

The Corporation has approximately 75 per cent of its baseload merchant generation in Alberta hedged in the $53 per MWh range for the remainder of 2020.

The Board and management have been monitoring the development of the outbreak 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 valuations 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.

B. Normal Course Issuer Bid

On May 26, 2020, the Corporation announced that the Toronto Stock Exchange ("TSX") accepted the notice filed by the Corporation to implement a Normal Course Issuer Bid ("NCIB") for a portion of its common shares. Pursuant to the NCIB, TransAlta may repurchase up to a maximum of 14,000,000 common shares, representing approximately 7.02 per cent of its public float of common shares as at May 25, 2020. Purchases under the NCIB may be made through open market transactions on the TSX and any alternative Canadian trading platforms on which the common shares are traded, based on the prevailing market price. Any common shares purchased under the NCIB will be cancelled.

The period during which TransAlta is authorized to make purchases under the NCIB commenced on May 29, 2020 and ends on May 28, 2021 or such earlier date on which the maximum number of common shares are purchased under the NCIB or the NCIB is terminated at the Corporation's election.

Under TSX rules, not more than 228,157 common shares (being 25 per cent of the average daily trading volume on the TSX of 912,630 common shares for the six months ended April 30, 2020) can be purchased on the TSX on any single trading day under the NCIB, with the exception that one block purchase in excess of the daily maximum is permitted per calendar week.

During the six months ended June 30, 2020, under the current and previous NCIB, the Corporation purchased and cancelled a total of 2,849,400 common shares at an average price of $7.51 per common share, for a total cost of $21 million.

C. Acquisition of a Contracted Cogeneration Asset in Michigan

On May 19, 2020, the Corporation closed the previously announced acquisition of a contracted natural gas-fired cogeneration facility from two private companies for a purchase price of approximately US$27 million, subject to working capital adjustments. The asset is a 29 MW cogeneration facility ("Ada") in Michigan which is contracted under a long-term power purchase agreement ("PPA") and steam sale agreement for approximately six years with Consumers Energy and Amway. This acquisition aligns with TransAlta's strategy of growing the on-site generation business and diversifying the Corporation's cogeneration portfolio.

The fair values of the identifiable assets and liabilities of the acquired entities as at the date of acquisition were:

As at May 19, 2020	Provisional fair value recognized on acquisition
Assets	
Net working capital	6
Property, plant and equipment[(1)]	1
Intangible assets[(1, 2)]	37
Risk management liabilities (current and long-term)[(1)]	(5)
Decommissioning provisions[(1)]	(1)
Total identifiable net assets at fair value	**38**
Cash consideration	**32**
Working capital consideration	**6**
Total purchase consideration transferred	**38**

(1) The valuation of property, plant and equipment, intangible assets, risk management liabilities and decommissioning provisions acquired has not been completed by the date the interim financial statements were approved for issue by the Board of Directors. Therefore, these balances may need to be subsequently adjusted prior to May 19, 2021 (one year after the transaction).
(2) This relates to the power sales contract acquired and will be amortized over six years.

D. Sale of the Pioneer Pipeline

During the second quarter of 2020, TransAlta entered into a definitive Purchase and Sale Agreement with respect to the previously announced sale of its 50 per cent interest in the Pioneer Pipeline, currently included in the Canadian Coal segment, to NOVA Gas Transmission Ltd. ("NGTL"), a wholly-owned subsidiary of TC Energy (the "Transaction"). The purchase price of $255 million represents both TransAlta's and Tidewater Midstream & Infrastructure Ltd.'s (“Tidewater”) interests. As part of the Transaction, NGTL intends to integrate the Pioneer Pipeline into its natural gas pipeline infrastructure in Alberta.

E. Sundance Unit 3 Retirement

On July 22, 2020, the Corporation announced that it gave notice to the Alberta Electric System Operator ("AESO") of its intention to retire the currently mothballed coal-fired Sundance Unit 3 effective July 31, 2020. The retirement decision was largely driven by TransAlta’s assessment of future market conditions, the age and condition of the unit and our ability to supply energy and capacity from our generation portfolio in Alberta. This decision advances our transition to 100 per cent clean electricity by 2025. An asset impairment of approximately $69 million ($52 million after-tax) will be recorded in the third quarter of 2020.

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 energy marketing and trading 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 June 30, 2020	**Canadian Coal**	**US Coal**	**North American Gas[(1)]**	**Australian Gas**	**Wind and Solar**	**Hydro**	**Energy Marketing**	**Corporate**	**Total**
Revenues from contracts with customers	**78**	**1**	**45**	**22**	**63**	**39**	**—**	**—**	**248**
Revenue from leases[(2)]	**14**	**—**	**—**	**16**	**—**	**—**	**—**	**—**	**30**
Revenue from derivatives	**20**	**67**	**—**	**—**	**(6)**	**—**	**25**	**1**	**107**
Government incentives	**—**	**—**	**—**	**—**	**2**	**—**	**—**	**—**	**2**
Revenue from other[(3)]	**28**	**—**	**3**	**1**	**15**	**3**	**—**	**—**	**50**
Total revenue	**140**	**68**	**48**	**39**	**74**	**42**	**25**	**1**	**437**
Revenues from contracts with customers									
Timing of revenue recognition									
At a point in time	**6**	**1**	**—**	**—**	**7**	**—**	**—**	**—**	**14**
Over time	**72**	**—**	**45**	**22**	**56**	**39**	**—**	**—**	**234**
Total revenue from contracts with customers	**78**	**1**	**45**	**22**	**63**	**39**	**—**	**—**	**248**

(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. Refer to Note 3(C) for further details.
(2) Total rental income, including contingent rent related to certain PPAs and other long-term contracts that meet the criteria of operating leases.
(3) Includes merchant revenue and other miscellaneous.

3 months ended June 30, 2019	Canadian Coal	US Coal	North American Gas[(1)]	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues from contracts with customers	89	2	50	22	57	42	—	—	262
Revenue from leases[(2)]	16	—	—	17	—	—	—	—	33
Revenue from derivatives	(19)	73	(3)	—	11	—	26	2	90
Government incentives	—	—	—	—	2	—	—	—	2
Revenue from other[(3)]	89	11	—	1	2	7	—	—	110
Total revenue	175	86	47	40	72	49	26	2	497
Revenues from contracts with customers									
Timing of revenue recognition									
At a point in time	15	2	—	—	9	—	—	—	26
Over time	74	—	50	22	48	42	—	—	236
Total revenue from contracts with customers	89	2	50	22	57	42	—	—	262

(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. Refer to Note 3(C) for further details.
(2) Total rental income, including contingent rent related to certain PPAs and other long-term contracts that meet the criteria of operating leases.
(3) Includes merchant revenue and other miscellaneous.

6 months ended June 30, 2020	**Canadian Coal**	**US Coal**	**North American Gas**[1]	**Australian Gas**	**Wind and Solar**	**Hydro**	**Energy Marketing**	**Corporate**	**Total**
Revenues from contracts with customers	**155**	**5**	**95**	**43**	**134**	**75**	**—**	**—**	**507**
Revenue from leases[2]	**27**	**—**	**—**	**31**	**—**	**—**	**—**	**—**	**58**
Revenue from derivatives	**22**	**166**	**1**	**—**	**5**	**—**	**53**	**3**	**250**
Government incentives	**—**	**—**	**—**	**—**	**3**	**—**	**—**	**—**	**3**
Revenue from other[3]	**142**	**39**	**3**	**4**	**37**	**5**	**—**	**(5)**	**225**
Total revenue	**346**	**210**	**99**	**78**	**179**	**80**	**53**	**(2)**	**1,043**
Revenues from contracts with customers									
Timing of revenue recognition									
At a point in time	**11**	**5**	**—**	**—**	**11**	**—**	**—**	**—**	**27**
Over time	**144**	**—**	**95**	**43**	**123**	**75**	**—**	**—**	**480**
Total revenue from contracts with customers	**155**	**5**	**95**	**43**	**134**	**75**	**—**	**—**	**507**

(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. Refer to Note 3(C) for further details.
(2) Total rental income, including contingent rent related to certain PPAs and other long-term contracts that meet the criteria of operating leases.
(3) Includes merchant revenue and other miscellaneous.

6 months ended June 30, 2019	Canadian Coal	US Coal	North American Gas[1]	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues from contracts with customers	196	4	109	44	132	77	—	—	562
Revenue from leases[2]	32	—	—	34	—	—	—	—	66
Revenue from derivatives	(52)	35	2	—	13	—	72	2	72
Government incentives	—	—	—	—	4	—	—	—	4
Revenue from other[3]	224	193	1	3	12	9	—	(1)	441
Total revenue	400	232	112	81	161	86	72	1	1,145
Revenues from contracts with customers									
Timing of revenue recognition									
At a point in time	23	4	—	—	15	—	—	—	42
Over time	173	—	109	44	117	77	—	—	520
Total revenue from contracts with customers	196	4	109	44	132	77	—	—	562

(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. Refer to Note 3(C) for further details.
(2) Total rental income, including contingent rent related to certain PPAs and other long-term contracts that meet the criteria of operating leases.
(3) Includes merchant revenue and other miscellaneous.

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 June 30				6 months ended June 30			
	2020		2019		**2020**		2019	
	Fuel and purchased power	**OM&A**	Fuel and purchased power	OM&A	**Fuel and purchased power**	**OM&A**	Fuel and purchased power	OM&A
Fuel	**88**	**—**	105	—	**247**	**—**	319	—
Purchased power	**25**	**—**	23	—	**64**	**—**	127	—
Mine depreciation	**25**	**—**	30	—	**53**	**—**	59	—
Salaries and benefits	**13**	**54**	19	60	**25**	**121**	38	109
Other operating expenses	**—**	**58**	—	70	**—**	**119**	—	125
Total	**151**	**112**	177	130	**389**	**240**	543	234

6. Net Interest Expense

The components of net interest expense are as follows:

	3 months ended June 30		6 months ended June 30	
	2020	2019	**2020**	2019
Interest on debt	**39**	42	**82**	83
Interest on exchangeable securities	**8**	5	**15**	5
Interest income	**(2)**	(3)	**(5)**	(5)
Capitalized interest	**(1)**	(1)	**(2)**	(2)
Interest on finance lease obligations	**2**	1	**4**	2
Credit facility fees, bank charges and other interest	**5**	4	**9**	7
Other	**—**	2	**1**	4
Accretion of provisions	**6**	6	**15**	12
Net interest expense	**57**	56	**119**	106

7. Income Taxes

The components of income tax expense are as follows:

	3 months ended June 30		6 months ended June 30	
	2020	2019	**2020**	2019
Current income tax expense	**12**	7	**21**	14
Deferred income tax recovery related to the origination and reversal of temporary differences	**(14)**	(10)	**(24)**	(19)
Deferred income tax recovery resulting from changes in tax rates or laws	**—**	(40)	**—**	(40)
Deferred income tax expense (recovery) arising from the writedown (reversal of previous writedowns) of deferred income tax assets[1]	**(15)**	(7)	**(12)**	12
Income tax recovery	**(17)**	(50)	**(15)**	(33)

	3 months ended June 30		6 months ended June 30	
	2020	2019	**2020**	2019
Current income tax expense	**12**	7	**21**	14
Deferred income tax recovery	**(29)**	(57)	**(36)**	(47)
Income tax recovery	**(17)**	(50)	**(15)**	(33)

(1) During the three and six months ended June 30, 2020, the Corporation recorded a reversal of a previous write-down of deferred tax assets of $15 million and $12 million, respectively (June 30, 2019 - reversed a previous writedown of $7 million and recorded a $12 million writedown, respectively). 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. Recognized ordinary income and other comprehensive income has given rise to taxable temporary differences, which forms the primary basis for utilization of some of the tax losses and the reversal of the write-down.

8. 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.

The Corporation's share of ownership and equity participation in TransAlta Renewables has changed as follows:

Period[1]	**Percentage**
Jan. 1, 2019 to March 31, 2019	60.8
Apr. 1, 2019 to June 30, 2019	60.6
July 1, 2019 to Sept. 30, 2019	60.5
Oct. 1, 2019 to Dec. 31, 2019	60.4
Jan. 1, 2020 to March 31, 2020	60.3
Apr. 1, 2020 to June 30, 2020	60.2

(1) Changes in these periods are a result of TransAlta Renewables' Dividend Reinvestment Plan ("DRIP"), which allows investors to reinvest their dividends into common shares. As a result of the DRIP, the ownership percentage changes every month. The Corporation does not participate in the DRIP.

	3 months ended June 30		6 months ended June 30, 2020	
	2020	2019	**2020**	2019
Net earnings				
TransAlta Cogeneration L.P.	**2**	5	**5**	9
TransAlta Renewables	**13**	11	**17**	42
	15	16	**22**	51
Total comprehensive income				
TransAlta Cogeneration L.P.	**2**	5	**5**	9
TransAlta Renewables	**(15)**	(25)	**7**	7
	(13)	(20)	**12**	16
Cash distributions paid to non-controlling interests				
TransAlta Cogeneration L.P.	**3**	6	**4**	21
TransAlta Renewables	**20**	18	**38**	35
	23	24	**42**	56

As at	**June 30, 2020**	Dec. 31, 2019
Equity attributable to non-controlling interests		
TransAlta Cogeneration L.P.	**162**	160
TransAlta Renewables	**906**	941
	1,068	1,101
Non-controlling interests share (per cent)		
TransAlta Cogeneration L.P.	**49.99**	49.99
TransAlta Renewables	**39.8**	39.6

9. Financial Instruments

A. Financial Assets and Liabilities – Measurement

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

B. Fair Value of Financial Instruments

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

The Level I, II, and III classifications in the fair value hierarchy utilized by the 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 14 of the 2019 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 volatilities and correlations, delivery volumes and shapes.

As at			**June 30, 2020**			
Description	**Base fair value**	**Sensitivity**	**Valuation technique**	**Unobservable input**	**Range**	**Reasonable possible change**
Long-term power sale – US	**776**	+45 -134	Long-term price forecast	Illiquid future power prices (per MWh)	US$22 to US$25	Price decrease of US$3 or price increase of US$9
Structured products - Eastern US	**4**	+1 -1	Option valuation techniques, historical bootstrap and historical price regression analysis	Basis relationship	57% to 103%	5.0% to 6.0%
				Non-standard shape factors	63% to 116%	2.0% to 11.0%
Full requirements – Eastern US	**19**	+6 -6	Historical bootstrap	Volume		(+/-) 5%
				Cost of supply		(+/-) US$1.00 per MWh
Long-term wind energy sale – Eastern US	**(29)**	+24 -24	Long-term price forecast	Illiquid future power prices (per MWh)	US$36 to US$54	US$6
				Illiquid future REC prices (per unit)	US$10	US$1
Others	**(1)**	+5 -5				

As at			Dec. 31, 2019			
Description	Base fair value	Sensitivity	Valuation technique	Unobservable input	Range	Reasonable possible change
Long-term power sale – US	737	+46 -139	Long-term price forecast	Illiquid future power prices (per MWh)	US$20 to US$28	Price decrease of US$3 or a price increase of US$9
Structured products - Eastern US	7	+2 -2	Option valuation techniques, historical bootstrap and historical price regression analysis	Basis relationship	91% to 112%	4.0% to 6.0%
				Non-standard shape factors	63% to 116%	4.0% to 10.0%
Full requirements – Eastern US	10	+3 -3	Historical bootstrap	Volume		(+/-) 5%
				Cost of supply		(+/-) US$1 per MWh
Long-term wind energy sale – Eastern US	(28)	+20 -20	Long-term price forecast	Illiquid future power prices (per MWh)	US$38 to US$60	US$6
				Illiquid future REC prices (per unit)	US$9	US$1
Others[1]	(6)	+8 -8				

(1) The Corporation has entered into fewer unit contingent power purchases and it is no longer material to separately disclose and these are now included in the 'Others' category. Accordingly, the Dec. 31, 2019 amounts have been reclassified for consistency.

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 strengthening of the US dollar relative to the Canadian dollar from Dec. 31, 2019 to June 30, 2020, the base fair value and the sensitivity values have increased by approximately $35 million and $6 million, respectively.

ii. Structured Products – Eastern US

The Corporation has fixed priced power in the eastern United States, where the Corporation has agreed to buy or sell power at non-liquid locations or during non-standard hours.

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 project, 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 FVTPL.

II. Commodity Risk Management Assets and Liabilities

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

Commodity risk management assets and liabilities classified by fair value levels as at June 30, 2020, are as follows: Level I - $1 million net liability (Dec. 31, 2019 – $3 million net liability), Level II – $27 million net asset (Dec. 31, 2019 – $9 million net asset) and Level III – $759 million net asset (Dec. 31, 2019 – $686 million net asset).

Significant changes in commodity net risk management assets and liabilities during the six months ended June 30, 2020, are primarily attributable to changes in market prices and foreign exchange rates, partially offset by 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 six months ended June 30, 2020 and 2019, respectively:

	6 months ended June 30, 2020			6 months ended June 30, 2019		
	Hedge	**Non-hedge**	**Total**	Hedge	Non-hedge	Total
Opening balance	**678**	**8**	**686**	689	6	695
Changes attributable to:						
Market price changes on existing contracts	**65**	**18**	**83**	17	—	17
Market price changes on new contracts	**—**	**4**	**4**	—	10	10
Contracts settled	**(42)**	**(5)**	**(47)**	(27)	(7)	(34)
Change in foreign exchange rates	**34**	**(1)**	**33**	(31)	(1)	(32)
Net risk management assets, end of period	**735**	**24**	**759**	648	8	656
Additional Level III information:						
Gains (losses) recognized in other comprehensive income	**99**	**—**	**99**	(14)	—	(14)
Total gains included in earnings before income taxes	**42**	**21**	**63**	27	9	36
Unrealized gains included in earnings before income taxes relating to net assets held at period end	**—**	**16**	**16**	—	2	2

III. Other Risk Management Assets and Liabilities

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

Other risk management assets and liabilities with a total net liability fair value of $11 million as at June 30, 2020 (Dec. 31, 2019 – $4 million net asset) are classified as Level II fair value measurements. The significant changes in other net risk management assets during the six months ended June 30, 2020, are primarily attributable to unfavorable foreign exchange rates and new contracts.

IV. Other Financial Assets and Liabilities

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

	Fair value[1]				Total carrying
	Level I	Level II	Level III	Total	value[1]
Exchangeable securities - June 30, 2020	**—**	**320**	**—**	**320**	**328**
Long-term debt - June 30, 2020	**—**	**3,137**	**—**	**3,137**	**2,966**
Exchangeable securities - Dec. 31, 2019	—	342	—	342	326
Long-term debt - Dec. 31, 2019	—	3,157	—	3,157	3,070

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

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. The fair values of these derivatives are determined using inputs that are not readily observable. Refer to section B of this Note 9 above for fair value Level III valuation techniques used. In some instances, a difference may arise between the fair value of a financial instrument at initial recognition (the "transaction price") and the amount calculated through a valuation model. This unrealized gain or loss at inception is recognized in net earnings (loss) only if the fair value of the instrument is evidenced by a quoted market price in an active market, observable current market transactions that are substantially the same, or a valuation technique that uses observable market inputs. Where these criteria are not met, the difference is deferred on the 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:

	6 months ended June 30	
	2020	2019
Unamortized net gain at beginning of period	**9**	49
New inception gains (losses)	**4**	—
Change in foreign exchange rates	**(1)**	—
Amortization recorded in net earnings during the period	**(25)**	(32)
Unamortized net gain (loss) at end of period	**(13)**	17

10. 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 15 of the 2019 Audited Annual Consolidated Financial Statements.

A. Net Risk Management Assets and Liabilities

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

As at June 30, 2020

	Cash flow hedges	Not designated as a hedge	Total
Commodity risk management			
Current	127	42	169
Long-term	607	9	616
Net commodity risk management assets	734	51	785
Other			
Current	2	(5)	(3)
Long-term	(10)	2	(8)
Net other risk management assets	(8)	(3)	(11)
Total net risk management assets	726	48	774

As at Dec. 31, 2019

	Cash flow hedges	Not designated as a hedge	Total
Commodity risk management			
Current	70	15	85
Long-term	606	1	607
Net commodity risk management assets	676	16	692
Other			
Current	—	—	—
Long-term	—	4	4
Net other risk management assets	—	4	4
Total net risk management assets	676	20	696

B. Nature and Extent of Risks Arising from Financial Instruments

I. Market Risk

a. 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 June 30, 2020, associated with the Corporation's proprietary trading activities was $2 million (Dec. 31, 2019 - $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 June 30, 2020, associated with the Corporation's commodity derivative instruments used in generation hedging activities was $8 million (Dec. 31, 2019 - $25 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 June 30, 2020, associated with these transactions was $5 million (Dec. 31, 2019 - $8 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 June 30, 2020:

	Investment grade *(Per cent)*	Non-investment grade *(Per cent)*	Total *(Per cent)*	Total amount
Trade and other receivables[1]	83	17	**100**	**428**
Long-term finance lease receivable	100	—	**100**	**168**
Risk management assets[1]	97	3	**100**	**939**
Loan receivable[2]	—	100	**100**	**50**
Total				**1,585**

(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 June 30, 2020, was $20 million (Dec. 31, 2019 - $5 million).

Amidst the current economic conditions resulting from the COVID-19 pandemic, TransAlta has implemented the following additional measures to monitor its counterparties for changes in their ability to meet obligations:

- daily monitoring of events impacting counterparty creditworthiness and counterparty credit downgrades;
- weekly oversight and follow-up, if applicable, of accounts receivables; and
- review and monitoring of key suppliers, counterparties and customers (i.e. off-takers).

As needed, additional risk mitigation tactics will be taken to reduce the risk to TransAlta. These risk mitigation tactics may include, but are not limited to, immediate follow-up on overdue amounts, adjusting payment terms to ensure a portion of funds are received sooner, requiring additional collateral, reducing transaction terms and working closely with impacted counterparties on negotiated solutions.

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 the upcoming debt maturity which is due November 2020. 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:

	2020	2021	2022	2023	2024	2025 and thereafter	Total
Accounts payable and accrued liabilities	401	—	—	—	—	—	401
Long-term debt[1]	447	99	651	263	106	1,432	2,998
Exchangeable securities[2]	—	—	—	—	—	350	350
Commodity risk management assets	(101)	(120)	(130)	(152)	(157)	(125)	(785)
Other risk management (assets) liabilities	1	16	(10)	5	—	(1)	11
Lease obligations	4	4	7	5	5	122	147
Interest on long-term debt and lease obligations[3]	138	134	126	98	92	710	1,298
Interest on exchangeable securities[2,3]	12	25	25	24	24	—	110
Dividends payable	38	—	—	—	—	—	38
Total	**940**	**158**	**669**	**243**	**70**	**2,488**	**4,568**

(1) Excludes impact of hedge accounting.
(2) Assumes the debentures will be exchanged on Jan. 1, 2025. Refer to Note 14 for further details.
(3) Not recognized as a financial liability on the Consolidated Statements of Financial Position.

IV. Interest Rate Risk

During the first quarter of 2020, the Corporation entered into interest rate derivatives with notional amounts of US $150 million, AUD$150 million and CAD$75 million to hedge interest rate risks associated with forecasted debt issuances expected to occur between late 2020 and late 2022. The hedges have been designated as cash flow hedges. As a result of IBOR reform, the LIBOR is scheduled to be replaced with an alternative benchmark interest rate on Jan. 1, 2022. As a result, the Corporation is exposed to uncertainties about the amount of IBOR-based cash flows of the hedging items as some of the derivatives are based on LIBOR.

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 June 30, 2020, the Corporation had posted collateral of $128 million (Dec. 31, 2019 – $112 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 $85 million (Dec. 31, 2019 – $51 million) of collateral to its counterparties.

11. Inventory

Inventory held in the normal course of business, which includes coal, emission credits, parts and materials, and natural gas, is valued at the lower of cost and net realizable value. Inventory held for trading, which includes natural gas and emission credits and allowances, is valued at fair value less costs to sell.

The components of inventory are as follows:

	June 30, 2020	Dec. 31, 2019
Parts and materials	**114**	108
Coal[(1)]	**152**	130
Deferred stripping costs	**10**	6
Natural gas	**2**	3
Purchased emission credits	**19**	4
Total	**297**	251

(1) Coal inventory increased mainly at Centralia as the units were on reserve shutdown due to dispatch optimization where low priced power purchases are used to fulfill contractual obligations.

12. Property, Plant and Equipment

During the three and six months ended June 30, 2020, the Corporation had additions of $75 million and $147 million, respectively. The year-to-date additions mainly relate to assets under construction for the coal-to-gas conversions, the Windrise wind facility, the Kaybob cogeneration facility, land and planned major maintenance expenditures.

During the three and six months ended June 30, 2019, the Corporation had additions of $110 million and $144 million, respectively, primarily related to the construction of the Big Level and Antrim wind facilities and other sustaining capital expenditures. In addition, during the six months ended June 30, 2019, the Corporation acquired property, plant and equipment related to the Antrim wind development project for $50 million and the Pioneer Pipeline for $83 million.

Depreciation expense increased mainly due to the Keephills 3 and Genesee 3 swap, the reversal of the impairment at Centralia and the changes in useful lives, all of which were effective in the second half of 2019. For further details on these changes, refer to Note 3(A)(IV) and Note 4(D) of the annual consolidated financial statements.

As at June 30, 2020, there was a substantial decrease in the decommissioning provision, which decreased the related assets included in property, plant and equipment by $41 million. Refer to Note 1(B) for further details.

13. Credit Facilities, Long-Term Debt and Lease Obligations

The amounts outstanding are as follows:

As at	June 30, 2020			Dec. 31, 2019		
	Carrying value	**Face value**	**Interest[1]**	Carrying value	Face value	Interest[1]
Credit facilities[2]	**111**	**111**	**1.7%**	220	220	3.5%
Debentures	**648**	**651**	**5.8%**	647	651	5.8%
Senior notes[3]	**949**	**958**	**5.4%**	905	914	5.4%
Non-recourse	**1,105**	**1,117**	**4.4%**	1,144	1,157	4.3%
Other[4]	**153**	**161**	**7.1%**	154	162	7.1%
	2,966	**2,998**		3,070	3,104	
Finance lease obligations	**147**			142		
	3,113			3,212		
Less: current portion of long-term debt	**(496)**			(494)		
Less: current portion of finance lease obligations	**(17)**			(19)		
Total current long-term debt and finance lease obligations	**(513)**			(513)		
Total credit facilities, long-term debt and finance lease obligations	**2,600**			2,699		

(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 June 30, 2020 - US$0.7 billion (Dec. 31, 2019 - US$0.7 billion).
(4) Includes US$112 million at June 30, 2020 (Dec. 31, 2019 - US$117 million) of tax equity financing.

As at June 30, 2020, the Corporation was in compliance with all debt covenants.

The strengthening of the US dollar has increased our US-denominated long-term debt balances, mainly the senior notes and tax equity financing, by $50 million as at June 30, 2020. Almost all our US-denominated debt is hedged either through financial contracts or net investments in our US operations. During the period, these changes in our US-denominated debt were offset as follows:

	June 30, 2020
Effects of foreign exchange on carrying amounts of US operations (net investment hedge)	**23**
Foreign currency economic cash flow hedges on debt	**9**
Economic hedges and other	**11**
Unhedged	**7**
Total	**50**

14. Exchangeable Securities

A. $350 Million Unsecured Subordinated Debentures

As at	June 30, 2020			Dec. 31, 2019		
	Carrying value	**Face value**	**Interest**	Carrying value	Face value	Interest
Exchangeable debentures – due May 1, 2039	**328**	**350**	**7%**	326	350	7%

B. Option to Exchange

As at	June 30, 2020		Dec. 31, 2019	
Description	**Base fair value**	**Sensitivity**	Base fair value	Sensitivity
Option to exchange – embedded derivative	**—**	**+32 -25**	—	+35 -27

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.

15. Common Shares

A. Issued and Outstanding

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

	6 months ended June 30			
	2020		2019	
	Common shares *(millions)*	**Amount**	Common shares *(millions)*	Amount
Issued and outstanding, beginning of period	**277.0**	**2,978**	284.6	3,059
Effect of share-based payment plans	**—**	**(4)**	—	—
Shares purchased and retired under NCIB	**(2.8)**	**(30)**	(2.4)	(26)
Stock options exercised	**—**	**—**	0.1	1
Issued and outstanding, end of period	**274.2**	**2,944**	282.3	3,034

B. NCIB Program

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

The following are the effects of the Corporation's purchase and cancellation of the common shares during the six months ended:

	June 30, 2020	June 30, 2019
Total shares purchased	**2,849,400**	2,398,200
Average purchase price per share	**$ 7.51**	$ 8.57
Total cost	**21**	21
Weighted average book value of shares cancelled	**30**	26
Amount recorded in deficit	**9**	5

C. Dividends

On April 20, 2020, the Corporation declared a quarterly dividend of $0.0425 per common share, payable on July 1, 2020. On July 22, 2020, the Corporation declared a quarterly dividend of $0.0425 per common share, payable on Oct. 1, 2020.

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

D. Stock Options

On March 3, 2020, the Board approved an increase in the number of common shares reserved for issuance under the Corporation's Stock Option Plan (the "Option Plan") to 16,500,000. Shareholder approval was received on April 21, 2020 and TSX approval was received on May 21, 2020. TransAlta last increased the share reserve in 2011 to 13,000,000 shares and has increased the number of common shares available under the Option Plan by 3,500,000 shares to continue to have sufficient shares available to grant options to eligible participants as part of the Corporation's overall compensation framework.

The stock options granted to executive officers of the Corporation during the six months ended June 30, 2020 and 2019 are as follows:

Grant month	Number of stock options granted *(millions)*	Exercise price	Vesting period *(years)*	Expiration length *(years)*
January 2020	0.7	$ 9.28	3	7
January 2019[(1)]	1.2	$ 5.59	3	7

(1) Certain stock options were forfeited when an executive officer left the Corporation.

16. Preferred Shares

A. Dividends

The following table summarizes the value of preferred share dividends declared during the three and six months ended June 30, 2020 and 2019:

Series	Quarterly amounts per share	**3 months ended June 30**		6 months ended June 30	
		2020	2019	**2020**	2019[(1)]
A	0.16931	**1**	2	3	2
B[(2)]	0.228	**1**	—	1	—
C	0.25169	**3**	3	6	3
E	0.32463	**3**	3	6	3
G	0.31175	**2**	2	4	2
Total for the period		**10**	10	**20**	**10**

(1) No dividends were declared in the first quarter of 2019 as the quarterly dividend related to the period covering the first quarter of 2019 was declared in December 2018.
(2) Series B Preferred Shares pay quarterly dividends at a floating rate based on the 90-day Government of Canada Treasury Bill rate, plus 2.03 per cent.

On July 22, 2020 the Corporation declared a quarterly dividend of $0.16931 per share on the Series A preferred shares, $0.14359 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 Sept. 30, 2020.

17. Commitments and Contingencies

A. Commitments

In addition to the commitments disclosed elsewhere in the financial statements and those disclosed in the 2019 annual audited financial statements, during 2020, the Corporation has incurred the following additional contractual commitments, either directly or through its interests in joint operations. Approximate future payments under these agreements are as follows:

	2020	2021	2022	2023	2024	2025 and thereafter	Total
Natural gas and transportation contracts	—	3	12	5	3	1	**24**
Transmission	—	3	5	5	5	7	**25**
Total	**—**	**6**	**17**	**10**	**8**	**8**	**49**

Natural Gas and Transportation Contracts
Includes the incremental change in fixed price or volume natural gas purchase and transportation contracts, as compared to the amounts disclosed in the 2019 annual audited consolidated financial statements. In addition to the commitments shown above, upon closing the sale of the Pioneer Pipeline, a 15-year transportation agreement will provide 275 TJ per day of natural gas on a firm basis by 2023, bringing the total firm natural gas transportation contracts to 400 TJ per day. This agreement would replace the Corporation's existing 15-year commitment to purchase 139 TJ per day of natural gas on the Pioneer Pipeline.

Transmission
Includes the incremental change in transmission agreements, as compared to the amounts disclosed in the 2019 annual audited consolidated financial statements.The Corporation has several agreements to purchase transmission network capacity in the Pacific Northwest. Provided certain conditions for delivering the service are met, the Corporation is committed to the transmission at the supplier’s tariff rate whether it is awarded immediately or delivered in the future after additional facilities are constructed.

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 35 of the Annual Audited Consolidated Financial Statements. The changes to these contingencies during the six months ended June 30, 2020 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 and issue a single invoice charging or crediting market participants for the difference in losses charges. A decision by the AUC determined the methodology to be used retroactively, which made it possible for the Corporation to estimate the total retroactive potential exposure faced by the Corporation for its non-PPA power generation. The single invoice for the historical adjustments was expected to be issued in April 2021, with cash settlement expected in June 2021. The previous provision, which was based on known data, was approximately $12 million.

The AESO requested the AUC approve a pay-as-you-go settlement, instead of issuing a single invoice, which request the Corporation challenged. This form of settlement would permit the AESO to issue an invoice for each historical year as the line loss factors are recalculated, advancing some charges into 2020. Based on the recently published AESO loss factors for the period of 2014 to 2016, using the AUC approved methodology, the provision has increased to $20 million mainly due to higher loss factors for Keephills 3 and Poplar Creek.

The AUC recently ruled on the AESO’s request and approved an invoice settlement process that will be broken down into three periods (2014 to 2016, 2010 to 2013 and 2006 to 2009) with the first invoice for line losses issued in 2020. The first invoice, which will be payable in 2020, is estimated to be approximately $6 million, with the other two invoices payable in 2021. It is important to note that the estimated amounts continue to be uncertain and the AESO’s recalculated loss factors remain subject to further review and change. TransAlta will continue to participate in the proceeding and carefully review all calculations to help ensure that the invoices are accurate and reflect the decisions of the AUC.

II. FMG Disputes
The Corporation is currently engaged in two disputes with Fortescue Metals Group Ltd. ("FMG"). The first arose as a result of FMG’s purported termination of the South Hedland PPA. TransAlta sued FMG, seeking payment 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. This matter has been re-scheduled to proceed to trial beginning May 3, 2021, instead of June 15, 2020, but it may be delayed further, depending on the extent of continued restrictions arising from the COVID-19 pandemic.

The second dispute involves FMG’s claims against TransAlta related to the transfer of the Solomon facility to FMG. FMG claims certain amounts related to the condition of the facility while TransAlta claims certain outstanding costs that should be reimbursed. A trial date for this matter has not yet been scheduled but it will not occur until 2021 at the earliest.

III. 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 is seeking to set aside the 2019 Brookfield transaction. TransAlta believes the claim is wholly lacking in merit and is taking all steps to defend against the allegations. This matter has been rescheduled and the two week trial will begin on April 19, 2021, instead of September 2020, but it may be delayed further, depending on the extent of restrictions arising from the COVID-19 pandemic.

IV. Keephills 1 Stator Force Majeure

The Balancing Pool and ENMAX Energy Corporation ("ENMAX") are seeking to set aside an arbitration award on the basis that they did not receive a fair hearing. The Alberta Court of Queen's Bench ("ABQB") dismissed the Balancing Pool and ENMAX's allegations of unfairness on June 26, 2019. The Balancing Pool and ENMAX, however, sought leave to appeal the ABQB's decision at the Court of Appeal, which was granted on Feb. 13, 2020. The appeal is scheduled to be heard on April 8, 2021. TransAlta believes that the Court of Appeal will affirm the ABQB decision that the arbitration proceeding was not unfair.

18. Segment Disclosures

A. Reported Segment Earnings (Loss)

3 months ended June 30, 2020	Canadian Coal	US Coal	North American Gas[(1)]	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues	140	68	48	39	74	42	25	1	437
Fuel, carbon compliance and purchased power	111	17	14	2	4	2	—	1	151
Gross margin	29	51	34	37	70	40	25	—	286
Operations, maintenance, and administration	33	15	12	9	13	10	6	14	112
Depreciation and amortization	68	25	10	12	34	7	1	6	163
Asset impairment	2	30	—	—	—	—	—	—	32
Taxes, other than income taxes	3	2	—	—	2	1	—	—	8
Net other operating income	(10)	—	—	—	—	—	—	—	(10)
Operating income (loss)	(67)	(21)	12	16	21	22	18	(20)	(19)
Finance lease income	—	—	1	—	—	—	—	—	1
Net interest expense									(57)
Foreign exchange gain									23
Gain on sale of assets									—
Loss before income taxes									(52)

(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. Refer to Note 3(C) for further details.

3 months ended June 30, 2019	Canadian Coal	US Coal	North American Gas[(1)]	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues	175	86	47	40	72	49	26	2	497
Fuel, carbon compliance and purchased power	122	34	12	2	3	2	—	2	177
Gross margin	53	52	35	38	69	47	26	—	320
Operations, maintenance, and administration	35	18	11	8	13	10	8	27	130
Depreciation and amortization	58	18	10	14	29	7	—	7	143
Taxes, other than income taxes	4	1	1	—	2	—	—	—	8
Net other operating (income) loss	(10)	—	—	—	(4)	—	—	2	(12)
Operating income (loss)	(34)	15	13	16	29	30	18	(36)	51
Finance lease income	—	—	1	—	—	—	—	—	1
Net interest expense									(56)
Foreign exchange loss									(8)
Other losses									(12)
Loss before income taxes									(24)

(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. Refer to Note 3(C) for further details.

6 months ended June 30, 2020	**Canadian Coal**	**US Coal**	**North American Gas[(1)]**	**Australian Gas**	**Wind and Solar**	**Hydro**	**Energy Marketing**	**Corporate**	**Total**
Revenues	**346**	**210**	**99**	**78**	**179**	**80**	**53**	**(2)**	**1,043**
Fuel, carbon compliance and purchased power	**260**	**85**	**28**	**5**	**9**	**4**	**—**	**(2)**	**389**
Gross margin	**86**	**125**	**71**	**73**	**170**	**76**	**53**	**—**	**654**
Operations, maintenance, and administration	**66**	**31**	**24**	**16**	**26**	**19**	**15**	**43**	**240**
Depreciation and amortization	**135**	**47**	**21**	**23**	**67**	**13**	**1**	**12**	**319**
Asset impairment reversal	**(2)**	**(7)**	**—**	**—**	**—**	**—**	**—**	**—**	**(9)**
Taxes, other than income taxes	**7**	**3**	**1**	**—**	**4**	**2**	**—**	**—**	**17**
Net other operating income	**(20)**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**(20)**
Operating income (loss)	**(100)**	**51**	**25**	**34**	**73**	**42**	**37**	**(55)**	**107**
Finance lease income	**—**	**—**	**2**	**—**	**—**	**—**	**—**	**—**	**2**
Net interest expense									**(119)**
Foreign exchange gain									**4**
Loss before income taxes									**(6)**

(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. Refer to Note 3(C) for further details.

6 months ended June 30, 2019	Canadian Coal	US Coal	North American Gas[1]	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues	400	232	112	81	161	86	72	1	1,145
Fuel, carbon compliance and purchased power	297	188	43	4	7	3	—	1	543
Gross margin	103	44	69	77	154	83	72	—	602
Operations, maintenance, and administration	68	32	22	18	25	18	17	34	234
Depreciation and amortization	119	36	20	25	58	15	1	14	288
Taxes, other than income taxes	7	2	1	—	4	1	—	—	15
Net other operating (income) loss	(20)	—	—	—	(4)	—	—	2	(22)
Operating income (loss)	(71)	(26)	26	34	71	49	54	(50)	87
Finance lease income	—	—	3	—	—	—	—	—	3
Net interest expense									(106)
Foreign exchange loss									(9)
Other losses									(12)
Loss before income taxes									(37)

(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. Refer to Note 3(C) for further details.

IV. Depreciation and Amortization on the Consolidated Statements of Cash Flows

The reconciliation between depreciation and amortization reported on the Consolidated Statements of Earnings (Loss) and the Consolidated Statements of Cash Flows is presented below:

	3 months ended June 30		6 months ended June 30	
	2020	2019	**2020**	2019
Depreciation and amortization expense on the Consolidated Statements of Earnings (Loss)	**163**	143	**319**	288
Depreciation included in fuel, carbon compliance and purchased power (Note 5)	**25**	30	**53**	59
Depreciation and amortization on the Consolidated Statements of Cash Flows	**188**	173	**372**	347

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 June 30, 2020:

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

1.7 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.

Supplemental Information

		June 30, 2020	Dec. 31, 2019
Closing market price (TSX) ($)		**8.05**	9.28
Price range for the last 12 months (TSX) ($)	High	**11.23**	10.14
	Low	**5.32**	5.50
FFO before interest to adjusted interest coverage(2)(times)		**4.4**	4.5
Adjusted FFO to adjusted net debt(2)(%)		**18.9**	19.0
Adjusted net debt to adjusted comparable EBITDA(1,2) (times)		**3.9**	3.9
Deconsolidated net debt to deconsolidated comparable EBITDA (1,2) (times)		**4.5**	4.2
Adjusted net debt to total capital(1) (%)		**50.8**	49.9
Return on equity attributable to common shareholders(2)(%)		**5.7**	3.3
Return on capital employed(2)(%)		**5.5**	4.3
Earnings coverage(2)(times)		**1.7**	1.5
Dividend payout ratio based on FFO(1, 2)(%)		**6.5**	6.6
Dividend coverage(2)(times)		**18.6**	18.6
Dividend yield(2)(%)		**2.0**	1.7

(1) These ratios incorporate items that are not defined under IFRS. None of these measurements should be used in isolation or as a substitute for the Corporation's reported financial performance or position as presented in accordance with IFRS. These ratios are useful complementary measurements for assessing the Corporation's financial performance, efficiency, and liquidity and are common in the reports of other companies but may differ by definition and application. For a reconciliation of the non-IFRS measures used in these calculations, refer to the Discussion of Financial Results section of this MD&A.
(2) Last 12 months.

Ratio Formulas

FFO before interest to adjusted interest coverage = FFO + interest on debt and lease obligations - interest income - capitalized interest / interest on debt and lease obligations + 50 per cent dividends paid on preferred shares - interest income

Adjusted FFO to adjusted net debt = FFO - 50 per cent dividends paid on preferred shares / period end long-term debt, lease obligations and exchangeable securities including current portion and fair value (asset) liability of hedging instruments on debt + 50 per cent issued preferred shares - cash and cash equivalents - principal portion of TransAlta OCP restricted cash

Adjusted net debt to comparable EBITDA = long-term debt, lease obligations and exchangeable securities including current portion and fair value (asset) liability of hedging instruments on debt + 50 per cent issued preferred shares - cash and cash equivalents - principal portion of TransAlta OCP restricted cash / comparable EBITDA

Deconsolidated net debt to deconsolidated comparable EBITDA = long-term debt, lease obligations and exchangeable securities including current portion and fair value (asset) liability of hedging instruments on debt + 50 per cent issued preferred shares - cash and cash equivalents - principal portion of TransAlta OCP restricted cash - TransAlta Renewables long-term debt and lease obligations including current portion - tax equity financing / comparable EBITDA - TransAlta Renewables comparable EBITDA - TA Cogen comparable EBITDA + dividends received from TransAlta Renewables + dividends received from TA Cogen

Adjusted net debt to total capital = long-term debt, lease obligations and exchangeable securities including current portion and fair value (asset) liability of hedging instruments on debt + 50 per cent issued preferred shares - cash and cash equivalents - principal portion of TransAlta OCP restricted cash / adjusted net debt + non-controlling interests + equity attributable to shareholders - 50 per cent issued preferred shares

Return on equity attributable to common shareholders = net earnings (loss) attributable to common shareholders / equity attributable to shareholders excluding AOCI - issued preferred shares

Return on capital employed = earnings (loss) before income taxes + net interest expense - net earnings (loss) attributable to non-controlling interests / invested capital excluding AOCI

Earnings coverage = net earnings (loss) attributable to shareholders + income taxes + net interest expense / interest on debt and lease obligations + 50 per cent dividends paid on preferred shares - interest income

Dividend payout ratio = dividends paid on common shares / FFO - 50 per cent dividends paid on preferred shares

Dividend coverage ratio based on comparable FFO = FFO - 50 per cent dividends paid on preferred shares/ dividends paid on common shares

Dividend yield = dividend paid per common share / current period's closing market price

Glossary of Key Terms

Alberta Hydro Assets
The Corporation's hydro assets located in Alberta consisting of the Barrier, Bearspaw, Cascade, Ghost, Horseshoe, Interlakes, Kananaskis, Pocaterra, Rundle, Spray, Three Sisters, Bighorn and Brazeau hydro generation facilities.

Alberta Power Purchase Arrangement (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.

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.

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

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

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.

Dispatch optimization
Purchasing power to fulfill contractual obligations, when economical.

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.

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.

Heat rate
A measure of conversion, expressed as Btu/MWh, of the amount of thermal energy required to generate electrical energy.

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.

Net maximum capacity
The maximum capacity or effective rating, modified for ambient limitations, that a generating unit or power plant can sustain over a specific period, less the capacity used to supply the demand of station service or auxiliary needs.

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

PPA Termination Payments
The Balancing Pool terminated the Sundance B and C Power Purchase Arrangements and as a result paid TransAlta $157 million in the first quarter of 2018 as well as an additional $56 million (plus GST and interest) on winning the arbitration against the Balancing Pool in the third quarter of 2019. Refer to the Significant and Subsequent Events section for further details.

Renewable power
Power generated from renewable terrestrial mechanisms including wind, geothermal, solar and biomass with regeneration.

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.

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