TRANSALTA CORPORATION

Third 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 nine months ended Sept. 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 Sept. 30, 2020. All tabular amounts in the following discussion are in millions of Canadian dollars unless otherwise noted. This MD&A is dated Nov. 3, 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: our conversions to gas, including the completion of the conversion of Sundance Unit 6 in mid-November 2020, the conversion of Keephills Unit 2 and Unit 3 in 2021, and the repowering of Sundance Unit 5 into a combined cycle unit in the fourth quarter of 2023; the remaining spend of the boiler conversions and the Sundance Unit 5 repowering; the maximum capability of Keephills Unit 1 and Sundance Unit 4 following the discontinuance of coal generation; the shutting down of the Highvale Mine and eliminating coal as a fuel source in Alberta; expected increases to our cost per tonne of coal; development and construction of renewable energy and carbon emission reduction initiatives with BHP Billiton Nickel West Pty Ltd; the sale of the Pioneer Pipeline to ATCO, including receipt of regulatory approvals and closing to occur during the second quarter of 2021; integration of the Pioneer Pipeline into the NGTL (as defined below) and ATCO integrated natural gas transmission systems; the growth of the renewables fleet, including the Windrise Wind Project and Skookumchuck Wind Project, including the timing of commercial operations and total estimated spend; expansion of the on-site generation and cogeneration business, including achieving commercial operations of the Kaybob Cogeneration Project in the first half of 2022, the total project spend and receiving all necessary regulatory approvals; the 2020 financial outlook, including comparable EBITDA, free cash flow and annualized dividend in 2020; sustaining and productivity capital in 2020, including routine capital, planned major maintenance and mine capital; significant planned major outages for the remainder of 2020; lost production due to planned major maintenance for the remainder of 2020; expected power prices in Alberta, Ontario and the Pacific Northwest; the cyclicality of the business, including as it relates to maintenance costs, production and loads; utilizing existing cash and credit facilities to repay the debt maturing in 2020 and refinancing the debt maturing in 2022; the total outstanding amount for the AESO transmission line loss rule proceeding; and the Corporation continuing to maintain a strong financial position and significant liquidity.

The forward-looking statements contained in this MD&A are based on many assumptions including, but not limited to, the following: the impacts arising from COVID-19 not becoming significantly more onerous on the Corporation, which includes the Corporation being able to continue to operate as an essential service; no significant changes to applicable laws and regulations, 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; no material changes to the carbon compliance costs and performance factors; the Corporation's proportionate ownership of TransAlta Renewables Inc. ("TransAlta Renewables") not changing materially; no decline in the dividends to be received from TransAlta Renewables; the expected life extension of the Alberta Thermal fleet and anticipated financial results generated on conversion or repowering; the growth of TransAlta Renewables; successfully defending against the claims alleged by Mangrove; 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, which cannot currently be predicted, and which present risks including, but not limited to: more restrictive directives of government and public health authorities; reduced labour availability and ability to continue to staff our operations and facilities; disruptions to our supply chains, including our ability to secure necessary equipment and to obtain regulatory approvals on the expected timelines or at all; COVID-19 related force majeure claims; restricted access to capital and increased borrowing costs; a further decrease in short-term and/or long-term electricity demand and lower merchant pricing in Alberta and Mid-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; a higher rate of losses on our accounts receivable due to credit defaults; impairments and/or write-downs of assets; and adverse impacts on our information technology systems and our internal control systems, including increased cyber security threats. The forward-looking statements are also subject to other risk factors that include, but are not limited to: fluctuations in market prices; changes in demand for electricity and capacity and our ability to contract our generation for prices that will provide expected returns and replace contracts as they expire; changes to the legislative, regulatory and political environments in the jurisdictions in which we operate; environmental requirements and changes in, or liabilities under, these requirements; operational risks involving our facilities, including unplanned outages at such facilities; disruptions in the transmission and distribution of electricity; the effects of weather, including man made or natural disasters and other climate-change related risks; unexpected increases in cost structure; disruptions in the source of fuels, including natural gas required for the converted or repowered generating units, as well as the extent of water, solar or wind resources required to operate our facilities; failure to meet financial expectations; the threat of domestic terrorism; 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; industry risk and competition; fluctuations in the value of foreign currencies and foreign political risks; structural subordination of securities; counterparty credit risk; changes to our relationship with, or ownership of, TransAlta Renewables; 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, including regulatory approvals for the Kaybob cogeneration project and/or the ability to reach a commercial agreement with SemCAMS on alternative operational configurations; 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 the payment of future dividends, including from TransAlta Renewables; inadequacy or unavailability of insurance coverage; 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 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 purpose of the financial outlooks contained herein are to give the reader information about management's current expectations and plans and readers are cautioned that such information may not be appropriate for other purposes and is given as of the date of this presentation. The forward-looking statements included in this document are made only as of the date hereof and we do not undertake to publicly update these forward-looking statements to reflect new information, future events or otherwise, except as required by applicable laws. In light of these risks, uncertainties and assumptions, the forward-looking statements might occur to a different extent or at a different time than we have described, or might not occur at all. We cannot assure that projected results or events will be achieved.

Highlights

	3 months ended Sept. 30		9 months ended Sept. 30	
	2020	2019	**2020**	2019
Adjusted availability (%)	**90.7**	95.2	**91.4**	89.5
Production (GWh)	**6,184**	7,558	**17,276**	20,918
Revenues	**514**	593	**1,557**	1,738
Fuel, carbon compliance and purchased power	**252**	257	**641**	800
Operations, maintenance and administration	**114**	114	**354**	348
Net (loss) earnings attributable to common shareholders(1)	**(136)**	51	**(169)**	(14)
Cash flow from operating activities(1)	**257**	328	**592**	668
Comparable EBITDA(1,2,3)	**256**	305	**693**	741
Funds from operations(1,2)	**193**	244	**524**	568
Free cash flow(1,3)	**106**	170	**306**	314
Net loss per share attributable to common shareholders, basic and diluted	**(0.50)**	0.18	**(0.61)**	(0.05)
Funds from operations per share(2)	**0.70**	0.87	**1.90**	2.00
Free cash flow per share(2)	**0.39**	0.60	**1.11**	1.11
Dividends declared per common share	**0.0425**	0.0400	**0.1275**	0.0800
Dividends declared per preferred share(4)	**0.2593**	0.2591	**0.7645**	0.5181

As at	Sept. 30, 2020	Dec. 31, 2019
Total assets	**9,230**	9,508
Total consolidated net debt(2,5)	**3,100**	3,110
Total long-term liabilities	**4,223**	4,329

(1) Includes $56 million settlement received for termination of the Sundance B and C PPAs (PPA Termination Payments) in the third quarter of 2019.
(2) These items are not defined and have no standardized meaning under IFRS. Presenting these items from period to period provides management and investors with the ability to evaluate earnings trends more readily in comparison with prior periods' results. 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.
(3) Comparable earnings before interest, taxes, depreciation and amortization ("comparable EBITDA").
(4) Weighted average of the Series A, B, C, E and G preferred share dividends declared. Dividends declared vary year over year due to timing of dividend declarations.
(5) Total consolidated net debt includes long-term debt, including current portion, amounts due under credit facilities, exchangeable 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, totaled $106 million and $306 million for the three and nine months ended Sept. 30, 2020, respectively. FCF for the three months ended Sept. 30, 2020, excluding the PPA Termination Payments that were received the third quarter of 2019, decreased by $8 million, compared to the same period in 2019. This was primarily driven by higher sustaining capital expenditures for conversion to gas outages at the Alberta Thermal segment. FCF for the nine months ended Sept. 30, 2020, excluding the PPA Termination Payments received in 2019, increased by $48 million compared to the same period in 2019, driven primarily by higher segmented cash flows, lower sustaining and productivity capital expenditures and lower distributions paid to subsidiaries' non-controlling interests. Segmented cash flows for the three months ended Sept. 30, 2020, excluding the PPA Termination Payments received in 2019, are $4 million lower compared to the same period in 2019, due to lower performance in our Alberta Thermal segment, mostly offset by higher performance in our Centralia, Australian Gas, Wind and Solar and Energy Marketing Segments. Segmented cash flows for the nine months ended Sept. 30, 2020, are $43 million higher, compared to the same period in 2019 primarily due to higher performance in our Centralia, North American Gas, Wind and Solar and Energy Marketing segments, which was partially offset by lower performance in our Alberta Thermal and Hydro segments and impacts of the total return swap in the Corporate segment.

Adjusted availability for the three months ended Sept. 30, 2020, was 90.7 per cent compared to 95.2 per cent for the same period in 2019, largely due to the planned outage at Alberta Thermal for the Sundance Unit 6 turnaround and conversion to gas. Adjusted availability for the nine months ended Sept. 30, 2020, was 91.4 per cent compared to 89.5 per cent, for the same period in 2019. The increase was primarily due to fewer planned and unplanned outages and derates within the generation segments, partially offset by the planned outages at Alberta Thermal for the Sundance Unit 6 turnaround and conversion to gas and the Sheerness turnaround and dual-fuel conversion.

Production for the three months ended Sept. 30, 2020 was 6,184 gigawatt hours ("GWh") compared to 7,558 GWh for the same period in 2019. The decrease in production was primarily due to the planned outage at Alberta Thermal for Sundance Unit 6, lower dispatching at Sundance Unit 4 and Keephills 3 as a result of lower prices, and timing of dispatch optimization at Centralia. Production for the nine months ended Sept. 30, 2020 was 17,276 GWh compared to 20,918 GWh for the same period in 2019. The decrease in production was primarily due to planned outages, curtailments and dispatch optimization reducing merchant production for our Alberta Thermal. In addition, both Centralia units at Centralia were taken out of service for the majority of the first half of 2020. 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 nine months ended Sept. 30, 2020, decreased by $79 million and $181 million, respectively, compared to the same periods in 2019, mainly as a result of lower production and power prices at our Alberta Thermal and Centralia segments. Production was down due to the planned outage at Sheerness in the first quarter of 2020 and the planned outage at Sundance Unit 6 during the third quarter of 2020, 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 $5 million and $159 million in the three and nine months ended Sept. 30, 2020, respectively, compared to the same periods in 2019. In the Centralia segment, we improved our margins by purchasing low priced power to fulfill our contractual obligations compared to 2019. In our Alberta Thermal segment, lower production and our ability to co-fire with natural gas reduced fuel costs as co-firing allows us to produce fewer greenhouse gas ("GHG") emissions than 100 per cent coal combustion and lowers our GHG compliance costs. This decrease was partially offset by higher coal costs and a coal inventory write-down at the Highvale Mine. In addition, our North American Gas segment had lower costs due to lower merchant production.

Operations, maintenance and administration ("OM&A") expenses for the three months ended Sept. 30, 2020 were consistent with the same period in 2019. OM&A for the nine months ended Sept. 30, 2020, increased by $6 million compared to the same period in 2019 as variability caused by the total return swap resulted in a increase of expense of $16 million for the period. In addition, OM&A costs increased by $6 million due to the addition of Ada cogeneration facility ("Ada"), Big Level and Antrim wind projects and the renegotiation of the Fort Saskatchewan maintenance agreement. Excluding the impact of the total return swap and additional facilities, OM&A decreased by $16 million due to tighter cost controls, units remaining on reserve shutdown during the second quarter of 2020 at Centralia, lower labour costs across multiple segments and lower legal fees.

Comparable EBITDA, excluding the PPA Termination Payments, for the three and nine months ended Sept. 30, 2020, increased by $7 million and $8 million, respectively, compared with the same periods in 2019 largely due to higher comparable EBITDA at Energy Marketing, Centralia and Wind and Solar segments, partially offset by lower performance at the Alberta Thermal and Hydro segments as well as higher Corporate costs due to the impact of the total return swap. 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 Sept. 30, 2020, was $136 million compared to earnings of $51 million in the same period in 2019. The decrease is largely due to lower revenues, coal inventory write-down, higher depreciation, increase in asset impairments and the PPA Termination Payments received in 2019, which were partially offset by foreign exchange gains and income tax recoveries. Net loss attributable to common shareholders for the nine months ended Sept. 30, 2020, was $169 million, compared to $14 million in the same period in 2019. The decrease is largely due to lower revenues, coal inventory write-down, higher depreciation, increase in asset impairments and the PPA Termination Payments received in 2019, which were partially offset by lower fuel, carbon compliance, purchased power costs, and foreign exchange gains.

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.

Issuance of $400 Million Preferred Shares

On Oct. 30, 2020, Brookfield Renewable Partners or its affiliates (collectively "Brookfield") invested the second and final close of $400 million in exchange for redeemable, retractable first preferred shares. As previously disclosed, Brookfield committed to invest $750 million in TransAlta through the purchase of exchangeable securities of TransAlta, which are exchangeable in the future into an equity ownership interest in TransAlta's Alberta hydro assets at a value based on a multiple of hydro assets' future adjusted EBITDA. The first close occurred May 1, 2019 and consisted of $350 million in unsecured, subordinated debentures. The Corporation intends to use the proceeds from the second tranche of the financing to advance the Corporation's conversion to gas program, to fund other growth initiatives and for general corporate purposes.

BHP Nickel West Contract Extension

On Oct. 22, 2020, Southern Cross Energy ("SCE"), a subsidiary of the Corporation, replaced and extended its current power purchase agreement ("PPA") with BHP Billiton Nickel West Pty Ltd. ("BHP"). Southern Cross Energy is composed of four generation facilities with a combined capacity of 245 MW in the Goldfields region of Western Australia.

The amendment to the PPA is effective one month after signing and replaces the previous contract that was scheduled to expire Dec. 31, 2023. The amendment to the PPA extends the term to Dec. 31, 2038 and provides SCE with the exclusive right to supply thermal and electrical energy from the Southern Cross Facilities for BHP's mining operations located in the Goldfields region of Western Australia. The extension will provide SCE a return of and on new capital investments, which will be required to support BHP's future power requirements and recently announced emission reduction targets. The amendments within the PPA also provide BHP participation rights in integrating renewable electricity generation, including solar and wind, with energy storage technologies, subject to the satisfaction of certain conditions. Evaluation of renewable energy supply and carbon emissions reduction initiative under the extended PPA with SCE are underway, including a 18.5MW solar photovoltaic farm supported by a battery energy storage system and a waste heat steam turbine system.

TEC Hedland Pty Ltd. Secures AU$800 Million Financing

On Oct. 22, 2020 TEC Hedland Pty Ltd., ("TEC") a subsidiary of the Corporation, closed an AU$800 million senior secured note ("Notes") offering, by way of a private placement, which is secured by, among other things, a first ranking charge over all assets of TEC. The Notes bear interest at 4.07 per cent per annum, payable quarterly and mature on June 30, 2042 with principal payments starting on Mar. 31, 2022. The Notes have a rating of BBB.

TransAlta Renewables has received $489 million (AU$517 million) of the proceeds through the redemption of certain intercompany structures. An additional AU$200 million has been loaned to TransAlta Renewables by TransAlta Energy (Australia) Pty Ltd. ("TEA"), which is a subsidiary of TransAlta. The loan bears interest at 4.32 per cent and will be repaid by Oct. 23, 2022. The remaining proceeds from the offering were set aside for required reserves and transaction costs.

TransAlta Renewables used a portion of the proceeds from the redemption and the intercompany loan to repay existing indebtedness on the credit facility. The remaining funds will be used to fund future growth opportunities within TransAlta Renewables.

TransAlta Renewables Acquires a Battery Storage Project from the Corporation

On Aug. 1, 2020, TransAlta Renewables acquired the 10 MW / 20 MWh WindCharger Battery storage project that is connected to the Alberta transmission system through the Summerview wind farm substation from a subsidiary of the Corporation for $12 million. TransAlta Renewables funded the remaining construction cost and the project commenced commercial operation on Oct 15, 2020. The total cost of the project is $14 million and 50 per cent of the construction cost is expected to be funded through Emissions Reduction Alberta. As the project was acquired by TransAlta Renewables, this did not impact the Corporation on a consolidated level. The Corporation also executed a 20-year battery storage usage contract with TransAlta Renewables in which the Corporation will pay a fixed monthly capacity charge for the exclusive right to operate and dispatch the battery in the Alberta market.

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 nine months ended Sept. 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.

Robert Flexon resigned from the Board effective Aug. 1, 2020. Mr. Flexon recently assumed the role of Chair of the Board of Directors of PG&E Corporation ("PG&E") and resigned from the Board due only to the potential for perceived conflicts of interests between PG&E and the Corporation.

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 continued to operate under its business continuity plan, 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 and third quarters of 2020, the Corporation successfully brought employees that were working remotely back to the office without sacrificing health and safety standards. All of TransAlta's offices and sites follow strict health screening and social distancing protocols with personal protective equipment readily available and in use. Further, TransAlta maintains travel bans aligned to local jurisdictional guidance, enhanced cleaning procedures, revised work schedules, contingent work teams and the reorganization of processes and procedures to limit contact with other employees and contractors on-site.

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

The Corporation continues to maintain a strong financial position due in part to the long-term contracts and hedged positions. At the end of the third quarter, we had access to $1.6 billion in liquidity including $270 million in cash and cash equivalents. Subsequent to the quarter, the Corporation raised approximately $1.1 billion in additional liquidity, as described earlier in this section, bringing our total position to $2.7 billion in liquidity.

The Corporation has approximately 90 per cent of its baseload merchant generation in Alberta hedged in the $53 per MWh range for the remainder of 2020.

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 nine months ended Sept. 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.

The Corporation has received $750 million from a strategic investment with Brookfield that we announced in March 2019. The first $350 million tranche of Brookfield's investment closed in May 2019 and facilitated the acceleration of our conversion to gas plan. The second $400 million tranche of Brookfield's investment, closed on Oct. 30, 2020 and will further the advancement and implementation of the remainder of the Clean Energy Investment Plan while helping the Corporation maintain a strong balance sheet and financial flexibility to carry out our strategic objectives discussed below.

During the first nine months of 2020, the following developments have occurred impacting those objectives:

Successfully eliminate coal as a fuel source in the Alberta Thermal fleet. We are on-track to complete the conversion to gas of Sundance Unit 6 in mid-November, 2020. The Corporation continues to advance conversion of its Keephills Unit 2 and Unit 3 for completion in 2021 and has issued Full Notice to Proceed ("FNTP") for both units. The Corporation announced that Keephills Unit 1 and Sundance Unit 4 will discontinue firing with coal and will only operate on gas effective Jan. 1, 2022. The maximum capability of these units will be reduced to 70 MW and 113 MW respectively. 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. During the third quarter, an equipment supply agreement was executed as part of the strategy to repower Sundance Unit 5 into a highly efficient combined cycle unit. We are on track to issue FNTP in 2021 for Sundance Unit 5, with the commercial operation date anticipated in the fourth quarter of 2023.

During the third quarter of 2020, the Board approved the accelerated shutdown of the Highvale Mine by the end of 2021 and accordingly the useful life of the related assets was adjusted to align with the Corporation's conversion to gas plans. As at Sept. 30, 2020, the carrying value of the Highvale Mine, including PP&E, ROU assets and intangible assets, was $403 million which the majority of will be recognized in the consolidated statement of earnings over the next five quarters. As a result, our cost per tonne of coal will increase as the fixed coal costs will be spread over lower volumes. In the third quarter, the increased depreciation expense and our cost per tonne of coal exceeded the net realizable value of the coal inventory and a write-down of $22 million was recognized in fuel, carbon compliance and purchased power. As the Highvale Mine moves into the reclamation phase, our anticipated coal consumption is expected to continue to decline, further increasing the cost of coal, and future expected write-downs in fuel costs.

On Oct 1, 2020, TransAlta announced that it had 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 ATCO Gas and Pipelines Ltd. ("ATCO") (the "Transaction"). The purchase price of $255 million represents both TransAlta's and Tidewater Midstream & Infrastructure Ltd.'s ("Tidewater") interests. This agreement replaces the Tidewater's previous agreement from the second quarter of 2020, to sell its interest in the Pioneer Pipeline to NOVA Gas Transmission Ltd. ("NGTL"). ATCO acquired the right to purchase the Pioneer Pipeline through an option agreement with NGTL. Following closing of the Transaction, Pioneer Pipeline will be integrated into NGTL's and ATCO's Alberta integrated natural gas transmission systems to provide reliable natural gas supply to TransAlta's Sundance and Keephills power generating stations.

In addition, TransAlta has 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 up 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, and is anticipated to close during the second quarter of 2021.

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. The Corporation recognized an impairment charge of approximately $70 million ($52 million after-tax) for the nine months ended Sept. 30, 2020.

Expand our renewables fleet. We continue to expand our renewables platform and the following significant developments on our renewables projects occurred in 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. However as a result of COVID-19 related delays in the delivery of the wind turbine components, construction and commissioning is not expected to occur until the second half of 2021.
- As of Sept. 30, 2020, Windrise is 45 per cent complete and began receiving wind turbine generators on site mid-October, 2020.
- The Skookumchuck Wind Project remains under construction and TransAlta's right to purchase occurs at the commercial operations date ("COD"). The project is expected to be completed and reach full COD before the end of 2020.
- The WindCharger Battery Storage Project has been completed and achieved COD on Oct. 15, 2020.

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 Ada asset is a 29 MW cogeneration facility 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. The Ada facility has been included in the North American Gas segment results, which was previously known as the Canadian Gas segment.

The Corporation has advanced the Kaybob Cogeneration Project, including the purchase of the reciprocating engine generator, generator step up transformers, electrical building and switchgear.

Growth and conversion to gas 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 $339 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		
Project	**Estimated spend**	**Spent to date[1]**	**estimated spend in 2020**	**Target completion date[2]**	**Details**
Skookumchuck wind project[3,4]	160 — 170	—	89	Q4 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	127	109	H2 2021	207 MW wind project with a 20-year Renewable Electricity Support Agreement with AESO
WindCharger battery[5,6]	7 — 8	6	1	Commissioned	10 MW/20 MWh utility-scale storage project
Boiler conversions[7]	120 — 200	49	29	2020 to 2022	Conversion to gas at Alberta Thermal
Repowering[8]	800 — 825	90	23	Q4 2023	Repower Sundance Unit 5 to a combined cycle design
Kaybob cogeneration project[4]	105 — 115	38	24	H1 2022	40 MW cogeneration project with SemCAMS under a 13-year fixed price contract
Total	**1,462 — 1,603**	**310**	**275**		

(1) Represents cumulative amounts spent as of Sept. 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) This project has been dropped down to TransAlta Renewables Inc.
(6) Net of expected government reimbursements.
(7) 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	January 2020 Outlook Power Prices ($/MWh)	Revised Expectations Power Prices ($/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	$150 million to $175 million

Our overall performance for the first three quarters of 2020 are in line with expectations. The Corporation continues to track 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. However, the Corporation continues to track to the mid-point of the guidance for FCF as we have been able to respond with our hedging activities and adjustments in our capital investment plans.

Operations

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

Fuel Costs

In the Pacific Northwest of the US, the coal mine adjacent to our Centralia power plant is in reclamation stage. Fuel at Centralia has been purchased primarily from external suppliers in the Powder River Basin and delivered by rail. In 2020, we amended our fuel contracts with fixed pricing through to 2025. The current rail agreement is in effect until the end of 2020 with a renewal targeted for completion in the fourth quarter of 2020. The new agreements will secure fuel supply through 2025.

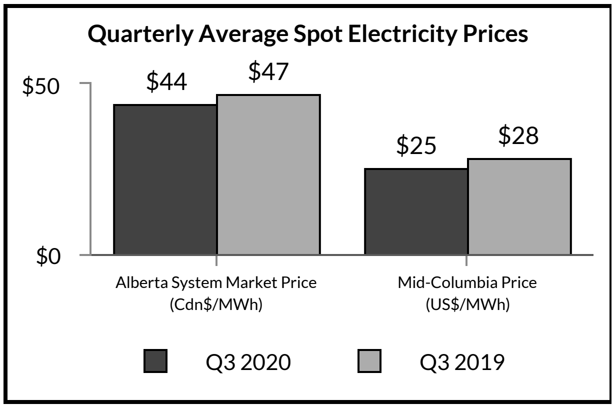
As a result of the accelerated shutdown of the Highvale Mine by the end of 2021, our anticipated coal consumption is expected to continue to decline as we shift to gas as our main fuel source, further increasing the cost of coal and future expected write-downs in fuel costs.

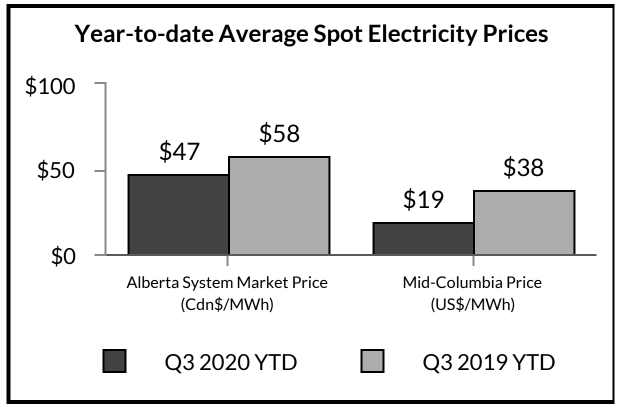
Market Pricing

In 2020, demand losses from COVID-19 and low oil prices resulted in lower prices for the quarter and year-to-date compared with the same periods 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 weakness in oil prices impacting activity in that sector.

Power prices were significantly lower in the Pacific Northwest in the three and nine months ended Sept. 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 that extended into July of 2020, which resulted in lower prices compared to the prior year. Pacific Northwest power prices for the remainder of 2020 are expected to be higher than in 2019 due to higher natural gas prices.

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 gross margin forecast for Energy Marketing has increased from a range of $75 million to $85 million and the segment is now expected to contribute between $125 million to $135 million in gross margin for the year.

Net Interest Expense
Interest expense for 2020 is expected to be higher than in 2019 largely due to higher levels of debt. The increase in debt is due to the issuance of AU$800 million Notes in Oct. 2020, partially offset by lower credit facility drawings.

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	**29**	53 — 60
Planned major maintenance	Regularly scheduled major maintenance	**63**	92 — 105
Mine capital	Capital related to mining equipment and land purchases	**7**	5 — 10
Total sustaining capital		**99**	**150 — 175**
Productivity capital	Projects to improve power production efficiency and corporate improvement initiatives	**1**	3 — 7
Total sustaining and productivity capital		**100**	**153 — 182**

(1) As at Sept. 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 Alberta Thermal segment during the third and fourth quarters of 2020. This work is being undertaken in parallel with the conversion to gas 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 Centralia, 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	629

(1) As at Sept. 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 nine months ended Sept. 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, adjusted 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.
- Coal inventory write-downs are not included as these are non-cash adjustments that are not reflective of our core business results upon conversion to gas. To accelerate our conversion to gas plans, a decision was made to accelerate the mine shutdown to 2021.
- On the commissioning of the South Hedland facility in July 2017, we prepaid approximately $74 million of electricity transmission and distribution costs. Interest income is recorded on the prepaid funds. We reclassify this interest income as a reduction in the transmission and distribution costs expensed each period to reflect the net cost to the business.
- Asset impairments (reversals) are removed to calculate comparable EBITDA as these are accounting adjustments that impact depreciation and amortization and do not reflect business performance.

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

	3 months ended Sept. 30		9 months ended Sept. 30	
	2020	2019	**2020**	2019
Net earnings (loss) attributable to common shareholders	**(136)**	51	**(169)**	(14)
Net earnings attributable to non-controlling interests	**7**	16	**29**	67
Preferred share dividends	**10**	10	**30**	20
Net earnings (loss)	**(119)**	77	**(110)**	73
Adjustments to reconcile net income to comparable EBITDA				
Income tax expense (recovery)	**(10)**	10	**(25)**	(23)
Other (gains) losses	**(2)**	6	**(2)**	18
Foreign exchange (gain) loss	**(11)**	9	**(15)**	18
Net interest expense	**56**	55	**175**	161
Depreciation and amortization	**162**	148	**481**	436
Comparable reclassifications				
Decrease in finance lease receivables	**3**	7	**11**	19
Mine depreciation included in fuel cost	**33**	30	**87**	90
Australian interest income	**1**	1	**3**	3
Unrealized mark-to-market (gains) losses	**45**	(16)	**(1)**	(32)
Adjustments to earnings to arrive at comparable EBITDA				
Coal inventory write-down	**22**	—	**22**	—
Asset impairment (reversal)(1)	**76**	(22)	**67**	(22)
Comparable EBITDA	**256**	305	**693**	741
Comparable EBITDA - excluding the PPA Termination Payments	**256**	249	**693**	685

(1) The asset impairment (reversal) for the three months ended Sept. 30, 2020 of $76 million mainly relate to the retirement of Sundance Unit 3 ($70 million), impairment on a BC hydro facility ($2 million) and an impairment on retired assets resulting from changes in discount rates for the decommissioning and restoration liabilities. The asset impairment (reversal) for the nine months ended Sept. 30, 2020 of $67 million, mainly relate to the retirement of Sundance Unit 3 ($70 million) and impairment on a BC hydro facility ($2 million), partially offset by asset impairment reversals resulting from changes in discount rates for the decommissioning and restoration liabilities for our retired assets. The changes for the same periods in 2019 includes a $151 million impairment reversal at Centralia, partially offset by the $109 million increase for the decommissioning and restoration liability at the Centralia mine and the $18 million write-off of project development costs. 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 Sept. 30		9 months ended Sept. 30	
	2020	2019	**2020**	2019
Cash flow from operating activities	**257**	328	**592**	668
Change in non-cash operating working capital balances	**(94)**	(92)	**(114)**	(122)
Cash flow from operations before changes in working capital	**163**	236	**478**	546
Adjustments				
Decrease in finance lease receivable	**3**	7	**11**	19
Coal inventory write-down	**22**	—	**22**	—
Other	**5**	1	**13**	3
FFO	**193**	244	**524**	568
Deduct:				
Sustaining capital	**(44)**	(25)	**(99)**	(111)
Productivity capital	**—**	(4)	**(1)**	(7)
Dividends paid on preferred shares[1]	**(10)**	(10)	**(30)**	(30)
Distributions paid to subsidiaries' non-controlling interests	**(28)**	(30)	**(73)**	(89)
Payments on lease obligations	**(5)**	(5)	**(15)**	(16)
Other	**—**	—	**—**	(1)
FCF	**106**	170	**306**	314
Weighted average number of common shares outstanding in the period	**274**	282	**276**	284
FFO per share	**0.70**	0.87	**1.90**	2.00
FCF per share	**0.39**	0.60	**1.11**	1.11

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

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

	3 months ended Sept. 30		9 months ended Sept. 30	
	2020	2019	**2020**	2019
Comparable EBITDA	**256**	305	**693**	741
Provisions and other	**2**	3	**17**	14
Interest expense	**(44)**	(45)	**(136)**	(133)
Current income tax expense	**(19)**	(14)	**(40)**	(28)
Realized foreign exchange gain (loss)	**—**	—	**9**	(7)
Decommissioning and restoration costs settled	**(5)**	(9)	**(13)**	(24)
Other cash and non-cash items	**3**	4	**(6)**	5
FFO	**193**	244	**524**	568
Deduct:				
Sustaining capital	**(44)**	(25)	**(99)**	(111)
Productivity capital	**—**	(4)	**(1)**	(7)
Dividends paid on preferred shares[1]	**(10)**	(10)	**(30)**	(30)
Distributions paid to subsidiaries' non-controlling interests	**(28)**	(30)	**(73)**	(89)
Payments on lease obligations	**(5)**	(5)	**(15)**	(16)
Other	**—**	—	**—**	(1)
FCF	**106**	170	**306**	314

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

Supplemental disclosure	3 months ended Sept. 30		9 months ended Sept. 30	
	2020	2019	**2020**	2019
FFO - excluding the PPA Termination Payments	**193**	188	**524**	512
FCF - excluding the PPA Termination Payments	**106**	114	**306**	258
FFO per share - excluding the PPA Termination Payments	**0.70**	0.67	**1.90**	1.80
FCF per share - excluding the PPA Termination Payments	**0.39**	0.40	**1.11**	0.91

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 Sept. 30		9 months ended Sept. 30	
	2020	2019	**2020**	2019
Segmented cash flow(1)				
Alberta Thermal(2)	**14**	117	**57**	177
Centralia(2)	**46**	30	**94**	29
North American Gas(3)	**27**	29	**81**	77
Australian Gas	**33**	28	**90**	87
Wind and Solar	**32**	28	**161**	134
Hydro	**22**	24	**72**	80
Generation segmented cash flow	**174**	256	**555**	584
Energy Marketing	**51**	30	**99**	74
Corporate(4)	**(21)**	(22)	**(72)**	(63)
Total segmented cash flow	**204**	264	**582**	595
Total segmented cash flow - excluding the PPA Termination Payments	**204**	208	**582**	539

(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) The Canadian Coal segment was renamed Alberta Thermal and US Coal segment was renamed Centralia in the third quarter of 2020.
(3) 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.
(4) Includes gains and losses on the total return swap.

Segmented cash flow generated by the business for the three months ended Sept. 30, 2020, excluding the PPA Termination Payments, are $4 million lower compared to the same period in 2019, due to lower performance in our Alberta Thermal segment, mostly offset by higher performance in our Centralia, Australian Gas, Wind and Solar and Energy Marketing Segments. For the nine months ended Sept. 30, 2020, segmented cash flow, excluding the PPA Termination Payments, increased by $43 million, compared to the same period in 2019. The increase was largely due to strong results from our Centralia segment resulting from dispatch optimization, additional production due to the Ada acquisition within North American Gas, a full nine months of operations from Big Level and Antrim within our Wind and Solar segment and market volatility within our Energy Marketing segment. This was offset by lower results due to planned outages at Alberta Thermal, lower demand impacting our Alberta Thermal and Hydro segments and the impact of the realized gains and losses on the total return swap in the Corporate segment. In the nine months ended Sept. 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 $8 million.

Alberta Thermal(1)

	3 months ended Sept. 30		9 months ended Sept. 30	
	2020	2019	**2020**	2019
Availability (%)	**86.3**	96.8	**88.8**	89.5
Contract production (GWh)	**1,385**	1,700	**4,225**	5,186
Merchant production (GWh)	**873**	1,373	**3,157**	4,395
Total production (GWh)	**2,258**	3,073	**7,382**	9,581
Gross installed capacity (MW)(2)	**2,861**	3,231	**2,861**	3,231
Revenues	**157**	205	**490**	626
Fuel, carbon compliance and purchased power	**84**	99	**290**	336
Comparable gross margin	**73**	106	**200**	290
Operations, maintenance and administration	**31**	34	**97**	102
Taxes, other than income taxes	**5**	3	**12**	10
Termination of Sundance B and C PPAs	**—**	(56)	**—**	(56)
Net other operating income	**(10)**	(10)	**(30)**	(30)
Comparable EBITDA	**47**	135	**121**	264
Deduct:				
Sustaining capital:				
Routine capital	**3**	4	**7**	11
Mine capital	**5**	8	**7**	18
Planned major maintenance	**19**	1	**39**	33
Total sustaining capital expenditures	**27**	13	**53**	62
Productivity capital	**—**	2	**1**	5
Total sustaining and productivity capital	**27**	15	**54**	67
Provisions	**—**	(4)	**(8)**	(3)
Payments on lease obligations	**4**	3	**11**	11
Decommissioning and restoration costs settled	**2**	4	**7**	12
Alberta Thermal cash flow	**14**	117	**57**	177

(1) The Canadian Coal segment was renamed Alberta Thermal in the third quarter of 2020.
(2) 2019 & 2020 includes 406 MW for Sundance Unit 5, which is temporarily mothballed. 2019 also includes 368 MW for Sundance Unit 3, which was temporarily mothballed and then retired during the third quarter of 2020. 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.

	3 months ended Sept. 30		9 months ended Sept. 30	
Supplemental disclosure	**2020**	2019	**2020**	2019
Comparable EBITDA - excluding the PPA Termination Payments	**47**	79	**121**	208
Alberta Thermal cash flow - excluding the PPA Termination Payments	**14**	61	**57**	121

Availability for the three months ended Sept. 30, 2020, was lower compared to the same period in 2019, mainly due to the Sundance Unit 6 turnaround and conversion to gas outage which commenced in September 2020 and higher derates and unplanned outages. Availability for the nine months ended Sept. 30, 2020 was consistent with the same period in 2019.

Production for the three and nine months ended Sept. 30, 2020, decreased 815 and 2,199 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 Alberta Thermal fleet due to lower demand due to COVID-19 and reduced oil sector activity in the province. Production also decreased due to lower availability. The Sundance Unit 6 turnaround and conversion to gas also contributed to lower production during the third quarter of 2020.

Revenue for the three and nine months ended Sept. 30, 2020, decreased by $48 million and $136 million, respectively, compared to the same periods in 2019, mainly due to lower merchant production.

	3 months ended Sept. 30		9 months ended Sept. 30	
	2020	2019	**2020**	2019
Revenues per MWh	**$70**	$67	**$66**	$65
Fuel, carbon compliance and purchased power per MWh	**$37**	$32	**$39**	$35

In the three and nine months ended Sept. 30, 2020, revenue per MWh of production increased by $3 per MWh and $1 per MWh, respectively, compared with the same periods in 2019, primarily due to higher realized prices as a result of optimizing production during periods of favourable pricing and hedging positions have minimized unfavourable market pricing.

In the three and nine months ended Sept. 30, 2020, fuel, carbon compliance and purchased power costs per MWh of production increased by $5 per MWh and $4 per MWh, respectively, compared the same periods in 2019. Costs per MWh increased due to fixed coal costs spread over less volumes resulting in increased costs per MWh. Consequently, comparable gross margin per MWh for the three and nine months ended Sept. 30, 2020, was $2 per MWh and $3 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 nine months ended Sept. 30, 2020, were $3 million and $5 million lower compared with the same periods in 2019, due to strong cost controls.

Comparable EBITDA, excluding PPA Termination Payments, for the three and nine months ended Sept. 30, 2020, decreased $32 million and $87 million, respectively, compared to the same periods in 2019. This largely reflects the weaker power demand conditions driving lower Alberta wholesale power prices resulting in lower merchant production and lower margins.

For the three months ended Sept. 30, 2020, sustaining and productivity capital expenditures increased by $12 million compared with the same period in 2019, mainly due to the turnaround and conversion to gas outage at Sundance Unit 6. For the nine months ended Sept. 30, 2020, sustaining and productivity capital expenditures decreased by $13 million, respectively, compared to the same period in 2019, mainly due to reductions in mine capital as we near the end of life of the mine.

Alberta Thermal's cash flow for the three months ended Sept. 30, 2020, excluding PPA Termination Payments, decreased by $47 million compared to the same period in 2019, mainly due to higher sustaining and productivity capital expenditures and the reduction in comparable EBITDA. For the nine months ended Sept. 30, 2020, cash flow decreased by $64 million, compared to the same period in 2019, mainly due to lower merchant production, partially offset by lower sustaining and productivity capital expenditures.

Centralia[1]

	3 months ended Sept. 30		9 months ended Sept. 30	
	2020	2019	**2020**	2019
Availability (%)	**88.4**	93.8	**69.8**	68.7
Adjusted availability (%)[2]	**92.9**	93.8	**88.4**	81.5
Contract sales volume (GWh)	**840**	839	**2,499**	2,489
Merchant sales volume (GWh)	**1,705**	2,494	**2,976**	5,065
Purchased power (GWh)	**(956)**	(997)	**(2,780)**	(2,847)
Total production (GWh)	**1,589**	2,336	**2,695**	4,707
Gross installed capacity (MW)	**1,340**	1,340	**1,340**	1,340
Revenues	**147**	161	**326**	392
Fuel and purchased power	**82**	107	**167**	295
Comparable gross margin	**65**	54	**159**	97
Operations, maintenance and administration	**15**	18	**46**	50
Taxes, other than income taxes	**1**	1	**4**	3
Comparable EBITDA	**49**	35	**109**	44
Deduct:				
Sustaining capital:				
Routine capital	**1**	1	**3**	2
Planned major maintenance	**—**	(1)	**7**	3
Total sustaining capital expenditures	**1**	—	**10**	5
Productivity capital	**—**	1	**—**	1
Total sustaining and productivity capital	**1**	1	**10**	6
Decommissioning and restoration costs settled	**2**	4	**5**	9
Centralia cash flow	**46**	30	**94**	29

(1) The US Coal segment was renamed Centralia in the third quarter of 2020.
(2) Adjusted for dispatch optimization.

Adjusted availability for the three months ended Sept. 30, 2020, was consistent with the same period in 2019. Adjusted availability for the nine months ended Sept. 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. This derate was resolved when the unit was offline during the second quarter of 2019.

Production for the three and nine months ended Sept. 30, 2020, decreased 747 GWh and 2,012 GWh, respectively, compared to the same periods in 2019. This was largely a result of lower merchant pricing 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 returned to service in mid-July 2020.

OM&A costs for the three and nine months ended Sept. 30, 2020, decreased by $3 million and $4 million, respectively, compared with the same periods in 2019, due to strong cost controls and as a result of the units remaining on reserve shutdown during the second quarter of 2020.

Comparable EBITDA returned to normalized levels for the nine months ended Sept. 30, 2020. For the three months ended Sept. 30, 2020 comparable EBITDA, increased by $14 million compared to the same period in 2019, primarily due to purchased power at a lower cost. For the nine months ended Sept. 30, 2020, comparable EBITDA increased by $65 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 2020 benefited from dispatch optimization and the strengthening of the US dollar relative to the Canadian dollar.

Sustaining and productivity capital expenditures for the three months ended Sept. 30, 2020, were consistent with the same period in 2019. Sustaining and capital expenditures for the nine months ended Sept. 30, 2020, were $4 million higher with the same period in 2019, mainly due to increased planned outage work in 2020 during the reserve shutdown.

Centralia's cash flow for the three and nine months ended Sept. 30, 2020, increased by $16 million and $65 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 Sept. 30		9 months ended Sept. 30	
	2020	2019	**2020**	2019
Availability (%)	**92.2**	93.4	**96.4**	94.0
Contract production (GWh)	**482**	400	**1,391**	1,260
Merchant production (GWh)(2)	**12**	15	**(39)**	115
Total production (GWh)	**494**	415	**1,352**	1,375
Gross installed capacity (MW)(3)	**974**	945	**974**	945
Revenues	**59**	54	**168**	181
Fuel and purchased power	**17**	14	**45**	57
Comparable gross margin	**42**	40	**123**	124
Operations, maintenance and administration	**13**	11	**37**	33
Taxes, other than income taxes	**—**	—	**1**	1
Net other operating income	**—**	(1)	**—**	(1)
Comparable EBITDA	**29**	30	**85**	91
Deduct:				
Sustaining capital:				
Routine capital	**1**	—	**3**	8
Planned major maintenance	**1**	1	**1**	6
Total sustaining capital expenditures	**2**	1	**4**	14
North American Gas cash flow	**27**	29	**81**	77

(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 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 months ended Sept. 30, 2020, decreased compared to the same period in 2019, primarily due to higher unplanned outages at our Sarnia facility and planned outages at our Fort Saskatchewan and Ada facilities in 2020. Availability for the nine months ended Sept. 30, 2020, increased compared to the same period in 2019, primarily due to lower planned and unplanned outages at our Sarnia and Ottawa facilities, partially offset by planned outages at our Fort Saskatchewan and Ada facility in 2020.

Production for the three months ended Sept. 30, 2020, increased by 79 GWh compared to the same period in 2019, mainly due to the new Ada facility and higher customer demand at our Sarnia facility, partially offset by lower market demand. Production for the nine months ended Sept. 30, 2020, decreased by 23 GWh compared to the same period in 2019, mainly due to lower Ontario market demand in 2020, which was partially offset by the new Ada facility and higher customer demand at our Sarnia 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 nine months ended Sept. 30, 2020, were $2 million and $4 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 passthrough provisions and from the addition of the new Ada facility.

Comparable EBITDA for the three months ended Sept. 30, 2020, remained consistent compared to the same period in 2019 and for the nine months ended Sept. 30, 2020, decreased by $6 million, compared with the same periods in 2019, primarily due to higher OM&A.

Sustaining capital expenditures for the three months ended Sept. 30, 2020 were consistent with the same period in 2019. Sustaining capital expenditures for the nine months ended Sept. 30, 2020, decreased by $10 million, compared with the same periods in 2019, mainly due to lower planned outages.

North American Gas' cash flow for the three months ended Sept. 30, 2020, decreased by $2 million, primarily due to timing of capital expenditures. Cash flow for the nine months ended Sept. 30, 2020, increased by $4 million compared to the the same period in 2019, as lower capital expenditures were partially offset by lower comparable EBITDA.

Australian Gas

	3 months ended Sept. 30		9 months ended Sept. 30	
	2020	2019	**2020**	2019
Availability (%)	**96.5**	97.7	**94.2**	89.9
Contract production (GWh)	**425**	450	**1,344**	1,369
Gross installed capacity (MW)	**450**	450	**450**	450
Revenues	**43**	39	**121**	120
Fuel and purchased power	**2**	1	**5**	3
Comparable gross margin	**41**	38	**116**	117
Operations, maintenance and administration	**7**	9	**23**	27
Comparable EBITDA	**34**	29	**93**	90
Deduct:				
Sustaining capital:				
Planned major maintenance	**1**	1	**3**	3
Total sustaining capital expenditures	**1**	1	**3**	3
Australian Gas cash flow	**33**	28	**90**	87

Availability for the three months ended Sept. 30, 2020, decreased compared with the same period in 2019, mainly due to timing of planned outages. Availability for the nine months ended Sept. 30, 2020, increased compared to the same periods in 2019, mainly due to unplanned outages in 2019.

Production for the three and nine months ended Sept. 30, 2020, decreased compared with the same periods in 2019, mainly due to changes in customer demand at the South Hedland facility. 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 nine months ended Sept. 30, 2020, increased by $5 million and $3 million, respectively, compared with the same periods in 2019, mainly due to timing of legal fees and the strengthening of the Australian dollar against the Canadian dollar.

Sustaining capital expenditures for the three and nine months ended Sept. 30, 2020, were consistent with the same periods in 2019, which was in line with expectations.

Australian Gas' cash flow for the three and nine months ended Sept. 30, 2020, increased by $5 million and $3 million, respectively, compared with the same periods in 2019, mainly due to higher comparable EBITDA.

Wind and Solar

	3 months ended Sept. 30		9 months ended Sept. 30	
	2020	2019	**2020**	2019
Availability (%)	**93.2**	93.9	**94.9**	94.7
Contract production (GWh)	**504**	396	**1,976**	1,671
Merchant production (GWh)	**213**	174	**814**	578
Total production (GWh)	**717**	570	**2,790**	2,249
Gross installed capacity (MW)[1]	**1,495**	1,382	**1,495**	1,382
Revenues	**58**	53	**232**	201
Fuel and purchased power	**5**	4	**14**	11
Comparable gross margin	**53**	49	**218**	190
Operations, maintenance and administration	**14**	12	**40**	37
Taxes, other than income taxes	**3**	2	**7**	6
Net other operating income	**—**	—	**—**	(4)
Comparable EBITDA	**36**	35	**171**	151
Deduct:				
Sustaining capital:				
Routine capital	**—**	1	**—**	1
Planned major maintenance	**4**	4	**9**	9
Total sustaining capital expenditures	**4**	5	**9**	10
Payments on lease obligations	**—**	2	**1**	2
Decommissioning and restoration costs settled	**—**	—	**—**	1
Other	**—**	—	**—**	4
Wind and Solar cash flow	**32**	28	**161**	134

(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 nine months ended Sept. 30, 2020, were consistent with the same periods in 2019.

Production for the three and nine months ended Sept. 30, 2020, increased by 147 GWh and 541 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 and strong wind resources across all regions, in particular for our Alberta wind facilities.

Comparable EBITDA for the three months ended Sept. 30, 2020, was consistent with the same period in 2019. Comparable EBITDA for the nine months ended Sept. 30, 2020, increased by $20 million compared with the same period in 2019, primarily due to the addition of the Big Level and Antrim wind facilities and higher production, partially offset by insurance proceeds received in 2019, lower Alberta pricing and the planned expiry of certain Wind power production incentives in 2019.

Sustaining capital expenditures for the three and nine months ended Sept. 30, 2020, were consistent with the same periods in 2019, which was in line with expectations.

Wind and Solar's cash flow for the three and nine months ended Sept. 30, 2020, increased by $4 million and $27 million, respectively, compared to the the same periods in 2019, mainly due to higher comparable EBITDA.

Hydro

	3 months ended Sept. 30		9 months ended Sept. 30	
	2020	2019	**2020**	2019
Production				
Energy contracted				
Alberta Hydro PPA assets (GWh)[1]	**553**	578	**1,367**	1,313
Other hydro energy (GWh)[1]	**112**	106	**279**	266
Energy merchant				
Other hydro energy (GWh)	**36**	30	**67**	58
Total energy production (GWh)	**701**	714	**1,713**	1,637
Ancillary service volumes (GWh)[2]	**642**	732	**2,231**	2,301
Gross installed capacity (MW)	**925**	926	**925**	926
Revenues				
Alberta Hydro PPA assets energy	**29**	28	**69**	84
Alberta Hydro PPA assets ancillary	**11**	17	**55**	74
Capacity payments received under Alberta Hydro PPA[3]	**15**	15	**45**	43
Other revenue[4]	**13**	12	**36**	35
Total gross revenues	**68**	72	**205**	236
Net payment relating to Alberta Hydro PPA[5]	**(27)**	(32)	**(84)**	(110)
Revenues	**41**	40	**121**	126
Fuel and purchased power	**5**	3	**9**	6
Comparable gross margin	**36**	37	**112**	120
Operations, maintenance and administration	**9**	8	**28**	26
Taxes, other than income taxes	**(1)**	1	**1**	2
Comparable EBITDA	**28**	28	**83**	92
Deduct:				
Sustaining capital:				
Routine capital	**4**	1	**6**	3
Planned major maintenance	**1**	1	**4**	6
Total sustaining capital expenditures	**5**	2	**10**	9
Productivity capital	**—**	1	**—**	1
Total sustaining and productivity capital	**5**	3	**10**	10
Decommissioning and restoration costs settled	**1**	1	**1**	2
Hydro cash flow	**22**	24	**72**	80

(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 months ended Sept. 30, 2020, was consistent with the same period in 2019. Production for the nine months ended Sept. 30, 2020, increased by 76 GWh, compared to the same period in 2019, mainly due to higher water resources.

Ancillary service volumes for the three and nine months ended Sept. 30, 2020 decreased by 90 GWh and 70 GWh, respectively, compared to the the same periods in 2019. This was primarily due to the AESO procuring less ancillary volumes in 2020. Additionally there has been weaker market conditions for ancillary services, partially due to COVID-19 and reduced oil sector activity.

	3 months ended Sept. 30		9 months ended Sept. 30	
	2020	2019	**2020**	2019
Gross Revenues per MWh				
Alberta Hydro PPA assets energy ($/MWh)	**$53**	$48	**$51**	$64
Alberta Hydro PPA assets ancillary ($/MWh)	**$17**	$23	**$25**	$32

In the three months ended Sept. 30, 2020, Alberta Hydro energy revenue per MWh of production increased by approximately $5 per MWh, compared to the same period in 2019. Despite Alberta merchant prices being slightly lower in the third quarter of 2020, optimization of the plant dispatching resulted in higher realized energy prices.

In the nine months ended Sept. 30, 2020, Alberta Hydro energy revenue per MWh of production decreased by approximately $13 per MWh, compared to the same period in 2019 as result of lower merchant prices in Alberta.

In the three and nine months ended Sept. 30, 2020, Alberta Hydro ancillary revenue per MWh of production decreased by approximately $6 per MWh and $7 per MWh, respectively, compared to the same periods in 2019. Lower realized prices are primarily due to unfavourable 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.

Total gross revenues for the three months ended Sept. 30, 2020, were consistent with the same period in 2019. Total gross revenues for the nine months ended Sept. 30, 2020, decreased by $31 million, compared to the same period in 2019, as lower energy and ancillary services revenues resulted from lower Alberta pricing and lower demand for ancillary products, partially offset by higher water resources.

Comparable EBITDA for the three months ended Sept. 30, 2020, was consistent with the same period in 2019. Comparable EBITDA for the nine months ended Sept. 30, 2020, decreased by $9 million, compared with the same period in 2019, as lower energy and ancillary services revenues resulted from lower Alberta pricing and prior years true up to AESO transmission line losses, which were partially offset by higher production.

Sustaining capital expenditures for the three months ended Sept. 30, 2020, were $3 million higher than the same period in 2019, due to the timing of planned outages. Sustaining capital expenditures for the nine months ended Sept. 30, 2020, were consistent with the same period in 2019, which was in line with expectations.

Hydro's cash flow for the three months ended Sept. 30, 2020, decreased by $2 million, compared with the same period in 2019, mainly due to timing of sustaining capital expenditures. For the nine months ended Sept. 30, 2020, cash flow decreased by $8 million, compared with the same period in 2019, mainly due to lower comparable EBITDA.

Energy Marketing

	3 months ended Sept. 30		9 months ended Sept. 30	
	2020	2019	**2020**	2019
Revenues and comparable gross margin	**58**	36	**114**	85
Operations, maintenance and administration	**9**	5	**24**	22
Comparable EBITDA	**49**	31	**90**	63
Deduct:				
Provisions and other	**(2)**	1	**(9)**	(11)
Energy Marketing cash flow	**51**	30	**99**	74

Comparable EBITDA for the three and nine months ended Sept. 30, 2020, increased by $18 million and $27 million, respectively, compared to the same periods in 2019. Results were primarily attained from market volatility arising from extreme weather events in California during the quarter as well as continued strong performance 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 nine months ended Sept. 30, 2020, increased by $21 million and $25 million, respectively, compared to the the same periods in 2019, mainly due to higher comparable EBITDA.

Corporate

	3 months ended Sept. 30		9 months ended Sept. 30	
	2020	2019	**2020**	2019
Operations, maintenance, and administration	**16**	17	**59**	51
Taxes, other than income taxes	**—**	1	**—**	1
Net other operating loss	**—**	—	**—**	2
Comparable EBITDA	**(16)**	(18)	**(59)**	(54)
Deduct:				
Sustaining capital:				
Routine capital	**4**	3	**10**	8
Total sustaining capital expenditures	**4**	3	**10**	8
Payments on lease obligations	**1**	1	**3**	3
Other	**—**	—	**—**	(2)
Corporate cash flow	**(21)**	(22)	**(72)**	(63)

Corporate overhead costs for the three months ended Sept. 30, 2020 were consistent with the same period in 2019. Corporate overhead costs for the nine months ended Sept. 30, 2020, increased by $5 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 employee share-based payment plans is fixed by entering into total return swaps, which are cash settled every quarter.

	3 months ended Sept. 30		9 months ended Sept. 30	
Supplemental disclosure	**2020**	2019	**2020**	2019
Corporate cash flow	**(21)**	(22)	**(72)**	(63)
Total return swap (gains) losses	**—**	1	**8**	(8)
Adjusted Corporate cash flow	**(21)**	(21)	**(64)**	(71)

Excluding the impact of the total return swap, Corporate overhead costs for the three months ended Sept. 30, 2020, were consistent with the same period in 2019, which is in line with expectations. Excluding the impact of the total return swap, Corporate overhead costs for the nine months ended Sept. 30, 2020, decreased by $7 million, compared to the same period in 2019, mainly due to lower legal fees, labour and travel costs, partially offset by additional costs to support growth and development projects.

Selected Quarterly Information

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

	Q4 2019	Q1 2020	Q2 2020	**Q3 2020**
Revenues	609	606	437	**514**
Comparable EBITDA	243	220	217	**256**
FFO	189	172	159	**193**
Net earnings (loss) attributable to common shareholders	66	27	(60)	**(136)**
Net earnings (loss) per share attributable to common shareholders, basic and diluted[(1)]	0.24	0.10	(0.22)	**(0.50)**

	Q4 2018	Q1 2019	Q2 2019	Q3 2019
Revenues	622	648	497	593
Comparable EBITDA	265	221	215	305
FFO	217	169	155	244
Net earnings (loss) attributable to common shareholders	(122)	(65)	—	51
Net earnings (loss) per share attributable to common shareholders, basic and diluted[(1)]	(0.43)	(0.23)	—	0.18

(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 nine months 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 and third quarters 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, second and third quarters of 2020, third and fourth quarters of 2019 and asset impairments during the fourth quarters of 2018;
- Effects of changes in useful lives of certain assets during the third quarter of 2020 and 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	Sept. 30, 2020	Dec. 31, 2019
FFO(1)	713	757
Less: PPA Termination Payments	—	(56)
Add: Interest on debt, exchangeable securities and leases, net of interest income and capitalized interest	179	166
FFO before interest	**892**	867
Interest on debt, exchangeable securities and leases, net of interest income	185	172
Add: 50 per cent of dividends paid on preferred shares	20	20
Adjusted interest	**205**	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 nine months ended Sept. 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	Sept. 30, 2020	Dec. 31, 2019
FFO(1, 2)	713	757
Less: PPA Termination Payments(1)	—	(56)
Less: 50 per cent of dividends paid on preferred shares(1)	(20)	(20)
Adjusted FFO(1)	**693**	681
Period-end long-term debt(3)	3,063	3,212
Exchangeable securities	329	326
Less: Cash and cash equivalents	(270)	(411)
Less: Principal portion of TransAlta OCP restricted cash	(11)	(10)
Add: 50 per cent of issued preferred shares	471	471
Fair value asset of hedging instruments on debt(4)	(11)	(7)
Adjusted net debt	**3,571**	3,581
Adjusted FFO to adjusted net debt (%)	**19.4**	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 nine months ended Sept. 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 Sept. 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 increased slightly due to lower adjusted net debt compared with 2019.

Adjusted Net Debt to Adjusted Comparable EBITDA

As at	Sept. 30, 2020	Dec. 31, 2019
Adjusted net debt	**3,571**	3,581
Comparable EBITDA(1)	**936**	984
Less: PPA Termination Payments(1)	**—**	(56)
Adjusted comparable EBITDA(1)	**936**	928
Adjusted net debt to adjusted comparable EBITDA (times)	**3.8**	3.9

(1) Last 12 months.

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

Deconsolidated Net Debt to Deconsolidated Comparable EBITDA

In addition to reviewing fully consolidated ratios and results, management reviews net debt to comparable EBITDA on a deconsolidated basis to highlight TransAlta's financial flexibility, balance sheet strength and leverage excluding the portion of TransAlta Renewables and 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	Sept. 30, 2020	Dec. 31, 2019
Period-end long-term debt(1)	**3,063**	3,212
Exchangeable securities	**329**	326
Less: Cash and cash equivalents	**(270)**	(411)
Add: TransAlta Renewables cash and cash equivalents(2)	**24**	63
Less: Principal portion of TransAlta OCP restricted cash	**(11)**	(10)
Add: 50 per cent of issued preferred shares	**471**	471
Less: Fair value asset of hedging instruments on debt(3)	**(11)**	(7)
Less: TransAlta Renewables long-term debt	**(816)**	(961)
Less: US tax equity financing(4)	**(140)**	(145)
Deconsolidated net debt	**2,639**	2,538
Comparable EBITDA(5)	**936**	984
Less: PPA Termination Payments(5)	**—**	(56)
Less: TransAlta Renewables comparable EBITDA(5)	**(454)**	(438)
Less: TA Cogen comparable EBITDA(5)	**(56)**	(80)
Add: Dividend from TransAlta Renewables(5)	**151**	151
Add: Dividend from TA Cogen(5)	**16**	37
Deconsolidated comparable EBITDA(5)	**593**	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 Sept. 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 Sept. 30, 2020			3 months ended Sept. 30, 2019		
	TransAlta Consolidated	**TransAlta Renewables**	**TransAlta Deconsolidated**	TransAlta Consolidated	TransAlta Renewables	TransAlta Deconsolidated
Cash flow from operating activities	**257**	**65**		328	75	
Change in non-cash operating working capital balances	**(94)**	**(7)**		(92)	(26)	
Cash flow from operations before changes in working capital	**163**	**58**		236	49	
Adjustments:						
Decrease in finance lease receivable	**3**	**—**		7	—	
Coal inventory write-down	**22**	**—**		—	—	
Finance and interest income - economic interests	**—**	**(13)**		—	(9)	
Adjusted FFO - economic interests	**—**	**38**		—	34	
Other	**5**	**—**		1	—	
FFO	**193**	**83**	**110**	244	74	170
Dividend from TransAlta Renewables			**38**			38
Distributions to TA Cogen's Partner			**(8)**			(12)
Less: PPA Termination Payments			**—**			(56)
Deconsolidated TransAlta FFO			**140**			140

	9 months ended Sept. 30, 2020			9 months ended Sept. 30, 2019		
	TransAlta Consolidated	**TransAlta Renewables**	**TransAlta Deconsolidated**	TransAlta Consolidated	TransAlta Renewables	TransAlta Deconsolidated
Cash flow from operating activities	**592**	**218**		668	258	
Change in non-cash operating working capital balances	**(114)**	**(30)**		(122)	(48)	
Cash flow from operations before changes in working capital	**478**	**188**		546	210	
Adjustments:						
Decrease in finance lease receivable	**11**	**—**		19	—	
Coal inventory write-down	**22**	**—**		—	—	
Finance and interest income - economic interests	**—**	**(31)**		—	(48)	
Adjusted FFO - economic interests	**—**	**120**		—	107	
Other	**13**	**—**		3	—	
FFO	**524**	**277**	**247**	568	269	299
Dividend from TransAlta Renewables			**113**			113
Distributions to TA Cogen's Partner			**(12)**			(33)
Less: PPA Termination Payments			**—**			(56)
Deconsolidated TransAlta FFO			**348**			323

Financial Position

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

As at	Sept. 30, 2020	Dec. 31, 2019	Increase (decrease)
Assets			
Cash and cash equivalents	**270**	411	(141)
Trade and other receivables	**485**	462	23
Inventory	**258**	251	7
Assets held for sale	**107**	—	107
Risk management assets (current and long-term)	**802**	806	(4)
Property, plant, and equipment, net	**5,889**	6,207	(318)
Intangible assets	**328**	318	10
Others(1)	**1,091**	1,053	38
Total assets	**9,230**	9,508	(278)
Liabilities and equity			
Accounts payable and accrued liabilities	**509**	413	96
Credit facilities, long-term debt and lease obligations (current and long-term)	**3,063**	3,212	(149)
Decommissioning and other provisions (current and long-term)	**616**	546	70
Risk management liabilities (current and long-term)	**138**	110	28
Equity attributable to shareholders	**2,663**	2,961	(298)
Others(2)	**2,241**	2,266	(25)
Total liabilities and equity	**9,230**	9,508	(278)

(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 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 increased largely due to timing of customer receipts, partially offset by lower collateral payments.
- Inventory increased mainly due to higher tonnes of coal at Centralia resulting from dispatch optimization beginning as early as February in 2020 ($19 million) as well as higher emission credits inventory ($24 million), partially offset by Highvale Mine coal inventory write-down ($22 million).
- Assets held for sale relate primarily to the sale of the Pioneer Pipeline (refer to the Corporate Strategy section of this MD&A for further details).
- Risk management assets, net of liabilities decreased primarily due to contract settlements substantially offset by changes in market prices and foreign exchange rates.
- Property, plant and equipment ("PP&E") decreased due to depreciation ($507 million) and reclass of pipeline and certain mining equipment to assets held for sale ($107 million) and asset impairments ($72 million), which was partially offset by additions ($276 million) relating to assets under construction for the conversion to gas, the Windrise wind facility, WindCharger battery storage project, the Kaybob cogeneration facility, land and planned major maintenance expenditures. Our PP&E was also impacted significantly due to changes in foreign exchange rates ($40 million increase) and net revisions to decommissioning provisions as a result of changes in cash flows and discount rates ($56 million).
- Intangible assets increased due to the Ada acquisition ($37 million) and sustaining project additions ($8 million), partially offset by depreciation ($38 million).
- Accounts payable and accrued liabilities increased largely due to timing of payments for operational payables.
- Credit facilities, long-term debt and lease obligations decreased due to lower drawings on the credit facilities ($117 million) and debt repayments ($61 million), partially offset by changes in outstanding balances as a result of the strengthening of the US dollar ($27 million).
- Decommissioning and other provisions have increased mainly due to revisions in estimated cash flows ($70 million), accretion ($23 million) and strengthening of the US dollar ($9 million), which was partially offset by changes in discount rates ($19 million) and liabilities settled ($13 million).

- Equity attributable to shareholders decreased mainly due to net losses for the period ($139 million), common and preferred share dividend payments ($65 million), net losses on cash flow hedges ($33 million), fair value investments losses ($51 million), actuarial losses on defined benefit plans ($12 million), the share repurchases under the NCIB ($21 million), the effect of share-based payment plans ($11 million), which was partially offset by net gains on translating net assets of foreign operations ($29 million).

Cash Flows

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

	9 months ended Sept. 30		
	2020	2019	Increase (decrease)
Cash and cash equivalents, beginning of period	**411**	89	322
Provided by (used in):			
Operating activities	**592**	668	(76)
Investing activities	**(368)**	(321)	(47)
Financing activities	**(369)**	(109)	(260)
Translation of foreign currency cash	**4**	(1)	5
Cash and cash equivalents, end of period	**270**	326	(56)

Cash provided by operating activities for the nine months ended Sept. 30, 2020, was lower compared with the same period in 2019 primarily due to lower revenues in 2020 .

Cash used in investing activities for the nine months ended Sept. 30, 2020, increased compared with the same period in 2019, largely due to:

- Changes in our restricted cash ($49 million), increased cash spent on construction activities ($36 million) and higher non-cash working capital related to the timing of construction payables for the assets under construction ($31 million);
- Offset by lower cash spent on acquisitions (TransAlta acquired Ada for $37 million in 2020, compared with the Antrim acquisition of $32 million and the Pioneer Pipeline acquisition of $83 million in 2019).

Cash from financing activities for the nine months ended Sept. 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 ($72 million) as a result of lower payments on the credit facilities ($62 million) and lower scheduled principal repayments on project debt ($10 million); and
- $16 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	Sept. 30, 2020		Dec. 31, 2019	
	$	%	$	%
TransAlta Corporation				
Recourse debt - CAD debentures	**648**	**9**	647	9
Recourse debt - US senior notes	**930**	**14**	905	13
Exchangeable securities	**329**	**5**	326	5
Other	**7**	**—**	9	—
Less: cash and cash equivalents	**(246)**	**(4)**	(348)	(5)
Less: principal portion of restricted cash on TransAlta OCP	**(11)**	**—**	(10)	—
Less: fair value asset of economic hedging instruments on debt	**(11)**	**—**	(7)	—
Net recourse debt, excluding US tax equity financing	**1,646**	**24**	1,522	22
US tax equity financing	**140**	**2**	145	2
Non-recourse debt	**399**	**6**	426	6
Lease obligations	**123**	**2**	119	2
Total net debt - TransAlta Corporation	**2,308**	**34**	2,212	32
TransAlta Renewables				
Credit facility	**103**	**1**	220	3
Less: cash and cash equivalents	**(24)**	**—**	(63)	(1)
Net recourse debt	**79**	**1**	157	2
Non-recourse debt	**691**	**10**	718	10
Lease obligations	**22**	**—**	23	—
Total net debt - TransAlta Renewables	**792**	**11**	898	12
Total consolidated net debt	**3,100**	**45**	3,110	44
Non-controlling interests	**1,107**	**16**	1,101	15
Equity attributable to shareholders				
Common shares	**2,944**	**43**	2,978	42
Preferred shares	**942**	**14**	942	13
Contributed surplus, deficit and accumulated other comprehensive income	**(1,223)**	**(18)**	(959)	(14)
Total capital	**6,870**	**100**	7,172	100

The Corporation continues to maintain a strong financial position in part due to our long-term contracts and hedged positions. At quarter end we had access to $1.6 billion in liquidity including $270 million in cash and cash equivalents.

In October 2020, the Corporation completed an AU$800 million senior secured note offering, which is secured among other things, a first ranking charge over all assets of its South Hedland operation and the Corporation also received $400 million from the second tranche of financing from the Brookfield investment. We also have access to additional capital through potential project financing of existing assets that are currently unencumbered. Between 2020 and 2022, we have $1.2 billion 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.

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

As at Sept. 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	421	—	829	Q2 2023
Canadian committed bilateral credit facilities(3)	240	233	—	7	Q2 2022
TransAlta Renewables					
Committed credit facility(2)	700	90	103	507	Q2 2023
Total	**2,190**	**744**	**103**	**1,343**	

(1) TransAlta has obligations to issue letters of credit and cash collateral to secure potential liabilities to certain parties, including those related to potential environmental obligations, commodity risk management and hedging activities, pension plan obligations, construction projects and purchase obligations. At Sept. 30, 2020, we provided cash collateral of $25 million.

(2) TransAlta has letters of credit of $110 million and TransAlta Renewables has letters of credit of $90 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 $27 million as at Sept. 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:

	Sept. 30, 2020
Effects of foreign exchange on carrying amounts of US operations (net investment hedge)	**12**
Foreign currency economic cash flow hedges on debt	**5**
Economic hedges and other	**6**
Unhedged	**4**
Total	**27**

Share Capital

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

As at	**Nov. 3, 2020**	**Sept. 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 Sept. 30, 2020, we own 60.1% per cent (Sept. 30, 2019 – 60.5 per cent) of TransAlta Renewables. Our ownership percent decreased due to common shares issued under TransAlta Renewables' Dividend Reinvestment Plan ("DRIP"). We do not participate in this plan. TransAlta Renewables has suspended the DRIP in respect of any future declared dividends until further notice. Accordingly, the dividend payable on Oct. 30, 2020 to shareholders of record on Oct. 15, 2020 will be the last dividend payment eligible for reinvestment by participating shareholders under the DRIP. Subsequent dividends will be paid only in cash.

We also own 50.01 per cent of TA Cogen (Sept. 30, 2019 - 50.01 per cent), which owns, operates or has an interest in three natural-gas-fired facilities (Ottawa, Windsor and Fort Saskatchewan) and one dual-fuel generating facility.

Reported earnings attributable to non-controlling interests for the three months and nine months ended Sept. 30, 2020 were $7 million and $29 million, respectively, a decrease of $9 million and $38 million compared to the same periods in 2019. Earnings decreased at TransAlta Renewables mainly due to lower revenues, a decrease in finance income, an increase in unrealized losses due to changes in the fair value of investments in subsidiaries of TransAlta and an increase in income tax expense, offset by foreign exchange gains resulting from the strengthening Australian dollar relative to the Canadian dollar. Earnings from TA Cogen for the nine months ended Sept. 30, 2020, also decreased compared with the same period in 2019, due to lower gross margin as a result of the planned outage for the dual-fuel conversion at the Sheerness plant and low Alberta market demand.

Returns to Providers of Capital
Net Interest Expense
The components of net interest expense are shown below:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2020	2019	**2020**	2019
Interest on debt	**39**	40	**121**	123
Interest on exchangeable securities	**7**	7	**22**	12
Interest income	**(2)**	(4)	**(7)**	(9)
Capitalized interest	**(2)**	(2)	**(4)**	(4)
Interest on lease obligations	**2**	1	**6**	3
Credit facility fees, bank charges, and other interest	**4**	4	**13**	11
Other	**—**	3	**1**	7
Accretion of provisions	**8**	6	**23**	18
Net interest expense	**56**	55	**175**	161

Net interest expense was higher in the three and nine months ended Sept. 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. The increase in interest expense was partially offset by the termination of the Keephills 3 contract liability in the fourth quarter of 2019, which had a significant financing component. 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 moved staff to work from home structures with the exception of their system operations staff. Currently, most staff have returned to work and most of the planned in-person consultation processes are still being held virtually. These actions initially delayed proceedings, however, most activities are back to regular timing and are working through a backlog from the spring. 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, Ontario and Canadian federal government delayed reporting requirements. Reporting requirements have now returned to regular schedules. TransAlta has completed all regulatory reporting for carbon related emission reporting regulations. The federal government accepted Ontario's Emissions Performance Standard ("EPS") as meeting the requirements of the Greenhouse Gas Pollution Pricing Act. Ontario's large emitters are expected to report under the EPS for the 2021 compliance year. The federal Output Based Performance Standard and EPS are very similar and use the same reporting platforms so changes to the business should be minimal.

Other Consolidated Analysis

Asset Impairment Charges and Reversals

As part of the Corporation's monitoring controls, long-range forecasts are prepared for each cash generating unit ("CGU"). The long-range forecast estimates are used to assess the significance of potential indicators of impairment and provide criteria to evaluate adverse changes in operations. The Corporation also considers the relationship between its market capitalization and its book value, among other factors, when reviewing for indicators of impairment. When indicators of impairment are present, the Corporation estimates a recoverable amount for each CGU by calculating an approximate fair value less costs of disposal using discounted cash flow projections based on the Corporation's long-range forecasts. The valuations used are subject to measurement uncertainty based on assumptions and inputs to the Corporation's long-range forecast, including changes to fuel costs, operating costs, capital expenditures, external power prices and useful lives of the assets extending to the last planned asset retirement in 2073.

I. 2020

Sundance Unit 3

In the third quarter of 2020, the Corporation recognized an impairment charge on the Sundance Unit 3 in the amount of $70 million, due to the Corporation's decision to retire the Unit 3. Refer to Note 3(F) of the interim condensed consolidated financial statements for further details. The impairment assessment was based on value in use and included the estimated future cash flows expected to be derived from the Unit until its retirement on July 31, 2020. Discounting did not have a material impact.

BC Hydro Facility

In the third quarter of 2020, the Corporation recorded an impairment of $2 million due to a post-construction review of water resources which resulted in a revision to the forecasted production at a BC hydro facility.

The impairments noted above were offset by an asset impairment reversal related to changes in the decommissioning liability related to the Centralia mine and Sundance Units 1, which are no longer operating and have reached the end of their useful lives. Refer to Note 1(B) of the interim condensed consolidated financial statements for further details.

II. 2019

Centralia Plant

In 2012, the Corporation recorded an impairment of $347 million relating to the Centralia Plant CGU. As part of the annual impairment test, the Corporation considers possible indicators of impairment at Centralia Plant CGU. In 2019, an internal valuation indicated the fair value less costs of disposal of the CGU exceeded the carrying value by a substantial margin, resulting in a full recoverability test in 2019. The updated fair value included sustained changes in the power price market and cost of coal due to contract renegotiations. As a result of the recoverability test an impairment reversal of $151 million was recorded in the Centralia segment. For additional information for the valuation and key assumptions refer to Note 7 of the 2019 audited annual consolidated financial statements.

In the third quarter of 2019, the Corporation increased the Centralia mine decommissioning and restoration provision by $109 million as management no longer believed that Coalview Centralia, LLC ("Coalview") would be able to complete the fine coal recovery and reclamation work as originally proposed. Since the Centralia mine is no longer operating and reached the end of its useful life in 2006, this adjustment resulted in an immediate recognition for the full $109 million, through asset impairment charges in net earnings.

III. Project Development Costs
During the three and nine months ended Sept. 30, 2019, the Corporation wrote-off $18 million in project development costs related to projects that are no longer proceeding.

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	—	2	11	5	3	4	**25**
Transmission	—	3	5	5	5	7	**25**
Total	**—**	**5**	**16**	**10**	**8**	**11**	**50**

Natural Gas and Transportation Contracts
The Corporation has fixed price or volume natural gas purchase and transportation contracts. The above table 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 an additional 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 by 2023. This agreement would replace the Corporation's existing 15-year commitment to purchase 139 TJ per day of natural gas on the Pioneer Pipeline, which remains in place until the closing of the Transaction.

Transmission
The reference to Transmission in the table above 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 nine months ended Sept. 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. 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. The AUC recently ruled on the AESO's request and approved an invoice settlement process that will be broken down into three periods (2006-2009, 2010-2013, 2014-2016).

We received the first invoice (2014-2016) for line losses in Oct 22, 2020, with payment due before the end of this year and expect the remaining two invoices to be issued in 2021. The net amount owing this year is approximately $6 million.

The total outstanding amount for the line losses (including the $6 million referenced above) is estimated at approximately $14 million. While we are relatively confident of the AESO's calculation for the first invoice, the remaining two invoice amounts continue to remain subject to review and change.

II. FMG Disputes
The Corporation is currently engaged in a dispute with Fortescue Metals Group Ltd. ("FMG") as a result of FMG's purported termination of the South Hedland PPA. TransAlta sued FMG, seeking 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 Corporation had a second dispute involving FMG's claims against TransAlta related to the transfer of the Solomon facility to FMG. FMG claimed certain amounts related to the condition of the facility while TransAlta claimed certain outstanding costs that should be reimbursed. The dispute was settled and dismissed in the Supreme Court of Western Australia on Sept. 9, 2020, resulting in a US$6 million payment to TransAlta.

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 (possibly three) week trial will begin on April 19, 2021, instead of Sept. 2020. 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 fair.

V. **Keephills 1 Superheater Force Majeure**
Keephills Unit 1 was taken offline March 17 to May 17, 2015, as a result of a large leak in the secondary superheater. TransAlta Generation Partnership ("TAGP") claimed force majeure under the Keephills Power Purchase Arrangement (the "PPA"). ENMAX, the PPA Buyer at the time, did not dispute the force majeure. The Balancing Pool argued and won in the Courts that it has a right under the PPA to commence an arbitration, independent of the PPA Buyer, ENMAX. As such, the arbitration over this force majeure will recommence and likely be heard before the end of 2021.

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 11 of the unaudited interim condensed consolidated financial statements as at and for the three and nine months ended Sept. 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
In the third quarter of 2020, the Corporation adjusted the Highvale Mine decommissioning and restoration provision to reflect the mine closure advancement, an updated mine plan and current mining activity including increased volume of

material movement. The Corporation's current best estimate of the decommissioning and restoration provision increased by $70 million. This resulted in an increase in the related assets in property, plant and equipment ("PP&E").

In addition, due to volatility within the market as a result of COVID-19, we have seen movement within the discount rates as a result of changes in credit spreads. On a year-to-date basis, as a result of changes in discount rates, the decommissioning provision has decreased by $19 million. The $19 million decrease in the decommissioning provision has resulted in a $14 million decrease in the related PP&E assets and a $5 million impairment reversal on the consolidated statement of earnings as it relates to Sundance Unit 1 and the Centralia Mine which are no longer operating and have reached the end of their useful lives.

In the third quarter of 2019, the Corporation increased the Centralia mine decommissioning and restoration provision by $109 million as management no longer believes that Coalview Centralia, LLC ("Coalview") will be able to complete the fine coal recovery and reclamation work as originally proposed. Since the Centralia mine is no longer operating and reached the end of its useful life in 2006, this adjustment results in immediate recognition for the full $109 million, through asset impairment in net earnings.

Useful Life of PP&E
During the third quarter, the Board approved the accelerated shutdown of the Highvale Mine by the end of 2021 and accordingly the useful life of the related assets was adjusted to align with the Corporation's conversion to gas plans. As at Sept. 30, 2020, the carrying value of the Highvale Mine, including PP&E, ROU assets and intangible assets, was $403 million, the majority of which will be recognized within the consolidated statements of earnings over the next five quarters.

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 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 ongoing 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 10 and 11 of our unaudited interim condensed consolidated financial statements as at and for the three and nine months ended Sept. 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 Sept. 30, 2020, Level III instruments had a net asset carrying value of $679 million (Dec. 31, 2019 - $686 million). The decrease during the period is primarily attributable to contract settlements substantially offset by changes in market prices and foreign exchange rates. 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 11 of our unaudited interim condensed consolidated financial statements for details on our risks and how we manage them. Our risk management profile and practices have not changed materially from Dec. 31, 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 including 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 90 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 nine months ended Sept. 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 Sept. 30, 2020, the end of the period covered by this report, our ICFR and DC&P were effective.

Supplemental Information

		Sept. 30, 2020	Dec. 31, 2019
Closing market price (TSX) ($)		**8.19**	9.28
Price range for the last 12 months (TSX) ($)	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)(%)		**19.4**	19.0
Adjusted net debt to adjusted comparable EBITDA(1,2) (times)		**3.8**	3.9
Deconsolidated net debt to deconsolidated comparable EBITDA (1, 2, 3) (times)		**4.5**	4.2
Adjusted net debt to total capital(1) (%)		**52.0**	49.9
Return on equity attributable to common shareholders(2)(%)		**(7.7)**	3.3
Return on capital employed(2)(%)		**2.4**	4.3
Earnings coverage(2)(times)		**0.7**	1.5
Dividend payout ratio based on FFO(1, 2)(%)		**6.6**	6.6
Dividend coverage(2)(times)		**17.1**	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.
(3) 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.

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.

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

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

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

Balancing Pool
The Balancing Pool was established in 1999 by the Government of Alberta to help manage the transition to competition in Alberta's electric industry. 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.

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

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

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

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

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.

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.

Pioneer Pipeline
The Pioneer gas pipeline is currently jointly owned and operated by TransAlta and Tidewater Midstream and Infrastructure Ltd. The asset is held for sale and subject to closing of the transaction.

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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