TRANSALTA CORPORATION

Third Quarter Report for 2021

Management's Discussion and Analysis

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

This MD&A should be read in conjunction with the unaudited interim condensed consolidated financial statements of TransAlta Corporation as at and for the three and nine months ended Sept. 30, 2021 and 2020, and should also be read in conjunction with the audited annual consolidated financial statements and MD&A contained within our 2020 Annual Integrated Report. In this MD&A, unless the context otherwise requires, "we", "our", "us", the "Corporation", and "TransAlta" refers to TransAlta Corporation and its subsidiaries. Our unaudited interim condensed consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") International Accounting Standards ("IAS") *34 Interim Financial Reporting* for Canadian publicly accountable enterprises as issued by the International Accounting Standards Board ("IASB") and in effect at Sept. 30, 2021. All tabular amounts in the following discussion are in millions of Canadian dollars unless otherwise noted. This MD&A is dated Nov. 8, 2021. Additional information respecting TransAlta, including its Annual Information Form, is available on SEDAR at **www.sedar.com**, on EDGAR at **www.sec.gov**, and on our website at **www.transalta.com**. Information on or connected to our website is not incorporated by reference herein.

Table of Contents

Forward-Looking Statements

This MD&A includes "forward-looking information" within the meaning of applicable Canadian securities laws, and "forward-looking statements" within the meaning of applicable United States securities laws, including the United States Private Securities Litigation Reform Act of 1995 (collectively referred to herein as "forward-looking statements"). All forward-looking statements are based on our beliefs as well as assumptions based on information available at the time the assumption was made and on management's experience and perception of historical trends, current conditions and expected future developments, as well as other factors deemed appropriate in the circumstances. Forward-looking statements are not facts, but only predictions and generally can be identified by the use of statements that include phrases such as "may", "will", "can", "could", "would", "shall", "believe", "expect", "estimate", "anticipate", "intend", "plan", "forecast", "foresee", "potential", "enable", "continue" or other comparable terminology. These statements are not guarantees of our future performance, events or results and are subject to risks, uncertainties and other important factors that could cause our actual performance, events or results to be materially different from that set out in or implied by the forward-looking statements.

In particular, this MD&A contains forward-looking statements including, but not limited to, statements relating to: our Clean Electricity Growth Plan and ability to achieve the target of 2 GW of incremental renewables capacity with an investment of $3 billion by 2025; the Corporation's future growth pipeline, including the timing of commercial operations and the costs of the advanced and early stage projects; expansion of the Corporation's development pipeline to 5 GW; the proportion of EBITDA to be generated from renewable sources by the end of 2025; the retirement of Sundance Unit 4 and Keephills Unit 1; the suspension of the Sundance 5 repowering project; expected average annual EBITDA of the North Carolina Solar (as defined below) portfolio; the Kent Hills incident and the extent of any remediation, the timing and cost of such remediation and the impact such incident could have on the Corporation's revenues and contracts; our conversions to natural gas and planned outages, including the conversion of Keephills Unit 3 from coal to natural gas and the associated timing and costs thereof; the Northern Goldfields Solar Project, including the total construction capital and expected average annual EBITDA; the Garden Plain wind project, including construction capital and expected annual average EBITDA; the Windrise wind project, including timing of commercial operation and total construction capital; the Corporation's response to the COVID-19 pandemic, including vaccination policies; the shutting down of the Highvale Mine to eliminate coal as a fuel source in Alberta by the end of 2021 and realizing the benefits of the transition off-coal; expected increases to our cost per tonne of coal; the expected impact and quantum of carbon compliance costs; the ability to realize future growth opportunities with BHP (as defined below); regulatory developments and their expected impact on the Corporation, including the Canadian federal climate plan and the implementation of the major aspects thereof (including increased carbon pricing, increased funding for clean technology and the implementation of the Clean Fuel Regulations (as defined below); the Government of Canada's commitment to achieve net zero emissions by 2035 and the adoption of a clean electricity standard; the Government of Ontario transitioning to a provincial emission performance standard; the implementation of the US Jobs Plan (as defined below) and Australian renewable energy initiatives; the ability of the Corporation to realize benefits from Canadian, US and Australian regulatory developments, including receiving funding for clean electricity projects; the potential increase in value of emission reduction credits; the 2021 financial outlook, including comparable earnings before interest, taxes, depreciation and amortization ("comparable EBITDA"), free cash flow ("FCF") and annualized dividend in 2021; increased gross margin contribution from Energy Marketing; hedged production and price in the fourth quarter of 2021 and full year 2022; hedged gas volume and gas price for the fourth quarter of 2021 and full year 2022; sustaining and productivity capital in 2021, including routine capital, planned major maintenance and mine capital; Alberta hedge positions for remainder of 2021 and 2022; significant planned major outages for 2021; lost production due to planned major maintenance for 2021; expected power prices in Alberta, Ontario and the Pacific Northwest; the cyclicality of the business, including as it relates to maintenance costs, production and loads; expectations regarding refinancing the debt maturing in 2022; the liquidated damages potentially payable in respect of the Sarnia outages in the second quarter of 2021; the satisfaction of the settlement conditions in respect of the dispute with Fortescue Metals Group Ltd. ("FMG"); and the Corporation continuing to maintain a strong financial position and significant liquidity.

The forward-looking statements contained in this MD&A are based on many assumptions including, but not limited to, the following: the impacts arising from COVID-19 not becoming significantly more onerous on the Corporation; no significant changes to applicable laws and regulations beyond those that have already been announced, including no material changes to the applicable Carbon Tax and performance factors; no significant changes to the fuel and purchased power costs; no material adverse impacts to the long-term investment and credit markets; Alberta spot prices of $95 /MWh to $105/MWh in 2021; Mid-Columbia spot prices of US$50/MWh to US$60/MWh in 2021; sustaining capital of $200 million to $225 million; 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 the growth of TransAlta Renewables. Forward-looking statements are subject to a number of significant risks and uncertainties that could cause actual plans, performance, results or outcomes to differ materially from current expectations. Factors that may adversely impact what is expressed or implied by forward-looking statements contained in this MD&A include risks relating to: the impact of COVID-19, including more restrictive directives of government and public health authorities; increased force majeure claims; reduced labour availability and ability to continue to staff our operations and facilities; disruptions to our supply chains, including our ability to secure necessary equipment and to obtain regulatory approvals on the expected timelines or at all in respect of our growth projects; restricted access to capital and increased borrowing costs; changes in short-term and/or long-term electricity supply and demand; fluctuations in market prices, including lower merchant pricing in Alberta, Ontario and Mid-Columbia; reductions in production; increased costs; changes in 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; adverse impacts on our information technology systems and our internal control systems, including increased cyber security threats; commodity risk management and energy trading risks, including the effectiveness of the Corporation's risk management tools associated with hedging and trading procedures to protect against significant losses; changes in demand for electricity and capacity and our ability to contract our generation for prices that will provide expected returns and replace contracts as they expire; changes to the legislative, regulatory and political environments in the jurisdictions in which we operate; environmental requirements and changes in, or liabilities under, these requirements; operational risks involving our facilities, including unplanned outages; disruptions in the transmission and distribution of electricity; the effects of weather, including man made or natural disasters and other climate-change related risks; unexpected increases in cost structure; reductions to our generating units' relative efficiency or capacity factors; disruptions in the source of fuels, including natural gas required for the converted or repowered generating units, as well as the extent of water, solar or wind resources required to operate our facilities; failure to meet financial expectations; the threat of terrorism, including cyberattacks; equipment failure and our ability to carry out or have completed the repairs in a cost-effective manner or timely manner or at all, including if the remediation at the Kent Hills wind facility is more costly than expected; industry risk and competition; fluctuations in the value of foreign currencies and foreign political risks; structural subordination of securities; counterparty credit risk; changes to our relationship with, or ownership of, TransAlta Renewables; changes in the payment or receipt of future dividends, including from TransAlta Renewables; risks associated with development projects and acquisitions, including capital costs, permitting, labour and engineering risks, and delays in the construction or commissioning of projects; increased costs or delays in the conversion of coal-fired generating units to gas-fired generating units; inadequacy or unavailability of insurance coverage; our provision for income taxes; legal, regulatory and contractual disputes and proceedings involving the Corporation; reliance on key personnel; and labour relations matters. The foregoing risk factors, among others, are described in further detail in the other risks and uncertainties contained in the Corporation's Annual Information Form and Management's Discussion and Analysis for the year ended Dec. 31, 2020, filed under the Corporation's profile with the Canadian securities regulators on www.sedar.com and the US Securities and Exchange Commission ("SEC") on www.sec.gov.

Readers are urged to consider these factors carefully in evaluating the forward-looking statements and are cautioned not to place undue reliance on them, which reflect the Corporation's expectations only as of the date hereof. The purpose of the financial outlooks contained herein are to give the reader information about management's current expectations and plans and readers are cautioned that such information may not be appropriate for other purposes and is given as of the date of this MD&A. The forward-looking statements included in this MD&A and associated financial statements 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.

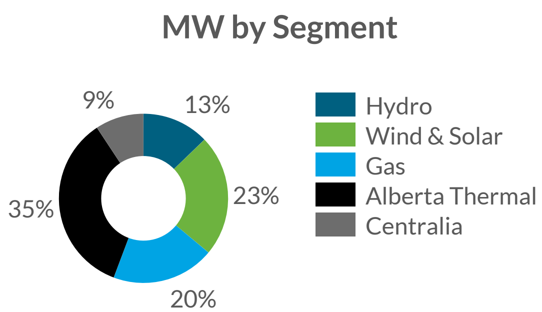
Description of the Business

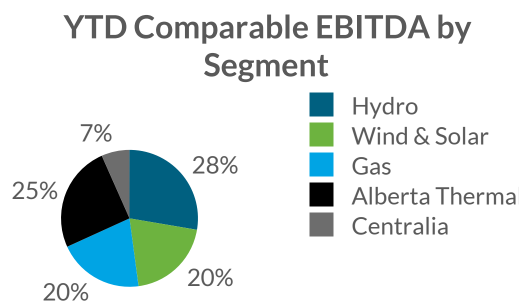
TransAlta is a Canadian corporation and one of Canada's largest publicly traded power generators with over 110 years of operating experience. We own, operate and manage a contracted and geographically diversified portfolio of assets utilizing a broad range of fuels that include water, wind, solar, natural gas and thermal coal.

As at Sept. 30, 2021, our asset base of gross installed capacity comprised 7,162 MW.

	Alberta, Canada		Canada, Excl. Alberta		United States		Australia		Total	
	Gross installed capacity (MW)	Number of facilities	Gross installed capacity (MW)	Number of facilities	Gross Installed capacity (MW)	Number of facilities	Gross installed capacity (MW)	Number of facilities	Gross installed capacity (MW)	Number of facilities
Hydro	834	17	91	9	1	1	—	—	926	27
Wind and Solar(1)	535	13	750	9	397	6	—	—	1,682	28
Gas	300	2	645	3	29	1	450	6	1,424	12
Alberta Thermal(2)(3)	2,460	7	—	—	—	—	—	—	2,460	7
Centralia	—	—	—	—	670	1	—	—	670	1
Total	**4,129**	**39**	**1,486**	**21**	**1,097**	**9**	**450**	**6**	**7,162**	**75**

(1) Additions during the quarter include 106 MW for that portion of the Windrise wind project that was operational as at Sept. 30, 2021 and 4 MW for the Corporation's acquisition of the Old Man Wind facility in Alberta.
(2) Includes 1,196 MW for 4 facilities that have been converted to natural gas.
(3) Excludes 406 MW for Sundance Unit 5 as the repowering project has been suspended during the third quarter of 2021.





Excluding those facilities within the Alberta Electricity Portfolio, 91 per cent of TransAlta's gross installed capacity is covered by long-term power purchase agreements ("PPA"). These PPAs have a weighted average remaining contractual term of 9 years.

Highlights

	3 months ended Sept. 30		9 months ended Sept. 30	
	2021	2020	**2021**	2020
Adjusted availability (%)(1)	**89.2**	91.5	**87.5**	92.0
Production (GWh)	**6,053**	6,184	**16,282**	17,276
Revenues	**850**	514	**2,111**	1,557
Fuel and purchased power(2)	**327**	214	**782**	523
Carbon compliance(2)	**47**	38	**139**	118
Operations, maintenance and administration	**131**	114	**387**	354
Net loss attributable to common shareholders	**(456)**	(136)	**(498)**	(169)
Cash flow from operating activities	**610**	257	**947**	592
Comparable EBITDA(3)	**381**	256	**993**	693
Funds from operations(3)	**297**	193	**758**	524
Free cash flow(3)	**189**	106	**456**	306
Net loss per share attributable to common shareholders, basic and diluted	**(1.68)**	(0.50)	**(1.84)**	(0.61)
Funds from operations per share(3)	**1.10**	0.70	**2.80**	1.90
Free cash flow per share(3)	**0.70**	0.39	**1.68**	1.11
Dividends declared per common share(4)	**0.0450**	0.0425	**0.0900**	0.1275
Dividends declared per preferred share(5)	**0.2484**	0.2593	**0.5075**	0.7645

As at	**Sept. 30, 2021**	Dec. 31, 2020
Total assets	**9,320**	9,747
Total consolidated net debt(3,6)	**2,325**	2,975
Total long-term liabilities	**5,194**	5,376

(1) Prior period adjusted availability has been revised to include our Hydro segment.
(2) As of the first quarter of 2021, carbon compliance costs have been reclassified from fuel and purchase power costs and disclosed separately. Prior periods have been adjusted for comparative purposes.
(3) These items are not defined and have no standardized meaning under IFRS. Presenting these items from period to period provides management and investors with the ability to evaluate earnings trends more readily in comparison with prior periods' results. Please refer to the Reconciliation of Non-IFRS Measures section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS. See also the Additional IFRS measures and Non-IFRS Measures section of this MD&A.
(4) No dividends were declared in first quarter of 2021 as the quarterly dividend related to the period covering the first quarter of 2021 was declared in December 2020.
(5) 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.
(6) Total consolidated net debt includes long-term debt, including current portion, amounts due under credit facilities, exchangeable debentures, US tax equity financing and lease liabilities, net of available cash and cash equivalents, the principal portion of restricted cash in TransAlta OCP LP ("OCP") and the fair value of economic hedging instruments on debt. Please see the table in the Financial Capital section of this MD&A for more details on the composition of total consolidated net debt.

For the three and nine months ended Sept. 30, 2021, we have seen exceptional performance from our Alberta Electricity Portfolio, driving overall strong performance for the Corporation. Both the Hydro and Alberta Thermal segments had high availability during periods of peak pricing, which resulted from abnormally warm summer weather and periods of province-wide planned thermal outages. The Alberta merchant portfolio was positioned to capture opportunities from these strong spot market conditions through both energy and ancillary services revenues. This was further supplemented by strong performance in our Energy Marketing segment. During the third quarter we revised and increased our guidance for comparable EBITDA and FCF based on the strong financial performance attained to date and our expectations for balance of year. Please refer to the 2021 Financial Outlook section of this MD&A for more details on our updated guidance.

Adjusted availability for the three months ended Sept. 30, 2021, was 89.2 per cent compared to 91.5 per cent for the same period in 2020. Higher planned and unplanned outages at our Hydro segment and higher unplanned outages at our Alberta Thermal segment, were partially offset by lower unplanned outages at Sarnia within our North American Gas segment. Adjusted availability for the nine months ended Sept. 30, 2021 was 87.5 per cent, compared to 92.0 per cent for the same period in 2020. The decrease was primarily due to higher planned and unplanned outages in the Centralia segment as Centralia outages had a greater adverse impact in the current year due to the retirement of Centralia Unit 1 at the end of December 2020. In addition, adjusted availability was reduced by the planned outages for the Keephills Unit 2 and Keephills Unit 3 boiler conversions, higher derates at the Alberta Thermal segment and higher planned and unplanned outages at our Hydro segment.

Production for the three and nine months ended Sept. 30, 2021 was 6,053 GWh and 16,282 GWh, respectively, compared to 6,184 GWh and 17,276 GWh for the same periods in 2020. The decrease in production for the three-month period was due to the retirement of Centralia Unit 1 and lower availability at the Hydro segment. This decrease was partially offset by higher dispatching at the Alberta Thermal segment and higher production at the Ada facility and Sarnia facility within our North American Gas segment. The decrease in production for the nine-month period was primarily due to the retirement of Centralia Unit 1, lower adjusted availability across the fleet, portfolio optimization activities at the Alberta Thermal segment, lower wind resources in the Wind and Solar segment and lower customer loads in the Australia segment. This decrease in production was partially offset by higher production at our Ada facility and Sarnia facility within our North American Gas segment and incremental production at the Wind and Solar segment from the Skookumchuck facility.

Revenues for the three and nine months ended Sept. 30, 2021, increased $336 million and $554 million, respectively, compared to the same periods in 2020, mainly as a result of capturing higher realized prices within the Alberta market through our optimization and operating activities and the elimination of the net payment obligations under the Alberta Hydro PPA in the prior period. Revenues also increased due to the strong performance from the Energy Marketing segment, an increase in revenues within the North American Gas segment from the addition of the Ada facility and an increase within the Wind and Solar segment from the addition of the Skookumchuck facility. These increases were partially offset by lower production at the Centralia, Hydro and Wind and Solar segments and lower year-to-date production at the Alberta Thermal segment.

Fuel and purchased power costs increased by $113 million and $259 million in the three and nine months ended Sept. 30, 2021, respectively, compared to the same periods in 2020. In our Centralia segment, our margins declined compared to 2020 due to higher fuel transportation costs and the acquisition of higher-priced power to fulfil our contractual obligations during planned and unplanned outages during periods of higher merchant pricing. In addition, the Alberta Thermal segment had higher natural gas pricing, higher coal mine depreciation and coal inventory write-downs at the Highvale mine, all of which contributed to higher fuel costs.

Carbon compliance costs increased by $9 million and $21 million in the three and nine months ended Sept. 30, 2021, respectively, compared to the same periods in 2020, due to an increase in the carbon price per tonne, partially offset by reductions in greenhouse gas ("GHG") emissions stemming from changes in the fuel mix ratio as we operated more on natural gas and fired less with coal. Operating with natural gas reduces carbon compliance costs as we produce fewer GHG emissions than by using coal. In addition, for the three-month period ended Sept. 30, 2021, the Alberta Thermal segment had increased production which contributed to higher carbon compliance costs, whereas for the nine-month period ended Sept. 30, 2021, carbon compliance costs were partially offset by lower production at the Alberta Thermal segment.

Operations, maintenance and administration ("OM&A") expenses for the three and nine months ended Sept. 30, 2021, increased by $17 million and $33 million, respectively, compared to the same periods in 2020. For the three and nine months ended Sept. 30, 2021, a writedown of $5 million and $30 million, respectively, was recorded on parts and material inventory related to the Highvale mine and coal operations at our natural gas converted facilities. In addition, for the three and nine months ended Sept. 30, 2021, variability caused by the total return swap resulted in an unfavourable change of $1 million and a favourable change of $12 million, respectively. During the first quarter of 2021, we received a Canada Emergency Wage Subsidy ("CEWS") of $8 million. Excluding the impact of the total return swap, CEWS funding and inventory writedown, OM&A expenses were higher for the three and nine months ended Sept. 30, 2021, compared to the same periods in 2020, primarily due to increased staffing costs for growth and strategic initiatives and higher incentive costs. In addition, on a year-to-date basis, there were additional costs associated with the settlement of provisions. As previously committed, the CEWS funding continues to be used to support incremental employment within the Corporation.

Comparable EBITDA for the three and nine months ended Sept. 30, 2021, increased by $125 million and $300 million, respectively, compared with the same periods in 2020, largely due to higher comparable EBITDA at our Hydro, Alberta Thermal, and Wind and Solar segments, which was driven by higher realized prices in the Alberta market, partially offset by lower performance at the Centralia segment. Increases in comparable EBITDA at Energy Marketing resulting from favourable short-term trading of both physical and financial power and natural gas products across all North American markets. Significant changes in segmented comparable EBITDA are highlighted in the Segmented Comparable Results within this MD&A.

FCF, one of the Corporation's key financial metrics, totaled $189 million and $456 million for the three and nine months ended Sept. 30, 2021, respectively. This represents an increase of $83 million and $150 million compared to the same periods in 2020, driven primarily by higher comparable EBITDA, partially offset by an increase in sustaining capital, settlement of provisions and higher distributions paid to subsidiaries' non-controlling interests.

Net loss attributable to common shareholders for the three and nine months ended Sept. 30, 2021, was $456 million and $498 million, respectively, compared to net losses of $136 million and $169 million, respectively, in the same periods in 2020. For the three and nine months ended Sept. 30, 2021, net loss attributable to common shareholders increased by $320 million and $329 million, respectively, from the same periods in 2020 due to greater asset impairments and expenses being incurred as a direct result of decisions to suspend the Sundance 5 repowering project, planned retirements of Sundance Unit 4 and Keephills Unit 1, the final execution of our clean energy transition plan and higher interest expense. These decisions were made based on our assessment of future market conditions, the age and condition of the units and the Corporation's strategic focus toward customer-centered renewable energy solutions. In addition, on a year-to-date basis there were higher income taxes. This was partially offset by higher comparable EBITDA, the gain on the sale of equipment at Alberta Thermal, lower depreciation, an increase in finance lease income and higher foreign exchange gains. In addition, on a year-to-date basis, we had a gain on the sale of the Pioneer Pipeline.

As part of the completion of our clean energy transition plan, we have reduced our CO_2 emissions by 61 per cent from 2005 levels.

Significant and Subsequent Events

North Carolina Solar

On Nov. 5, 2021, the Corporation closed the previously announced acquisition of a 122 MW portfolio of operating solar facilities located in North Carolina (collectively, "North Carolina Solar"). The assets were acquired from a fund managed by Copenhagen Infrastructure Partners for approximately US$99 million (including working capital adjustments) and the assumption of existing tax equity obligations. The acquisition was funded using existing liquidity.

At the closing of the acquisition, TransAlta Renewables acquired a 100 per cent economic interest in North Carolina Solar from a wholly-owned subsidiary of TransAlta Corporation through a tracking share structure for aggregate consideration of approximately US$102 million, subject to closing adjustments.

The North Carolina Solar portfolio consists of 20 solar photovoltaic facilities across North Carolina, with an aggregate capacity of 122 MW. The facilities are all operational and were commissioned between November 2019 and May 2021. The facilities are secured by long-term power purchase agreements ("PPAs") with two subsidiaries of Duke Energy ("Duke Energy"), which have an average remaining term of 12 years. Under the PPAs, Duke Energy receives the renewable electricity, capacity, and environmental attributes from each facility. North Carolina Solar is expected to generate an average annual EBITDA of approximately US$9 million.

Kent Hills Wind Facility Outage

On Sept. 27, 2021, the Corporation's subsidiary, Kent Hills Wind LP, experienced a single tower failure at its 167 MW Kent Hills wind facility in Kent Hills, New Brunswick. The failure involved a collapsed tower located within the Kent Hills 2 site. There were no injuries as a result of the collapse. No one was in the area when the incident occurred and there are no homes in the immediate vicinity. The Corporations's emergency response team has secured the area to ensure safety. This incident has resulted in an impairment being booked against the turbine.

The facility consists of 50 turbines at Kent Hills 1 and Kent Hills 2 and 5 turbines at Kent Hills 3. The turbines at the Kent Hills 1 and Kent Hills 2 sites have been taken offline pending a satisfactory independent engineering and safety assessment. The engineering assessment, which is ongoing, has identified sub-surface crack propagation at several of the foundations of the turbines located at the Kent Hills 1 and Kent Hills 2 sites. As a result, further inspection and testing will be required for all turbines at Kent Hills 1 and Kent Hills 2 to determine the required remediation plan, on a turbine-by-turbine basis. It is presently expected that the outage at Kent Hills 1 and Kent Hills 2 will require repairs or replacements for a significant portion of the existing foundations. Foundation replacements would require expenditures of approximately $1.5 million to $2.0 million per foundation. The remediation plan is expected to be implemented in 2022. The outage is expected to result in foregone revenue of approximately $3.4 million per month on an annualized basis so long as all 50 turbines are offline, based on average historical wind production, with revenue expected to be earned as the wind turbines are returned to service. The foundation issues at the Kent Hills 1 and Kent Hills 2 sites are unique to the design of those sites and there is no indication of any foundation issue at the Kent Hills 3 site nor any other wind sites in the fleet. The Corporation is maintaining communication with all key stakeholders and keeping them fully apprised of the situation. The Corporation has notified its insurers regarding an insurance claim for both property loss and business interruption.

Investor Day

On Sept. 28, 2021, TransAlta held our 2021 Investor Day and announced our Clean Electricity Growth Plan. The Corporation has established targets to deliver 2 GW of incremental renewables capacity with a targeted investment of $3 billion by 2025. TransAlta will accelerate its growth with a focus on customer-centred renewables and storage through the execution of its 3 GW development pipeline. Please see the Accelerated Clean Electricity Growth Plan section of this MD&A.

Retirement of Sundance Unit 4, Keephills Unit 1 and Sundance Unit 5 Suspension

The Corporation announced on Investor Day its decision to suspend the Sundance Unit 5 repowering project, retire Keephills Unit 1 at the end of 2021 and retire Sundance Unit 4 in 2022. Please see the Clean Energy Transition section of this MD&A for additional details on these thermal assets.

Announced Common Share Dividend Increase

On Sept. 28, 2021, the Corporation announced an 11 per cent increase on its common share dividend and declared a dividend of $0.05 per common share to be payable on Jan. 1, 2022 to shareholders of record at the close of business on Dec. 1, 2021. The quarterly dividend of $0.05 per common share represents an annualized dividend of $0.20 per common share.

Northern Goldfields Solar Project

On July 29, 2021, TransAlta Renewables announced that Southern Cross Energy, a subsidiary of the Corporation and an entity in which TransAlta Renewables owns an indirect economic interest, had reached an agreement to provide BHP with renewable electricity to its Goldfields-based operations through the construction of the Northern Goldfields Solar Project. The project comprises the 27 MW Mount Keith Solar Farm, 11 MW Leinster Solar Farm, 10 MW/5MWh Leinster battery energy storage system and interconnecting transmission infrastructure, all of which will be integrated into our existing 169 MW Southern Cross Energy North remote network in Western Australia. Construction activities are scheduled to start in the first quarter of 2022 with completion of the projects expected in the second half of 2022. Total construction capital of the project is estimated at approximately AU$69 million to AU$73 million.

Sundance Unit 5 Retirement as a Coal-Fired Unit

On July 29, 2021, in accordance with applicable regulatory requirements, the Corporation gave notice to the Alberta Electric System Operator ("AESO") of its intention to retire the mothballed coal-fired Sundance Unit 5 effective Nov. 1, 2021 and to terminate the associated transmission service agreement. Under the applicable regulatory rules, a mothball outage can extend no later than 24 months after the commencement of such mothball outage; following which time either the unit must be returned to service, or the transmission service agreement must be terminated (effectively retiring the unit as a coal-fired facility).

Keephills Unit 2 and Sundance Unit 6 Conversion to Gas Completions

On July 19, 2021, the Corporation announced the completion of the conversion of Keephills Unit 2 from thermal coal to natural gas. In February 2021, the Corporation also completed the conversion to natural gas of Sundance Unit 6. Both Keephills Unit 2 and Sundance Unit 6 will maintain the same generator nameplate capacity of 395 MW and 401 MW, respectively. These conversion to natural gas projects will reduce CO_2 emissions from the units by more than half and advances our plan to be 100 per cent off-coal in Alberta by the end of 2021.

Sale of the Pioneer Pipeline

On June 30, 2021, the Corporation closed the previously announced sale of the Pioneer Pipeline to ATCO Gas and Pipelines Ltd. ("ATCO") for the aggregate sale price of $255 million. The net cash proceeds to TransAlta from the sale of its 50 per cent interest, were approximately $128 million, subject to certain adjustments. Following closing of the transaction, the Pioneer Pipeline was integrated into NOVA Gas Transmission Ltd. ("NGTL") and ATCO's Alberta natural gas transmission systems to provide reliable natural gas supply to the Corporation's power generation stations at Sundance and Keephills. As part of the transaction, TransAlta entered into additional long-term gas transportation agreements with NGTL for new and existing transportation service of 400 TJ per day by the end of 2023.

Sarnia Cogeneration Facility Contract Extension

On May 12, 2021, the Corporation executed an Amended and Restated Energy Supply Agreement with one of its large industrial customers at the Sarnia cogeneration facility which provides for the supply of electricity and steam. This agreement will extend the term of the original agreement from Dec. 31, 2022 to Dec. 31, 2032. The agreement provides that if the Corporation is unable to enter into a new contract with the Ontario Independent Electricity System Operator ("IESO") or enter into agreements with its other industrial customers at the Sarnia cogeneration facility that extend past Dec. 31, 2025, then the agreement will automatically terminate on Dec. 31, 2025. The Corporation is in active discussions with the three other existing industrial customers regarding extensions to their supply of electricity and steam from the Sarnia cogeneration facility on comparable terms. The current contract with the IESO in respect of the Sarnia cogeneration facility expires on Dec. 31, 2025. On July 19, 2021, the IESO released its Annual Acquisition Report which included draft details for mid- and long-term procurement mechanisms for capacity for 2026 and beyond for existing and new generation. The Corporation is participating in the consultation process, seeking to secure a contract extension for the Sarnia cogeneration facility following the end of the current contract.

Garden Plain Wind Project

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

TransAlta Renewables is named on the Best 50 Corporate Citizens List

During the second quarter of 2021, TransAlta Renewables, a subsidiary of the Corporation, was recognized by Corporate Knights as one of the Best 50 Corporate Citizens for 2021. The Best 50 Corporate Citizens list evaluates and ranks Canadian corporations against a set of 24 key performance indicators covering environmental, social and governance ("ESG") indicators relative to their industry peers and using publicly available information. The Corporation is committed to continuous improvement on key ESG issues and to ensuring its economic value creation is balanced with a value proposition for the environment and its communities.

Equity, Diversity and Inclusion Program

On May 3, 2021, TransAlta announced that it had received certification from Diversio, a technology company focused on diversity and inclusion, for its continued commitment to, and meaningful performance on, equity, diversity and inclusion ("ED&I") in the workplace. TransAlta is the first publicly-traded energy company to be certified. The certification is endorsed by several leading organizations and signals to investors, employees, customers and other stakeholders that the Corporation is shifting from words to actions in order to advance ED&I at TransAlta.

Sustainability-Linked Loan

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

Mangrove Claim

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

Keephills 1 Superheater Force Majeure

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

TransAlta Renewables Acquisitions

The Corporation completed the sale of its 100 per cent direct interest in the 206 MW Windrise wind project ("Windrise") to TransAlta Renewables on Feb. 26, 2021 for $213 million. The remaining construction costs for Windrise will be paid by TransAlta Renewables. All turbine erection activities have now been completed, with final commissioning activities currently underway and commercial operation tracking to be achieved in November, 2021.

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

Normal Course Issuer Bid

On May 25, 2021, the Toronto Stock Exchange ("TSX") accepted the notice filed by the Corporation to renew its normal course issuer bid ("NCIB") for a portion of its common shares. Pursuant to the NCIB, TransAlta may repurchase up to a maximum of 14,000,000 common shares, representing approximately 7.16 per cent of its public float of common shares as at May 18, 2021. Purchases under the NCIB may be made through open market transactions on the TSX and any alternative Canadian trading platforms on which the common shares are traded, based on the prevailing market price. Any common shares purchased under the NCIB will be cancelled. The period during which TransAlta is authorized to make purchases under the NCIB commenced on May 31, 2021 and ends on May 30, 2022 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.

No common shares have been repurchased by the Corporation in 2021.

Management Changes

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

Effective April 30, 2021, Brett Gellner, our Chief Development Officer, retired after almost 13 years with TransAlta. Mr. Gellner will continue to serve on the Board of Directors of TransAlta Renewables as a non-independent director.

Board of Director Changes

On May 4, 2021, the Corporation announced that the Board of Directors elected four new directors: Ms. Laura W. Folse, Ms. Sarah Slusser, Mr. Thomas O'Flynn and Mr. Jim Reid, who each bring diverse expertise and new perspectives to the Board. Mrs. Georgia Nelson, Mr. Richard Legault and Mr. Yakout Mansour did not stand for re-election and retired from the Board immediately following the annual shareholder meeting on May 4, 2021.

COVID-19

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

The Corporation continues to operate under its business continuity plan, which focused on ensuring that: (i) employees who can work remotely do so; and (ii) employees who operate and maintain our facilities, and who are not able to work remotely, are able to work safely and in a manner that ensures their health and safety. TransAlta has adopted local public health authority and government guidelines in all jurisdictions in which we operate to promote the health and safety of all employees and contractors with our health and safety protocols. All of TransAlta's offices and sites follow health screening and social distancing protocols, including personal protective equipment. As of Nov. 15, 2021, TransAlta will implement a two phase mandatory rapid testing protocol for those employees that are not fully vaccinated. The first phase will commence on Nov. 15, 2021 to Jan. 31, 2022 and will require onsite testing every 72 hours, at TransAlta's cost. On or about Feb. 1, 2022, those employees who are not fully vaccinated will still be required to deliver proof of a negative test every 72 hours, but at the employees cost. Employees can be exempt from rapid testing if they are able to provide proof of vaccination. Further, TransAlta maintains travel limitations that are aligned to local jurisdictional guidance, enhanced cleaning procedures, revised work schedules, contingent work teams and the reorganization of processes and procedures to minimize any workplace transmission of the virus.

Notwithstanding the challenges associated with the pandemic, all of our facilities continue to remain fully operational and are capable of meeting our customers' needs, with exception of the Kent Hills wind facility as described above, which is not related to the pandemic. 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 as a result of COVID-19. Electricity and steam supply continue to remain a critical service requirement to all of our customers and have been deemed an essential service in our jurisdictions.

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

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

Please refer to Note 4 of the 2020 audited annual consolidated financial statements within our 2020 Annual Integrated Report and Note 3 of our unaudited interim condensed consolidated financial statements for the three and nine months ended Sept. 30, 2021, for significant events impacting both prior and current year results.

2021 Financial Outlook

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

Our overall performance for the first three quarters of 2021 is ahead of expectations. Electricity demand has recovered from its lows in 2020 and we are observing strengthened power prices in the Alberta and Pacific Northwest markets. During the second and third quarters of 2021, the Corporation revised upward its outlook range for comparable EBITDA and FCF and announced an increase in dividend rates.

Based on results attained to date and our expectations for balance of year performance, the Corporation is further revising upwards its outlook range for 2021, which is reflected in the table below:

Measure	Original Target	Updated Target
Comparable EBITDA[(1)]	$960 million - $1,080 million	$1,200 million - $1,300 million
FCF[(1)]	$340 million - $440 million	$500 million - $560 million
Dividend	$0.18 per share annualized	$0.20 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. Please refer to the Reconciliation of Non-IFRS Measures section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS. See also the Additional IFRS measures and Non-IFRS Measures section of this MD&A.

Range of key 2021 power price assumptions	**Original Expectations**	**Updated Expectations**
Market	**Power Prices ($/MWh)**	**Power Prices ($/MWh)**
Alberta Spot	$58 - $68	$95 - $105
Mid-C Spot (US$)	US$25 - US$35	US$50 - US$60
Other assumptions relevant to the 2021 financial outlook		
Sustaining capital	$175 million to $210 million	$200 million to $225 million

Alberta Hedging

Range of hedging assumptions	Q4 - 2021	Full year 2022
Hedged production (GWh)	1,407	4,387
Hedge Price ($/MWh)	76	71
Hedged gas volumes (GJ)	15 million	49 million
Hedge gas prices ($/GJ)	2.77	2.74

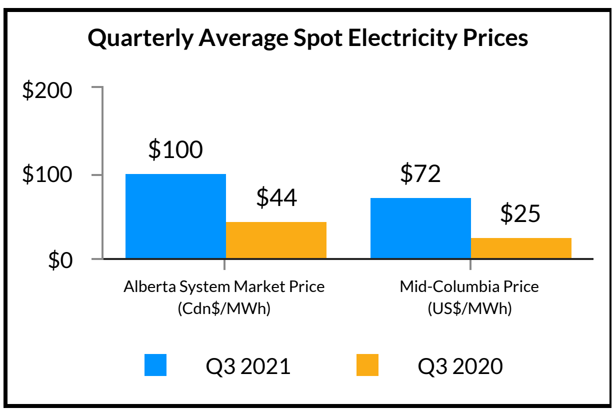
Operations

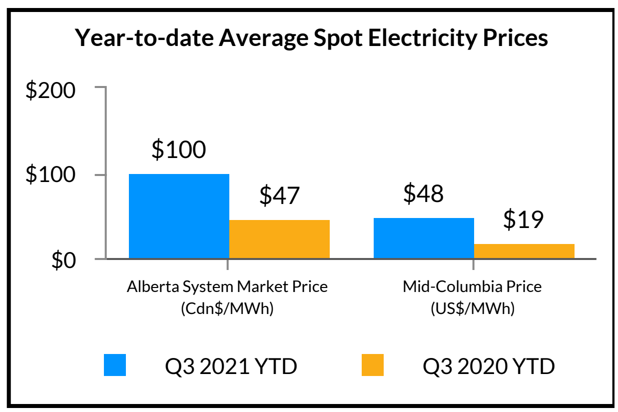
The following provides updates to our original assumptions included in the 2021 Financial Outlook.

Market Pricing

Power prices were higher in Alberta in the three and nine months ended Sept. 30, 2021, compared to the same periods in 2020. This resulted from commercial offer behavior following the expiry of the Alberta PPAs with the Balancing Pool on Dec. 31, 2020, higher carbon compliance costs, higher natural gas prices, demand recovery from 2020, and tighter market conditions during periods of strong weather-driven demand in addition to planned outages. Alberta power prices for the remainder of 2021 are expected to continue to be higher than in 2020 as a result of the factors discussed above.

Power prices were also higher in the Pacific Northwest in the three and nine months ended Sept. 30, 2021, compared to the same periods in 2020, due to lower hydro generation and higher natural gas prices. Higher prices are expected in the Pacific Northwest for the remainder of 2021 compared to 2020.





Energy Marketing

Comparable 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 updated 2021 objective for Energy Marketing is for the segment to contribute between $195 million to $210 million in gross margin for the year, an increase from the $90 million to $110 million expected at the start of the year.

Sustaining and Productivity Capital Expenditures

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

Category	Description	Spent to date(1)	Expected spend in 2021		
Routine capital(2)	Capital required to maintain our existing generating capacity	**30**	49	—	59
Planned major maintenance	Regularly scheduled major maintenance	**114**	150	—	164
Mine capital	Capital related to mining equipment and land purchases	**—**	1	—	2
Total sustaining capital		**144**	**200**	**—**	**225**
Productivity capital	Projects to improve power production efficiency and corporate improvement initiatives	**2**	3	—	7
Total sustaining and productivity capital		**146**	**203**	**—**	**232**

(1) As at Sept. 30, 2021.
(2) Includes hydro life extension expenditures.

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

- Major maintenance turnaround at Keephills Unit 3 is currently underway with expected completion during the fourth quarter;
- Distributed planned maintenance expenditures across the entire hydro fleet; and
- Distributed expenditures across our wind fleet, focusing on major 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 2021:

	Alberta Thermal	Gas and renewables	Lost to date(1)
GWh lost	1,700 - 1,800	500 - 600	1,744

(1) As at Sept. 30, 2021.

Alberta Electricity Portfolio

The Alberta Electricity Portfolio includes hydro, wind, energy storage and thermal units operating, primarily, on a merchant basis in the Alberta market. The variability in production by facility is driven by the diversity in our fuel types, which enables portfolio management and allows for maximization of operating margins. A portion of the installed generation capacity in the portfolio has been hedged to provide cash flow certainty.

On Dec. 31, 2020, the Alberta Power Purchase Arrangements ("Alberta PPA") for our Alberta Hydro Assets, Sheerness 1 and 2 Units, and the Keephills 1 and 2 Units expired. Effective Jan. 1, 2021, these facilities began operating on a fully merchant basis in the Alberta market and form a core part of our Alberta portfolio optimization activities.

As highlighted within the Clean Energy Transition section of this MD&A, due to the Corporation's assessment of future market conditions, the age and condition of the units and change in the Corporation's strategic focus, Keephills Unit 1 and Sundance Unit 4 will be retired on Dec. 31, 2021 and April 1, 2022, respectively. These units will continue to operate within the portfolio until their retirement dates. As of Sept. 30, 2021, production from Keephills Unit 1 and Sundance Unit 4 units was 1,170 GWh and 246 GWh, respectively, and gross installed capacity was 395 MW and 406 MW, respectively.

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

	3 months ended Sept. 30		9 months ended Sept. 30	
	2021	2020	**2021**	2020
Production (GWh)				
Hydro	**513**	589	**1,263**	1,434
Wind	**237**	211	**744**	811
Gas	**117**	131	**367**	413
Thermal	**2,508**	2,257	**7,002**	7,382
Total Alberta Electricity Portfolio Production (GWh)	**3,375**	3,188	**9,376**	10,040
Alberta Electricity Portfolio comparable revenues[1]	**$381**	$208	**$1,033**	$654
Economic hedge position (percentage) - Alberta Thermal[2]	74	100	74	100
Spot power price average per MWh	**$100**	$44	**$100**	$47
Realized power prices per MWh[1,3]	**$113**	$65	**$110**	$65

(1) Includes comparable adjustments to revenues. Please refer to the Reconciliation of Non-IFRS Measures section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS. See also the Additional IFRS measures and Non-IFRS Measures section of this MD&A.
(2) Represents the percentage of production sold forward at the end of the reporting period for the Alberta Thermal assets only. The hedge program is focused primarily on generation from the Alberta Thermal assets.
(3) Realized power price for the Alberta Electricity Portfolio is the average price realized as a result of the Corporation's commercial contracted sales and portfolio optimization activities divided by total GWh produced.

Accelerated Clean Electricity Growth Plan

On Sept. 28, 2021, TransAlta announced its strategic growth targets and accelerated Clean Electricity Growth Plan. Our goal is to be a leading customer-centred electricity company and one that is committed to a sustainable future. Our strategy includes meeting our customer needs for clean, low-cost, reliable electricity and providing operational excellence and continuous improvement in everything we do. Our goal is to increase shareholder value by growing our portfolio of high quality electricity facilities with stable and predictable cash flows.

The Corporation's enhanced focus on renewable generation and storage solutions for customers is driven largely by global decarbonization policies and the increase in demand and growth projections in the renewable sector, namely for companies to achieve their ESG ambitions. For additional information on the regulatory developments, see the Regulatory Updates section of this MD&A.

Our Clean Electricity Growth Plan has established the following strategic priorities and targets to guide our path from 2021 to 2025. These include:

- Deliver 2 GW of incremental renewable capacity with a targeted capital investment of $3 billion to achieve incremental annual EBITDA from new growth projects of $250 million by the end of 2025;
- Accelerate growth into customer-centred renewables and storage through the deployment of a 3 GW development pipeline;
- Expand the Corporation's development pipeline to 5 GW by 2025 to enable a two-fold increase in its renewables fleet by 2030;
- Realize targeted diversification and value creation by focusing on expanding our platform in each of our core geographies (Canada, United States and Australia);
- Lead in ESG policy development to enable the successful evolution of the markets in which we operate and compete; and
- Define the next generation of power solutions and technologies and potential for parallel investments in new complementary sectors by the end of 2025.

We expect the EBITDA generated from renewable sources, including hydro, wind, and solar technologies, to increase from 35 per cent to 70 per cent by the end of 2025.

The Clean Electricity Growth Plan will largely be funded from current cash balances, cash generated from operations, and asset-level financing.

Growth

In 2021, the Corporation has announced 385 MW of new build projects and asset acquisitions and has 500 MW in advanced-stage development. In addition, the current growth pipeline has a potential capacity ranging from 2,425 MW to 3,025 MW from projects in the early stages of development.

Announced Acquisition

North Carolina Solar

On Nov. 5, 2021, the Corporation closed the previously announced acquisition of a 122 MW portfolio of operating solar facilities located in North Carolina (collectively, "North Carolina Solar"). The North Carolina Solar portfolio consists of 20 solar photovoltaic facilities across North Carolina. The facilities were commissioned between November 2019 and May 2021 and are all operational. The facilities are secured by long-term PPAs with two subsidiaries of Duke Energy, which have an average remaining term of 12 years. Under the PPAs, Duke Energy receives the renewable electricity, capacity, and environmental attributes from each facility. North Carolina Solar is expected to generate an average annual EBITDA of approximately US$9 million and average annual cash available for distribution of approximately US$7 million.

Announced Construction Projects

Northern Goldfields Solar Project

The Corporation reached agreement to provide BHP Nickel West Pty Ltd. ("BHP") with renewable electricity to its Goldfields-based operations through the construction of the Northern Goldfields Solar Project. The project comprises the 27 MW Mount Keith Solar Farm, 11 MW Leinster Solar Farm, 10 MW/5MWh Leinster battery energy storage system and interconnecting transmission infrastructure, all of which will be integrated into our existing 169 MW Southern Cross Energy North remote network in Western Australia. In the third quarter of 2021, we issued full notice to proceed to our EPC contractor and construction activities are scheduled to start in the first quarter of 2022 with completion of the projects expected in the second half of 2022. Total construction capital of the project is estimated at approximately AU$69 million to AU$73 million and is expected to generate average annual EBITDA of approximately AU$9 million to AU$10 million. This is the first approved major growth project under the extended power purchase agreement with BHP which was executed in October of 2020. The Corporation continues to actively explore other growth opportunities with BHP.

Garden Plain Wind

The Corporation entered into a long-term PPA with Pembina pursuant to which Pembina has contracted for the renewable electricity and environmental attributes for 100 MW of the 130 MW Garden Plain wind project ("Garden Plain"). Under a separate agreement, Pembina has the option to purchase a 37.7 per cent interest in the project (49 per cent of the quantity under the PPA). The option must be exercised no later than 30 days after the commercial operational date. TransAlta would remain the operator of the facility and earn a management fee if Pembina exercises this option. The Garden Plain wind project will be located approximately 30 km north of Hanna, Alberta. Initial construction activities started in the third quarter of 2021 and completion of the project is expected in the second half of 2022. Total construction capital of the project is estimated at approximately $195 million.

Projects Under Construction

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

Project	Type	Region	MW	Total project Estimated spend	Target completion date[1]	PPA Term	Expected Annual EBITDA[2]	Status
Projects Under Construction								
Canada								
Windrise[3]	Wind	AB	206	$270 — $285	Q4 2021	20	$20 - $22	– Transmission line was energized on June 10 – Turbine erection activities are complete – Final commissioning activities are underway – Commercial operation tracking to be achieved in November, 2021.
Garden Plain[4]	Wind	AB	130	$190 — $200	H2 2022	18	$14 - $18	– Advancing through procurement process – Initial construction activities started in Q3, 2021 – Secured all major regulatory permits and approvals – On track to be completed on schedule
Australia								
Northern Goldfields[5]	Hybrid Solar	WA	48	$ 64 — $68	H2 2022	16	$8 - $9	– Final Notice to Proceed issued on Sept. 28, 2021 – On track to be completed on schedule
Total			**384**	**$524 — $553**			**$42 - $49**	

(1) H2 is defined as the second half of the year.
(2) Expected average annual EBITDA to be generated by the project.
(3) The Windrise wind development project was sold to TransAlta Renewables on Feb. 26, 2021.
(4) The Garden Plain PPA is for 100 MW of the total 130 MW capacity of the facility.
(5) The numbers reflected above are in Canadian dollars, but the actual cash spend on this project is in Australian dollars and therefore these amounts will fluctuate with changes in foreign exchange rates. Estimated spend is approximately AU$69 million to AU$73 million and expected annual EBITDA is approximately AU$9 million to AU$10 million.

Advanced Stage Development

These projects have detailed engineering, advanced positions in the interconnection queue and the Corporation is in discussions with parties to progress off-take opportunities. The following table shows the pipeline of future growth projects currently under advanced stage development:

Project	Type	Region	Gross Installed Capacity (MW)	Estimated Spend	Expected Annual EBITDA[1]
Advanced Stage Development					
US					
Horizon Hill	Wind	Oklahoma	200	US$275 - US$290	US$20 - US$30
White Rock East	Wind	Oklahoma	200	US$275 - US$290	US$20 - US$30
White Rock West	Wind	Oklahoma	100	US$135 - US$145	US$10 - US$15
		Total	**500**	**US$685 - US$725**	**US$50 - US$75**

(1) Expected average annual EBITDA to be generated by the project.

Early Stage Development

These projects are in the early stages and may or may not move ahead. Generally these projects have collected meteorological data; commenced securing land control; started environmental studies; confirmed appropriate access to transmission; and started preliminary permitting and other regulatory approval processes.

The following table shows the pipeline of future growth projects currently under early stage development:

Project	Type	Region	Gross Installed Capacity (MW)
Early Stage Development			
Canada			
Riplinger Wind	Wind	Alberta	300
Willow Creek 1 & 2	Wind	Alberta	140
Tempest	Wind	Alberta	90
Alberta storage opportunities	Battery Storage	Alberta	100
Cogeneration opportunities	Gas	Alberta and Ontario	30
Alberta solar opportunities	Solar	Alberta	170
Canadian wind opportunities	Wind	Alberta & Saskatchewan	250
Brazeau Pumped Hydro	Hydro	Alberta	300 - 900
		Total	**1,380 - 1,980**
US			
Prairie Violet[1]	Wind	Illinois	315
Big Timber	Wind	Pennsylvania	50
Wild Waters	Wind	Minnesota	40
Pennsylvania/West Virginia wind prospects	Wind	Pennsylvania/Wyoming	220
US solar prospects	Solar	Texas/Indiana	200
		Total	**825**
Australia			
Northern Goldfields Expansions	Gas, Solar and Wind	Western Australia	85
South Hedland Solar	Solar	Western Australia	50
Remote mining on-site	Gas	Western Australia	85
		Total	**220**
Canada, US and Australia		**Total**	**2,425- 3,025**

(1) Gross installed capacity increased by 130MW as dual interconnection will allow for a larger project.

Clean Energy Transition

We are in the process of successfully completing our clean energy transition plan, originally announced in 2019. We have reduced the number of coal units in our our Alberta Thermal Fleet by 33 per cent since 2019 and are in the process of successfully transitioning our remaining coal unit in Alberta to natural gas by the end of the year.

The Keephills Unit 3 conversion to natural gas began during the third quarter of 2021, with expected completion in November. Earlier in 2021, Keephills Unit 2, Sundance Unit 6 and our non-operated Sheerness Unit 1 completed their conversions to natural gas, resulting in all three units now running solely on natural gas.

The following table shows our completed and in progress conversions to natural gas:

Project	MW	Conversion Project Spend(1)	Project Completion Date
Keephills Unit 3(2)	463	$31 - $35	In progress
Keephills Unit 2	395	$35	Q2 2021
Sundance Unit 6	401	$39	Q1 2021
Sheerness Unit 1	200	$7	Q1 2021
Sheerness Unit 2	200	$14	Q1 2020

(1) Conversion project spend only includes costs associated with the conversion to gas-burning technology. Any additional planned major maintenance has been included as part of sustaining capital spend.
(2) Represents total expected conversion project spend as conversion to natural gas project will be completed in the fourth quarter of 2021. Actual spend as of Sept. 30, 2021 was $20 million.

The Corporation has announced its decision to retire Keephills Unit 1 effective Dec. 31, 2021 and to retire Sundance Unit 4 effective April 1, 2022, and has provided notice to the Alberta Electric System Operator of its intention to retire such units. The retirement decisions were largely driven by TransAlta's assessment of future market conditions, the age and condition of the units and the Corporation's strategic focus toward customer-centred renewable energy solutions. As a result of the decision to retire these units, the Corporation has recorded impairment charges of $78 million and $56 million, respectively, on these units based on the estimated salvage value.

In addition, following an in-depth evaluation and assessment of the Sundance Unit 5 repowering project, the Corporation has suspended the project. The decision was made due to escalating costs, changing supply and demand dynamics and forecasted power prices in the Alberta market, as well as risks associated with carbon pricing and the evolving regulatory environment. With the suspension of the project, the Corporation will redeploy the capital previously allocated to the Sundance Unit 5 repowering project to renewable growth projects. The Corporation recorded an impairment charge of $190 million during the third quarter of 2021 based on our estimated salvage value of $33 million. Included in the impairment charge is $141 million for assets under construction and $49 million for the balance of the plant steam equipment. An additional $27 million was expensed for amounts due to contractors arising from the suspension of the project.

With the suspension of the Sundance Unit 5 repowering project and the shift in the Corporation's strategy, we have also impaired a previously recognized deferred asset, as it is no longer likely that we will incur sufficient capital or operating expenditures to utilize the remaining credit. The Corporation impaired the remaining balance of the credit of $10 million (US$8 million) in the third quarter of 2021.

With all of the remaining units having been converted or in the process of being converted to natural gas, the Highvale Mine is no longer considered to be providing significant economic benefit to the Alberta Merchant cash generating unit ("CGU") and has been removed from the CGU which resulted in an impairment recognized in the third quarter of 2021 of $185 million. An onerous contract provision of $14 million relating to future Highvale Mine royalty payments (2022 and 2023), has also been recognized to expense in the third quarter of 2021.

Asset impairment charges, additional expenses arising on the suspension of the Sundance Unit 5 repowering project and the Highvale Mine's onerous contract provision, are all excluded from our our Segmented Comparable Results section within this MD&A. Please also refer to Additional IFRS Measures and Non-IFRS Measure section within this MD&A for further details.

With the final natural gas conversion of Keephills Unit 3, our thermal coal units in Alberta will discontinue firing with coal and we will have eliminated coal as a fuel source in Alberta by the end of the year.

Our off-coal transition will reduce carbon compliance significantly in the future. In 2021, carbon compliance costs on coal-fired generation is approximately $29 per MWh, while carbon compliance costs on gas-fired generation is approximately $9 per MWh. During the third quarter of 2021, our carbon compliance costs were $41 million. Under a fully-converted Alberta fleet, carbon compliance costs would have been $15 million to $20 million dollars lower.

As part of this process and the completion of our clean energy transition plan, we have reduced our CO_2 emissions by 61 per cent from 2005 levels.

Our Centralia coal-fired facility in Washington State is committed to be retired under the *TransAlta Energy Transition Bill*. Consistent with our commitment under this bill, Centralia Unit 1 retired on Dec. 31, 2020, and the remaining unit is set to retire on Dec. 31, 2025.

Segmented Comparable Results

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

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

	3 months ended Sept. 30		9 months ended Sept. 30	
	2021	2020	**2021**	2020
Segmented cash flow[1]				
Hydro	**76**	22	**238**	72
Wind and Solar	**51**	32	**170**	161
North American Gas	**21**	27	**80**	81
Australian Gas	**21**	33	**79**	90
Alberta Thermal	**88**	14	**131**	57
Centralia	**28**	46	**41**	94
Generation segmented cash flow	**285**	174	**739**	555
Energy Marketing	**52**	51	**132**	99
Corporate[2]	**(28)**	(21)	**(68)**	(72)
Total segmented cash flow	**309**	204	**803**	582

(1) Segmented cash flow is a non-IFRS measure and has no standardized meaning under IFRS. Please refer to the Additional IFRS Measures and Non-IFRS Measures section for further details.
(2) Includes gains and losses on the total return swap.

Segmented cash flow generated by the business for the three and nine months ended Sept. 30, 2021, increased by $105 million and $221 million, respectively, compared to the same periods in 2020. The increase was largely due to strong results from the Alberta Electricity Portfolio through optimizing assets during periods of higher realized pricing and favourable short-term trading within Energy Marketing. This was partially offset by major maintenance costs associated with conversion to natural gas outages at Alberta Thermal and higher fuel and purchased power costs at Centralia and Alberta Thermal segments. Fuel and purchased power costs were higher at Centralia due to increases in fuel transportation costs and the acquisition of higher-priced power to fulfil our contractual obligations during planned and unplanned outages during periods of higher merchant pricing on a year-to-date basis, while Alberta Thermal experienced higher natural gas pricing and transmission costs. In the Corporate segment, we realized a net loss of $1 million and a net gain of $4 million, respectively, for the three and nine months ended Sept. 30, 2021, from the total return swap on our share-based payment plans, whereas in the same periods last year we realized a net loss of nil and $8 million. In addition, Corporate costs were lower on a year-to-date basis compared to the same period in 2020 due to the receipt of $8 million in CEWS funding.

For the three and nine months ended Sept. 30, 2021, approximately 45 per cent and 55 per cent, respectively, of our generation segmented cash flows were generated by renewable resources, compared to 31 per cent and 42 per cent for the same periods in 2020.

Hydro

	3 months ended Sept. 30		9 months ended Sept. 30	
	2021	2020	**2021**	2020
Gross installed capacity (MW)	**926**	926	**926**	926
Availability (%)	**90.3**	97.3	**91.8**	96.1
Alberta Hydro Assets (GWh)[1]	**475**	553	**1,187**	1,367
Other Hydro Assets (GWh)[1]	**136**	148	**338**	346
Total energy production (GWh)	**611**	701	**1,525**	1,713
Ancillary service volumes (GWh)[2]	**657**	642	**2,155**	2,231
Revenues				
Alberta Hydro Assets[1]	**54**	31	**145**	76
Other Hydro Assets and other revenue[1][2]	**12**	11	**32**	28
Capacity payments[3]	**—**	15	**—**	45
Alberta Hydro Ancillary services[4]	**30**	11	**125**	55
Environmental credits	**—**	—	**1**	1
Total gross revenues	**96**	68	**303**	205
Net payment relating to Alberta Hydro PPA[5]	**—**	(27)	**(4)**	(84)
Total Revenues	**96**	41	**299**	121
Fuel and purchased power	**3**	5	**7**	9
Comparable gross margin	**93**	36	**292**	112
Operations, maintenance and administration	**11**	9	**35**	28
Taxes, other than income taxes	**—**	(1)	**2**	1
Comparable EBITDA	**82**	28	**255**	83
Deduct:				
Sustaining capital:				
Routine capital	**3**	4	**7**	6
Planned major maintenance	**3**	1	**11**	4
Total sustaining capital expenditures	**6**	5	**18**	10
Productivity capital	**1**	—	**1**	—
Total sustaining and productivity capital	**7**	5	**19**	10
Provisions	**—**	—	**(2)**	—
Decommissioning and restoration costs settled	**(1)**	1	**—**	1
Hydro cash flow	**76**	22	**238**	72

(1) Alberta Hydro Assets include 13 hydro facilities on the Bow and North Saskatchewan river systems in Alberta that are not owned by TransAlta Renewables. Other Hydro Assets include our hydro facilities in BC, Ontario and the hydro facilities in Alberta owned by TransAlta Renewables.
(2) Other Hydro Assets includes transmission revenues.
(3) Capacity payments include the annual capacity charge as described in the Power Purchase Arrangements Determination Regulation AR 175/2000. The Alberta Hydro PPA expired on Dec. 31, 2020.
(4) Ancillary Services as described in the AESO Consolidated Authoritative Document Glossary.
(5) The net payment relating to the Alberta PPA in respect of the Alberta Hydro Assets represents the Corporation's financial obligations for notional amounts of energy and Ancillary Services in accordance with the Alberta Hydro PPA that expired on Dec. 31, 2020. The amount shown for the nine months ended Sept. 30, 2021, is related to adjustments for the final payments under the Alberta Hydro PPA recorded in the first and second quarters of 2021.

Availability for the three and nine months ended Sept. 30, 2021, decreased compared to the the same periods in 2020, primarily due to higher planned and unplanned outages.

Production for the three and nine months ended Sept. 30, 2021, decreased by 90 GWh and 188 GWh, respectively, compared to the same periods in 2020, mainly due to higher planned outages and lower precipitation.

Ancillary service volumes for the three months ended Sept. 30, 2021 were consistent with the same period in 2020. For the nine months ended Sept. 30, 2021, ancillary service volumes decreased by 76 GWh, compared to the same period in 2020, primarily due to lower availability and the AESO procuring less volumes.

	3 months ended Sept. 30		9 months ended Sept. 30	
	2021	2020	**2021**	2020
Gross Revenues per MWh				
Alberta Hydro assets ($/MWh)	**$114**	$56	**$122**	$56
Alberta Hydro ancillary services ($/MWh)	**$46**	$17	**$58**	$25

For the three and nine months ended Sept. 30, 2021, Alberta Hydro assets revenue per MWh of production increased by approximately $58 per MWh and $66 per MWh, respectively, compared to the same periods in 2020 as a result of higher merchant prices in Alberta. For the three and nine months ended Sept. 30, 2021, Alberta Hydro ancillary revenue per MWh of production increased by approximately $29 per MWh and $33 per MWh, respectively, compared to the same periods in 2020 as a result of higher merchant pricing in Alberta. For further discussion on the market conditions and pricing, please refer to the 2021 Financial Outlook section and Alberta Electricity Portfolio section of this MD&A.

Comparable EBITDA for the three and nine months ended Sept. 30, 2021, increased by $54 million and $172 million, respectively, compared with the same periods in 2020. On Dec. 31, 2020, the PPA for our Alberta Hydro assets expired and effective Jan. 1, 2021, these facilities operate on a merchant basis in the Alberta power market. With strong availability during periods of market volatility, the Corporation captured higher energy and ancillary service revenue and benefited from the elimination of net payment obligations under the Alberta PPA that expired Jan. 1, 2021. Comparable EBITDA also had a favourable variance for the AESO transmission line loss recorded in 2020, which was offset by higher maintenance costs, higher portfolio management services and increased dam safety staffing costs. Portfolio management services support our strategy for maximizing our overall return on assets in the merchant Alberta electricity market.

Sustaining capital expenditures for the three and nine months ended Sept. 30, 2021, increased by $1 million and $8 million, respectively, compared to the same periods in 2020, due to a greater number of outages.

Hydro cash flow for the three and nine months ended Sept. 30, 2021, increased by $54 million and $166 million, respectively, compared with the same periods in 2020, mainly due to higher comparable EBITDA partially offset by increased capital expenditures.

Wind and Solar

	3 months ended Sept. 30		9 months ended Sept. 30	
	2021	2020	**2021**	2020
Gross installed capacity (MW)(1)	**1,682**	1,495	**1,682**	1,495
Availability (%)	**94.0**	93.2	**94.8**	94.9
Contract production (GWh)	**514**	504	**1,964**	1,976
Merchant production (GWh)	**204**	213	**711**	814
Total production (GWh)	**718**	717	**2,675**	2,790
Revenues	**76**	58	**247**	232
Fuel and purchased power	**4**	5	**11**	14
Comparable gross margin	**72**	53	**236**	218
Operations, maintenance and administration	**14**	14	**42**	40
Taxes, other than income taxes	**3**	3	**8**	7
Comparable EBITDA	**55**	36	**186**	171
Deduct:				
Sustaining capital:				
Planned major maintenance	**4**	4	**8**	9
Total sustaining capital expenditures	**4**	4	**8**	9
Provisions	**—**	—	**7**	—
Principal payments on lease liabilities	**—**	—	**1**	1
Wind and Solar cash flow	**51**	32	**170**	161

(1) The 2021 gross installed capacity includes 106 MW for the Windrise wind project and 4 MW for Old Man Wind facility which was added in the third quarter of 2021. The addition of the WindCharger battery storage facility and our proportionate share of the Skookumchuck wind facility were added in the fourth quarter of 2020.

Availability for the three and nine months ended Sept. 30, 2021, was consistent with the same periods in 2020.

Production for the three months ended Sept. 30, 2021 was consistent compared to the same period in 2020 and production for the nine months ended Sept. 30, 2021, decreased by 115 GWh, compared to the same period in 2020. Production was impacted by lower wind resources across our entire fleet, which was partially offset by incremental production from the new Skookumchuck facility.

Comparable EBITDA for the three and nine months ended Sept. 30, 2021, increased by $19 million and $15 million, respectively, compared with the same periods in 2020. The increases were primarily due to higher pricing in Alberta, new incremental production from the Skookumchuck wind facility, the sale of environmental attributes and a favourable variance for the AESO transmission line loss recorded in 2020, which was partially offset by lower production and the impact of the weakening U.S. dollar.

Sustaining capital expenditures for the three and nine months ended Sept. 30, 2021, were consistent with the same periods in 2020.

Wind and Solar cash flow for the three and nine months ended Sept. 30, 2021, increased $19 million and $9 million, respectively, compared to the the same periods in 2020, mainly due to higher comparable EBITDA. In addition, for the nine months ended Sept. 30, 2021, cash flows further decreased due to settlement of provisions related to the transmission line loss rule proceeding.

North American Gas

	3 months ended Sept. 30		9 months ended Sept. 30	
	2021	2020	**2021**	2020
Gross installed capacity (MW)	**974**	974	**974**	974
Availability (%)	**95.1**	92.2	**95.4**	96.4
Contract production (GWh)	**505**	482	**1,448**	1,391
Merchant production (GWh)(1)	**118**	54	**221**	89
Purchased power (GWh)(1)	**(25)**	(42)	**(129)**	(128)
Total production (GWh)	**598**	494	**1,540**	1,352
Revenues	**86**	59	**219**	168
Fuel and purchased power	**32**	17	**74**	44
Carbon compliance	**6**	—	**18**	1
Comparable gross margin	**48**	42	**127**	123
Operations, maintenance and administration	**13**	13	**38**	37
Taxes, other than income taxes	**—**	—	**1**	1
Comparable EBITDA	**35**	29	**88**	85
Deduct:				
Sustaining capital:				
Routine capital	**2**	1	**4**	3
Planned major maintenance	**—**	1	**3**	1
Total sustaining capital expenditures	**2**	2	**7**	4
Productivity capital	**1**	—	**1**	—
Total sustaining and productivity capital	**3**	2	**8**	4
Provisions and other	**11**	—	**—**	—
North American Gas cash flow	**21**	27	**80**	81

(1) Purchased power used for dispatch optimization has been separated from merchant production in the current year. Comparable periods have been adjusted to reflect this change.

Availability for the three months ended Sept. 30, 2021, was higher compared with the same period in 2020, primarily as a result of lower unplanned outage events at Sarnia during the third quarter of 2021. Availability for the nine months ended Sept. 30, 2021, was lower compared with the same period in 2020, primarily as a result of unplanned outage events at Sarnia and higher levels of planned outages at other facilities.

Production for the three and nine months ended Sept. 30, 2021, increased by 104 GWh and 188 GWh, respectively, compared to the same periods in 2020, mainly due to higher merchant production at Sarnia and higher production at the Ada facility. On a year-to-date basis, there is incremental production in 2021 from Ada as it was acquired in May 2020.

Comparable EBITDA for the three and nine months ended Sept. 30, 2021, increased by $6 million and $3 million, respectively, compared with the same periods in 2020, primarily due to higher production at the Ada facility and higher realized pricing in Alberta, which was partially offset by year-to-date unplanned short-term steam supply outages at Sarnia.

Sustaining capital expenditures for the three months ended Sept. 30, 2021, was consistent with the same period in 2020. Sustaining capital expenditures for the nine months ended Sept. 30, 2021, increased $3 million, compared with the same period in 2020, mainly due to higher planned outages.

North American Gas cash flow for the three months ended Sept. 30, 2021, decreased by $6 million, compared to the same period in 2020 due to changes in provisions and other which was partially offset by higher comparable EBITDA. North American Gas' cash flow for the nine months ended Sept. 30, 2021, was consistent with the same period in 2020, as increases in comparable EBITDA were offset by higher capital expenditures.

Australian Gas

	3 months ended Sept. 30		9 months ended Sept. 30	
	2021	2020	**2021**	2020
Gross installed capacity (MW)	**450**	450	**450**	450
Availability (%)	**95.5**	96.5	**93.1**	94.2
Contract production (GWh)	**405**	425	**1,244**	1,344
Revenues	**46**	43	**130**	121
Fuel and purchased power	**1**	2	**4**	5
Comparable gross margin	**45**	41	**126**	116
Operations, maintenance and administration	**9**	7	**27**	23
Comparable EBITDA	**36**	34	**99**	93
Deduct:				
Sustaining capital:				
Routine capital	**1**	—	**2**	—
Planned major maintenance	**14**	1	**18**	3
Total sustaining capital expenditures	**15**	1	**20**	3
Australian Gas cash flow	**21**	33	**79**	90

Availability for the three and nine months ended Sept. 30, 2021, decreased slightly compared to the same periods in 2020, mainly due to unplanned outages at our Southern Cross Energy Northern sites.

Production for the three and nine months ended Sept. 30, 2021, decreased compared with the same periods in 2020, mainly due to a change in customer loads. Changes in production do not have a significant financial impact as our contracts are structured as capacity payments with customer supplied fuel or a passthrough of fuel costs.

Comparable EBITDA for the three and nine months ended Sept. 30, 2021, increased by $2 million and $6 million, respectively, compared with the same periods in 2020. The increase was mainly due to the strengthening of the Australian dollar relative to the Canadian dollar and the Solomon meter station upgrade revenue recognised in 2021.

Sustaining capital expenditures for the three and nine months ended Sept. 30, 2021, increased by $14 million and $17 million, respectively, compared with the same periods in 2020. The increase was mainly due to planned major maintenance and the purchase of an additional engine at South Hedland.

Australian Gas cash flow for the three and nine months ended Sept. 30, 2021, decreased by $12 million and $11 million, compared with the same period in 2020, mainly due to higher sustaining capital expenditures partially offset by higher comparable EBITDA.

Alberta Thermal

	3 months ended Sept. 30		9 months ended Sept. 30	
	2021	2020	**2021**	2020
Gross installed capacity (MW)[1]	**2,460**	2,861	**2,460**	2,861
Availability (%)	**82.2**	86.3	**81.4**	88.8
Contract production (GWh)	**—**	1,385	**—**	4,225
Merchant production (GWh)	**2,508**	873	**7,002**	3,157
Total production (GWh)[2]	**2,508**	2,258	**7,002**	7,382
Revenues	**254**	157	**661**	490
Fuel and purchased power	**86**	46	**235**	173
Carbon compliance	**41**	38	**121**	117
Comparable gross margin	**127**	73	**305**	200
Operations, maintenance and administration	**29**	31	**92**	97
Taxes, other than income taxes	**5**	5	**13**	12
Net other operating income	**(11)**	(10)	**(32)**	(30)
Comparable EBITDA	**104**	47	**232**	121
Deduct:				
Sustaining capital:				
Routine capital	**3**	3	**9**	7
Mine capital	**—**	5	**—**	7
Planned major maintenance	**11**	19	**61**	39
Total sustaining capital expenditures	**14**	27	**70**	53
Productivity capital	**—**	—	**—**	1
Total sustaining and productivity capital	**14**	27	**70**	54
Provisions	**—**	—	**25**	(8)
Principal payments on lease liabilities	**—**	4	**1**	11
Decommissioning and restoration costs settled	**2**	2	**5**	7
Alberta Thermal cash flow	**88**	14	**131**	57

(1) The 2021 gross installed capacity excludes 406 MW for Sundance Unit 5 as the repowering project has been suspended during the third quarter of 2021. Sheerness Unit 2's capacity was increased in 2020 following a generator rewind and final testing.
(2) Estimated production generated from natural gas fuel source for three and nine months ended Sept. 30, 2021 were 1,625 GWh and 4,097 GWh, respectively (2020 - 1,442 GWh and 4,808 GWh).

Availability for the three months months ended Sept. 30, 2021, decreased compared with the same period in 2020, as a result of the higher unplanned outages. Availability for the nine months ended Sept. 30, 2021, decreased compared with the same period in 2020, as a result of the Keephills Unit 2 and Unit 3 conversions. In addition, the fleet experienced higher derates and unplanned outages in the nine months ended Sept. 30, 2021 compared to the same period in 2020.

Production for the three months ended Sept. 30, 2021, increased by 250 GWh, compared to the same period in 2020, mainly due to higher dispatching of our facilities. Production for the nine months ended Sept. 30, 2021 decreased by 380 GWh, compared to the same period in 2020, due to portfolio optimization activities.

Revenue for the three and nine months ended Sept. 30, 2021, increased by $97 million and $171 million, respectively, compared to the same periods in 2020, mainly due to higher realized prices within the Alberta market.

	3 Months Ended Sept. 30,		9 months ended Sept. 30	
	2021	2020	**2021**	2020
Economic hedge position (percentage)(1)	**74**	100	**74**	100
Spot power price average per MWh	**$100**	$44	**$100**	$47
Realized power prices per MWh(2)	**$101**	$70	**$94**	$66
Natural gas price (AECO) per GJ	**$3.29**	$2.14	**$3.04**	$1.99
Fuel and purchased power per MWh	**$34**	$20	**$34**	$23
Carbon compliance per MWh	**$16**	$17	**$17**	$16

(1) Represents the percentage of production sold forward at the end of the reporting period for the Alberta Thermal assets.
(2) Realized power prices is the average price realized as a result of the Corporation's commercial contracted sales and portfolio optimization activities divided by total GWh produced.

In the three and nine months ended Sept. 30, 2021, the realized power prices per MWh of production increased by $31 per MWh and $28 per MWh, respectively, compared with the same periods in 2020, primarily due to the optimization of production during periods of favourable pricing. The realized prices include gains or losses from hedging positions that are entered into to mitigate the impact of unfavourable market pricing.

In the three and nine months ended Sept. 30, 2021, the fuel and purchased power costs per MWh of production increased by $14 per MWh and $11 per MWh, respectively, compared to the same periods in 2020. Costs per MWh increased due to higher natural gas pricing and higher transmission costs.

In the three and nine ended Sept. 30, 2021, carbon compliance costs per MWh of production were consistent with the same periods in 2020. Carbon compliance costs have increased in 2021 primarily due to an increase in carbon costs from $30/tonne to $40/tonne, however this was substantially offset by changes in fuel ratios as we increased our natural gas combustion versus coal. The shift in fuel ratio effectively lowered our GHG compliance costs as natural gas combustion produces fewer GHG emissions than coal combustion.

OM&A costs for the three and nine months ended Sept. 30, 2021, were $2 million and $5 million lower, respectively, compared with the same periods in 2020. The decrease was due to planned reductions resulting from our clean energy transition plan and conversion to natural gas strategy.

Comparable EBITDA for the three and nine months ended Sept. 30, 2021, increased by $57 million and $111 million, respectively, compared with the same periods in 2020. Higher availability during periods of tight market conditions and higher Alberta pricing was partially offset by increases in fuel and carbon compliance costs.

For the three months ended Sept. 30, 2021, sustaining and productivity capital expenditures decreased by $13 million, compared to the same periods in 2020. In 2021, we incurred capital expenditures for the Keephills Unit 3 conversion to natural gas outage, compared to 2020 which included the Sundance Unit 6 conversion to natural gas and the mine dragline capital expenditures. For the nine months ended Sept. 30, 2021, sustaining and productivity capital expenditures increased $16 million, respectively, compared to the same periods in 2020, mainly due to the major maintenance costs associated with conversion to natural gas outages at our coal facilities.

For the three months ended Sept. 30, 2021, cash flow was higher compared with the same period in 2020, as a result of higher comparable EBITDA, lower sustaining capital and lower payments on lease liabilities. For the nine months ended Sept. 30, 2021, cash flow was higher compared with the same period in 2020, as higher comparable EBITDA and lower lease payments were partially offset by higher settlement of provisions and higher year to date sustaining capital spend.

Centralia

	3 months ended Sept. 30		9 months ended Sept. 30	
	2021	2020	**2021**	2020
Gross installed capacity (MW) (1)	**670**	1,340	**670**	1,340
Availability (%)	**91.2**	88.4	**64.5**	69.8
Adjusted availability (%)(2)	**91.2**	92.9	**74.7**	88.4
Contract sales volume (GWh)	**839**	840	**2,489**	2,499
Merchant sales volume (GWh)	**1,298**	1,705	**2,544**	2,976
Purchased power (GWh)	**(924)**	(956)	**(2,737)**	(2,780)
Total production (GWh)	**1,213**	1,589	**2,296**	2,695
Revenues	**168**	147	**348**	326
Fuel and purchased power	**120**	82	**247**	167
Comparable gross margin	**48**	65	**101**	159
Operations, maintenance and administration	**13**	15	**38**	46
Taxes, other than income taxes	**—**	1	**2**	4
Comparable EBITDA	**35**	49	**61**	109
Deduct:				
Sustaining capital:				
Routine capital	**—**	1	**—**	3
Planned major maintenance	**—**	—	**13**	7
Total sustaining capital expenditures	**—**	1	**13**	10
Provisions	**3**	—	**(1)**	—
Decommissioning and restoration costs settled	**4**	2	**8**	5
Centralia cash flow	**28**	46	**41**	94

(1) Centralia Unit 1 was retired from services on Dec. 31, 2020.
(2) Adjusted for dispatch optimization.

Adjusted availability for the three months ended Sept. 30, 2021, were consistent with the same period in 2020, as higher unplanned outages were mostly offset by lower planned outages. Adjusted availability for the nine months ended Sept. 30, 2021, decreased compared to the same period in 2020, due to higher planned and unplanned outages and the retirement of Centralia Unit 1 on Dec. 31, 2020.

Production for the three months ended Sept. 30, 2021, was lower compared to the same period in 2020, due to the retirement of Centralia Unit 1. Production for the nine months ended Sept. 30, 2021, was lower compared to the same period in 2020, primarily due to the retirement of Centralia Unit 1 and lower availability.

Comparable gross margin for the three months ended Sept. 30, 2021, decreased $17 million, primarily due to lower generation as a result of the retirement of Centralia Unit 1 and higher fuel transportation costs. Comparable gross margin for the nine months ended Sept. 30, 2021, decreased $58 million, primarily due to planned and unplanned outages necessitating power purchases during periods of higher merchant pricing to meet contractual obligations, lower generation from retirement of Centralia Unit 1 and lower availability.

OM&A costs for the three and nine months ended Sept. 30, 2021, decreased by $2 million and $8 million, respectively, compared with the same periods in 2020, due to the retirement of Centralia Unit 1 and enhanced cost controls.

Comparable EBITDA for the three and nine months ended Sept. 30, 2021, decreased by $14 million and $48 million, respectively, compared with the same periods in 2020. The decrease for the three months ended Sept. 30, 2021 was primarily due to the retirement of Centralia Unit 1 and higher fuel transportation costs, which was partially offset by lower OM&A cost. The decrease for the nine months ended Sept. 30, 2021 was due to planned and unplanned outages during period of high merchant pricing and the retirement of Centralia Unit 1, which was partially offset by lower OM&A costs.

Sustaining capital expenditures for the three months ended Sept. 30, 2021 were consistent with the same period in 2020. Sustaining capital expenditures for the nine months ended Sept. 30, 2021, were $3 million higher, compared to the same period in 2020, mainly due to higher planned major maintenance.

Centralia's cash flow for the three and nine months ended Sept. 30, 2021, decreased by $18 million and $53 million, respectively, compared to the the same periods in 2020, mainly due to lower comparable EBITDA, higher decommissioning and restoration costs and higher year-to-date sustaining capital expenditures.

Energy Marketing

	3 months ended Sept. 30		9 months ended Sept. 30	
	2021	2020	**2021**	2020
Revenues and comparable gross margin	**72**	58	**159**	114
Operations, maintenance and administration	**14**	9	**31**	24
Comparable EBITDA	**58**	49	**128**	90
Deduct:				
Provisions and other	**6**	(2)	**(4)**	(9)
Energy Marketing cash flow	**52**	51	**132**	99

Comparable EBITDA for the three and nine months ended Sept. 30, 2021, increased by $9 million and $38 million, respectively, compared to the same periods in 2020, due to favourable short-term trading of both physical and financial power and natural gas products across all North American markets. This was partially offset by OM&A increases due to higher incentives related to stronger performance. The Energy Marketing team was able to capitalize on short-term arbitrage opportunities in the markets in which we trade without materially changing the risk profile of the business unit.

Energy Marketing's cash flow for the three and nine months ended Sept. 30, 2021, increased by $1 million and $33 million, respectively, compared to the same periods in 2020, mainly due to higher comparable EBITDA, partially offset by changes in emissions obligations and prepaid balances for transmission rights.

Corporate

	3 months ended Sept. 30		9 months ended Sept. 30	
	2021	2020	**2021**	2020
Operations, maintenance and administration	**23**	16	**55**	59
Taxes, other than income taxes	**1**	—	**1**	—
Comparable EBITDA	**(24)**	(16)	**(56)**	(59)
Deduct:				
Sustaining capital:				
Routine capital	**3**	4	**8**	10
Total sustaining capital expenditures	**3**	4	**8**	10
Productivity capital	**(1)**	—	**—**	—
Total sustaining and productivity capital expenditures	**2**	4	**8**	10
Principal payments on lease liabilities	**2**	1	**4**	3
Corporate cash flow	**(28)**	(21)	**(68)**	(72)

Corporate overhead costs for the three months ended Sept. 30, 2021, increased by $8 million, compared to the same period in 2020, primarily due to higher incentive payments, higher staffing costs, increases in insurance costs and realized losses from the the total return swap. Corporate overhead costs for the nine months ended Sept. 30, 2021, decreased by $3 million, compared to the same period in 2020, primarily due to the receipt of CEWS funding and realized gains from the total return swap, partially offset by higher incentive payments and legal dispute settlement costs. A portion of the settlement costs of our employee share-based payment plans is hedged by entering into total return swaps, which are cash settled every quarter.

Supplemental disclosure	3 months ended Sept. 30 2021	2020	9 months ended Sept. 30 2021	2020
Corporate cash flow	**(28)**	(21)	**(68)**	(72)
Total return swap (gains) losses	**1**	—	**(4)**	8
CEWS funding received	**—**	—	**(8)**	—
CEWS funding applied to incremental employment	**2**	—	**2**	—
Adjusted Corporate cash flow	**(25)**	(21)	**(78)**	(64)

Adjusted corporate overhead costs for the three months ended Sept. 30, 2021, increased by $4 million, compared to the same period in 2020 due to incentive payments and higher staffing costs. For the nine months ended Sept. 30, 2021, adjusted corporate overhead costs increased by $14 million, compared to the same period in 2020, due to higher incentive costs, higher legal fees for settlement of outstanding legal issues and an increase in staffing costs. Staffing costs increased due to additional headcount to support growth initiatives. As previously committed, the CEWS funding is being used to support incremental employment within the Corporation.

Additional IFRS Measures and Non-IFRS Measures

An additional IFRS measure is a line item, heading or subtotal that is relevant to an understanding of the consolidated financial statements but is not a minimum line item mandated under IFRS, or the presentation of a financial measure that is relevant to an understanding of the consolidated financial statements but is not presented elsewhere in the consolidated financial statements. We have included line items entitled gross margin and operating income (loss) in our unaudited interim condensed consolidated statements of loss for the three and nine months ended Sept. 30, 2021 and 2020. Presenting these line items provides management and investors with a measurement of ongoing operating performance that is readily comparable from period to period.

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

Reconciliation of Non-IFRS Measures

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

Comparable EBITDA

EBITDA is a widely adopted valuation metric and an important metric for management that represents our core business profitability. Interest, taxes, depreciation and amortization are not included, as differences in accounting treatments may distort our core business results. In addition, under comparable EBITDA we reclassify certain transactions to facilitate the discussion of the performance of our business:

- Comparable EBITDA is adjusted to exclude the impact of unrealized mark-to-market gains or losses.
- Any gains or losses on asset sales or foreign exchange gains or losses are not included as these are not part of operating income.
- Certain assets we own in Canada and in Australia are fully contracted and recorded as finance leases under IFRS. We believe it is more appropriate to reflect the payments we receive under the contracts as a capacity payment in our revenues instead of as finance lease income and a decrease in finance lease receivables.
- We also reclassify the depreciation on our mining equipment from fuel, carbon compliance and purchased power to reflect the actual cash cost of our business in our comparable EBITDA.
- Certain impairments and expenses have been recognized in the third quarter of 2021 with our recently announced change in strategy which resulted in accelerated plans to shut down the Highvale Mine and the suspension of the Sundance Unit 5 repowering project. This includes coal and inventory writedowns, which are not reflective of our core on-going business results upon conversion to natural gas, payments associated with suspending Sundance Unit 5 and onerous contracts related to those decisions, which are not reflective of ongoing operations and therefore have been removed for comparable EBITDA.
- On the commissioning of the South Hedland facility in July 2017, we prepaid approximately $74 million of electricity transmission and distribution costs. Interest income is recorded on the prepaid funds. We reclassify this interest income as a reduction in the transmission and distribution costs expensed each period to reflect the net cost to the business.
- Asset impairments (reversals) are removed to calculate comparable EBITDA as these are accounting adjustments that impact depreciation and amortization and do not reflect business performance.
- During the fourth quarter of 2020, we acquired a 49 per cent interest in the Skookumchuck wind facility, which is treated as an equity investment under IFRS and our proportionate share of the net earnings is reflected as equity income on the statement of earnings under IFRS. As this investment is part of our regular power-generating operations, we have included our proportionate share of the comparable EBITDA of Skookumchuck in our total comparable EBITDA. In addition, in the Wind and Solar comparable results, we have included our proportionate share of revenues and expenses to reflect the full operational results of this investment. We have not included EMG International, LLC's comparable EBITDA in our total comparable EBITDA as it does not represent our regular power-generating operations.

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

	3 months ended Sept. 30		9 months ended Sept. 30	
	2021	2020	**2021**	2020
Net loss attributable to common shareholders	**(456)**	(136)	**(498)**	(169)
Net earnings (loss) attributable to non-controlling interests	**27**	7	**88**	29
Preferred share dividends	**10**	10	**20**	30
Net loss	**(419)**	(119)	**(390)**	(110)
Adjustments to reconcile net income to comparable EBITDA				
Income tax expense (recovery)	**(22)**	(10)	**42**	(25)
Gain on sale of assets and other	**(23)**	(2)	**(56)**	(2)
Foreign exchange gain	**(1)**	(11)	**(22)**	(15)
Net interest expense	**63**	56	**186**	175
Equity income	**(1)**	—	**(5)**	—
Depreciation and amortization	**123**	162	**395**	481
Comparable reclassifications				
Decrease in finance lease receivables	**10**	3	**30**	11
Mine depreciation included in fuel cost	**74**	33	**179**	87
Australian interest income	**1**	1	**3**	3
Unrealized mark-to-market and foreign exchange (gains) losses	**(70)**	45	**(103)**	(1)
Adjustments to earnings to arrive at comparable EBITDA				
Asset impairment(1)	**575**	76	**620**	67
Clean energy transition provisions and adjustments(2)(3)	**69**	22	**105**	22
Share of adjusted EBITDA from joint venture(4)	**2**	—	**9**	—
Comparable EBITDA	**381**	256	**993**	693

(1) The asset impairment for the three months ended Sept. 30, 2021 of $575 million was mainly the result of the impact of the clean energy transition plan and changes in the decommissioning and restoration liability at the Centralia mine, Keephills Unit 1 and Sundance Units 1, 2 ,3, 4, and 5. The asset impairment for the nine months ended Sept. 30, 2021, includes impairments of $45 million, related to the Kaybob project, the impact of the clean energy transition plan and changes in decommissioning and restoration liability at the Centralia mine, Keephills Unit 1 and Sundance Units 1, 2 ,3, 4, and 5. The asset impairment for the three and nine months ended Sept. 30, 2020 of $76 million and $67 million, respectively, mainly relate to the retirement of Sundance Unit 3, impairment on a hydro facility and an changes in the decommissioning and restoration liability on retired assets.
(2) As a result of the Corporation's strategic decision to transition to clean energy, we have recorded writedowns on parts and material inventory for our coal operations for the three and nine months ended Sept. 30, 2021 of $5 million and $30 million, respectively, and writedowns on coal inventory of $5 million and $16 million (2020 - $22 million and $22 million), respectively, to net realizable value. In addition, as a result of the decision to suspend the Sundance Unit 5 repowering project, payments related to the suspension of Sundance unit 5 were recorded during the third quarter of 2021. Included in the provision was $27 million for amounts due to contractors for not proceeding with the project, the impairment of previously recognized deferred asset of $10 million (US$8 million), as it is no longer likely that we will incur sufficient capital or operating expenditures to utilize the remaining credit and $6 million was expensed for amounts due to contractors for not proceeding with the construction of equipment for Keephills Unit 1.
(3) Included in this amount is an onerous contract provision of $14 million was recognized during the third quarter of 2021, as a result of a decision to accelerate the plans to shut down the Highvale Mine.
(4) Includes our share of amounts for Skookumchuck, an equity accounted joint venture.

Funds from Operations and Free Cash Flow

FFO is an important metric as it provides a proxy for cash generated from operating activities before changes in working capital and provides the ability to evaluate cash flow trends in comparison with results from prior periods. FCF is a key metric as it represents the amount of cash that is available to invest in growth initiatives, make scheduled principal repayments on debt, repay maturing debt, pay common share dividends or repurchase common shares. Changes in working capital are excluded so that 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	
	2021	2020	**2021**	2020
Cash flow from operating activities(1)	**610**	257	**947**	592
Change in non-cash operating working capital balances	**(378)**	(94)	**(322)**	(114)
Cash flow from operations before changes in working capital	**232**	163	**625**	478
Adjustments				
Share of adjusted FFO from joint venture(1)	**3**	—	**7**	—
Decrease in finance lease receivable	**10**	3	**30**	11
Clean energy transition provisions and adjustments(2)	**49**	**22**	**85**	**22**
Other	**3**	5	**11**	13
FFO	**297**	193	**758**	524
Deduct:				
Sustaining capital	**(44)**	(44)	**(144)**	(99)
Productivity capital	**(1)**	—	**(2)**	(1)
Dividends paid on preferred shares	**(9)**	(10)	**(29)**	(30)
Distributions paid to subsidiaries' non-controlling interests	**(52)**	(28)	**(121)**	(73)
Principal payments on lease liabilities	**(2)**	(5)	**(6)**	(15)
FCF	**189**	106	**456**	306
Weighted average number of common shares outstanding in the period	**271**	274	**271**	276
FFO per share	**1.10**	0.70	**2.80**	1.90
FCF per share	**0.70**	0.39	**1.68**	1.11

(1) Includes our share of amounts for Skookumchuck, an equity accounted joint venture.
(2) Includes writedowns on parts and material inventory for our coal operations, writedowns on coal inventory to net realizable value, amounts due to contractors for not proceeding with the Sundance Unit 5 repowering project and impairment of a previously recognized deferred asset, as it is no longer likely that we will incur sufficient capital or operating expenditures to utilize the remaining credit.

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

	3 months ended Sept. 30		9 months ended Sept. 30	
	2021	2020	**2021**	2020
Comparable EBITDA[1]	**381**	256	**993**	693
Provisions and other	**(20)**	2	**(25)**	17
Interest expense	**(50)**	(44)	**(149)**	(136)
Current income tax expense	**(23)**	(19)	**(58)**	(40)
Realized foreign exchange gain	**5**	—	**2**	9
Decommissioning and restoration costs settled	**(5)**	(5)	**(13)**	(13)
Other cash and non-cash items	**9**	3	**8**	(6)
FFO	**297**	193	**758**	524
Deduct:				
Sustaining capital	**(44)**	(44)	**(144)**	(99)
Productivity capital	**(1)**	—	**(2)**	(1)
Dividends paid on preferred shares	**(9)**	(10)	**(29)**	(30)
Distributions paid to subsidiaries' non-controlling interests	**(52)**	(28)	**(121)**	(73)
Principal payments on lease liabilities	**(2)**	(5)	**(6)**	(15)
FCF	**189**	106	**456**	306

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

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

	3 months ended Sept. 30, 2021				9 months ended Sept. 30, 2021			
	Reported	Adjustments[1]	Joint venture investment[2]	Comparable total	Reported	Adjustments[1]	Joint venture investment[2]	Comparable total
Revenues	850	(54)	3	799	2,111	(54)	12	2,069
Fuel, carbon compliance and purchased power	327	(80)	—	247	782	(198)	—	584
Carbon compliance	47	—	—	47	139	—	—	139
Gross margin	476	26	3	505	1,190	144	12	1,346
Operations, maintenance and administration	131	(6)	1	126	387	(31)	2	358
Asset impairment	575	(575)	—	—	620	(620)	—	—
Taxes, other than income taxes	9	—	—	9	26	—	1	27
Net other operating income	47	(58)	—	(11)	26	(58)	—	(32)
Comparable EBITDA	(286)	665	2	381	131	853	9	993

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

Alberta Electricity Portfolio Comparable Revenues

A reconciliation of revenues to Alberta Electricity Portfolio comparable revenues is set out below:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2021	2020	**2021**	2020
Revenues	**850**	514	**2,111**	1,557
Less: Segments not applicable to the Alberta Electricity Portfolio				
Australian Gas	**(46)**	(43)	**(130)**	(121)
Centralia	**(168)**	(147)	**(348)**	(326)
Energy Marketing	**(72)**	(58)	**(159)**	(114)
Corporate	**(1)**	(1)	**(6)**	1
Adjusted Segment Revenues	**563**	265	**1,468**	997
Comparable reclassifications				
Finance lease income	**6**	2	**19**	4
Decrease in finance lease receivables	**10**	3	**30**	11
Unrealized mark-to-market (gains) losses and commodity foreign exchange	**(70)**	45	**(103)**	(1)
Adjustments to earnings to arrive at comparable revenues for the Alberta Electricity Portfolio				
Revenues from Wind Assets not within Alberta	**(44)**	(49)	**(171)**	(192)
Revenues from Hydro Assets not within Alberta	**(7)**	(7)	**(20)**	(20)
Revenues from Gas Assets not within Alberta	**(77)**	(51)	**(190)**	(145)
Alberta Electricity Portfolio comparable revenues	**381**	208	**1,033**	654

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 2020	Q1 2021	Q2 2021	**Q3 2021**
Revenues	544	642	619	**850**
Comparable EBITDA	234	310	302	**381**
FFO	161	211	250	**297**
Net loss attributable to common shareholders	(167)	(30)	(12)	**(456)**
Net loss per share attributable to common shareholders, basic and diluted[1]	(0.61)	(0.11)	(0.04)	**(1.68)**

	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)

(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 (loss) attributable to common shareholders has also been impacted by the following variations and events:

- Effective Jan. 1, 2021, many of our Alberta hydro facilities, Keephills Units 1 and 2 and Sheerness began operating on a merchant basis in the Alberta market;
- Revenues declined due to weaker market conditions during the last three quarters of 2020 as a result of the COVID-19 pandemic and low oil prices;
- The suspension of the Sundance Unit 5 repowering project resulted in a provision for amounts due to contractors for not proceeding with the project and impairment of a previously recognized deferred asset, as it is no longer likely that we will incur sufficient capital or operating expenditures to utilize the remaining credit in the third quarter of 2021;
- Accelerated plans to shut down the Highvale Mine resulted in remaining future royalty payments being recognized as an onerous contract in the third quarter of 2021;
- Sheerness going off-coal has resulted in the remaining coal supply payments on the existing coal supply agreement being recognized as an onerous contract in the fourth quarter of 2020;
- Coal inventory writedowns incurred in the first three quarters of 2021 and third and fourth quarters of 2020;
- Coal-related parts and materials inventory writedowns incurred in the second and third quarters of 2021;
- The impact of the updated provision estimates for the transmission line loss rule during the first quarter of 2021 and the last three quarters of 2020;
- The unplanned outages at Sarnia in the second quarter of 2021;
- Significant foreign exchange gains in the last three quarters of 2020, which more than offset foreign exchange losses experienced during the first quarter of 2020;
- Gains relating to the sale of the Pioneer Pipeline in the second quarter of 2021 and gains on sale of Alberta Thermal equipment in the third quarter of 2021;
- Gains relating to the Keephills Unit 3 and Genesee Unit 3 swap in the fourth quarter of 2019;
- The effects of impairments and reversals during all periods shown;
- The effects of changes in decommissioning and restoration provisions for retired assets in all periods shown;
- The effects of changes in useful lives of certain assets during the third quarter of 2020; and
- Current tax expense increases since the fourth quarter of 2020, mainly due to the Energy Marketing segment and certain Hydro operations becoming taxable, increased valuation allowances taken on US deferred tax assets along with a decreased deferred tax recovery mainly due to increased revenues in the first, second and third quarters of 2021.

Key Financial Ratios

The methodologies and ratios used by rating agencies to assess our credit rating are not publicly disclosed. We have developed our own definitions of ratios and targets to help evaluate the strength of our financial position. These metrics and ratios are not defined and have no standardized meaning under IFRS and may not be comparable to those used by other entities or by rating agencies.

Adjusted Net Debt to Adjusted Comparable EBITDA

As at	Sept. 30, 2021	Dec. 31, 2020
Period-end long-term debt(1)	**3,090**	3,361
Exchangeable debentures	**333**	330
Less: Cash and cash equivalents	**(1,080)**	(703)
Add: 50 per cent of issued preferred shares and exchangeable preferred shares(2)	**671**	671
Other(3)	**(17)**	(13)
Adjusted net debt(4)(5)	**2,997**	3,646
Comparable EBITDA(5)(6)	**1,227**	927
Adjusted net debt to adjusted comparable EBITDA (times)	**2.4**	3.9

(1) Consists of current and long-term portion of debt, which includes lease liabilities and tax equity financing.
(2) Exchangeable preferred shares are considered equity with dividend payments for credit purposes. For accounting purposes, they are accounted for as debt with interest expense in the consolidated financial statements.
(3) Includes fair value asset of hedging instruments on debt included in risk management assets and/or liabilities and the principal portion of OCP restricted cash included in restricted cash on the consolidated financial statements as at Sept. 30, 2021 and Dec. 31, 2020.
(4) The interest on the tax equity financing for Skookumchuck, an equity accounted joint venture, is not represented in the amounts.
(5) These items are not defined and have no standardized meaning under IFRS. Presenting these items from period to period provides management and investors with the ability to evaluate earnings trends more readily in comparison with prior periods' results. Please refer to the Reconciliation of Non-IFRS Measures section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS. See also the Additional IFRS measures and Non-IFRS Measures section of this MD&A.
(6) Last 12 months.

Our adjusted net debt to adjusted comparable EBITDA ratio was lower than 2020 as a result of strong comparable EBITDA in the first three quarters of 2021, debt repayments and the weakening of the US dollar compared to the Canadian dollar in 2021.

Deconsolidated Net Debt to Deconsolidated Comparable EBITDA

In addition to reviewing fully consolidated ratios and results, management reviews net debt to comparable EBITDA on a deconsolidated basis to highlight TransAlta's financial flexibility, balance sheet strength and leverage, excluding the portion of TransAlta Renewables and TransAlta Cogeneration L.P. ("TA Cogen") that are not wholly 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. Please also refer to the IFRS Measures and Non-IFRS Measures section of this MD&A for further details.

As at	**Sept. 30, 2021**	Dec. 31, 2020
Period-end long-term debt(1)	**3,090**	3,361
Exchangeable debentures	**333**	330
Less: Cash and cash equivalents	**(1,080)**	(703)
Add: TransAlta Renewables cash and cash equivalents	**240**	582
Add: 50 per cent of issued preferred shares and exchangeable preferred shares(2)	**671**	671
Other(3)	**(17)**	(13)
Less: TransAlta Renewables long-term debt	**(665)**	(692)
Less: US tax equity financing and South Hedland debt(4)	**(859)**	(905)
Deconsolidated net debt	**1,713**	2,631
Comparable EBITDA(5)(6)	**1,227**	927
Less: TransAlta Renewables comparable EBITDA(5)	**(455)**	(462)
Less: TA Cogen comparable EBITDA(5)	**(119)**	(54)
Less: comparable EBITDA from equity accounted investments(5)(6)	**(12)**	(3)
Add: Dividend from TransAlta Renewables(5)	**151**	151
Add: Dividend from TA Cogen(5)	**30**	17
Deconsolidated comparable EBITDA(5)	**822**	576
Deconsolidated net debt to deconsolidated comparable EBITDA(5) (times)	**2.1**	4.6

(1) Consists of current and long-term portion of debt, which includes lease liabilities and tax equity financing.
(2) Exchangeable preferred shares are considered equity with dividend payments for credit purposes. For accounting purposes, they are accounted for as debt with interest expense in the consolidated financial statements.
(3) Includes fair value asset of hedging instruments on debt included in risk management assets and/or liabilities and the principal portion of OCP restricted cash included in restricted cash on the consolidated financial statements as at Sept. 30, 2021 and Dec. 31, 2020.
(4) Relates to assets where TransAlta Renewables has economic interests.
(5) Last 12 months.
(6) Comparable EBITDA includes our share of amounts for Skookumchuck, an equity accounted joint venture.

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

Deconsolidated Comparable EBITDA by Segment

Comparable EBITDA is a key metric for TransAlta and TransAlta Renewables and provides management and shareholders a representation of core business profitability. Deconsolidated comparable EBITDA is used in key planning and credit metrics and segment results highlight the operating performance of assets held directly at TransAlta that are comparable from period to period.

A reconciliation of comparable EBITDA to deconsolidated comparable EBITDA by segment results is set out below:

	3 months ended Sept. 30, 2021			3 months ended Sept. 30, 2020		
	TransAlta Consolidated	**TransAlta Renewables**	**TransAlta Deconsolidated**	TransAlta Consolidated	TransAlta Renewables	TransAlta Deconsolidated
Hydro	**82**	**6**		28	5	
Wind and Solar	**55**	**40**		36	44	
North American Gas	**35**	**24**		29	20	
Australian Gas	**36**	**36**		34	33	
Alberta Thermal	**104**	**—**		47	—	
Centralia	**35**	**—**		49	—	
Energy Marketing	**58**	**—**		49	—	
Corporate	**(24)**	**(4)**		(16)	(6)	
Comparable EBITDA	**381**	**102**	**279**	256	96	160
Less: TA Cogen comparable EBITDA			**(41)**			(17)
Less: EBITDA from joint venture investments[1]			**(2)**			—
Add: Dividend from TransAlta Renewables			**38**			38
Add: Dividend from TA Cogen			**22**			8
Deconsolidated comparable EBITDA			**296**			189

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

	9 months ended Sept. 30, 2021			9 months ended Sept. 30, 2020		
	TransAlta Consolidated	**TransAlta Renewables**	**TransAlta Deconsolidated**	TransAlta Consolidated	TransAlta Renewables	TransAlta Deconsolidated
Hydro	**255**	**14**		83	14	
Wind and Solar	**186**	**172**		171	179	
North American Gas	**88**	**52**		85	58	
Australian Gas	**99**	**99**		93	94	
Alberta Thermal	**232**	**—**		121	—	
Centralia	**61**	**—**		109	—	
Energy Marketing	**128**	**—**		90	—	
Corporate	**(56)**	**(15)**		(59)	(16)	
Comparable EBITDA	**993**	**322**	**671**	693	329	364
Less: TA Cogen comparable EBITDA			**(104)**			(39)
Less: EBITDA from joint venture investments[1]			**(9)**			—
Add: Dividend from TransAlta Renewables			**113**			113
Add: Dividend from TA Cogen			**25**			12
Deconsolidated TransAlta comparable EBITDA			**696**			450

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

Deconsolidated FFO

The Corporation has set a target to return 10 to 15 per cent of TransAlta's deconsolidated FFO to shareholders as it aligns shareholder returns to the assets held directly at TransAlta. This metric is not defined and has no standardized meaning under IFRS, and may not be comparable to those used by other entities or by rating agencies. Please refer to the IFRS Measures and Non-IFRS Measures section of this MD&A for further details.

	3 months ended Sept. 30, 2021			3 months ended Sept. 30, 2020		
	TransAlta Consolidated	**TransAlta Renewables**	**TransAlta Deconsolidated**	TransAlta Consolidated	TransAlta Renewables	TransAlta Deconsolidated
Cash flow from operating activities	**610**	**83**		257	65	
Change in non-cash operating working capital balances	**(378)**	**(23)**		(94)	(7)	
Cash flow from operations before changes in working capital	**232**	**60**		163	58	
Adjustments:						
Decrease in finance lease receivable	**10**	**—**		3	—	
Clean energy transition provisions and adjustments[1]	**49**			**—**		
Share of FFO from joint venture[2]	**3**	**—**		22	—	
Finance and interest income - economic interests	**—**	**(19)**		—	(13)	
AFFO - economic interests	**—**	**23**		—	38	
Sustaining capital expenditures - economic interests[3]	**—**	**16**		—	—	
Tax equity distributions - economic interests[3]	**—**	**7**		—	4	
Other	**3**	**—**		5	—	
FFO	**297**	**87**	**210**	193	87	106
Dividend from TransAlta Renewables			**38**			38
Distributions to TA Cogen's Partner			**(25)**			(8)
Less: Share of adjusted FFO from joint venture			**(3)**			—
Deconsolidated TransAlta FFO			**220**			136

(1) Includes writedowns on parts and material inventory for our coal operations, writedowns on coal inventory to net realizable value, amounts due to contractors for not proceeding with the Sundance Unit 5 repowering project and impairment of a previously recognized deferred asset, as it is no longer likely that we will incur sufficient capital or operating expenditures to utilize the remaining credit.

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

(3) During the first quarter of 2021, sustaining capital expenditures and tax equity distributions for TransAlta Renewables' economic interests have been added back to the Adjusted Funds from Operations ("AFFO") to align with the Corporation's calculation of FFO. Prior comparative periods have been adjusted.

	9 months ended Sept. 30, 2021			9 months ended Sept. 30, 2020		
	TransAlta Consolidated	**TransAlta Renewables**	**TransAlta Deconsolidated**	TransAlta Consolidated	TransAlta Renewables	TransAlta Deconsolidated
Cash flow from operating activities	**947**	**265**		592	218	
Change in non-cash operating working capital balances	**(322)**	**(57)**		(114)	(30)	
Cash flow from operations before changes in working capital	**625**	**208**		478	188	
Adjustments:						
Decrease in finance lease receivable	**30**	**—**		11	—	
Clean energy transition provisions and adjustments(1)	**85**			**22**		
Share of FFO from joint venture(2)	**7**	**—**		—	—	
Finance and interest income - economic interests	**—**	**(68)**		—	(31)	
AFFO - economic interests	**—**	**88**		—	120	
Sustaining capital expenditures - economic interests(3)	**—**	**22**		—	3	
Tax equity distributions - economic interests(3)	**—**	**21**		—	16	
Other	**11**	**—**		13	—	
FFO	**758**	**271**	**487**	524	296	228
Dividend from TransAlta Renewables			**113**			113
Distributions to TA Cogen's Partner			**(42)**			(12)
Less: Share of adjusted FFO from joint venture			**(7)**			—
Deconsolidated TransAlta FFO			**551**			329

(1) Includes writedowns on parts and material inventory for our coal operations, writedowns on coal inventory to net realizable value, amounts due to contractors for not proceeding with the Sundance Unit 5 repowering project and impairment of a previously recognized deferred asset, as it is no longer likely that we will incur sufficient capital or operating expenditures to utilize the remaining credit.
(2) Represents our share of amounts for Skookumchuck, an equity accounted joint venture.
(3) During the first quarter of 2021, sustaining capital expenditures and tax equity distributions for TransAlta Renewables' economic interests have been added back to the AFFO to align with the Corporation's calculation of FFO. Prior comparative periods have been adjusted.

Financial Position

The following table provides a summary of account balances derived from the unaudited interim condensed consolidated statements of financial position as at Sept. 30, 2021 and Dec. 31, 2020:

As at	Sept. 30, 2021	Dec. 31, 2020	Increase (decrease)
Assets			
Cash and cash equivalents	**1,080**	703	377
Trade and other receivables	**516**	583	(67)
Inventory	**186**	238	(52)
Risk management assets (current and long-term)	**856**	692	164
Assets held for sale	**—**	105	(105)
Finance lease receivables (long-term)	**192**	228	(36)
Property, plant and equipment, net	**5,210**	5,822	(612)
Right of use assets	**80**	141	(61)
Intangible assets	**259**	313	(54)
Others(1)	**941**	922	19
Total assets	**9,320**	9,747	(427)
Liabilities and equity			
Accounts payable and accrued liabilities	**774**	599	175
Credit facilities, long-term debt and lease liabilities (current and long-term)	**3,090**	3,361	(271)
Decommissioning and other provisions (current and long-term)	**842**	673	169
Risk management liabilities (current and long-term)	**531**	162	369
Deferred income tax liabilities	**339**	396	(57)
Defined benefit obligation and other long-term liabilities	**253**	298	(45)
Equity attributable to shareholders	**1,629**	2,352	(723)
Non-controlling interests	**1,024**	1,084	(60)
Others(2)	**838**	822	16
Total liabilities and equity	**9,320**	9,747	(427)

(1) Includes restricted cash, prepaid expenses, investments, goodwill, deferred income tax assets and other assets.
(2) Includes income taxes payable, dividends payable, exchangeable securities and contract liabilities.

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

- Please refer to the Cash Flow section of this MD&A for details on the change in cash during the period.
- Trade and other receivables decreased mainly due to timing of cash receipts, partially offset by higher revenues.
- Coal Inventory at Alberta Thermal decreased to 138,253 tonnes as at Sept. 30, 2021, compared to 973,298 tonnes at Dec. 31, 2020, resulting in $39 million released from working capital, including the coal inventory writedowns. In addition, a writedown of $30 million was recorded on parts and material inventory related to the Highvale Mine and coal operations at our facilities that have been converted to natural gas.
- Assets held for sale decreased as a result of the sale of the Pioneer Pipeline. Please refer to the Significant and Subsequent Events section of this MD&A for further details.
- Finance lease receivables decreased mainly due to scheduled principal receipts.
- Property, plant and equipment ("PP&E") decreased due to depreciation ($498 million), changes in foreign exchange rates ($27 million) and asset impairments ($558 million), which was partially offset by additions ($344 million) relating to planned major maintenance, assets under construction for the boiler conversions, Windrise wind project, Garden Plain wind project, and the Sundance Unit 5 repowering project. Please refer to the Corporate Strategy section in this MD&A for more details on the status of the Sundance Unit 5 repowering project. In addition, PP&E increased by $134 million due to increases in the decommissioning provision for wind assets. Please refer to Critical Accounting Policies and Estimates section in this MD&A for more details on changes in decommissioning and restoration provisions.
- Right of use assets decreased due to the 15-year natural gas transportation agreement with Pioneer Pipeline LP being terminated upon the close of the sale of the Pioneer Pipeline, which was accounted for as a lease ($41 million) and depreciation ($10 million).
- Intangible assets decreased due to a $17 million impairment of coal rights and depreciation expense of $40 million.
- Accounts payable and accrued liabilities increased due of timing of cash payments and additional provision for amounts due to contractors for not proceeding with the Sundance Unit 5 repowering project.

- Credit facilities, long-term debt and lease liabilities decreased due to lower drawings on the credit facilities ($114 million) and debt repayments ($63 million), the termination of the pipeline lease liability ($43 million) and changes in outstanding balances as a result of the weakening of the US dollar ($7 million) and weakening of the Australian closing rates ($41 million).
- Decommissioning and other provisions increased primarily due to revisions in cash flows as a result of updated estimates for our wind assets due to the review of a recent wind engineering study and the adjusted useful lives of Sundance Unit 6 and Keephills Unit 2, accretion of provisions and revisions in discount rates, partially offset by settlement of provisions.
- Decreases in net risk management assets and liabilities are primarily attributable to volatility in market prices on both existing contracts and new contracts as well as contract settlements.
- Deferred Income tax liabilities decreased primarily due to increase in impairment expenses recorded in the third quarter of 2021 and increase in loss before tax in Canada.
- Defined benefit obligation and other long-term liabilities decreased due to net actuarial gains resulting from increases in actuarial discount rates.
- Equity attributable to shareholders decreased mainly due to net losses for the period ($478 million), net losses on translating net assets of foreign operations ($17 million), and net losses on cash flow hedges ($247 million), partially offset by changes in fair value investments ($32 million) and actuarial gains on defined benefit plans ($40 million).
- Non-controlling interests decreased mainly due to distributions ($117 million) and fair value investment losses on intercompany fair value through other comprehensive income ("FVOCI") investments ($32 million), partially offset by net loss attributable to non-controlling interests ($88 million).

Cash Flows

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

	9 months ended Sept. 30		Increase
	2021	2020	(decrease)
Cash and cash equivalents, beginning of period	**703**	411	292
Provided by (used in):			
Operating activities	**947**	592	355
Investing activities	**(202)**	(368)	166
Financing activities	**(364)**	(369)	5
Translation of foreign currency cash	**(4)**	4	(8)
Cash and cash equivalents, end of period	**1,080**	270	810

Cash provided by operating activities for the nine months ended Sept. 30, 2021, increased compared with the same period in 2020 primarily due to higher revenues being realized in Alberta on the merchant assets, partially offset by higher fuel and purchased power and OM&A costs as the Corporation transitions off coal.

Cash used in investing activities for the nine months ended Sept. 30, 2021, decreased compared with the same period in 2020, largely due to:

- proceeds on the sale of Pioneer Pipeline ($128 million) and sale of equipment at Alberta Thermal and Centralia ($37 million);
- no acquisitions in 2021, whereas 2020 had the Ada acquisition ($37 million); and
- partially offset by increased cash spent on construction activities ($68 million).

Cash used in financing activities for the nine months ended Sept. 30, 2021, decreased compared with the same period in 2020, largely due to:

- lower common share repurchases under the NCIB ($17 million);
- proceeds on issuing common shares from the exercise of stock options ($8 million);
- lower realized losses ($7 million) on financial instruments;
- changes in working capital related to financing activities ($14 million); and
- partially offset by increased distributions paid to subsidiaries' non-controlling interests ($48 million).

Financial Capital

Capital Structure

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

As at	Sept. 30, 2021		Dec. 31, 2020	
	$	%	$	%
TransAlta Corporation				
Net senior unsecured debt				
Recourse debt - CAD debentures	**251**	**5**	249	3
Recourse debt - US senior notes	**881**	**16**	886	13
Credit facilities	**—**	**—**	114	2
Other	**4**	**—**	7	—
Less: cash and cash equivalents	**(840)**	**(16)**	(121)	(2)
Less: Other cash and liquid assets(1)	**(18)**	**—**	(13)	—
Net senior unsecured debt	**278**	**5**	1,122	16
Other debt liabilities				
Exchangeable debentures	**333**	**6**	330	5
Non-recourse debt	**367**	**7**	385	6
Lease liabilities	**62**	**1**	112	2
Total net debt - TransAlta Corporation	**1,040**	**19**	1,949	29
TransAlta Renewables				
Net TransAlta Renewables reported debt				
Non-recourse debt	**643**	**12**	670	10
Lease liabilities	**22**	**—**	22	—
Less: cash and cash equivalents	**(240)**	**(4)**	(582)	(9)
Debt on TransAlta Renewables Economic Investments				
US tax equity financing(2)	**128**	**2**	134	2
Non-recourse debt(3)	**732**	**14**	782	11
Total net debt - TransAlta Renewables	**1,285**	**24**	1,026	14
Total consolidated net debt(4)	**2,325**	**43**	2,975	43
Non-controlling interests	**1,024**	**19**	1,084	16
Exchangeable preferred securities(5)	**400**	**7**	400	6
Equity attributable to shareholders				
Common shares	**2,901**	**54**	2,896	43
Preferred shares	**942**	**18**	942	14
Contributed surplus, deficit and accumulated other comprehensive income	**(2,214)**	**(41)**	(1,486)	(22)
Total capital	**5,378**	**100**	6,811	100

(1) Includes principal portion of OCP restricted cash and fair value asset of hedging instruments on debt.
(2) TransAlta Renewables has an economic interest in the entities holding these debts.
(3) TransAlta Renewables has an economic interest in the Australia entities, which includes the AU$800 million senior secured notes.
(4) The tax equity financing for Skookumchuck, an equity accounted joint venture, is not represented in these amounts.
(5) Exchangeable preferred securities are considered equity with dividend payments for credit purposes. For accounting purposes, they are accounted for as debt with interest expense in the consolidated financial statements.

The Corporation continues to maintain a strong financial position in part due to our long-term contracts and hedged positions. At quarter end, we had access to $2.3 billion in liquidity including $1,080 million in cash and cash equivalents.

We have access to additional capital through potential project financings of existing assets that are currently unencumbered. Between 2021 and 2023, we have $813 million of debt maturing, including $512 million of recourse debt, with the balance mainly related to scheduled non-recourse debt repayments. We currently expect to refinance the senior notes maturing in 2022.

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

As at Sept. 30, 2021	Facility size	Utilized: Outstanding letters of credit[1]	Utilized: Actual drawings	Available capacity	Maturity date
TransAlta Corporation					
Committed syndicated bank facility[2]	1,250	566	—	684	Q2 2025
Canadian committed bilateral credit facilities	240	211	—	29	Q2 2023
TransAlta Renewables					
Committed credit facility[2]	700	94	—	606	Q2 2025
Total	**2,190**	**871**	**—**	**1,319**	

(1) TransAlta has obligations to issue letters of credit and cash collateral to secure potential liabilities to certain parties, including those related to potential environmental obligations, commodity risk management and hedging activities, pension plan obligations, construction projects and purchase obligations. As at Sept. 30, 2021, we provided cash collateral of $25 million.
(2) TransAlta has letters of credit of $97 million and TransAlta Renewables has letters of credit of $94 million issued from uncommitted demand facilities. These obligations are backstopped and reduce the available capacity on the committed credit facilities.

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

As at	Nov. 8, 2021	Sept. 30, 2021	Dec. 31, 2020
	Number of shares *(millions)*		
Common shares issued and outstanding, end of period	**271.0**	**271.0**	269.8
Preferred shares			
Series A[1]	9.6	**9.6**	10.2
Series B[1]	2.4	**2.4**	1.8
Series C	11.0	**11.0**	11.0
Series E	9.0	**9.0**	9.0
Series G	6.6	**6.6**	6.6
Preferred shares issued and outstanding in equity, end of period	**38.6**	**38.6**	38.6
Series I - Exchangeable Securities[2]	**0.4**	**0.4**	0.4
Preferred shares issued and outstanding, end of period	**39.0**	**39.0**	39.0

(1) On March 18, 2021, the Corporation announced that 1,417,338 of its 10.2 million Series A Cumulative Fixed Redeemable Rate Reset Preferred Shares ("Series A Shares") and 871,871 of its 1.8 million Series B Cumulative Redeemable Floating Rate Preferred Shares ("Series B Shares") were tendered for conversion, on a one-for-one basis, into Series B Shares and Series A Shares, respectively after having taken into account all election notices.
(2) Brookfield invested $400 million in consideration for redeemable, retractable, first preferred shares on Oct. 30, 2020. For accounting purposes, these preferred shares are considered debt and disclosed as such in the consolidated financial statements.

Non-Controlling Interests
As at Sept. 30, 2021, we own 60.1 per cent (Sept. 30, 2020 – 60.1 per cent) of TransAlta Renewables. Our ownership percentage remained consistent as TransAlta Renewables suspended its Dividend Reinvestment Plan ("DRIP") in the fourth quarter of 2020. We did not participate in this plan. Dividends after the suspension of the DRIP are being paid in cash.

We also own 50.01 per cent of TA Cogen (Sept. 30, 2020 - 50.01 per cent), which owns, operates or has an interest in three natural-gas-fired facilities (Ottawa, Windsor and Fort Saskatchewan) and one dual-fuel generating facility (Sheerness).

Reported net earnings attributable to non-controlling interests for the three and nine months ended Sept. 30, 2021, was $27 million and $88 million, an increase in net earnings of $20 million and $59 million, respectively, compared to the same periods in 2020. Earnings from TA Cogen for the three and nine months ended Sept. 30, 2021, increased compared with the same periods in 2020 due to higher prices in the Alberta market.

For the three and nine months ended Sept. 30, 2021, net earnings from TransAlta Renewables increased primarily due to the acquisition of Ada and Skookumchuck, higher finance income from investments in subsidiaries of TransAlta and no fair value losses recognized in the current period, partially offset by lower production from the Canadian and US Wind and Solar fleets. For the nine months ended Sept. 30, 2021, net earnings at TransAlta Renewables was also partially offset by the liquidated damages recognized related to unplanned outages and unfavourable steam reconciliation adjustment to Canadian Gas and lower foreign exchange gains.

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	
	2021	2020	**2021**	2020
Interest on debt	**41**	39	**121**	121
Interest on exchangeable debentures	**8**	7	**22**	22
Interest on exchangeable preferred shares	**7**	—	**21**	—
Interest income	**(2)**	(2)	**(8)**	(7)
Capitalized interest	**(5)**	(2)	**(13)**	(4)
Interest on lease liabilities	**1**	2	**5**	6
Credit facility fees, bank charges and other interest	**5**	4	**13**	13
Tax shield on tax equity financing	**—**	—	**1**	—
Other	**(1)**	—	**1**	1
Accretion of provisions	**9**	8	**23**	23
Net interest expense	**63**	56	**186**	175

Net interest expense for the three and nine months ended Sept. 30, 2021, was higher than the same periods in 2020. Interest expense increased in 2021 mainly due to the exchangeable preferred shares that were issued in 2020, and the project financing related to South Hedland obtained in the fourth quarter of 2020, partially offset by an increase in capitalized interest on development projects, the redemption of $400 million medium-term notes in the fourth quarter of 2020 and lower interest on other debt balances due to scheduled repayments.

Regulatory Updates

Please refer to the Policy and Legal Risks discussion in our 2020 annual MD&A as well as the Corporate Strategy section of this MD&A for further details that supplement the recent developments as discussed below.

Canada

Federal Climate Plan

On Dec. 11, 2020, the Government of Canada released its "*A Healthy Environment and a Healthy Economy*" climate plan that outlines how the federal government intends to use policies, regulations and funding to achieve Canada's Paris Agreement emissions reduction target. The three major aspects of the plan include increased carbon prices and obligations, increased funding for clean technology and the implementation of the Clean Fuel Regulation ("CFR"). The 2021 federal budget included significant spending to undertake the elements of the climate plan as well as additional measures, including a potential tax credit for carbon capture, utilization and storage. In April 2021, the federal government increased Canada's UNFCC Paris Agreement emissions reductions target to 40-45 per cent from 2005 levels by 2030. The government stated that it will consult with provinces and industry regarding many elements of the plan so significant uncertainty remains regarding the final form of the related regulations and other initiatives. This policy will provide TransAlta with the opportunity to provide clean electricity solutions to industries seeking to reduce their regulatory exposure, benefit from federal funding for clean electricity projects, and may, under certain circumstances, increase the value of emissions reductions credits from new renewables projects. TransAlta continues to engage with governments to mitigate risks and identify opportunities within the new federal plan.

During the 2021 federal election campaign, the government committed to achieving a net zero electricity grid by 2035 by adopting a national clean electricity standard. The government has not publicly shared how such a standard might be structured. TransAlta will actively engage the federal government as it designs the new standard. This policy may create new opportunities for the development of renewables and energy storage projects in the lead up to 2035.

Federal Carbon Pricing on GHG

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

Based Pricing Standard ("OBPS"). The Carbon Tax sets a carbon price per tonne of GHG emissions related to transportation fuels, heating fuels and other small emission sources. The carbon price is also the OBPS compliance price for carbon obligations.

On Feb. 12, 2021, the federal government began planning for a 2022 review of the OBPS and other aspects of the GGPPA. On June 5, 2021, the federal government published draft amendments to the GGPPA regulations clarifying the treatment of boilers. If adopted, this clarification will provide greater certainty regarding the treatment of gas-fired generating facilities under the OBPS. On Aug. 5, 2021, the Canadian federal government published updated benchmark criteria for provincial carbon pricing systems, which will come into force for the 2023 compliance year. TransAlta will closely engage governments regarding the review, amendments, and regulatory clarification.

Ontario Transition to Provincial Emission Performance Standard ("EPS")

In the fall of 2020, the federal government confirmed the EPS met the requirements of the GGPPA permitting Ontario to transition from the OBPS to the EPS. Ontario will transition to the EPS on Jan. 1, 2022.

Ontario's proposed standalone facility electricity performance standard differs from the performance standard for cogeneration facilities. This may place cogeneration electricity at a carbon pricing disadvantage relative to standalone electricity facilities as the efficiency benefits of cogeneration are not fully realized. However, as carbon costs are passed through under current contracts, risks related to changes under the Ontario EPS are reduced.

Net-Zero Emissions Accountability Act

The federal government has committed to a net zero emission target by 2050. The *Canadian Net-Zero Emissions Accountability Act*, which received Royal Assent on June 30, 2021, requires the federal government to set an interim target for 2026 and emission targets for the years 2030, 2035, 2040 and 2045 at least 5 years before the target date. When setting targets, the government will also publish an action plan of measures that it will implement to support the achievement of the target. The federal Department of Finance will provide an annual report on costs of the measures and progress.

United States

President Biden's US Job Plan

On March 31, 2021, President Biden announced his American Jobs Plan (the "US Jobs Plan") which is heavily focused on climate change. The US Jobs Plan proposes to spend $2 trillion over the next decade to rebuild transportation infrastructure, make existing and new infrastructure climate change resilient, create cleaner energy systems, support the deployment of electric vehicles and ensure job growth, particularly for low income and communities of colour. This plan will increase demand for electricity in the US market. This policy provides TransAlta with the opportunity to benefit from further government incentives for renewables development and an overall uplift in demand due to increased electrification of the economy and continued corporate efforts to decarbonize to meet regulatory and ESG objectives.

The US federal government continues to consider enacting clean energy bills and tax credit incentive programs in support of the deployment of renewable energy and battery storage, along with funding for grid infrastructure. TransAlta will continue to follow these developments and take advantage of opportunities that align with our growth strategy.

President Biden's Updated 2030 Emissions Reduction Commitment

On April 22, 2021, during a climate summit hosted by President Biden, the President committed to reduce US GHG emissions by 50 to 52 per cent below 2005 levels by 2030.

President Biden Executive Order on Climate-Related Financial Risk

On May 25, 2021, President Biden's administration published an Executive Order that tasks the US Secretary of Treasury with the responsibility to determine the federal government and the economy's financial exposure to climate change impacts and to develop strategy documents outlining approaches to deal with the impacts of climate change. This work will likely lead to more formalized and consistent climate risk reporting by public and private sector entities.

Australia

Australia's transition to renewables has been historically facilitated by a combination of Commonwealth and State government renewable energy initiatives. Currently, all Australian states have state-based renewable energy targets, with many having aggressive near term targets. The two largest states by population, New South Wales ("NSW") and Victoria, have legislated targets of 60 per cent renewables and 50 per cent renewables, respectively, by 2030. The need for firm supply and storage as part of a rapid renewable transition has also been recognized and some states have included targets for this in their renewable transition programs, such as NSW and Queensland. Within the National Electricity Market ("NEM"), renewable energy zones are being established as a means of seeking to reduce some network access and network performance risk for new renewable and storage projects. The regulatory framework supporting the renewable transition is still evolving and the rapid supply system transition, which will result from the above initiatives, provides an opportunity for the entry of a considerable volume of new renewable generation and storage capacity into the NEM and potential opportunities for TransAlta to participate.

In Australia, corporations are responding to government initiatives, as well as feedback from shareholders and customers with many committing to CO2 reduction targets above and beyond legislated targets. This provides additional support for investments in renewable projects such as the recently announced solar farm to be built by TransAlta for its customer, BHP Nickel West, at Mount Keith and Leinster in Western Australia.

There are no immediate policy risks to our contracted Australian assets. Our growth team continues to watch the evolution of state-level policy as Australian state governments seek to manage the reliability of their electricity systems given the ongoing retirement of coal generation and growth in renewable generation.

Other Consolidated Analysis

Commitments

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

Natural Gas Purchase and Transportation Contracts

As part of the sale of the Pioneer Pipeline, the Corporation entered into a 15-year agreement for an additional 275 TJ per day of natural gas transportation on a firm basis by 2023, representing a new commitment of $439 million over the next 15 years. This agreement replaces, in part, the Corporation's existing 15-year commitment for natural gas transportation for 139 TJ per day on the Pioneer Pipeline, which was terminated on June 30, 2021, and was accounted for as a lease. As a result, the Corporation now has firm gas transportation contracts in place for 400 TJ per day by 2023. Additionally, on June 30, 2021, the Corporation's agreement to purchase 139 TJ per day of natural gas from Tidewater was terminated, which reduces the commitments disclosed at Dec. 31, 2020 by $1.7 billion.

Growth

As part of the Northern Goldfields Solar Contract, engineering, procurement and construction contracts have been entered into for the construction of the Northern Goldfields Solar Project. New commitments of $13 million for the remainder of 2021 and $44 million in 2022 have been entered into during the third quarter of 2021. The project comprises the 27 MW Mount Keith Solar Farm, 11 MW Leinster Solar Farm, 10 MW/5MWh Leinster battery energy storage system and interconnecting transmission infrastructure. Construction activities will start in the first quarter of 2022 with expected project completion during the second half of 2022.

Contingencies

For the current significant outstanding contingencies, please refer to the Other Consolidated Analysis section of the 2020 Annual MD&A included in the 2020 Annual Integrated Report. Changes to these contingencies during the nine months ended Sept. 30, 2021, are included with the Significant and Subsequent Events section of the MD&A and below.

I. Sarnia Outages

The Sarnia cogeneration facility experienced three separate events between May 19, 2021 and June 9, 2021 that resulted in steam interruptions to its industrial customers. As a result, the customers have submitted claims for liquidated damages. Steam supply disruptions of this nature are atypical and infrequent at the Sarnia cogeneration facility. The Corporation commenced an investigation to determine the root cause of each of the three events, which should be completed later in the year, or the first quarter of 2022. The results of the investigation will help to determine if any liquidated damages are owing and, if so, the quantum.

II. Transmission Line Loss Rule Proceeding

The Corporation has been participating in a transmission line loss rule proceeding before the Alberta Utilities Commission ("AUC"). The AUC determined that it has the ability to retroactively adjust line loss charges going back to 2006 and directed the AESO to recalculate loss factors for 2006 to 2016. The first two invoices were received during 2020 for a cumulative amount of $17 million and the third and final invoice for $11 million was received in the first quarter of 2021. All invoices have been settled as of the second quarter of 2021, which remain subject to true-up invoices issued by the AESO in October 2021 to be settled in December 2021. The impact of the true-up invoices is expected to be $1 million.

III. Kaybob 3 Cogeneration Dispute

The Corporation is engaged in a dispute with Energy Transfer Canada ULC, formerly SemCAMS Midstream ULC ("ET Canada") as a result of ET Canada's purported termination of agreements between the parties to develop, construct and operate a 40 MW cogeneration facility at the Kaybob South No. 3 sour gas processing facility. TransAlta commenced an arbitration seeking full compensation for ET Canada's wrongful termination of the agreements. ET Canada seeks a declaration that the agreements were lawfully terminated. A hearing is scheduled for two weeks starting January 9, 2023.

IV. Fortescue Metals Group Ltd. Dispute

The Corporation has been engaged in a dispute with FMG as a result of FMG's purported termination of the South Hedland PPA. TransAlta sued FMG, seeking payments of amounts invoiced and not paid under the South Hedland PPA, as well as a declaration that the PPA is valid and in force. FMG, on the other hand, seeks a declaration that the PPA was lawfully terminated. The trial for this matter was to start on May 3, 2021 but, on May 2, 2021, the Corporation entered into a conditional settlement with FMG. The trial has been adjourned pending satisfaction of the settlement conditions, which the Corporation expects to occur before Dec. 31, 2021.

V. Keephills 1 Stator Force Majeure Appeal

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 was heard on July 8, 2021. After the hearing, counsel for ENMAX raised concerns that one of the three justices on the appeal panel was distracted during the hearing. The justice has since recused herself from the hearing and the parties made submissions with respect to whether the remaining two justices can continue to issue the decision or whether a new hearing is required. On Nov. 8, 2021, the Alberta Court of Appeal released its decision and ordered that the appeal be re-heard by a new three-person panel of the Court of Appeal, which has yet to be scheduled.

Critical Accounting Policies and Estimates

The preparation of unaudited interim condensed consolidated financial statements requires management to make judgments, estimates and assumptions that could affect the reported amounts of assets, liabilities, revenues, expenses and disclosures of contingent assets and liabilities during the period. These estimates are subject to uncertainty. Actual results could differ from these estimates due to factors such as fluctuations in interest rates, foreign exchange rates, inflation and commodity prices, and changes in economic conditions, legislation and regulations. There were no material changes in estimates in the quarter, except for the following:

Defined benefit obligation

The liability for pension and post-employment benefits and associated costs included in compensation expenses are impacted by estimates related to changes in key actuarial assumptions, including discount rates. As a result of increases in discount rates, largely driven by increases in market benchmark rates, the defined benefit obligation decreased to $230 million as at Sept. 30, 2021 from $282 million as at Dec. 31, 2020.

Decommissioning

In the third quarter of 2021, the Corporation adjusted the wind assets decommissioning and restoration provision as estimates were updated after the review of a recent engineering study. The Corporation's current best estimate of the decommissioning and restoration provision increased by $120 million. The Corporation also increased the decommissioning and restoration provision by approximately $39 million for the Sundance and Keephills Units included in Alberta Thermal to reflect the change in the timing of the expected reclamation work resulting from asset retirements and change in useful lives.

Accounting Changes

Current Accounting Changes

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

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

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

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

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

The Corporation's credit facilities references US LIBOR for US-dollar drawings and the Canadian Dollar Offered Rate for Canadian drawings, and includes appropriate fallback language to replace these benchmark rates if a benchmark transition event were to occur. There was no financial impact upon adoption. As at Sept. 30, 2021, there were no drawings under the credit facilities. The Corporation is monitoring the reform and does not expect any material impact.

Future Accounting Policy and National Instrument Changes

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

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

Amendments to IAS 12 Deferred Tax Related to Assets and Liabilities Arising from a Single Transaction

On May 7, 2021, the IASB issued amendments to IAS 12 *Deferred Tax Related to Assets and Liabilities Arising from a Single Transaction*. The amendments clarify that the initial recognition exemption under IAS 12 does not apply to transactions such as leases and decommissioning obligations. These transactions give rise to equal and offsetting temporary differences in which deferred tax should be recognized.

The amendments are effective for annual periods beginning on or after Jan. 1, 2023 with early application permitted. The Corporation is currently assessing the potential impact of this amendment on the financial statements.

Amendments to IAS 37 Provisions, Contingent Liabilities and Contingent Assets

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

National Instrument 52-112 Non-GAAP and Other Financial Measures Disclosure

On May 27, 2021, the Canadian Securities Administrators published the final National Instrument 52-112 *Non-GAAP and Other Financial Measures Disclosure* ("the Instrument"), effective Aug. 25, 2021 and will apply to reporting issuers for documents filed for a financial year ending on or after Oct. 15, 2021. The Instrument addresses disclosure of non-GAAP financial measures, non-GAAP ratios and other financial measures with the intent to provide clarity and consistency with respect to an issuer's disclosure obligations. The Corporation plans to apply the Instrument on its filings for the year ended Dec. 31, 2021.

For further details and changes in estimates relating to prior years, please refer to Note 3 of the 2020 audited annual consolidated financial statements and Note 2 of the unaudited interim condensed consolidated financial statements.

Financial Instruments

Please refer to Note 15 of the notes to the 2020 audited annual consolidated financial statements and Note 11 and 12 of our unaudited interim condensed consolidated financial statements as at and for the three and nine months ended Sept. 30, 2021, for details on Financial Instruments.

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

At Sept. 30, 2021, Level III instruments had a net asset carrying value of $13 million (Dec. 31, 2020 - $582 million net asset). The decrease during the period is primarily attributable to volatility in market prices on both existing contracts and new contracts as well as contract settlements. Our risk management profile and practices have not changed materially from Dec. 31, 2020.

Governance and Risk Management

Please refer to the Governance and Risk Management section of our 2020 Annual Integrated Report and Note 12 of our unaudited interim condensed consolidated financial statements for details on our risks and how we manage them. Our risk management profile and practices have not changed materially from Dec. 31, 2020. The following factor may contribute to those risks and uncertainties:

COVID-19 Global Pandemic

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

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

Disclosure Controls and Procedures

Management is responsible for establishing and maintaining adequate internal control over financial reporting ("ICFR") and disclosure controls and procedures ("DC&P"). During the three and nine months ended Sept. 30, 2021, the majority of our workforce supporting and executing our ICFR and DC&P worked remotely. There has been minimal impact to the design and performance of our internal controls. Management has reviewed the changes as a result of changes implemented in response to COVID-19 and is reasonably assured that adjustments to process have not materially affected, or are reasonably likely to materially affect, our ICFR or DC&P.

ICFR is a framework designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with IFRS. Management has used the *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) in order to assess the effectiveness of the Corporation's ICFR.

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

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

Management has evaluated, with the participation of our Chief Executive Officer and Chief Financial Officer, the effectiveness of our ICFR and DC&P as of the end of the period covered by this MD&A. Based on the foregoing evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as at Sept. 30, 2021, the end of the period covered by this MD&A, our ICFR and DC&P were effective.

Condensed Consolidated Statements of Loss

(in millions of Canadian dollars except per share amounts)

	3 months ended Sept. 30		9 months ended Sept. 30	
Unaudited	**2021**	2020	**2021**	2020
Revenues (Note 4)	**850**	514	**2,111**	1,557
Fuel and purchased power (Note 5)	**327**	214	**782**	523
Carbon compliance	**47**	38	**139**	118
Gross margin	**476**	262	**1,190**	916
Operations, maintenance and administration (Note 5)	**131**	114	**387**	354
Depreciation and amortization	**123**	162	**395**	481
Asset impairment (Note 6)	**575**	76	**620**	67
Taxes, other than income taxes	**9**	8	**26**	25
Net other operating expense (income) (Note 7)	**47**	(10)	**26**	(30)
Operating income (loss)	**(409)**	(88)	**(264)**	**19**
Equity income	**1**	—	**5**	—
Finance lease income	**6**	2	**19**	4
Net interest expense (Note 8)	**(63)**	(56)	**(186)**	(175)
Foreign exchange gain	**1**	11	**22**	15
Gain on sale of assets and other (Note 3 and 14)	**23**	2	**56**	2
Loss before income taxes	**(441)**	(129)	**(348)**	(135)
Income tax expense (recovery) (Note 9)	**(22)**	(10)	**42**	(25)
Net loss	**(419)**	(119)	**(390)**	(110)
Net earnings (loss) attributable to:				
TransAlta shareholders	**(446)**	(126)	**(478)**	(139)
Non-controlling interests (Note 10)	**27**	7	**88**	29
	(419)	(119)	**(390)**	(110)
Net loss attributable to TransAlta shareholders	**(446)**	(126)	**(478)**	(139)
Preferred share dividends (Note 19)	**10**	10	**20**	30
Net loss attributable to common shareholders	**(456)**	(136)	**(498)**	(169)
Weighted average number of common shares outstanding in the period *(millions)*	**271**	274	**271**	276
Net loss per share attributable to common shareholders, basic and diluted	**(1.68)**	(0.50)	**(1.84)**	(0.61)

See accompanying notes.

Condensed Consolidated Statements of Comprehensive Loss

(in millions of Canadian dollars)

	3 months ended Sept. 30		9 months ended Sept. 30	
Unaudited	**2021**	2020	**2021**	2020
Net loss	**(419)**	(119)	**(390)**	(110)
Other comprehensive income (loss)				
Net actuarial gains (loss) on defined benefit plans, net of tax (Note 1B)[1]	**2**	3	**40**	(12)
Gains (losses) on derivatives designated as cash flow hedges, net of tax[2]	**—**	(2)	**(1)**	3
Total items that will not be reclassified subsequently to net loss	**2**	1	**39**	(9)
Gains (losses) on translating net assets of foreign operations, net of tax	**17**	(27)	**(20)**	40
Gains (losses) on financial instruments designated as hedges of foreign operations, net of tax[3]	**(11)**	12	**3**	(11)
Gains (losses) on derivatives designated as cash flow hedges, net of tax[4]	**(107)**	(7)	**(238)**	48
Reclassification of losses (gains) on derivatives designated as cash flow hedges to net earnings, net of tax[5]	**19**	(35)	**(7)**	(84)
Total items that will be reclassified subsequently to net loss	**(82)**	(57)	**(262)**	(7)
Other comprehensive loss	**(80)**	(56)	**(223)**	(16)
Total comprehensive loss	**(499)**	(175)	**(613)**	(126)
Total comprehensive income (loss) attributable to:				
TransAlta shareholders	**(533)**	(243)	**(670)**	(206)
Non-controlling interests (Note 10)	**34**	68	**57**	80
	(499)	(175)	**(613)**	(126)

(1) Net of income tax expense of $1 million and $12 million for the three and nine months ended Sept. 30, 2021 (2020 - $1 million expense and $4 million recovery).
(2) Net of income tax expense of nil for the three and nine months ended Sept. 30, 2021 (2020 - nil and $1 million expense).
(3) Net of income tax expense of nil for the three and nine months ended Sept. 30, 2021 (2020 - 1 million recovery and $1 million recovery).
(4) Net of income tax recovery of $29 million and $65 million for the three and nine months ended Sept. 30, 2021 (2020 - $1 million recovery and $15 million expense).
(5) Net of reclassification of income tax recovery of $5 million and expense of $2 million for the three and nine months ended Sept. 30, 2021 (2020 - 9 million and $22 million expense).

See accompanying notes.

Condensed Consolidated Statements of Financial Position

(in millions of Canadian dollars)

Unaudited	**Sept. 30, 2021**	Dec. 31, 2020
Cash and cash equivalents	**1,080**	703
Restricted cash	**74**	71
Trade and other receivables	**516**	583
Prepaid expenses	**45**	31
Risk management assets (Note 11 and 12)	**410**	171
Inventory (Note 13)	**186**	238
Assets held for sale (Note 3)	**—**	105
	2,311	1,902
Investments	**102**	100
Long-term portion of finance lease receivables	**192**	228
Risk management assets (Note 11 and 12)	**446**	521
Property, plant and equipment (Note 6 and 14)		
Cost	**13,217**	13,398
Accumulated depreciation	**(8,007)**	(7,576)
	5,210	5,822
Right of use asset (Note 3)	**80**	141
Intangible assets	**259**	313
Goodwill	**463**	463
Deferred income tax assets	**67**	51
Other assets	**190**	206
Total assets	**9,320**	9,747
Accounts payable and accrued liabilities	**774**	599
Decommissioning and other provisions (Note 15)	**60**	59
Risk management liabilities (Note 11 and 12)	**428**	94
Current portion of contract liabilities	**13**	1
Income taxes payable	**28**	18
Dividends payable (Note 18 and 19)	**51**	59
Current portion of long-term debt and lease liabilities (Note 16)	**119**	105
	1,473	935
Credit facilities, long-term debt and lease liabilities (Note 16)	**2,971**	3,256
Exchangeable securities (Note 17)	**733**	730
Decommissioning and other provisions (Note 15)	**782**	614
Deferred income tax liabilities	**339**	396
Risk management liabilities (Note 11 and 12)	**103**	68
Contract liabilities	**13**	14
Defined benefit obligation and other long-term liabilities (Note 1B)	**253**	298
Equity		
Common shares (Note 18)	**2,901**	2,896
Preferred shares (Note 19)	**942**	942
Contributed surplus	**37**	38
Deficit	**(2,361)**	(1,826)
Accumulated other comprehensive income	**110**	302
Equity attributable to shareholders	**1,629**	2,352
Non-controlling interests (Note 10)	**1,024**	1,084
Total equity	**2,653**	3,436
Total liabilities and equity	**9,320**	9,747

Significant and subsequent events (Note 3)
Commitments and contingencies (Note 20)

See accompanying notes.

Condensed Consolidated Statements of Changes in Equity

(in millions of Canadian dollars)

Unaudited

9 months ended Sept. 30, 2021	**Common shares**	**Preferred shares**	**Contributed surplus**	**Deficit**	**Accumulated other comprehensive income**	**Attributable to shareholders**	**Attributable to non-controlling interests**	**Total**
Balance, Dec. 31, 2020	2,896	942	38	(1,826)	302	2,352	1,084	3,436
Net loss	**—**	**—**	**—**	**(478)**	**—**	**(478)**	**88**	**(390)**
Other comprehensive income (loss):								
Net losses on translating net assets of foreign operations, net of hedges and of tax	**—**	**—**	**—**	**—**	**(17)**	**(17)**	**—**	**(17)**
Net gain (losses) on derivatives designated as cash flow hedges, net of tax	**—**	**—**	**—**	**—**	**(247)**	**(247)**	**1**	**(246)**
Net actuarial gains on defined benefits plans, net of tax	**—**	**—**	**—**	**—**	**40**	**40**	**—**	**40**
Intercompany FVOCI investments	**—**	**—**	**—**	**—**	**32**	**32**	**(32)**	**—**
Total comprehensive income (loss)	**—**	**—**	**—**	**(478)**	**(192)**	**(670)**	**57**	**(613)**
Common share dividends	**—**	**—**	**—**	**(37)**	**—**	**(37)**	**—**	**(37)**
Preferred share dividends	**—**	**—**	**—**	**(20)**	**—**	**(20)**	**—**	**(20)**
Effect of share-based payment plans	**5**	**—**	**(1)**	**—**	**—**	**4**	**—**	**4**
Distributions paid, and payable, to non-controlling interests (Note 10)	**—**	**—**	**—**	**—**	**—**	**—**	**(117)**	**(117)**
Balance, Sept. 30, 2021	**2,901**	**942**	**37**	**(2,361)**	**110**	**1,629**	**1,024**	**2,653**

9 months ended Sept. 30, 2020	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec. 31, 2019	2,978	942	42	(1,455)	454	2,961	1,101	4,062
Net earnings (loss)	—	—	—	(139)	—	(139)	29	(110)
Other comprehensive income (loss):								
Net gains on translating net assets of foreign operations, net of hedges and tax	—	—	—	—	29	29	—	29
Net gains on derivatives designated as cash flow hedges, net of tax	—	—	—	—	(33)	(33)	—	(33)
Net actuarial losses on defined benefits plans, net of tax	—	—	—	—	(12)	(12)	—	(12)
Intercompany FVOCI investments	—	—	—	—	(51)	(51)	51	—
Total comprehensive income (loss)	—	—	—	(139)	(67)	(206)	80	(126)
Common share dividends	—	—	—	(35)	—	(35)	—	(35)
Preferred share dividends	—	—	—	(30)	—	(30)	—	(30)
Shares purchased under NCIB	(30)	—	—	9	—	(21)	—	(21)
Changes in non-controlling interests in TransAlta Renewables (Note 10)	—	—	—	5	—	5	13	18
Effect of share-based payment plans	(4)	—	(7)	—	—	(11)	—	(11)
Distributions paid, and payable, to non-controlling interests (Note 10)	—	—	—	—	—	—	(87)	(87)
Balance, Sept. 30, 2020	2,944	942	35	(1,645)	387	2,663	1,107	3,770

See accompanying notes.

Condensed Consolidated Statements of Cash Flows

(in millions of Canadian dollars)

	3 months ended Sept. 30		9 months ended Sept. 30	
Unaudited	**2021**	2020	**2021**	2020
Operating activities				
Net loss	**(419)**	(119)	**(390)**	(110)
Depreciation and amortization (Note 21)	**197**	195	**574**	567
Gain on sale of assets (Note 3)	**(23)**	(2)	**(56)**	(2)
Accretion of provisions (Note 8)	**9**	8	**23**	23
Decommissioning and restoration costs settled (Note 15)	**(5)**	(5)	**(13)**	(13)
Deferred income tax recovery (Note 9)	**(46)**	(29)	**(17)**	(65)
Unrealized (gain) loss from risk management activities	**(67)**	44	**(100)**	(2)
Unrealized foreign exchange (gains) losses	**1**	(13)	**(24)**	(11)
Changes in provisions and contract liability	**3**	1	**(19)**	10
Asset Impairment (Note 6)	**575**	76	**620**	67
Equity income, net of distributions from Joint Ventures	**(2)**	—	**(3)**	—
Other non-cash items	**9**	7	**30**	14
Cash flow from operations before changes in working capital	**232**	163	**625**	478
Change in non-cash operating working capital balances	**378**	94	**322**	114
Cash flow from operating activities	**610**	257	**947**	592
Investing activities				
Additions to property, plant and equipment (Note 14)	**(127)**	(129)	**(344)**	(276)
Additions to intangibles	**(1)**	(3)	**(4)**	(8)
Restricted cash	**(20)**	(16)	**(5)**	—
Acquisitions, net of cash acquired	**—**	—	**—**	(37)
Proceeds on the sale of Pioneer Pipeline (Note 3)	**—**	—	**128**	—
Proceeds on sale of property, plant and equipment	**33**	1	**37**	2
Realized gains (losses) on financial instruments	**(1)**	(3)	**(4)**	3
Decrease in finance lease receivable	**10**	3	**30**	11
Other	**6**	(5)	**(14)**	(4)
Change in non-cash investing working capital balances	**19**	(12)	**(26)**	(59)
Cash flow used in investing activities	**(81)**	(164)	**(202)**	(368)
Financing activities				
Net decrease in borrowings under credit facilities (Note 16)	**—**	(8)	**(114)**	(117)
Repayment of long-term debt (Note 16)	**(18)**	(17)	**(63)**	(61)
Dividends paid on common shares (Note 18)	**(13)**	(12)	**(37)**	(35)
Dividends paid on preferred shares (Note 19)	**(9)**	(10)	**(29)**	(30)
Net proceeds on issuance of common shares (Note 18)	**—**	—	**8**	—
Repurchase of common shares under NCIB (Note 18)	**—**	(2)	**(4)**	(21)
Realized losses on financial instruments	**(1)**	—	**—**	(7)
Distributions paid to subsidiaries' non-controlling interests (Note 10)	**(50)**	(27)	**(117)**	(69)
Repayment of lease liabilities (Note 16)	**(2)**	(5)	**(6)**	(15)
Other	**1**	—	**(2)**	—
Change in non-cash financing working capital balances	**1**	2	**—**	(14)
Cash flow used in financing activities	**(91)**	(79)	**(364)**	(369)
Cash flow from (used in) operating, investing, and financing activities	**438**	14	**381**	(145)
Effect of translation on foreign currency cash	**—**	(1)	**(4)**	4
Increase (decrease) in cash and cash equivalents	**438**	13	**377**	(141)
Cash and cash equivalents, beginning of period	**642**	257	**703**	411
Cash and cash equivalents, end of period	**1,080**	270	**1,080**	270
Cash income taxes paid	**13**	9	**40**	29
Cash interest paid	**49**	35	**161**	134

See accompanying notes.

Notes to Condensed Consolidated Financial Statements

(Unaudited)

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

1. Accounting Policies

A. Basis of Preparation

These unaudited interim condensed consolidated financial statements have been prepared in compliance with International Accounting Standard ("IAS") 34 Interim Financial Reporting using the same accounting policies as those used in TransAlta Corporation's ("TransAlta" or the "Corporation") most recent audited annual consolidated financial statements, except as outlined in Note 2. These unaudited interim condensed consolidated financial statements do not include all of the disclosures included in the Corporation's audited annual consolidated financial statements. Accordingly, they should be read in conjunction with the Corporation's most recent audited annual consolidated financial statements which are available on SEDAR at www.sedar.com and on EDGAR at www.sec.gov.

The unaudited interim condensed consolidated financial statements include the accounts of the Corporation and the subsidiaries that it controls.

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

These unaudited interim condensed consolidated financial statements reflect all adjustments which consist of normal recurring adjustments and accruals that are, in the opinion of management, necessary for a fair presentation of results. TransAlta's results are partly seasonal due to the nature of the electricity market and related fuel costs. Higher maintenance costs are ordinarily incurred in the second and third quarters when electricity prices are expected to be lower, as electricity prices generally increase in the winter months in the Canadian market.

These unaudited interim condensed consolidated financial statements were authorized for issue by the Audit, Finance and Risk Committee on behalf of the Board of Directors on Nov. 8, 2021.

B. Use of Estimates and Significant Judgments

The preparation of these unaudited interim condensed consolidated financial statements in accordance with IAS 34 requires management to use judgment and make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and disclosures of contingent assets and liabilities. These estimates are subject to uncertainty. Please refer to Note 2(Z) of the Corporation's most recent audited annual consolidated financial statements for further details. Actual results could differ from these estimates due to factors such as fluctuations in interest rates, foreign exchange rates, inflation and commodity prices, and changes in economic conditions, legislation and regulations.

Change in Estimates

Defined benefit obligation

The liability for pension and post-employment benefits and associated costs included in compensation expenses are impacted by estimates related to changes in key actuarial assumptions, including discount rates. As a result of increases in discount rates in 2021, largely driven by increases in market benchmark rates, the defined benefit obligation has decreased by $52 million to $230 million as at Sept. 30, 2021 (Dec. 2020 - $282 million).

Provisions for Decommissioning and Restoration Activities

TransAlta recognizes provisions for decommissioning and restoration obligations. Initial decommissioning provisions, and subsequent changes thereto, are determined using the Corporation's best estimate of the required cash expenditures, adjusted to reflect the risks and uncertainties inherent in the timing and amount of settlement. During the third quarter of 2021, there was a $120 million increase in estimated cash flows for our wind assets as estimates were updated after the review of a recent engineering study. The Corporation also increased the decommissioning and restoration provision by approximately $39 million for the Sundance and Keephills Units included in Alberta Thermal to reflect the change in the timing of the expected reclamation work resulting from asset retirements and change in useful lives. These changes resulted in an increased in the related assets in property, plant and equipment. Please refer to Note 15 for more details for changes in decommissioning and restoration provisions.

2. Significant Accounting Policies

A. Current Accounting Changes

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

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

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

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

The Corporation's credit facilities references US LIBOR for US-dollar drawings and the Canadian Dollar Offered Rate for Canadian drawings, and includes appropriate fallback language to replace these benchmark rates if a benchmark transition event were to occur. There was no financial impact upon adoption. As at Sept. 30, 2021, there were no drawings under the credit facilities. The Corporation is monitoring the reform and does not expect any material impact.

B. Future Accounting Policy Changes

I. Amendments to IAS 37 Provisions, Contingent Liabilities and Contingent Assets

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

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

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

III. Amendments to IAS 12 Deferred Tax Related to Assets and Liabilities Arising from a Single Transaction

On May 7, 2021, the IASB issued amendments to IAS 12 *Deferred Tax Related to Assets and Liabilities Arising from a Single Transaction*. The amendments clarify that the initial recognition exemption under IAS 12 does not apply to transactions such as leases and decommissioning obligations. These transactions give rise to equal and offsetting temporary differences in which deferred tax should be recognized.

The amendments are effective for annual periods beginning on or after Jan. 1, 2023 with early application permitted. The Corporation is currently assessing the potential impact of this amendment on the financial statements.

C. Comparative Figures

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

3. Significant and Subsequent Events

A. Acquisition of North Carolina Solar

On Nov. 5, 2021, the Corporation closed the acquisition of a 100 per cent membership interest in CI-II Mitchell Holding LLC, owner of a 122 MW portfolio of operating solar facilities located in North Carolina (collectively, "North Carolina Solar"), for cash consideration of US$99 million (including working capital adjustments) and the assumption of existing tax equity obligations. The acquisition was funded using existing liquidity. The North Carolina Solar portfolio consists of 20 solar photovoltaic facilities across North Carolina. The facilities were commissioned between November 2019 and May 2021 and are all operational. The facilities are secured by long-term power purchase agreements ("PPAs") with two subsidiaries of Duke Energy ("Duke Energy"), which have an average remaining term of 12 years. Under the PPAs, Duke Energy receives the renewable electricity, capacity, and environmental attributes from each facility.

In accordance IFRS 3, Business Combinations, the substance of this transaction constituted a business combination for TransAlta. Accordingly, management is in the process of gathering the relevant information that existed at the acquisition date to determine the fair value of net identifiable assets acquired. Given the close proximity between the acquisition date and the release date of these financial statements management has yet to determine a provisional allocation of the fair value of net identifiable assets acquired.

At the closing of the acquisition, TransAlta Renewables Inc. ("TransAlta Renewables"), a subsidiary of the Corporation, acquired a 100 per cent economic interest in North Carolina Solar from a wholly-owned subsidiary of TransAlta Corporation through a tracking share structure for US$102 million. Pursuant to the transaction, a TransAlta subsidiary owns North Carolina Solar indirectly and has issued to TransAlta Renewables tracking preferred shares reflecting its economic interest in the facilities.

B. Kent Hills Wind Facility Outage

On Sept. 27, 2021, the Corporation's subsidiary, Kent Hills Wind LP, experienced a single tower failure at its 167 MW Kent Hills wind facility in Kent Hills, New Brunswick. The failure involved a collapsed tower located within the Kent Hills 2 site. There were no injuries as a result of the collapse. Please see Note 6 for further details on the impairment.

The facility consists of 50 turbines at Kent Hills 1 and Kent Hills 2 and 5 turbines at Kent Hills 3. The turbines at the Kent Hills 1 and Kent Hills 2 sites have been taken offline pending a satisfactory independent engineering and safety assessment. The engineering assessment, which is ongoing, has identified sub-surface crack propagation at several of the foundations of the turbines located at the Kent Hills 1 and Kent Hills 2 sites. As a result, further inspection and testing will be required for all turbines at Kent Hills 1 and Kent Hills 2 to determine the required remediation plan, on a turbine-by-turbine basis. It is presently expected that the outage at Kent Hills 1 and Kent Hills 2 will require repairs or replacements for a significant portion of the existing foundations. Foundation replacements would require expenditures of approximately $1.5 million to $2.0 million per foundation. The remediation plan is expected to be implemented in 2022. The outage is expected to result in foregone revenue of approximately $3.4 million per month on an annualized basis so long as all 50 turbines are offline, based on average historical wind production, with revenue expected to be earned as the wind turbines are returned to service. The foundation issues at the Kent Hills 1 and Kent Hills 2 sites are unique to the design of those sites and there is no indication of any foundation issue at the Kent Hills 3 site nor any other wind sites in the fleet. The Corporation is maintaining communication with all key stakeholders and keeping them fully apprised of the situation. The Corporation has notified its insurers regarding an insurance claim for both property loss and business interruption.

C. Retirement of Sundance Unit 4, Keephills Unit 1 and Sundance Unit 5 Suspension

TransAlta has decided to retire Keephills Unit 1 effective Dec. 31, 2021, retire Sundance Unit 4 effective April 1, 2022 and suspend the Sundance Unit 5 Repowering Project. The evaluation of these facilities and project resulted in the Corporation recording asset impairment charges totalling $324 million ($245 million after-tax) during the third quarter of 2021. Please see Note 6 for further details on these impairment charges.

D. Highvale Mine Impairment

With all of TransAlta's remaining coal-fired units having been converted or in the process of being converted to natural gas, the Highvale Mine is no longer considered to be providing significant economic benefit to the Alberta Merchant CGU and has been removed from the CGU which resulted in an impairment recognized in the third quarter of 2021 of $185 million. Please see Note 6 for further details on this impairment charge.

E. Announced Common Dividend Increase

On Sept. 28, 2021, the Corporation announced that its Board of Directors approved an 11 per cent increase on its common share dividend and declared a dividend of $0.05 per common share to be payable on Jan. 1, 2022 to shareholders of record at the close of business on Dec. 1, 2021. The quarterly dividend of $0.05 per common share represents an annualized dividend of $0.20 per common share.

F. Northern Goldfields Solar Project

On July 29, 2021, TransAlta Renewables announced that Southern Cross Energy, a subsidiary of the Corporation and an entity in which TransAlta Renewables owns an indirect economic interest, had reached an agreement to provide BHP Nickel West Pty Ltd. ("BHP") with renewable electricity to its Goldfields-based operations through the construction of the Northern Goldfields Solar Project. The project comprises the 27 MW Mount Keith Solar Farm, 11 MW Leinster Solar Farm, 10 MW/5MWh Leinster battery energy storage system and interconnecting transmission infrastructure, all of which will be integrated into our existing 169 MW Southern Cross Energy North remote network in Western Australia.

G. Sundance Unit 5 Retirement as a Coal-Fired Unit

On July 29, 2021, in accordance with applicable regulatory requirements, the Corporation gave notice to the Alberta Electric System Operator ("AESO") of its intention to retire the mothballed coal-fired Sundance Unit 5 effective Nov. 1, 2021 and to terminate the associated transmission service agreement.

During the third quarter of 2021, the Corporation recorded an impairment charge on Sundance Unit 5, please refer to Note 6 for further details.

H. Keephills Unit 2 and Sundance Unit 6 Conversion to Gas Completions

On July 19, 2021, the Corporation announced the completion of the conversion of Keephills Unit 2 from thermal coal to natural gas. In February 2021, the Corporation also completed the conversion to natural gas of Sundance Unit 6. Both Keephills Unit 2 and Sundance Unit 6 will maintain the same generator nameplate capacity of 395 MW and 401 MW, respectively.

I. Sale of the Pioneer Pipeline

On June 30, 2021, the Corporation closed the previously announced sale of the Pioneer Pipeline to ATCO Gas and Pipelines Ltd. ("ATCO") for the aggregate sale price of $255 million. The net cash proceeds to TransAlta from the sale of its 50 per cent interest, were approximately $128 million, subject to certain adjustments. Following closing of the transaction, the Pioneer Pipeline was integrated into NOVA Gas Transmission Ltd. ("NGTL") and ATCO's Alberta natural gas transmission systems to provide reliable natural gas supply to the Corporation's power generation stations at Sundance and Keephills. As part of the transaction, TransAlta entered into additional long-term gas transportation agreements with NGTL for new and existing transportation service of 400 TJ per day by the end of 2023. Please refer to Note 20 for further details.

As a result of this sale, the Corporation has derecognized the related Pioneer Pipeline assets which were classified as assets held for sale ($97 million) and recognized a gain on sale of $31 million on the statement of earnings. In addition, as part of the transaction, the natural gas transportation agreement with the Pioneer Pipeline Limited Partnership was terminated which resulted in the derecognition of the right of use asset ($41 million) and lease liability ($43 million) related to the pipeline, resulting in a gain of $2 million.

J. Sarnia Cogeneration Facility Contract Extension

On May 12, 2021, the Corporation executed an Amended and Restated Energy Supply Agreement with one of its large industrial customers at the Sarnia cogeneration facility which provides for the supply of electricity and steam. This agreement will extend the term of the original agreement from Dec. 31, 2022 to Dec. 31, 2032. The agreement provides that if the Corporation is unable to enter into a new contract with the Ontario Independent Electricity System Operator (“IESO”) or enter into agreements with its other industrial customers at the Sarnia cogeneration facility that extend past Dec. 31, 2025, then the agreement will automatically terminate on Dec. 31, 2025.

K. Garden Plain Wind Project

On May 3, 2021, the Corporation announced that it entered into a long-term PPA with Pembina Pipeline Corporation ("Pembina") pursuant to which Pembina has contracted for the renewable electricity and environmental credits of 100 MWs of the 130 MW Garden Plain wind project ("Garden Plain") in Alberta. Under a separate agreement, Pembina has the option to purchase a 37.7 per cent interest in the project (49 per cent of the PPA). The option must be exercised no later than 30 days after commercial operational date. TransAlta would remain the operator of the facility and earn a service fee if Pembina exercises this option. Initial construction activities have started in the third quarter of 2021 and completion of the project is expected in the second half of 2022.

L. Mangrove Claim

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

M. Keephills 1 Superheater Force Majeure

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

N. TransAlta Renewables Acquisitions

The Corporation completed the sale of its 100 per cent direct interest in the 206 MW Windrise wind project ("Windrise") to TransAlta Renewables on Feb. 26, 2021 for $213 million. The remaining construction costs for Windrise are paid by TransAlta Renewables. All turbine erection activities have now been completed, with final commissioning activities currently underway and commercial operation tracking to be achieved in November, 2021.

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

O. Global Pandemic

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

Notwithstanding the challenges associated with the pandemic, all of the Corporation's facilities continue to remain fully operational and capable of meeting our customers' needs, with exception of Kent Hills wind facility as described above, which is not related to the pandemic. The Corporation continues to work and serve all customers and counterparties under the terms of their contracts. The Corporation has not experienced interruptions to service requirements as a result of COVID-19. Electricity and steam supply continue to remain a critical service requirement to all customers and have been deemed an essential service in the Corporation's jurisdictions.

4. Revenue

A. Disaggregation of Revenue

The majority of the Corporation's revenues are derived from the sale of physical power, capacity and environmental attributes, leasing of power facilities, and from asset optimization activities, which the Corporation disaggregates into the following groups for the purpose of determining how economic factors affect the recognition of revenue.

3 months ended Sept. 30, 2021	Hydro	Wind and Solar	North American Gas	Australian Gas	Alberta Thermal	Centralia	Energy Marketing	Corporate	Total
Revenue from contracts with customers									
Power and other[1]	8	37	68	33	9	3	—	—	158
Environmental credits[2]	—	14	—	—	—	—	—	—	14
Revenue from contracts with customers	8	51	68	33	9	3	—	—	172
Revenue from leases[3]	—	—	4	—	—	—	—	—	4
Revenue from derivatives and other trading activities[4]	—	(20)	7	—	15	52	86	1	141
Merchant revenue and other[1]	88	21	9	2	297	116	—	—	533
Total revenue	96	52	88	35	321	171	86	1	850
Revenue from contracts with customers									
Timing of revenue recognition									
At a point in time	—	14	—	—	6	3	—	—	23
Over time	8	37	68	33	3	—	—	—	149
Total revenue from contracts with customers	8	51	68	33	9	3	—	—	172

(1) The Alberta PPAs for the Hydro and Alberta Thermal segments with the Balancing Pool expired at Dec. 31, 2020. These facilities began operating on a merchant basis in the Alberta market.
(2) Environmental credit revenue includes inter-segment revenues generated by the Wind and Solar and Hydro segments. Revenues are recognized as emission credits and are used to offset environmental obligations. Elimination of these revenues are reflected at the Corporate segment.
(3) Total rental income, including contingent rent related to certain PPAs and other long-term contracts that meet the criteria of operating leases.
(4) Represents realized and unrealized gains or losses from hedging positions.

3 months ended Sept. 30, 2020	Hydro	Wind and Solar	North American Gas	Australian Gas	Alberta Thermal	Centralia	Energy Marketing	Corporate	Total
Revenue from contracts with customers									
Power and other[1]	37	29	51	24	81	3	—	—	225
Environmental credits[2]	—	18	—	—	—	—	—	—	18
Total revenue from contracts with customers	37	47	51	24	81	3	—	—	243
Revenue from leases[3]	—	—	—	16	14	—	—	—	30
Revenue from derivatives and other trading activities[4]	—	3	3	—	(5)	45	50	1	97
Merchant revenue and other	4	11	3	3	52	71	—	—	144
Total revenue	41	61	57	43	142	119	50	1	514
Revenue from contracts with customers									
Timing of revenue recognition									
At a point in time	—	7	—	—	6	3	—	—	16
Over time	37	40	51	24	75	—	—	—	227
Total revenue from contracts with customers	37	47	51	24	81	3	—	—	243

(1) Certain contract balances within the Wind and Solar segment have been reclassified from revenue from contracts with customers to merchant revenue and other or revenue from leases.
(2) Environmental credit revenue includes inter-segment revenues generated by the Wind and Solar and Hydro segments. Revenues are recognized as emission credits and are used to offset environmental obligations. Elimination of these revenues are reflected at the Corporate segment.
(3) Total rental income, including contingent rent related to certain PPAs and other long-term contracts that meet the criteria of operating leases.
(4) Represents realized and unrealized gains or losses from hedging positions.

9 months ended Sept. 30, 2021	**Hydro**	**Wind and Solar**	**North American Gas**	**Australian Gas**	**Alberta Thermal**	**Centralia**	**Energy Marketing**	**Corporate**	**Total**
Revenue from contracts with customers									
Power and other[1]	**21**	**149**	**176**	**90**	**23**	**6**	**—**	**—**	**465**
Environmental credits[2]	**—**	**23**	**—**	**—**	**—**	**—**	**—**	**—**	**23**
Revenue from contracts with customers	**21**	**172**	**176**	**90**	**23**	**6**	**—**	**—**	**488**
Revenue from leases[3]	**—**	**—**	**14**	**—**	**—**	**—**	**—**	**—**	**14**
Revenue from derivatives and other trading activities[4]	**—**	**(21)**	**11**	**—**	**(81)**	**150**	**185**	**6**	**250**
Merchant revenue and other[1]	**278**	**62**	**14**	**6**	**833**	**166**	**—**	**—**	**1,359**
Total revenue	**299**	**213**	**215**	**96**	**775**	**322**	**185**	**6**	**2,111**
Revenue from contracts with customers									
Timing of revenue recognition									
At a point in time	**—**	**23**	**—**	**—**	**14**	**6**	**—**	**—**	**43**
Over time	**21**	**149**	**176**	**90**	**9**	**—**	**—**	**—**	**445**
Total revenue from contracts with customers	**21**	**172**	**176**	**90**	**23**	**6**	**—**	**—**	**488**

(1) The Alberta PPAs for the Hydro and Alberta Thermal segments with the Balancing Pool expired at Dec. 31, 2020. These facilities began operating on a merchant basis in the Alberta market.
(2) Environmental credit revenue includes inter-segment revenues generated by the Wind and Solar and Hydro segments. Revenues are recognized as emission credits and are used to offset environmental obligations. Elimination of these revenues are reflected at the Corporate segment.
(3) Total rental income, including contingent rent related to certain PPAs and other long-term contracts that meet the criteria of operating leases.
(4) Represents realized and unrealized gains or losses from hedging positions.

9 months ended Sept. 30, 2020	Hydro	Wind and Solar	North American Gas	Australian Gas	Alberta Thermal	Centralia	Energy Marketing	Corporate	Total
Revenue from contracts with customers									
Power and other[1]	112	160	146	67	236	8	—	—	729
Environmental credits[2]	—	18	—	—	—	—	—	(5)	13
Total revenue from contracts with customers	112	178	146	67	236	8	—	(5)	742
Revenue from leases[3]	—	—	—	47	41	—	—	—	88
Revenue from derivatives and other trading activities[4]	—	8	4	—	17	211	103	4	347
Merchant revenue and other	9	54	6	7	194	110	—	—	380
Total revenue	121	240	156	121	488	329	103	(1)	1,557
Revenue from contracts with customers									
Timing of revenue recognition									
At a point in time	—	18	—	—	17	8	—	—	43
Over time	112	160	146	67	219	—	—	(5)	699
Total revenue from contracts with customers	112	178	146	67	236	8	—	(5)	742

(1) Certain contract balances within the Wind and Solar segment have been reclassified from revenue from contracts with customers to merchant revenue and other or revenue from leases.
(2) Environmental credit revenue includes inter-segment revenues generated by the Wind and Solar and Hydro segments. Revenues are recognized as emission credits and are used to offset environmental obligations. Elimination of these revenues are reflected at the Corporate segment.
(3) Total rental income, including contingent rent related to certain PPAs and other long-term contracts that meet the criteria of operating leases.
(4) Represents realized and unrealized gains or losses from hedging positions.

5. Expenses by Nature

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

	3 months ended Sept. 30				9 months ended Sept. 30			
	2021		2020		**2021**		2020	
	Fuel and purchased power	**OM&A**	Fuel and purchased power	OM&A	**Fuel and purchased power**	**OM&A**	Fuel and purchased power	OM&A
Gas fuel costs[1]	**80**	**—**	30	—	**200**	**—**	101	—
Coal fuel costs[1][2]	**53**	**—**	86	—	**123**	**—**	171	—
Royalty, land lease, other direct costs	**4**	**—**	5	—	**14**	**—**	16	—
Purchased power	**107**	**—**	46	—	**240**	**—**	110	—
Mine depreciation[3]	**74**	**—**	33	—	**179**	**—**	86	—
Salaries and benefits	**9**	**67**	14	60	**26**	**174**	39	181
Other operating expenses[4]	**—**	**64**	—	54	**—**	**213**	—	173
Total	**327**	**131**	214	114	**782**	**387**	523	354

(1) As of the first quarter of 2021, fuel costs have been split to show natural gas and coal fuel costs separately within the above table and carbon compliance costs have been reclassified from fuel and purchased power to a separate line called carbon compliance costs on the condensed consolidated statements of loss. Prior periods have been adjusted to reflect these reclassifications.
(2) Included in coal fuel costs for the three and nine months ended Sept. 30, 2021, were $5 million and $16 million, respectively, related to the impairment of coal inventory recorded during 2021 (Sept. 30, 2020 - $22 million and $22 million) . Please refer to Note 13 for further details.
(3) Included in mine depreciation for the three and nine months ended Sept. 30, 2021, were $19 million and $48 million, respectively, related to the mine depreciation that was initially recorded in the standard cost of coal inventory and then subsequently impaired during 2021. Please refer to Note 13 for further details.
(4) Included in OM&A costs for the three and nine months ended Sept. 30, 2021, were $5 million and $30 million, respectively, related to the writedown of parts and material inventory related to the Highvale mine and coal operations at our natural gas converted facilities. Please refer to Note 13 for further details.

6. Asset Impairment Charges and Reversals

	3 months ended Sept. 30		9 months ended Sept. 30	
	2021	2020	**2021**	2020
PP&E Impairments:				
Alberta Thermal Facilities and Projects	**324**	70	**324**	70
Highvale Mine	**185**	—	**185**	—
Kaybob Cogeneration Project	**—**	—	**27**	—
Alberta Thermal other(1)	**—**	—	**10**	—
Wind Facilities	**10**	—	**10**	—
Hydro Facilities	**9**	2	**9**	2
Intangible asset impairment - Coal Rights(2)	**3**	—	**17**	—
Changes in decommissioning and restoration provisions for retired assets(3)	**44**	4	**38**	(5)
Asset impairment	**575**	76	**620**	67

(1) Certain capital spares and vehicles at the Highvale mine have been impaired as they will not be utilized in our converted natural gas facilities. Amounts have been adjusted to the expected recoverable amount less costs of disposal.
(2) Impaired to nil as no future coal will be extracted from this area of the mine.
(3) Change primarily due to changes in discount rates on retired assets.

A. 2021

Alberta Thermal Projects

In the third quarter of 2021, the Corporation recognized asset impairments charges in the Alberta Thermal segment as a result of the decision to suspend the Sundance Unit 5 repowering project ($190 million) and planned retirements of Keephills Unit 1, effective Dec. 31, 2021 ($78 million) and Sundance Unit 4, effective April 1, 2022 ($56 million). Keephills Unit 1 and Sundance Unit 4 impairment assessments were based on the estimated salvage values of these units which were in excess of the expected economic benefits from these units. For Sundance Unit 5 repowering project, impairment assessments were based on the estimated recoverable amount of estimated fair value less costs of disposal of reselling the equipment for assets under construction and estimated salvage value for the balance of the costs. The fair value measurement for assets under construction is categorized as a Level III fair value measurement. The total remaining estimated recoverable amount and salvage values for Sundance Unit 5 repowering project was $33 million at at Sept. 30, 2021. Discounting did not have a material impact to these asset impairments. These asset retirement and project suspension decisions were based on the Corporations's assessment of future market conditions, the age and condition of in-service units and TransAlta's strategic focus toward customer-centred renewable energy solutions.

Highvale Mine

In the third quarter of 2021, with the expected shut down of the Highvale Mine at the end of 2021, it was determined that the estimated salvage value exceeded the economic benefit to the Alberta Merchant CGU. The asset has been removed from the Alberta Merchant CGU for impairment purposes and was assessed for impairment as an individual asset which resulted in the recognized impairment charge of $185 million in the Alberta Thermal segment, with the asset being written down to salvage value.

Wind Facilities

During the third quarter of 2021, the Corporation recorded an impairment of $8 million for a wind asset as result of an increase in estimated decommissioning costs after the review of a recent engineering study. Please refer to Note 15 for more details for changes in decommissioning and restoration provisions. The resulting fair value measurement less cost of disposal is categorized as a Level III fair value measurement and the Corporation has adjusted the expected value down to $65 million at at Sept. 30, 2021 using discount rates of 5.0 per cent (Dec. 31, 2020 - 5.3 per cent). The key assumptions impacting the determination of fair value are electricity production, sales prices and cost inputs, which are subject to measurement uncertainty.

As at Sept. 30, 2021, the Corporation recognized an impairment of $2 million related to the Kent Hills Wind LP tower failure. Please refer to Note 3B for further details.

Hydro Facilities

During the third quarter of 2021, the Corporation recorded an impairment charge of $9 million in the Hydro segment on the balance of project development costs at one of our hydro facilities as there is uncertainty on timing of when the project will proceed.

Kaybob Cogeneration Project

Energy Transfer Canada, formerly SemCAMS Midstream ULC ("ET Canada") purported to terminate the agreements related to the development and construction of the Kaybob Cogeneration Project. As a result, during the first quarter of 2021, the Corporation recorded an impairment of $27 million in the Corporate segment as this facility was not yet operational. The recoverable amount was based on estimated fair value less costs of disposal of reselling the equipment purchased to date. TransAlta has commenced an arbitration seeking compensation for ET Canada's wrongful termination of the agreements. ET Canada seeks a declaration that the Agreements were lawfully terminated. Please refer to Note 20 for further details.

B. 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 effective July 31, 2020. 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 for 2020 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.

7. Net Other Operating Expense (Income)

	3 months ended Sept. 30		**9 months ended Sept. 30**	
	2021	2020	**2021**	2020
Alberta Off-Coal Agreement	**(10)**	(10)	**(30)**	(30)
Supplier settlements	**43**	—	**43**	—
Highvale Mine onerous contract provision	**14**	—	**14**	—
Insurance recoveries	**—**	—	**(1)**	—
Net other operating expense (income)	**47**	(10)	**26**	(30)

A. Alberta Off-Coal Agreement

The Corporation receives payments from the Government of Alberta for the cessation of coal-fired emissions from its interest in the Keephills 3, Genesee 3 and Sheerness coal-fired plants on or before Dec. 31, 2030.

Under the terms of the agreement, the Corporation receives annual cash payments on or before July 31 of approximately $40 million, which commenced Jan. 1, 2017, and will terminate at the end of 2030. The Corporation recognizes the off-coal payments evenly throughout the year. Receipt of the payments is subject to certain terms and conditions. The OCA's main condition is the cessation of all coal-fired emissions on or before Dec. 31, 2030. The affected plants are not, however, precluded from generating electricity at any time by any method, other than generation resulting in coal-fired emissions after Dec. 31, 2030. In July 2018, the Corporation obtained financing against the off-coal payments. Refer to Note 4(X) and Note 24 in our 2020 audited annual consolidated financial statements for further details.

B. Supplier Settlements

During the third quarter of 2021, $27 million was expensed for amounts due to contractors for not proceeding with the Sundance Unit 5 repowering project. With the suspension of the Sundance Unit 5 repowering project and the shift in the Corporation's strategy, we have also impaired a previously recognized deferred asset, as it is no longer likely that we will incur sufficient capital or operating expenditures to utilize the remaining credit. The Corporation impaired the remaining balance of the credit of $10 million (US$8 million) during the third quarter of 2021. An additional $6 million was expensed for amounts due to contractors for not proceeding with the construction of equipment for Keephills Unit 1 during the third quarter of 2021.

C. Onerous Contract Provision for Coal Royalty Agreement

During the third quarter of 2021, an onerous contract provision for future royalty payments of $14 million was recognized as a result of a decision to accelerate the plans to shut down the Highvale Mine. The Highvale Mine has now been removed from the Alberta Merchant Cash Generating Unit ("CGU"). Any remaining future royalty payments related to the extraction of coal has no future economic benefit and therefore represents an onerous contract which requires the full recognition of the expense as at Sept. 30, 2021.

8. Net Interest Expense

The components of net interest expense are as follows:

	3 months ended Sept. 30		**9 months ended Sept. 30**	
	2021	2020	**2021**	2020
Interest on debt	**41**	39	**121**	121
Interest on exchangeable debentures	**8**	7	**22**	22
Interest on exchangeable preferred shares	**7**	—	**21**	—
Interest income	**(2)**	(2)	**(8)**	(7)
Capitalized interest	**(5)**	(2)	**(13)**	(4)
Interest on lease liabilities	**1**	2	**5**	6
Credit facility fees, bank charges and other interest	**5**	4	**13**	13
Tax shield on tax equity financing	**—**	—	**1**	—
Other	**(1)**	—	**1**	1
Accretion of provisions	**9**	8	**23**	23
Net interest expense	**63**	56	**186**	175

9. Income Taxes

The components of income tax expense (recovery) are as follows:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2021	2020	**2021**	2020
Current income tax expense	**24**	19	**59**	40
Deferred income tax recovery related to the origination and reversal of temporary differences	**(125)**	(38)	**(144)**	(62)
Deferred income tax expense related to temporary difference on investment in subsidiary	**2**	—	**2**	—
Deferred income tax expense arising from the writedown (reversal of previous writedowns) of deferred income tax assets[1]	**77**	9	**125**	(3)
Income tax expense (recovery)	**(22)**	(10)	**42**	(25)

	3 months ended Sept. 30		9 months ended Sept. 30	
	2021	2020	**2021**	2020
Current income tax expense	**24**	19	**59**	40
Deferred income tax recovery	**(46)**	(29)	**(17)**	(65)
Income tax expense (recovery)	**(22)**	(10)	**42**	(25)

(1) During the three and nine months ended Sept. 30, 2021, the Corporation recorded a writedown on deferred tax assets of $77 million and $125 million, respectively (Sept. 30, 2020 - writedown of $9 million and reversed a previous writedown of $3 million). The deferred income tax assets mainly relate to the tax benefits of losses associated with the Corporation's directly owned US operations. The Corporation evaluates at each period end, whether it is probable that sufficient future taxable income would be available from the Corporation's directly owned US operations to utilize the underlying tax losses. The Corporation wrote these assets off as it is not considered probable that sufficient future taxable income will be available from the Corporation's directly owned US operations to utilize the underlying tax losses.

10. Non-Controlling Interests

The Corporation's subsidiaries with significant non-controlling interests are TransAlta Renewables and TransAlta Cogeneration L.P. The net earnings, distributions, and equity attributable to TransAlta Renewables' non-controlling interests include the 17 per cent non-controlling interest in Kent Hills Wind LP, which owns the 167 MW Kent Hills wind farm located in New Brunswick.

	3 months ended Sept. 30		9 months ended Sept. 30	
	2021	2020	**2021**	2020
Net earnings				
TransAlta Cogeneration L.P.	**17**	5	**48**	10
TransAlta Renewables	**10**	2	**40**	19
	27	7	**88**	29
Total comprehensive income				
TransAlta Cogeneration L.P.	**17**	5	**48**	10
TransAlta Renewables	**17**	63	**9**	70
	34	68	**57**	80
Cash distributions paid to non-controlling interests				
TransAlta Cogeneration L.P.	**25**	8	**42**	12
TransAlta Renewables	**25**	19	**75**	57
	50	27	**117**	69

As at	Sept. 30, 2021	Dec. 31, 2020
Equity attributable to non-controlling interests		
TransAlta Cogeneration L.P.	**142**	136
TransAlta Renewables	**882**	948
	1,024	1,084
Non-controlling interests share (per cent)		
TransAlta Cogeneration L.P.	**49.99**	49.99
TransAlta Renewables	**39.9**	39.9

11. Financial Instruments

A. Financial Assets and Liabilities – Measurement

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

B. Fair Value of Financial Instruments

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

The Level I, II, and III classifications in the fair value hierarchy utilized by the Corporation are defined below. The fair value measurement of a financial instrument is included in only one of the three levels, the determination of which is based on the lowest level input that is significant to the derivation of the fair value.

a. Level I

Fair values are determined using inputs that are quoted prices (unadjusted) in active markets for identical assets or liabilities that the Corporation has the ability to access at the measurement date.

b. Level II

Fair values are determined, directly or indirectly, using inputs that are observable for the asset or liability.

c. Level III

Fair values are determined using inputs for the assets or liabilities that are not readily observable.

For assets and liabilities that are recognized at fair value on a recurring basis, the Corporation determines whether transfers have occurred between levels in the hierarchy by re-assessing categorization (based on the lowest level input that is significant to the fair value measurement as a whole) at the end of each reporting period.

There were no changes in the Corporation's valuation processes, valuation techniques, and types of inputs used in the fair value measurements during the period. For additional information, please refer to Note 15 of the 2020 audited annual consolidated financial statements.

Information on risk management contracts or groups of risk management contracts that are included in Level III measurements and the related unobservable inputs and sensitivities, is as follows, and excludes the effects on fair value of certain unobservable inputs such as liquidity and credit discount (described as "base fair values"), as well as inception gains or losses or the offsetting impact of Level II positions. Sensitivity ranges for the base fair values are determined using reasonably possible alternative assumptions for the key unobservable inputs, which may include forward commodity prices, commodity volatility and correlations, delivery volumes, escalation rates and cost of supply.

As at	Sept. 30, 2021					
Description	**Base fair value**	**Sensitivity**	**Valuation technique**	**Unobservable input**	**Range**	**Reasonable possible change**
Long-term power sale – US	**252**	+25 -152	Long-term price forecast	Illiquid future power prices (per MWh)	US$27 to US$48	Price decrease of US$3 or price increase of US$18
Coal transportation - US	**(41)**	+2 -12	Numerical derivation valuation	Illiquid future power prices (per MWh)	US$27 to US$48	Price decrease of US$3 or price increase of US$18
				Volatility	33% to 65%	80% to 120%
				Rail rate escalation	$22 to $24	zero to 4%
Full requirements - Eastern US	**(156)**	+6 -5	Historical bootstrap	Volume		95% to 105%
				Cost of supply		(+/-) US$1 per MWh
Long-term wind energy sale – Eastern US	**(33)**	+23 -22	Long-term price forecast	Illiquid future power prices (per MWh)	US$34 to US$48	Price increase or decrease of US$6
				Illiquid future REC prices (per unit)	US$2 to US$16	Price decrease of US$3 or price increase of US$2
Long-term wind energy sale – Canada	**(10)**	+41 -17	Long-term price forecast	Illiquid future power prices (per MWh)	$65 to $100	Price decrease of $27 or increase of $5
				Monthly wind discounts	38% to 54%	5% decrease or 5% increase
Others	**(8)**	+7 -5				

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

i. Long-Term Power Sale – US

The Corporation has a long-term fixed price power sale contract in the US for delivery of power at the following capacity levels: 380 MW through Dec. 31, 2024, and 300 MW through Dec. 31, 2025. The contract is designated as an all-in-one cash flow hedge.

The contract is denominated in US dollars. With the weakening of the US dollar relative to the Canadian dollar from Dec. 31, 2020 to Sept. 30, 2021, the base fair value and the sensitivity values have decreased by approximately $2 million and $1 million, respectively.

ii. Coal Transportation - US

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

iii. Full Requirements – Eastern US

The Corporation has a portfolio of full requirement service contracts, as a fixed price non-asset backed proprietary transaction, the Corporation agrees to supply specific utility customer needs for a range of products that may include electrical energy, capacity, transmission, ancillary services, renewable credits and independent system operator costs. At inception, the Corporation actively hedges market price exposure through financial and physical transactions with third parties.

iv. Long-Term Wind Energy Sale – Eastern US

In relation to the Big Level wind facility, the Corporation has a long-term contract for differences whereby the Corporation receives a fixed price per MWh and pays the prevailing real-time energy market price per MWh as well as the physical delivery of renewable energy credits ("RECs") based on proxy generation. Commercial operation of the facility was achieved in December 2019, with the contract commencing on July 1, 2019, and extending for 15 years after the commercial operation date. The contract is accounted for at fair value through profit or loss.

v. Long-Term Wind Energy Sale – Canada

In relation to the Garden Plain wind facility, the Corporation has entered into a virtual PPA whereby the Corporation receives the difference between the fixed contract price per MWh and the Alberta Electric System Operator ("AESO") settled pool price per MWh. The contract commences on commercial operation of the facility, which is expected by the end of 2022, and extending for 18 years past that date. The energy component of the contract is accounted for at fair value through profit or loss.

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

The key unobservable inputs used in the valuation of the contracts are the non-liquid forward prices for power and monthly wind discounts.

II. Commodity Risk Management Assets and Liabilities

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

Commodity risk management assets and liabilities classified by fair value levels as at Sept. 30, 2021, are as follows: Level I - $27 million net asset (Dec. 31, 2020 – $13 million net liability), Level II – $274 million net asset (Dec. 31, 2020 – $27 million net liability) and Level III – $13 million net asset (Dec. 31, 2020 – $582 million net asset).

Significant changes in commodity net risk management assets and liabilities during the nine months ended Sept. 30, 2021, are primarily attributable to volatility in market prices on both existing contracts and new contracts as well as contract settlements.

The following tables summarize the key factors impacting the fair value of the Level III commodity risk management assets and liabilities by classification level during the nine months ended Sept. 30, 2021 and 2020, respectively:

	9 months ended Sept. 30, 2021			9 months ended Sept. 30, 2020		
	Hedge	**Non-hedge**	**Total**	Hedge	Non-hedge	Total
Opening balance	**573**	**9**	**582**	678	8	686
Changes attributable to:						
Market price changes on existing contracts	**(249)**	**(100)**	**(349)**	23	17	40
Market price changes on new contracts	**—**	**(123)**	**(123)**	—	(6)	(6)
Contracts settled	**(83)**	**(10)**	**(93)**	(52)	(5)	(57)
Change in foreign exchange rates	**(4)**	**—**	**(4)**	18	(2)	16
Net risk management assets (liabilities), end of period	**237**	**(224)**	**13**	667	12	679
Additional Level III information:						
Gains (losses) recognized in other comprehensive income	**(253)**	**—**	**(253)**	41	—	41
Total gains (losses) included in earnings before income taxes	**83**	**(223)**	**(140)**	52	9	61
Unrealized gains (losses) included in earnings before income taxes relating to net assets held at period end	**—**	**(233)**	**(233)**	—	4	4

III. Other Risk Management Assets and Liabilities

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

Other risk management assets and liabilities with a total net asset fair value of $11 million as at Sept. 30, 2021 (Dec. 31, 2020 – $12 million net liability) are classified as Level II fair value measurements. The significant changes in other net risk management assets during the nine months ended Sept. 30, 2021, are primarily attributable to favourable changes in foreign exchange and interest rates.

IV. Other Financial Assets and Liabilities

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

	Fair value(1)				Total carrying
	Level I	**Level II**	**Level III**	**Total**	**value(1)**
Exchangeable securities - Sept. 30, 2021	**—**	**779**	**—**	**779**	**733**
Long-term debt - Sept. 30, 2021	**—**	**3,157**	**—**	**3,157**	**3,006**
Exchangeable securities - Dec. 31, 2020	—	769	—	769	730
Long-term debt - Dec. 31, 2020	—	3,480	—	3,480	3,227

(1) Includes current portion.

The fair values of the Corporation's debentures, senior notes and exchangeable securities are determined using prices observed in secondary markets. Non-recourse and other long-term debt fair values are determined by calculating an implied price based on a current assessment of the yield to maturity.

The carrying amount of other short-term financial assets and liabilities (cash and cash equivalents, restricted cash, trade accounts receivable, collateral paid, accounts payable and accrued liabilities, collateral received and dividends payable) approximates fair value due to the liquid nature of the asset or liability. The fair values of the loan receivable recorded in other assets approximate the carrying amounts as amounts receivable represent cash flows from repayments of principal and interest.

C. Inception Gains and Losses

The majority of derivatives traded by the Corporation are based on adjusted quoted prices on an active exchange or extend beyond the time period for which exchange-based quotes are available. For derivatives that extend beyond the time period for which exchange-based quotes are available, the fair values of these derivatives are determined using inputs that are not readily observable. Please refer to section B of this Note 11 above for fair value Level III valuation techniques used. In some instances, a difference may arise between the fair value of a financial instrument at initial recognition (the "Transaction Price") and the amount calculated through a valuation model. This unrealized gain or loss at inception is recognized in net earnings (loss) only if the fair value of the instrument is evidenced by a quoted market price in an active market, observable current market transactions that are substantially the same, or a valuation technique that uses observable market inputs. Where these criteria are not met, the difference is deferred on the condensed consolidated statements of financial position in risk management assets or liabilities, and is recognized in net earnings (loss) over the term of the related contract. The difference between the Transaction Price and the fair value determined using a valuation model, yet to be recognized in net earnings, and a reconciliation of changes is as follows:

	9 months ended Sept. 30	
	2021	2020
Unamortized net gain (loss) at beginning of period	**(33)**	9
New inception gains	**15**	4
Change in foreign exchange rates	**—**	(1)
Amortization recorded in net earnings during the period	**(6)**	(30)
Unamortized net loss at end of period[(1)]	**(24)**	(18)

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

12. Risk Management Activities

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

A. Net Risk Management Assets and Liabilities

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

As at Sept. 30, 2021

	Cash flow hedges	Not designated as a hedge	Total
Commodity risk management			
Current	**(42)**	**19**	**(23)**
Long-term	**278**	**59**	**337**
Net commodity risk management assets	**236**	**78**	**314**
Other			
Current	**6**	**(1)**	**5**
Long-term	**—**	**6**	**6**
Net other risk management assets	**6**	**5**	**11**
Total net risk management assets	**242**	**83**	**325**

As at Dec. 31, 2020

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

B. Nature and Extent of Risks Arising from Financial Instruments

I. Market Risk

i. Commodity Price Risk Management – Proprietary Trading

The Corporation's Energy Marketing segment conducts proprietary trading activities and uses a variety of instruments to manage risk, earn trading revenue and gain market information. Value at risk ("VaR") is used to determine the potential change in value of the Corporation's proprietary trading portfolio, over a three-day period within a 95 per cent confidence level, resulting from normal market fluctuations. Changes in market prices associated with proprietary trading activities affect net earnings in the period that the price changes occur. VaR at Sept. 30, 2021, associated with the Corporation's proprietary trading activities was $7 million (Dec. 31, 2020 - $1 million).

ii. Commodity Price Risk – Generation

The generation segments utilize various commodity contracts to manage the commodity price risk associated with electricity generation, fuel purchases, emissions and byproducts, as considered appropriate. VaR is used to determine the potential change in value of the Corporation's commodity derivative instruments used in association with generation activities, over a three-day period within a 95 per cent confidence level, resulting from normal market fluctuations. Changes in market prices associated with these activities affect net earnings in the period that the price changes occur. VaR at Sept. 30, 2021, associated with the Corporation's commodity derivative instruments used in generation hedging activities was $43 million (Dec. 31, 2020 - $12 million). For positions and economic hedges that do not meet hedge accounting requirements or for short-term optimization transactions such as buybacks entered into to offset existing hedge positions, these transactions are marked to the market value with changes in market prices associated with these transactions affecting net earnings in the period in which the price change occurs. VaR at Sept. 30, 2021, associated with these transactions was $34 million (Dec. 31, 2020 - $15 million).

II. Credit Risk

The Corporation uses external credit ratings, as well as internal ratings in circumstances where external ratings are not available, to establish credit limits for customers and counterparties. The following table outlines the Corporation's maximum exposure to credit risk without taking into account collateral held, including the distribution of credit ratings, as at Sept. 30, 2021:

	Investment grade *(Per cent)*	**Non-investment grade** *(Per cent)*	**Total** *(Per cent)*	**Total amount**
Trade and other receivables[(1)]	91	9	**100**	**516**
Long-term finance lease receivable	100	—	**100**	**192**
Risk management assets[(1)]	99	1	**100**	**856**
Loan receivable[(2)]	—	100	**100**	**55**
Total				**1,619**

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

The maximum credit exposure to any one customer for commodity trading operations and hedging, including the fair value of open trades, net of any collateral held, at Sept. 30, 2021, was $53 million (Dec. 31, 2020 - $22 million). TransAlta has implemented additional monitoring and risk mitigation measures to address the on-going impacts from the COVID-19 pandemic.

III. Liquidity Risk

TransAlta continues to be in a strong financial position with no liquidity issues. The Corporation has sufficient existing liquidity available to meet its upcoming debt maturities. The next major debt repayment is scheduled for November 2022. Our highly diversified asset portfolio, by both fuel type and operating region, provide stability in our cash flows and highlight the strength of our long-term contracted asset base.

Liquidity risk relates to the Corporation's ability to access capital to be used for capital projects, debt refinancing, proprietary trading activities, commodity hedging and general corporate purposes. A maturity analysis of the Corporation's financial liabilities as well as financial assets that are expected to generate cash inflows to meet cash outflows on financial liabilities, is as follows:

	2021	2022	2023	2024	2025	2026 and thereafter	Total
Accounts payable and accrued liabilities	774	—	—	—	—	—	774
Long-term debt[(1)]	30	621	162	119	134	1,972	3,038
Exchangeable securities[(2)]	—	—	—	—	750	—	750
Commodity risk management liabilities (assets)	5	9	(85)	(140)	(100)	(3)	(314)
Other risk management liabilities (assets)	1	(5)	(3)	(3)	—	(1)	(11)
Lease liabilities[(3)]	2	(6)	4	3	2	79	84
Interest on long-term debt and lease obligations[(4)]	55	145	121	115	109	858	1,403
Interest on exchangeable securities[(2,4)]	13	52	53	53	—	—	171
Dividends payable	51	—	—	—	—	—	51
Total	**931**	**816**	**252**	**147**	**895**	**2,905**	**5,946**

(1) Excludes impact of hedge accounting and derivatives.
(2) Assumes the debentures will be exchanged on Jan. 1, 2025. Please refer to Note 17 for further details.
(3) Lease liabilities include a lease incentive of $13 million expected to be received in 2022.
(4) Not recognized as a financial liability on the condensed consolidated statements of financial position.

C. Collateral and Contingent Features in Derivative Instruments

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

As at Sept. 30, 2021, the Corporation had posted collateral of $332 million (Dec. 31, 2020 – $163 million) in the form of letters of credit on derivative instruments in a net liability position. Certain derivative agreements contain credit-risk contingent features, which if triggered could result in the Corporation having to post an additional $181 million (Dec. 31, 2020 – $85 million) of collateral to its counterparties.

13. Inventory

The cost of coal from the Highvale mine continues to increase as a result of the Corporation's decision to convert coal fired facilities to natural gas. The cost of coal is not expected to be recovered based on current power pricing. For the three and nine months ended Sept. 30, 2021, the fuel and purchased power includes a $24 million and $64 million writedown, respectively, on internally produced coal inventory to its net realizable value, of which $19 million and $48 million relates to increased depreciation from the accelerated closure of the mine.

The components of inventory are as follows:

As at	Sept. 30, 2021	Dec. 31, 2020
Parts and materials	**76**	107
Coal	**43**	83
Deferred stripping costs	**3**	8
Natural gas	**2**	2
Purchased emission credits	**62**	38
Total	**186**	238

For the nine months ended Sept. 30, 2021, OM&A costs included a writedown of $30 million, for parts and material inventory related to the Highvale Mine and coal operations at our natural gas converted facilities. With the accelerated shut down of the Highvale Mine and progression towards full conversion to natural gas by the end of 2021, it was determined that a portion of the coal-related parts and materials inventory would not be utilized in the operations of our converted natural gas facilities and adjusted their values down to the expected net realizable amounts for the remainder of 2021.

Carbon compliance costs are regulated costs that the business incurs as a result of greenhouse gas emissions generated from our operating units. TransAlta's exposure to carbon compliance costs is mitigated through the use of eligible emission credits generated from the Corporation's Wind and Solar and Hydro segments, as well as, purchasing emission credits from the market at prices lower than the regulated compliance price of carbon. Emission credits generated from our Alberta business have no recorded book value but are expected to be used to offset emission obligations from our Alberta Thermal and North American Gas segments in the future when the compliance price of carbon is expected to increase, resulting in a reduced cash cost for carbon compliance. At Sept. 30, 2021, we currently hold 1,898,832 credits of inventory purchased externally with a recorded book value of $62 million (Dec. 31, 2020 — 1,434,761 credits with a recorded book value of $38 million). The Corporation has approximately 1,143,695 (Dec. 31, 2020 — 502,653) of internally generated eligible emission credits with no recorded book value.

14. Property, Plant and Equipment

During the three and nine months ended Sept. 30, 2021, the Corporation had additions of $127 million and $344 million, respectively. The additions mainly related to planned major maintenance, assets under construction for the boiler conversions, the Windrise wind project, the Garden Plain wind project, and the Sundance Unit 5 repowering project. Please refer to the Note 6 for more details on impairments charges recognized during 2021.

As at Sept. 30, 2021, there was a substantial increase in the decommissioning provision, which increased the related assets included in PP&E by $134 million. Please refer to Note 15 for further details on significant changes in estimates for decommissioning provisions.

During the three and nine months ended Sept. 30, 2020, the Corporation had additions of $129 million and $276 million, respectively. The additions related to assets under construction for the boiler conversions, the Windrise wind project, the WindCharger battery storage project, the Kaybob cogeneration facility, land and planned major maintenance expenditures.

During the third quarter of 2021, the Corporation sold equipment at Alberta Thermal which resulted in a gain of sale of $23 million.

15. Decommissioning and Other Provisions

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

	Decommissioning and restoration	Other	Total
Balance, Dec. 31, 2020	608	65	673
Liabilities incurred	—	**22**	**22**
Liabilities settled	**(13)**	**(43)**	**(56)**
Accretion	**23**	—	**23**
Revisions in estimated cash flows	**159**	**11**	**170**
Revisions in discount rates	**11**	—	**11**
Change in foreign exchange rates	**(1)**	—	**(1)**
Balance, Sept. 30, 2021	**787**	**55**	**842**

	Decommissioning and restoration	Other	Total
Balance, Dec. 31, 2020	608	65	673
Current portion	21	38	59
Non-current portion	587	27	614
Balance, Sept. 30, 2021	**787**	**55**	**842**
Current portion	**30**	**30**	**60**
Non-current portion	**757**	**25**	**782**

A. Decommissioning and Restoration

In the third quarter of 2021, the Corporation adjusted the wind assets decommissioning and restoration provision as estimates were updated after the review of a recent engineering study. The Corporation's current best estimate of the decommissioning and restoration provision increased by $120 million. The Corporation also increased the decommissioning and restoration provision by approximately $39 million for the Sundance and Keephills Units included in Alberta Thermal to reflect the change in the timing of the expected reclamation work resulting from asset retirements and change in useful lives.

B. Other Provisions

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

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

The amounts outstanding are as follows:

As at	Sept. 30, 2021			Dec. 31, 2020		
	Carrying value	**Face value**	**Interest[(1)]**	Carrying value	Face value	Interest[(1)]
Credit facilities[(2)]	**—**	**—**	**—%**	114	114	2.7%
Debentures	**251**	**251**	**7.1%**	249	251	7.1%
Senior notes[(3)]	**881**	**888**	**5.4%**	886	894	5.4%
Non-recourse[(4)]	**1,742**	**1,761**	**4.1%**	1,837	1,858	4.1%
Other[(5)]	**132**	**138**	**7.1%**	141	147	7.1%
	3,006	**3,038**		3,227	3,264	
Lease liabilities	**84**			134		
	3,090			3,361		
Less: current portion of long-term debt	**(112)**			(97)		
Less: current portion of lease liabilities	**(7)**			(8)		
Total current long-term debt and lease liabilities	**(119)**			(105)		
Total credit facilities, long-term debt and lease liabilities	**2,971**			3,256		

(1) Interest is an average rate weighted by principal amounts outstanding before the effect of hedging.
(2) Composed of bankers' acceptances and other commercial borrowings under long-term committed credit facilities.
(3) US face value at Sept. 30, 2021 - US$700 million (Dec. 31, 2020 - US$700 million).
(4) Includes AU$800 million (Dec 31, 2020 - AU$800 million) senior secured note offering by TEC Hedland Pty Ltd., a subsidiary of the Corporation.
(5) Includes US$106 million at Sept. 30, 2021 (Dec. 31, 2020 - US$110 million) of tax equity financing.

The Corporation has $2.0 billion of committed syndicated credit facilities and $0.2 billion of committed bilateral credit facilities, of which $1.3 billion was available as at Sept. 30, 2021 (Dec. 31, 2020 – $1.5 billion) including the undrawn letters of credit. This includes a $1.25 billion credit facility which was converted into a facility with a Sustainability-Linked Loan ("SLL") and which was extended to June 30, 2025. The facility's financing terms will align the cost of borrowing to TransAlta's greenhouse gas emission reduction and gender diversity targets, which are part of the Corporation's overall environment, social and governance, or ESG. The SLL will have a cumulative pricing adjustment to the borrowing costs on the facilities and a corresponding adjustment to the standby fee (the "Sustainability Adjustment"). Depending on performance against interim targets that have been set for each year of the credit facility term, the Sustainability Adjustment is structured as a two-way mechanic and could move either up, down or remain unchanged for each sustainability performance target based on performance. In addition, the Corporation's committed bilateral credit facilities were also extended to June 30, 2023.

As at Sept. 30, 2021, the Corporation was in compliance with all debt covenants.

The weakening of the US dollar has decreased our US-denominated long-term debt balances, mainly the senior notes and tax equity financing, by $7 million as at Sept. 30, 2021. Almost all our US-denominated debt is hedged either through financial contracts or net investments in our US operations.

Additionally, the weakening of the Australian dollar has decreased our Australian-denominated non-recourse senior secured notes by approximately $41 million as at Sept. 30, 2021. As this debt is issued by an Australian subsidiary, the foreign currency translation impacts are recognized within other comprehensive income and not in foreign exchange gains (losses) on the statement of earnings.

17. Exchangeable Securities

A. $750 Million Exchangeable Securities

As at	Sept. 30, 2021			Dec. 31, 2020		
	Carrying value	**Face value**	**Interest**	Carrying value	Face value	Interest
Exchangeable debentures – due May 1, 2039	**333**	**350**	**7 %**	330	350	7 %
Exchangeable preferred shares[1]	**400**	**400**	**7 %**	400	400	7 %
Total Exchangeable Securities	**733**	**750**		730	750	

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

On Aug. 5, 2021, the Corporation declared a dividend of $7 million in aggregate for the issued and outstanding Cumulative Redeemable First Preferred Share, Series I ("Exchangeable Preferred Shares") at the fixed rate of 1.745 per cent per cent per Share will be paid on Nov. 30 2021. On Nov. 1, 2021, the Corporation declared a dividend of $7 million in aggregate for Exchangeable Preferred Shares at the fixed rate of 1.764 per cent, per share payable on Nov. 30, 2021. The Exchangeable Preferred Shares are considered debt for accounting purposes, and as such, dividends are reported as interest expense (Note 8).

B. Option to Exchange

As at	Sept. 30, 2021		Dec. 31, 2020	
Description	**Base fair value**	**Sensitivity**	Base fair value	Sensitivity
Option to exchange – embedded derivative	—	+nil -31	—	+nil -33

The Corporation entered into an investment agreement pursuant to which Brookfield Renewable Partners and its affiliates (collectively “Brookfield”) invested $750 million in the Corporation through the purchase of exchangeable securities.

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

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

18. Common Shares

A. Issued and Outstanding

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

	9 months ended Sept. 30			
	2021		2020	
	Common shares *(millions)*	**Amount**	Common shares *(millions)*	Amount
Issued and outstanding, beginning of period	**269.8**	**2,896**	277.0	2,978
Effect of share-based payment plans	**—**	**(3)**	—	(4)
Purchased and cancelled under the NCIB	**—**	**—**	(2.8)	(30)
Stock options exercised	**1.2**	**8**	—	—
Issued and outstanding, end of period	**271.0**	**2,901**	274.2	2,944

B. NCIB Program

On May 25, 2021, the Toronto Stock Exchange ("TSX") accepted the notice filed by the Corporation to implement a normal course issuer bid ("NCIB") for a portion of our common shares. Pursuant to the NCIB, TransAlta may repurchase up to a maximum of 14,000,000 common shares, representing approximately 7.16 per cent of its public float of common shares as at May 18, 2021. Any common shares purchased under the NCIB will be cancelled. The period during which TransAlta is authorized to make purchases under the NCIB commences on May 31, 2021 and ends on May 30, 2022.

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

	Sept. 30, 2021	Sept. 30, 2020
Total shares purchased	—	2,849,400
Average purchase price per share		$ 7.51
Total cost	—	21
Weighted average book value of shares cancelled	—	30
Amount recorded in deficit	—	9

C. Dividends

On August 5, 2021, the Corporation declared a quarterly dividend of $0.045 per common share, paid on Oct. 1, 2021. On Sept. 28, 2021, the Corporation declared a quarterly dividend of $0.05 per common share, payable on Jan. 1, 2022.

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

D. Stock Options

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

19. Preferred Shares

A. Issued and Outstanding

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

	Sept. 30, 2021		Dec. 31, 2020	
Series	**Number of shares** *(millions)*	**Amount**	Number of shares (millions)	Amount
Series A	**9.6**	**235**	10.2	248
Series B	**2.4**	**58**	1.8	45
Series C	**11.0**	**269**	11.0	269
Series E	**9.0**	**219**	9.0	219
Series G	**6.6**	**161**	6.6	161
Issued and outstanding, end of period	**38.6**	**942**	38.6	942

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

B. Dividends

The following table summarizes the value of preferred share dividends declared during the nine months ended Sept. 30, 2021 and 2020:

		3 months ended Sept. 30		9 months ended Sept. 30	
Series	**Quarterly amounts per share**	**2021**	2020	**2021**[(1)]	2020
A	0.17981	**1**	2	**3**	5
B[(2)]	0.13479	**1**	—	**1**	1
C	0.25169	**3**	3	**6**	9
E	0.32463	**3**	3	**6**	9
G	0.31175	**2**	2	**4**	6
Total for the period		**10**	10	**20**	30

(1) No dividends were declared in the first quarter of 2021 as the quarterly dividend related to the period covering the first quarter of 2021 was declared in December 2020.
(2) Series B Preferred Shares pay quarterly dividends at a floating rate based on the 90-day Government of Canada Treasury Bill rate, plus 2.03 per cent.

On Aug. 5, 2021, the Corporation declared a quarterly dividend of $0.17981 per share on the Series A preferred shares, $0.13479 per share on the Series B preferred shares, $0.25169 per share on the Series C preferred shares, $0.32463 per share on the Series E preferred shares, and $0.31175 per share on the Series G preferred shares, paid on Sept. 30, 2021.

On Nov. 1, 2021, the Corporation declared a quarterly dividend of $0.17981 per share on the Series A preferred shares, $0.13970 per share on the Series B preferred shares, $0.25169 per share on the Series C preferred shares, $0.32463 per share on the Series E preferred shares, and $0.31175 per share on the Series G preferred shares, payable on Dec. 31, 2021.

20. Commitments and Contingencies

A. Commitments

In addition to the commitments disclosed elsewhere in these unaudited interim condensed consolidated financial statements and those disclosed in the 2020 audited annual financial statements, during 2021, 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 shown in the table below. In addition, certain commitments disclosed in the 2020 audited annual financial statements are based on variable pricing. Any material updates to contracts containing variable pricing are discussed below.

Natural Gas and Transportation Contracts

As part of the sale of the Pioneer Pipeline, the Corporation entered into a 15-year agreement for an additional 275 TJ per day of natural gas transportation on a firm basis by 2023, representing a new commitment of $439 million over the next 15 years. This agreement replaces, in part, the Corporation's existing 15-year commitment for natural gas transportation for 139 TJ per day on the Pioneer Pipeline, which was terminated on June 30, 2021, and was accounted for as a lease. As a result, the Corporation now has firm gas transportation contracts in place for 400 TJ per day by 2023. Additionally, on June 30, 2021 the Corporation's agreement to purchase 139 TJ per day of natural gas from Tidewater was terminated, which reduces the commitments disclosed at Dec. 31, 2020 by $1.7 billion.

Growth

As part of the Northern Goldfields Solar Project, engineering, procurement and construction contracts have been entered into for the construction of the Northern Goldfields Solar Project. New commitments of $13 million for the remainder of 2021 and $44 million in 2022 have entered into during the third quarter of 2021.

B. Contingencies

TransAlta is occasionally named as a party in various claims and legal and regulatory proceedings that arise during the normal course of its business. TransAlta reviews each of these claims, including the nature of the claim, the amount in dispute or claimed, and the availability of insurance coverage. There can be no assurance that any particular claim will be resolved in the Corporation's favour or that such claims may not have a material adverse effect on TransAlta. Inquiries from regulatory bodies may also arise in the normal course of business, to which the Corporation responds as required. For the current significant outstanding contingencies, please refer to Note 36 of the 2020 audited annual consolidated financial statements. The changes to these contingencies during the nine months ended Sept. 30, 2021 are included below:

I. Sarnia Outages

The Sarnia cogeneration facility experienced three separate events between May 19, 2021 and June 9, 2021 that resulted in steam interruptions to its industrial customers. As a result, the customers have submitted claims for liquidated damages. Steam supply disruptions of this nature are atypical and infrequent at the Sarnia cogeneration facility. The Corporation commenced an investigation to determine the root cause of each of the three events, which should be completed later in the year, or the first quarter of 2022. The results of the investigation will help to determine if any liquidated damages are owing and, if so, the quantum.

II. Transmission Line Loss Rule Proceeding

The Corporation has been participating in a transmission line loss rule proceeding before the Alberta Utilities Commission ("AUC"). The AUC determined that it has the ability to retroactively adjust line loss charges going back to 2006 and directed the AESO to recalculate loss factors for 2006 to 2016. The first two invoices were received during 2020 for a cumulative amount of $17 million and the third and final invoice for $11 million was received in the first quarter of 2021. All invoices have been settled as of the second quarter of 2021, which remain subject to true-up invoices issued by the AESO in October 2021 to be settled in December 2021. The impact of the true-up invoices is expected to be $1 million.

III. Kaybob 3 Cogeneration Dispute

The Corporation is engaged in a dispute with ET Canada as a result of ET Canada's purported termination of agreements between the parties to develop, construct and operate a 40 MW cogeneration facility at the Kaybob South No. 3 sour gas processing facility. TransAlta commenced an arbitration seeking full compensation for ET Canada's wrongful termination of the agreements. ET Canada seeks a declaration that the agreements were lawfully terminated. A hearing is scheduled for two weeks starting January 9, 2023.

IV. Fortescue Metals Group Ltd. Dispute

The Corporation is currently engaged in a dispute with Fortescue Metals Group Ltd. ("FMG") as a result of FMG's purported termination of the South Hedland PPA. TransAlta sued FMG, seeking payments of amounts invoiced and not paid under the South Hedland PPA, as well as a declaration that the PPA is valid and in force. FMG, on the other hand, seeks a declaration that the PPA was lawfully terminated. The trial for this matter was to start on May 3, 2021 but, on May 2, 2021, the Corporation entered into a conditional settlement with FMG. The trial has been adjourned pending satisfaction of the settlement conditions, which the Corporation expects to occur before Dec. 31, 2021.

V. Keephills 1 Stator Force Majeure Appeal

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 was heard on July 8, 2021. After the hearing, counsel for ENMAX raised concerns that one of the three justices on the appeal panel was distracted during the hearing. The justice has since recused herself from the hearing and the parties made submissions with respect to whether the remaining two justices can continue to issue the decision or whether a new hearing is required. On Nov. 8, 2021, the Alberta Court of Appeal released its decision and ordered that the appeal be re-heard by a new three-person panel of the Court of Appeal, which has yet to be scheduled.

21. Segment Disclosures

A. Reported Segment Earnings (Loss)

3 months ended Sept. 30, 2021	Hydro	Wind and Solar	North American Gas	Australian Gas	Alberta Thermal	Centralia	Energy Marketing	Corporate	Total	Equity accounted investments[1]	IFRS Financials
Revenues	96	55	88	35	321	171	86	1	853	(3)	850
Fuel and purchased power[2]	3	4	32	2	165	120	—	1	327	—	327
Carbon compliance[2]	—	—	6	—	41	—	—	—	47	—	47
Gross margin	93	51	50	33	115	51	86	—	479	(3)	476
Operations, maintenance, and administration	11	14	13	9	35	13	14	23	132	(1)	131
Depreciation and amortization	8	35	11	7	43	14	—	6	124	(1)	123
Asset impairment	—	10	—	—	555	—	—	10	575	—	575
Taxes, other than income taxes	—	3	—	—	5	—	—	1	9	—	9
Net other operating expense	—	—	—	—	47	—	—	—	47	—	47
Operating income (loss)	74	(11)	26	17	(570)	24	72	(40)	(408)	(1)	(409)
Equity income from associate	—	—	—	—	—	—	—	—	—	1	1
Finance lease income	—	—	1	5	—	—	—	—	6	—	6
Net interest expense									(61)	(2)	(63)
Foreign exchange gain									1	—	1
Gain on sale of assets									23	—	23
Loss before income taxes									**(439)**	**(2)**	**(441)**

(1) Skookumchuck has been included on a proportionate basis in the Wind and Solar segment.
(2) As of the first quarter of 2021, carbon compliance costs have been reclassified from fuel and purchase power costs and disclosed separately. Prior periods have been adjusted for comparative purposes.

3 months ended Sept. 30, 2020	Hydro	Wind and Solar	North American Gas	Australian Gas	Alberta Thermal	Centralia	Energy Marketing	Corporate	Total
Revenues	41	61	57	43	142	119	50	1	514
Fuel and purchased power[1]	5	5	17	3	101	82	—	1	214
Carbon compliance[1]	—	—	—	—	38	—	—	—	38
Gross margin	36	56	40	40	3	37	50	—	262
Operations, maintenance, and administration	9	14	13	7	31	15	9	16	114
Depreciation and amortization	8	34	13	11	65	24	—	7	162
Asset impairment	2	—	—	—	70	4	—	—	76
Taxes, other than income taxes	(1)	3	—	—	5	1	—	—	8
Net other operating income	—	—	—	—	(10)	—	—	—	(10)
Operating income (loss)	18	5	14	22	(158)	(7)	41	(23)	(88)
Finance lease income	—	—	2	—	—	—	—	—	2
Net interest expense									(56)
Foreign exchange gain									11
Gain on sale of assets									2
Loss before income taxes									(129)

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

9 months ended Sept. 30, 2021	Hydro	Wind and Solar	North American Gas	Australian Gas	Alberta Thermal	Centralia	Energy Marketing	Corporate	Total	Equity accounted investments[1]	IFRS Financials
Revenues	299	225	215	96	775	322	185	6	2,123	(12)	2,111
Fuel and purchased power[2]	7	11	74	7	430	247	—	6	782	—	782
Carbon compliance[2]	—	—	18	—	121	—	—	—	139	—	139
Gross margin	292	214	123	89	224	75	185	—	1,202	(12)	1,190
Operations, maintenance, and administration	35	42	38	27	123	38	31	55	389	(2)	387
Depreciation and amortization	21	106	34	21	157	42	1	18	400	(5)	395
Asset impairment	—	10	—	—	573	—	—	37	620	—	620
Taxes, other than income taxes	2	8	1	—	13	2	—	1	27	(1)	26
Net other operating expense	—	—	—	—	26	—	—	—	26	—	26
Operating income (loss)	234	48	50	41	(668)	(7)	153	(111)	(260)	(4)	(264)
Equity income from associate	—	—	—	—	—	—	—	(2)	(2)	7	5
Finance lease income	—	—	3	16	—	—	—	—	19	—	19
Net interest expense									(182)	(4)	(186)
Foreign exchange gain									22	—	22
Gain on sale of assets									56	—	56
Loss before income taxes									(347)	(1)	(348)

(1) Skookumchuck has been included on a proportionate basis in the Wind and Solar segment.
(2) As of the first quarter of 2021, carbon compliance costs have been reclassified from fuel and purchase power costs and disclosed separately. Prior periods have been adjusted for comparative purposes.

9 months ended Sept. 30, 2020	Hydro	Wind and Solar	North American Gas	Australian Gas	Alberta Thermal	Centralia	Energy Marketing	Corporate	Total
Revenues	121	240	156	121	488	329	103	(1)	1,557
Fuel and purchased power[1]	9	14	44	8	282	167	—	(1)	523
Carbon compliance[1]	—	—	1	—	117	—	—	—	118
Gross margin	112	226	111	113	89	162	103	—	916
Operations, maintenance, and administration	28	40	37	23	97	46	24	59	354
Depreciation and amortization	21	101	34	34	200	71	1	19	481
Asset impairment reversal	2	—	—	—	68	(3)	—	—	67
Taxes, other than income taxes	1	7	1	—	12	4	—	—	25
Net other operating income	—	—	—	—	(30)	—	—	—	(30)
Operating income (loss)	60	78	39	56	(258)	44	78	(78)	19
Finance lease income	—	—	4	—	—	—	—	—	4
Net interest expense									(175)
Foreign exchange gain									15
Gain on sale of assets									2
Loss before income taxes									(135)

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

B. Depreciation and Amortization on the Condensed Consolidated Statements of Cash Flows

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

	3 months ended Sept. 30		9 months ended Sept. 30	
	2021	2020	**2021**	2020
Depreciation and amortization expense on the condensed consolidated statements of loss	**123**	162	**395**	481
Depreciation included in fuel and purchased power (Note 5)	**74**	33	**179**	86
Depreciation and amortization on the condensed consolidated statements of cash flows	**197**	195	**574**	567

Exhibit 1

(Unaudited)

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

To the Financial Statements of TransAlta Corporation

EARNINGS COVERAGE RATIO

The following selected financial ratio is calculated for the twelve months ended Sept. 30, 2021:

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

(1.7) times

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

Glossary of Key Terms

Alberta Electric System Operator (AESO)
The independent system operator and regulatory authority for the Alberta Interconnected Electric System.

Alberta Electricity Portfolio
The Alberta portfolio includes hydro, wind, energy storage and thermal units operating, primarily, on a merchant basis in the Alberta market.

Alberta Hydro Assets
The Corporation's hydroelectric assets, owned through a wholly owned subsidiary, TA Alberta Hydro LP. These assets are located in Alberta consisting of the Barrier, Bearspaw, Cascade, Ghost, Horseshoe, Interlakes, Kananaskis, Pocaterra, Rundle, Spray, Three Sisters, Bighorn and Brazeau hydro facilities.

Alberta Power Purchase Arrangement (Alberta PPA)
A long-term arrangement that had been established by Alberta 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 natural gas in place of coal. The segment includes the legacy and converted generating units at our Sundance and Keephills sites, the Highvale Mine and includes our non operated Sheerness facility.

AUC
Alberta Utilities Commission.

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

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

Balancing Pool
The Balancing Pool was established in 1999 by the Government of Alberta to help manage the transition to competition in Alberta's electric industry. Their current obligations and responsibilities are governed by the Alberta *Electric Utilities Act* (effective June 1, 2003) and the Balancing Pool Regulation. For more information go to www.balancingpool.ca.

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

Carbon Tax
The carbon price per tonne of greenhouse gas emissions related to transportation fuels, heating fuels and other small emission sources.

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

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

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

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

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

Disclosure Controls and Procedures (DC&P)
Refers to controls and other procedures designed to ensure that information required to be disclosed in the reports filed by the Corporation or submitted under securities legislation is recorded, processed, summarized and reported within the time frame specified in applicable securities legislation. DC&P include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Corporation in its reports that it files or submits under applicable securities legislation is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

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

Emission Performance Standards (EPS)
Under the Government of Ontario, emission performance standards establish greenhouse gas emissions limits for covered facilities.

Force Majeure
Literally means “greater force.” These clauses generally excuse a party from liability if some unforeseen event beyond the control of that party prevents it from performing its obligations under the contract.

Free Cash Flow (FCF)
Represents the amount of cash that is available to invest in growth initiatives, make scheduled principal repayments on debt, repay maturing debt, pay common share dividends or repurchase common shares. Amount is calculated as cash generated by the Corporation through its operations (cash from operations) minus the funds used by the Corporation for the purchase improvement, or maintenance of the long-term assets to improve the efficiency or capacity of the Corporation (capital expenditures).

Funds from Operations (FFO)
Represents a proxy for cash generated from operating activities before changes in working capital and provides the ability to evaluate cash flow trends in comparison with results from prior periods. Amount is calculated as cash flow from operating activities before changes in working capital and is adjusted for transactions and amounts that the Corporation believes are not representative of ongoing cash flows from operations.

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

Gigajoule (GJ)
A metric unit of energy commonly used in the energy industry. One GJ equals 947,817 British Thermal Units ("Btu"). One GJ is also equal to 277.8 kilowatt hours ("kWh").

Gigawatt (GW)
A measure of electric power equal to 1,000 megawatts.

Gigawatt hour (GWh)
A measure of electricity consumption equivalent to the use of 1,000 megawatts of power over a period of one hour.

Greenhouse Gas (GHG)
A gas that has the potential to retain heat in the atmosphere, including water vapour, carbon dioxide, methane, nitrous oxide, hydrofluorocarbons and perfluorocarbons.

IFRS
International Financial Reporting Standards.

ICFR
Internal control over financial reporting.

Megawatt (MW)
A measure of electric power equal to 1,000,000 watts.

Megawatt Hour (MWh)
A measure of electricity consumption equivalent to the use of 1,000,000 watts of power over a period of one hour.

Merchant
A term used to describe assets that are not contracted and are exposed to market pricing.

OM&A
Operations, maintenance and administration costs.

Other Hydro Assets
The Corporation's hydroelectric assets located in British Columbia, Ontario and assets owned by TransAlta Renewables which include the Taylor, Belly River, Waterton, St. Mary, Upper Mamquam, Pingston, Bone Creek, Akolkolex, Ragged Chute, Misema, Galetta, Appleton and Moose Rapids facilities.

Power Purchase Agreement (PPA)
An agreement for the sale of electric energy.

PP&E
Property, plant and equipment.

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

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

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

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