

## Management's Discussion and Analysis

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

This MD&A should be read in conjunction with the unaudited interim condensed consolidated financial statements of TransAlta Corporation as at and for the three and six months ended June 30, 2019 and 2018, and should also be read in conjunction with the audited annual consolidated financial statements and MD&A contained within our 2018 Annual Integrated Report. In this MD&A, unless the context otherwise requires, "we", "our", "us", the "Corporation", and "TransAlta" refers to TransAlta Corporation and its subsidiaries. Our unaudited interim condensed consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") International Accounting Standards ("IAS") 34 *Interim Financial Reporting* for Canadian publicly accountable enterprises as issued by the International Accounting Standards Board ("IASB") and in effect at June 30, 2019. All tabular amounts in the following discussion are in millions of Canadian dollars unless otherwise noted. This MD&A is dated August 8, 2019. Additional information respecting TransAlta, including its Annual Information Form, is available on SEDAR at [www.sedar.com](http://www.sedar.com), on EDGAR at [www.sec.gov](http://www.sec.gov), and on our website at [www.transalta.com](http://www.transalta.com). Information on or connected to our website is not incorporated by reference herein.

## 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 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 financial statements but is not presented elsewhere in the financial statements. We have included line items entitled gross margin and operating income in our Condensed Consolidated Statements of Earnings (Loss) for the three and six months ended June 30, 2019 and 2018. 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. Certain of the financial measures discussed in this MD&A are not defined 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 earnings before interest, tax, depreciation and amortization ("EBITDA"), funds from operations ("FFO"), free cash flow ("FCF"), total consolidated net debt, adjusted net debt and segmented cash flow generated by the business, all as defined below, are non-IFRS measures that are presented in this MD&A. See the Discussion of Consolidated Financial Results, Segmented Comparable Results, Key Financial Ratios and Capital Structure and Liquidity sections of this MD&A for additional information.

## Forward-Looking Statements

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

In particular, this MD&A contains forward-looking statements including, but not limited to: our strategic focus, including as it pertains to our operating performance and transitioning to clean power generation; achieving the upper end of its FCF guidance; the \$750 million investment by Brookfield, including the closing of the second tranche of \$400 million of preferred shares, the use of proceeds, and the expected benefits associated with the Brookfield investment; the share buybacks of up to \$250 million; expectations regarding the Pioneer Pipeline, including the throughput of approximately 130 MMcf/day of natural gas on November 1, 2019 and the increase of co-firing; the key financial ratios and target ranges; the investment in the Skookumchuck Wind Energy Facility; the conversion of some or all of the units at Sundance and Keephills and the timing thereof; the timing of issuing limited or full notices to proceed on conversions; the cost to convert a unit and increase co-firing; the repowering of one or more steam turbines to create highly efficient combined cycle units; pit development work and planned power maintenance outages; cost estimates for the development of the US

Wind Projects; the commercial operation date for the US Wind Projects; the Windrise wind project, including the cost and commercial operation date thereof; the WindCharger Project and that this project will be the first utility-scale battery storage project in Alberta, the receipt of funds from Emissions Reduction Alberta, the supply of lithium-ion batteries, the receipt of regulatory approvals and the construction and commercial operation dates, and expected cost; the expected benefits from Project Greenlight and embedding the program into the business and realization of new value; that TransAlta and Brookfield will work together to complete TransAlta's transition to clean energy, maximize the value of TransAlta's Alberta Hydro Assets consisting of 13 facilities currently subject to power purchase agreements with the Balancing Pool (the "Hydro Assets"), and create long-term shareholder value; Brookfield's increase in its share ownership to 9%; Canadian Federal regulatory developments, including carbon pricing, the "backstop" mechanism and clean fuel standard; Alberta regulatory changes, including the Technology Innovation and Emission Reduction regime and maintaining an energy-only market; Ontario regulatory changes, including as it pertains to the large greenhouse gas emitter regulation, carbon tax, and the electricity market review; the terms of the new lease commitment; the exposure under the Alberta Utilities Commission line loss proceeding; the FMG claims; the dispute with the Balancing Pool; the section under "2019 Financial Outlook", including the Comparable EBITDA, FCF, dividend levels, availability for our generating segments, market pricing and hedging strategy, portfolio management strategy, fuel costs, energy marketing, net interest expense, liquidity and capital resources, growth expenditures, lost production; source of capital for funding capital expenditures; and impact of accounting changes.

The forward looking statements in this MD&A are based on TransAlta's beliefs and assumptions based on information available at the time the assumptions were made, including assumptions pertaining to: the Company's ability to successfully defend against any existing or potential legal actions or regulatory proceedings; the closing of the second tranche of the Brookfield investment occurring and other risks to the Brookfield investment not materializing; no significant changes to regulatory, securities, credit or market environments; our ownership of or relationship with TransAlta Renewables Inc. not materially changing; the Alberta Hydro Assets achieving their anticipated future value, cash flows and adjusted EBITDA; the anticipated benefits and financial results generated on the coal-to-gas conversions and the Corporation's other strategies; the Corporation's strategies and plans; no significant changes in applicable laws, including any tax or regulatory changes in the markets in which we operate; the anticipated structure and framework of an Alberta capacity market in the future; risks associated with the impact of the Brookfield investment on the Corporation's stakeholders, including its shareholders, debtholders and other securityholders and credit ratings; assumptions referenced in our 2019 guidance, including: Alberta spot power price equal to \$50 to \$60 per megawatt hours ("MWh"); Alberta contracted power price equal to \$50 to \$55 per MWh; Mid-C spot power prices equal to US\$20 to US\$25 per MWh; Mid-C contracted power price of US\$47 to US\$53 per MWh; sustaining capital between \$140 million and \$165 million; no material decline in the dividends expected to be received from TransAlta Renewables Inc.; the expected life extension of the coal fleet and anticipated financial results generated on conversion; and assumptions relating to the completion of the strategic partnership with and investment by Brookfield and proposed share buy-backs.

The forward-looking statements contained in this MD&A are subject to a number of risks and uncertainties that may cause actual performance, events or results to differ materially from those contemplated by the forward-looking statements. Some of the factors that could cause such differences include: the failure of the second tranche of the Brookfield investment to close; the outcomes of existing or potential legal actions or regulatory proceedings not being as anticipated, including those pertaining to the Brookfield investment; changes in our relationships with Brookfield and its affiliated entities or our other shareholders; our Alberta Hydro Assets not achieving their anticipated value, cash flows or adjusted EBITDA; the Brookfield investment not resulting in the expected benefits for the Corporation and its shareholders; the inability to complete share buy-backs within the timeline or on the terms anticipated, or at all; fluctuations in demand, market prices and the availability of fuel supplies required to generate electricity; changes in the current or anticipated legislative, regulatory and political environments in the jurisdictions in which we operate; environmental requirements and changes in, or liabilities under, these requirements; risks associated with the calculation of the Hydro Assets' EBITDA, including non-financial measures included in that calculation; the anticipated benefits of the joint Brookfield/TransAlta hydro operating committee not materializing; the timing and value of Brookfield's exchange of exchangeable securities and the amount of equity interest in the Hydro Assets resulting therefrom; changes in general economic conditions including interest rates; operational risks involving our facilities; unexpected increases in cost structure; failure to meet financial expectations; structural subordination of securities; and other risks and uncertainties contained in the Corporation's Management Proxy Circular dated March 26, 2019 and its Annual Information Form and Management's Discussion and Analysis for the year ended December 31, 2018, filed under the Company's profile with the Canadian securities regulators on [www.sedar.com](http://www.sedar.com) and the U.S. Securities and Exchange Commission ("SEC") on [www.sec.gov](http://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 Corporation is providing the guidance and other forward looking information for the purpose of assisting shareholders and financial analysts in understanding our financial position and results of operations as at and for the periods ended on the dates presented, as well as our financial performance objectives, vision and strategic goals, and may not be appropriate for other purposes. The forward-looking statements included in this document are made only as of the date hereof and we do not undertake to publicly update these forward-looking statements to reflect new information, future events or otherwise, except as required by applicable laws. In light of these risks, uncertainties and assumptions, the forward-looking statements might occur to a different extent or at a different time than we have described, or might not occur at all. We cannot assure that projected results or events will be achieved.

## Highlights

	3 months ended June 30,		6 months ended June 30,	
	2019	2018	2019	2018
Revenues	497	446	1,145	1,034
Net earnings (loss) attributable to common shareholders	—	(105)	(65)	(40)
Cash flow from operating activities	258	104	340	529
Comparable EBITDA <sup>(1,2,3)</sup>	215	248	436	641
FFO <sup>(1,3)</sup>	155	188	324	506
FCF <sup>(1,3)</sup>	49	96	144	334
Net earnings (loss) per share attributable to common shareholders, basic and diluted	—	(0.36)	(0.23)	(0.14)
FFO per share <sup>(1)</sup>	0.55	0.65	1.14	1.76
FCF per share <sup>(1)</sup>	0.17	0.33	0.51	1.16
Dividends declared per common share	0.04	0.04	0.04	0.08
Dividends declared per preferred share <sup>(4)</sup>	0.26	0.26	0.26	0.52

As at	June 30, 2019	Dec. 31, 2018
Total assets	9,199	9,428
Total consolidated net debt <sup>(5)</sup>	3,157	3,141
Total long-term liabilities	4,547	4,414

(1) These items are not defined under IFRS. Presenting these items from period to period provides management and investors with the ability to evaluate earnings trends more readily in comparison with prior periods' results. Refer to the Reconciliation of Non-IFRS Measures section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS.

(2) During the first quarter of 2019, we revised our approach to reporting adjustments to arrive at comparable EBITDA, mainly to be more comparable with other companies in the industry. Comparable EBITDA is now adjusted to exclude the impact of unrealized mark-to-market gains or losses. Both the current and prior period amounts have been adjusted to reflect this change.

(3) Includes \$157 million received from the Balancing Pool for the early termination of Sundance B and C PPAs in the first quarter of 2018.

(4) Weighted average of the Series A, B, C, E, and G preferred share dividends declared. Dividends declared vary year over year due to timing of dividend declarations.

(5) Total consolidated net debt includes long-term debt including current portion, amounts due under credit facilities, tax equity, and lease obligations, net of available cash and the fair value of economic hedging instruments on debt. See the table in the Capital Structure and Liquidity section of this MD&A for more details on the composition of net debt.

Year to date, the overall performance of our portfolio is in line with expectations and based on the outlook for the balance of the year, the Corporation is currently tracking to achieve the upper end of its FCF guidance of \$270 - \$330 million.

In Alberta, Canadian Coal and our wind assets benefited from higher power prices. Average prices during the second quarter in Alberta were consistent at \$57 per MWh compared with \$56 per MWh in 2018. For the first half of the year, average prices increased to \$63 per MWh from \$45 per MWh in 2018, mainly reflecting the impact of the extreme cold weather during the first quarter of 2019.

Excluding the one time receipt of \$157 million for the termination of the Sundance B and C Power Purchase Arrangements ("PPA") received during the first quarter of 2018, comparable EBITDA at our Canadian Coal segment for the three and six months ended June 30, 2019, increased due to strong merchant pricing and lower operations, maintenance, and administration ("OM&A") costs. In addition, performance from our Energy Marketing segment was stronger than the same periods in 2018. As expected, comparable EBITDA for the three and six months ended June 30, 2019, decreased in our Canadian Gas segment, primarily as a result of the expiry of the Mississauga contract and lower scheduled payments on the Poplar Creek contract. Comparable EBITDA as for the six months ended June 30, 2019 was negatively impacted by the unplanned outage at US Coal during the first quarter of 2019.

Net earnings attributable to common shareholders for the three and six months ended June 30, 2019, excluding the one time receipt of \$157 million (\$115 million after tax) for the termination of the Sundance B and C PPAs, were \$105 million and \$90 million higher, respectively. Stronger earnings are attributable to the Alberta tax rate reduction, strong Alberta pricing, lower year-to-date OM&A costs, and lower interest expense, partially offset by other gains and losses.

FCF, one of the Corporation's key financial metrics, after adjusting for the one time receipt for the termination of the Sundance B and C PPAs received in 2018, was \$47 million and \$33 million lower for the three and six months ended June 30, 2019, respectively, compared with the same periods in 2018.

- Excluding the one time receipt for the termination of the Sundance B and C PPAs of \$157 million received in 2018, Canadian Coal cash flow was \$5 million and \$15 million lower in the three and six months ended June 30, 2019, respectively, compared to the same periods in 2018, mainly due to higher sustaining capital spend, which was partially offset by stronger comparable EBITDA.
- US Coal cash flow was significantly lower on a year-to-date basis due to an unplanned outage for one of the units during extreme market conditions driven by low temperatures and high natural gas prices in early March 2019.
- Canadian Gas cash flow in the three and six months ended June 30, 2019, was \$30 million and \$66 million lower, respectively, mainly due to the Mississauga contract ending Dec. 31, 2018 and lower scheduled payments from the Poplar Creek finance lease.
- Hydro cash flow was lower for both the quarter and the year-to-date periods compared to the same periods in 2018, mainly due to strong results in 2018 and decreased opportunities for ancillary services in 2019.

- Sustaining capital increased significantly during both the three and six months ended June 30, 2019, mainly due to planned major maintenance at Canadian Coal. There were no planned maintenance outages in the same period in 2018.

### Significant Events

Our focus continues to be improving our operating performance and transitioning to clean power generation. The Corporation made the following progress throughout the period:

- During the second quarter of 2019, the Pioneer Pipeline transported first gas four months ahead of schedule to TransAlta's generating units at Sundance and Keephills.
- During the first half of the year, we purchased and cancelled 2,398,200 common shares at an average price of \$8.57 per common share through our normal course issuer bid ("NCIB") program, for a total cost of \$21 million.
- On April 12, 2019, TransAlta signed an agreement to purchase a 49 per cent interest in the 136.8 MW Skookumchuk Wind Energy Facility.
- On March 28, 2019, the Corporation closed its acquisition of the Antrim wind project following the receipt of required regulatory approvals.
- On March 25, 2019, the Corporation announced a \$750 million investment in exchangeable securities by Brookfield Renewable Partners or its affiliates (collectively "Brookfield"). On May 1, 2019, Brookfield invested the initial tranche of \$350 million in exchange for unsecured subordinated debentures.
- On March 8, 2019, the Alberta Electric System Operator ("AESO") approved the Corporation's decision to extend the mothballing of Sundance Unit 3 and 5 until Nov. 1, 2021.
- On March 4, 2019, TransAlta approved the WindCharger Battery Storage Project ("Windcharger"), an innovative 10 MW / 20 MWh energy storage project.

See the Strategic Growth and Corporate Transformation and Significant and Subsequent Events sections of this MD&A for further details.

### Adjusted Availability and Production

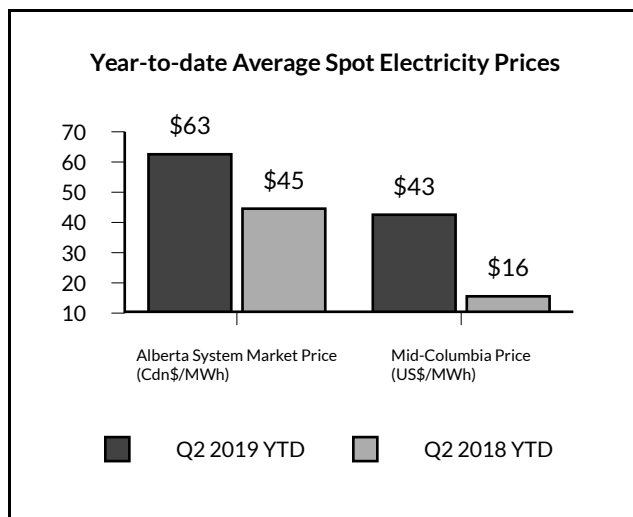
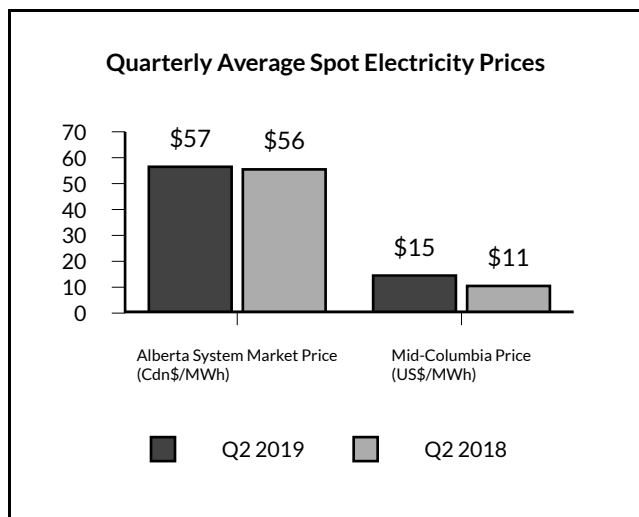
Adjusted availability for the three and six months ended June 30, 2019 was 83.8 per cent and 86.7 per cent, respectively, compared to 85.8 per cent and 90.1 per cent for the same periods in 2018. The decreases were mainly due to higher planned outages at Canadian Coal, unplanned outages and derates at US Coal and an unplanned outage at Australian Gas.

Production for the three and six months ended June 30, 2019 was 5,235 and 13,360 gigawatt hours ("GWh"), respectively, compared to 5,199 and 12,370 GWh for the same periods in 2018. The higher year-to-date production was primarily due to a strong price environment in the Pacific Northwest during the first quarter of 2019, which resulted in higher dispatching at US Coal. This was partially offset by lower production at Canadian Coal due to higher planned outages in 2019 and the mothballing of Sundance Units 3 and 5 on April 1, 2018.

### Electricity Prices

The average spot electricity prices in Alberta for the three months ended June 30, 2019 remained consistent with 2018. For the six months ended June 30, 2019, the average spot electricity prices in Alberta increased significantly compared to 2018 primarily due to significantly below average temperatures in February and early March.

Similarly, power prices were only slightly higher in the Pacific Northwest in the three months ended June 30, 2019, whereas power prices for the six months ended June 30, 2019 were substantially higher than 2018 mainly due to stronger weather driven demand in February and March as well as regional daily natural gas prices that averaged approximately US\$14/mmBtu in the first quarter of 2019.



## Discussion of Consolidated Financial Results

We evaluate our performance and the performance of our business segments using a variety of measures. Comparable figures are not defined under IFRS. Those discussed below, and elsewhere in this MD&A, are not defined 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 are not necessarily comparable to a similarly titled measure of another company. 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 performance. Interest, taxes, and depreciation and amortization are not included, as differences in accounting treatments may distort our core business results. In addition, we reclassify certain transactions to facilitate the discussion on the performance of our business:

- (i) Certain assets we own in Canada are fully contracted and recorded as finance leases under IFRS. We believe it is more appropriate to reflect the payments we receive under the contracts as a capacity payment in our revenues instead of as finance lease income and a decrease in finance lease receivables. We depreciate these assets over their expected lives;
- (ii) We also reclassify the depreciation on our mining equipment from fuel and purchased power to reflect the actual cash cost of our business in our comparable EBITDA;
- (iii) In December 2016, we agreed to terminate our existing arrangement with the Independent Electricity System Operator (“IESO”) relating to our Mississauga cogeneration facility in Ontario and entered into a new Non-Utility Generator (“NUG”) Enhanced Dispatch Contract (the “NUG Contract”) effective Jan. 1, 2017. Under the NUG Contract, we received fixed monthly payments until Dec. 31, 2018 with no delivery obligations. Under IFRS, for our reported results in 2016, as a result of the NUG Contract, we recognized a receivable of \$207 million (discounted), a pre-tax gain of approximately \$191 million net of costs to mothball the units, and accelerated depreciation of \$46 million. In 2017 and 2018, on a comparable basis, we recorded the payments we received as revenues as a proxy for operating income, and depreciated the facility until Dec. 31, 2018;
- (iv) On commissioning the South Hedland Power Station in Australia, 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; and
- (v) During the first quarter of 2019, we revised our approach to reporting adjustments to arrive at comparable EBITDA, mainly to be more comparable with other companies in the industry. Comparable EBITDA is now adjusted to exclude the impact of unrealized mark-to-market gains or losses. Both the current and prior period amounts have been adjusted to reflect this change.

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

	3 months ended June 30 <sup>(1)</sup>		6 months ended June 30 <sup>(1)</sup>	
	2019	2018	2019	2018
Net earnings (loss) attributable to common shareholders <sup>(2)</sup>	–	(105)	(65)	(40)
Net earnings attributable to non-controlling interests	16	28	51	56
Preferred share dividends	10	10	10	20
<b>Net earnings (loss)</b>	<b>26</b>	<b>(67)</b>	<b>(4)</b>	<b>36</b>
<i>Adjustments to reconcile net income to comparable EBITDA</i>				
Depreciation and amortization	143	146	288	276
Foreign exchange loss	8	5	9	7
Other (gains) losses	12	–	12	–
Net interest expense	56	59	106	127
Income tax expense (recovery)	(50)	(6)	(33)	31
<i>Comparable reclassifications</i>				
Decrease in finance lease receivables	6	14	12	29
Mine depreciation included in fuel cost	31	37	60	68
Australian interest income	1	1	2	2
Unrealized (gains) losses from risk management activities	(18)	23	(16)	–
<i>Adjustments to earnings to arrive at comparable EBITDA</i>				
Impacts associated with Mississauga recontracting <sup>(3)</sup>	–	24	–	53
Asset impairment charge	–	12	–	12
<b>Comparable EBITDA</b>	<b>215</b>	<b>248</b>	<b>436</b>	<b>641</b>
Comparable EBITDA - excluding the PPA settlement	215	248	436	484

(1) During the first quarter of 2019, we revised comparable EBITDA to remove the unrealized mark-to-market gains (losses). 2018 results have been revised to reflect this change.

(2) Includes \$157 million received from the Balancing Pool for the early termination of Sundance B and C PPAs in the first quarter of 2018.

(3) The Mississauga recontracting ended in 2018. The impact for the three and six months ended June 30, 2019 was a decrease to revenue of \$25 million and \$54 million, respectively and a decrease to fuel and purchased power and de-designated hedges of \$1 million for both periods.

Excluding the one time receipt of \$157 million for the termination of the Sundance B and C PPAs received during the first quarter of 2018, comparable EBITDA for the three and six months ended June 30, 2019 decreased \$33 million and \$48 million, respectively, compared to the same periods in 2018. The reduction was primarily a result of the expiry of the Mississauga NUG Contract, lower revenues on the Poplar Creek contract in Canadian Gas and an unplanned outage in US Coal. The decrease was partially offset by stronger performance in Energy Marketing and lower year-to-date Corporate costs. Excluding the termination of the Sundance B and C PPAs, Canadian Coal comparable EBITDA increased due to strong merchant pricing lower fuel, carbon costs and purchased power and lower OM&A costs.

### Funds from Operations and Free Cash Flow

FFO is an important metric as it provides a proxy for cash generated from operating activities before changes in working capital, and provides the ability to evaluate cash flow trends in comparison with results from prior periods. FCF is an important metric as it represents the amount of cash that is available to invest in growth initiatives, make scheduled principal repayments on debt, repay maturing debt, pay common share dividends, or repurchase common shares. Changes in working capital are excluded so FFO and FCF are not distorted by changes that we consider temporary in nature, reflecting, among other things, the impact of seasonal factors and timing of receipts and payments. FFO per share and FCF per share are calculated using the weighted average number of common shares outstanding during the period.

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

	3 months ended June 30,		6 months ended June 30,	
	2019	2018	2019	2018
Cash flow from operating activities <sup>(1)</sup>	258	104	340	529
Change in non-cash operating working capital balances	(110)	69	(30)	(54)
<b>Cash flow from operations before changes in working capital</b>	<b>148</b>	<b>173</b>	<b>310</b>	<b>475</b>
Adjustment:				
Decrease in finance lease receivable	6	14	12	29
Other	1	1	2	2
<b>FFO</b>	<b>155</b>	<b>188</b>	<b>324</b>	<b>506</b>
Deduct:				
Sustaining capital <sup>(2)</sup>	(61)	(34)	(86)	(54)
Productivity capital	(1)	(2)	(3)	(6)
Dividends paid on preferred shares <sup>(3)</sup>	(10)	(10)	(20)	(20)
Distributions paid to subsidiaries' non-controlling interests	(27)	(40)	(59)	(81)
Payments on lease obligations <sup>(2)</sup>	(6)	(5)	(11)	(9)
Other	(1)	(1)	(1)	(2)
<b>FCF</b>	<b>49</b>	<b>96</b>	<b>144</b>	<b>334</b>
Weighted average number of common shares outstanding in the year	284	288	284	288
<b>FFO per share</b>	<b>0.55</b>	<b>0.65</b>	<b>1.14</b>	<b>1.76</b>
<b>FCF per share</b>	<b>0.17</b>	<b>0.33</b>	<b>0.51</b>	<b>1.16</b>

(1) Includes \$157 million received from the Balancing Pool for the early termination of Sundance B and C PPAs in the first quarter of 2018.

(2) During the first quarter of 2019, we revised the way in which FFO and FCF are reconciled to reflect the payments related to lease obligations as a separate line and removed finance leases from sustaining capital. 2018 results have been revised to reflect these changes.

(3) Dividends paid on preferred shares for the three months ended June 30, 2018 and 2019 have been adjusted to include the dividends payable in the second quarter.

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

	3 months ended June 30,		6 months ended June 30,	
	2019	2018	2019	2018
Comparable EBITDA <sup>(1)</sup>	215	248	436	641
Interest expense	(46)	(49)	(88)	(102)
Provisions	7	2	11	(1)
Current income tax expense (recovery)	(7)	(10)	(14)	(19)
Realized foreign exchange gain (loss)	(2)	3	(7)	6
Decommissioning and restoration costs settled	(8)	(6)	(15)	(13)
Other cash and non-cash items	(4)	—	1	(6)
<b>FFO</b>	<b>155</b>	<b>188</b>	<b>324</b>	<b>506</b>
Deduct:				
Sustaining capital <sup>(2)</sup>	(61)	(34)	(86)	(54)
Productivity capital	(1)	(2)	(3)	(6)
Dividends paid on preferred shares <sup>(3)</sup>	(10)	(10)	(20)	(20)
Distributions paid to subsidiaries' non-controlling interests	(27)	(40)	(59)	(81)
Payments on lease obligations <sup>(2)</sup>	(6)	(5)	(11)	(9)
Other	(1)	(1)	(1)	(2)
<b>FCF</b>	<b>49</b>	<b>96</b>	<b>144</b>	<b>334</b>

(1) During the first quarter of 2019, we revised comparable EBITDA to remove the unrealized mark-to-market gains (losses). 2018 results have been revised to reflect this change. 2018 includes \$157 million received from the Balancing Pool in the first quarter of 2018, for the early termination of Sundance B and C PPAs.

(2) During the first quarter of 2019, we revised the way in which FFO and FCF are reconciled to reflect the payments related to lease obligations as a separate line and removed finance leases from sustaining capital. 2018 results have been revised to reflect these changes.

(3) Dividends paid on preferred shares for the three months ended June 30, 2018 and 2019 have been adjusted to include the dividends payable in the second quarter.

Supplemental disclosure	3 months ended June 30,		6 months ended June 30,	
	2019	2018	2019	2018
FFO - excluding the PPA settlement	155	188	324	349
FCF - excluding the PPA settlement	49	96	144	177

After adjusting for the 2018 one time receipt of \$157 million for the termination of the Sundance B and C PPAs, FFO was down \$33 million and \$25 million over the three and six months ended June 30, 2018, respectively, mainly due to lower comparable EBITDA of \$33 million and \$48 million, respectively, primarily due to the expiry of the Mississauga contract, lower revenues on the Poplar Creek contract and the unplanned outage at US Coal during the first quarter of 2019. Lower comparable EBITDA was partially offset by lower interest expense and favourable timing of cash settlements.

## Segmented Comparable Results

Segmented cash flow generated by the business, shown in the table below, measures the net cash generated by each of our segments after sustaining and productivity capital expenditures, reclamation costs, provisions, and non-cash mark-to-market gains or losses. This is the cash flow available to: pay our interest and cash taxes, make distributions to our non-controlling partners and dividends to our preferred shareholders, grow the business, pay down debt and return capital to our shareholders.

	3 months ended June 30,		6 months ended June 30,	
	2019	2018	2019	2018
<b>Segmented cash flow<sup>(1)</sup></b>				
Canadian Coal <sup>(2)</sup>	19	24	60	232
US Coal	11	13	(1)	31
Canadian Gas	24	54	48	114
Australian Gas	29	31	59	62
Wind and Solar	39	48	105	113
Hydro	32	47	56	63
<b>Generation cash flow</b>	<b>154</b>	<b>217</b>	<b>327</b>	<b>615</b>
Energy Marketing	20	9	44	(9)
Corporate	(30)	(23)	(41)	(48)
<b>Total comparable cash flow</b>	<b>144</b>	<b>203</b>	<b>330</b>	<b>558</b>
Total comparable cash flow - excluding PPA settlement	144	203	330	401

(1) Segmented cash flow is a non-IFRS measure.

(2) Includes \$157 million received from the Balancing Pool for the early termination of Sundance B and C PPAs in the first quarter of 2018.

## Canadian Coal

	3 months ended June 30,		6 months ended June 30,	
	2019	2018	2019	2018
Availability (%)	80.3	91.0	85.7	90.7
Contract production (GWh)	1,424	1,658	3,486	4,958
Merchant production (GWh)	1,365	1,265	3,022	2,173
Total production (GWh)	2,789	2,923	6,508	7,131
Gross installed capacity (MW) <sup>(1)</sup>	3,231	3,231	3,231	3,231
Revenues <sup>(2)</sup>	186	183	421	451
Fuel, carbon costs, and purchased power <sup>(2)</sup>	91	99	237	264
<b>Comparable gross margin</b>	<b>95</b>	<b>84</b>	<b>184</b>	<b>187</b>
Operations, maintenance, and administration	35	43	68	90
Taxes, other than income taxes	4	4	7	7
Termination of Sundance B and C PPAs	—	—	—	(157)
Net other operating income	(10)	(10)	(20)	(21)
<b>Comparable EBITDA<sup>(2)</sup></b>	<b>66</b>	<b>47</b>	<b>129</b>	<b>268</b>
<b>Deduct:</b>				
<b>Sustaining capital:</b>				
Routine capital	4	3	7	7
Mine capital	5	9	10	11
Planned major maintenance	29	1	32	1
<b>Total sustaining capital expenditures<sup>(3)</sup></b>	<b>38</b>	<b>13</b>	<b>49</b>	<b>19</b>
Productivity capital	1	2	3	3
<b>Total sustaining and productivity capital expenditures</b>	<b>39</b>	<b>15</b>	<b>52</b>	<b>22</b>
Provisions	—	1	1	(2)
Payments on lease obligations <sup>(3)</sup>	4	4	8	7
Decommissioning and restoration costs settled	4	3	8	9
<b>Canadian Coal cash flow</b>	<b>19</b>	<b>24</b>	<b>60</b>	<b>232</b>

(1) Includes units temporarily mothballed (774 MW Sundance Units 3 and 5).

(2) During the first quarter of 2019, we revised comparable EBITDA to remove the unrealized mark-to-market gains (losses). 2018 results have been revised to reflect this change.

(3) On implementation of IFRS 16 in 2019, we have removed the finance leases from sustaining capital and included principal payments on lease obligations as a separate line in arriving at segmented cash flow.

Supplemental disclosure	3 months ended June 30,		6 months ended June 30,	
	2019	2018	2019	2018
Comparable EBITDA - excluding the PPA settlement	66	47	129	111
Canadian Coal cash flow - excluding the PPA settlement	19	24	60	75

Availability for the second quarter and year-to-date periods declined compared to the same periods in 2018, mainly due to higher planned maintenance outages during the second quarter of 2019. In 2018, there were no planned maintenance outages in this same period.

Production for the three and six months ended June 30, 2019 decreased 134 GWh and 623 GWh, respectively, compared to the same periods in 2018. Lower total production in both periods was due to planned maintenance outages mainly in the second quarter of 2019, on the Sundance 4, Keephills 1 and Keephills 2 units. Lower contract production was partially offset by higher merchant production.

Revenue for the three months ended June 30, 2019 was consistent with the same period in 2018. Revenue for the six months ended June 30, 2019 decreased by \$30 million compared to the same period in 2018, mainly due to lower production as a result of the termination of the Sundance B and C PPAs on March 31, 2018, partially offset by higher market prices.

In the three and six months ended June 30, 2019, revenue per MWh of production increased to approximately \$67 per MWh and \$65 per MWh, respectively, compared with \$63 per MWh and \$63 per MWh, respectively, for the same periods in 2018. Revenues in the first quarter of 2018 included the Sundance B and C PPA revenue as well as the pass through revenues associated with carbon compliance costs, which are no longer recoverable on the Sundance units as the PPAs have been terminated.

Fuel, carbon compliance costs, and purchased power costs per MWh of production were lower for the three and six months ended June 30, 2019, at \$33 per MWh and \$36 per MWh, respectively, compared with \$34 per MWh and \$37 per MWh, respectively, in the



same periods in 2018. Consequently, comparable gross margin per MWh for the three and six months ended June 30, 2019, improved by \$5/MWh and \$2/MWh, respectively, compared to the same periods in 2018.

We continued to co-fire with natural gas at the merchant units, when economical. Co-firing lowers the carbon compliance costs as the GHG emissions are lower. In addition, fuel costs can be lower by co-firing, depending on the market price for natural gas. We expect the level of co-firing to increase as the higher capacity Pioneer Pipeline began to transport gas late in the second quarter of 2019. See the Strategic Growth and Corporate Transformation section of this MD&A for further details.

OM&A costs were \$8 million and \$22 million lower in the three and six months ended June 30, 2019 compared to 2018, respectively. 2019 OM&A reflects the full impact of cost reductions progressively implemented over the preceding year. These cost reductions arose from a combination of factors including fewer units operating, lower capacity factor operation on merchant units, co-firing with gas, and operations and maintenance work optimization.

Excluding the one time receipt of \$157 million for the termination of the Sundance B and C PPAs in the first quarter of 2018, comparable EBITDA for the three and six months ended June 30, 2019 was \$19 million and \$18 million higher, respectively, compared with the same periods in 2018. This largely reflects the combined impact of higher prices, lower fuel, carbon compliance and purchased power costs as well as lower OM&A costs.

Sustaining and productivity capital expenditures increased \$24 million and \$30 million for the second quarter and year-to-date periods, respectively, compared to the same periods in 2018, as capital increased due to planned power plant maintenance outages in 2019. There were no planned maintenance outages on operated power plants in the same periods in 2018.

Canadian Coal cash flow for the three and six months ended June 30, 2019, declined by \$5 million and \$15 million (excluding the one time receipt of \$157 million for the termination of the Sundance B and C PPAs), respectively, compared to the same periods in 2018, mainly due to increased sustaining capital expenditures associated with the planned maintenance outages in 2019, partially offset by higher comparable EBITDA. There were no planned maintenance outages in these periods in 2018.

## US Coal

	3 months ended June 30,		6 months ended June 30,	
	2019	2018	2019	2018
Availability (%)	35.2	25.9	55.9	32.2
Adjusted availability (%) <sup>(1)</sup>	73.6	63.5	75.2	81.5
Contract sales (GWh)	830	830	1,650	1,651
Merchant sales (GWh)	397	90	2,571	839
Purchased power (GWh)	(881)	(836)	(1,850)	(1,688)
Total production (GWh)	346	84	2,371	802
Gross installed capacity (MW)	1,340	1,340	1,340	1,340
Revenues <sup>(2)</sup>	72	58	231	143
Fuel and purchased power	34	20	188	64
<b>Comparable gross margin</b>	<b>38</b>	<b>38</b>	<b>43</b>	<b>79</b>
Operations, maintenance, and administration	18	12	32	27
Taxes, other than income taxes	1	1	2	2
<b>Comparable EBITDA<sup>(2)</sup></b>	<b>19</b>	<b>25</b>	<b>9</b>	<b>50</b>
<b>Deduct:</b>				
<b>Sustaining capital:</b>				
Routine capital	1	2	1	2
Planned major maintenance	4	6	4	11
<b>Total sustaining capital expenditures<sup>(3)</sup></b>	<b>5</b>	<b>8</b>	<b>5</b>	<b>13</b>
Productivity capital	—	—	—	—
<b>Total sustaining and productivity capital expenditures<sup>(3)</sup></b>	<b>5</b>	<b>8</b>	<b>5</b>	<b>13</b>
Payments on lease obligations <sup>(3)</sup>	—	1	—	2
Decommissioning and restoration costs settled	3	3	5	4
<b>US Coal cash flow</b>	<b>11</b>	<b>13</b>	<b>(1)</b>	<b>31</b>

(1) Adjusted for dispatch optimization.

(2) During the first quarter of 2019, we revised comparable EBITDA to remove the unrealized mark-to-market gains (losses). 2018 results have been revised to reflect this change.

(3) On implementation of IFRS 16 in 2019, we have removed the finance leases from sustaining capital and included principal payments on lease obligations as a separate line. The contractual arrangement that was accounted for as a finance lease in 2018 and prior periods is not considered a lease under IFRS 16. Accordingly, the costs are reflected in fuel and purchased power and there are no payments on lease obligations from Jan. 1, 2019.

Adjusted availability for the three months ended June 30, 2019 was up compared to the same period in 2018, due to reduced planned maintenance. Adjusted availability for the six months ended June 30, 2019 was down compared to the same period in 2018, due to higher unplanned outages and derates. In 2019, both Centralia Units remained in service into April due to higher prices in the Pacific Northwest, whereas in 2018, both Centralia Units were taken out of service in February as a result of seasonally lower prices in the Pacific Northwest. In 2018, we performed major maintenance on both units during that time. Availability was also lower in 2019 as Centralia Unit 1 operated with a derate due to blocked precipitator hoppers impacting the six months ended June 30, 2019. This derate was resolved during the period the unit was offline during the second quarter of 2019.

Production for the three and six months ended June 30, 2019 increased 262 GWh and 1,569 GWh, respectively, compared to the same periods in 2018, due mainly to higher merchant pricing and the timing of dispatch optimization. Prices did not support dispatch optimization at Centralia until mid April in 2019.

Comparable EBITDA for the three and six months ended June 30, 2019, was down \$6 million and \$41 million, respectively, compared to the same periods in 2018. During an isolated and extreme pricing event in March, Centralia was unable to commit one of its units to physical production for day ahead supply due to an unplanned forced outage repair. As a result, the Corporation incurred cash losses of \$25 million on its day ahead hedging position. This isolated and extreme pricing event was the result of cold weather and strong demand in the Pacific Northwest as well as from extremely high natural gas prices. The affected unit was able to return to service earlier than expected for delivery in the real time market, however, it was only able to recover a portion of the day ahead hedge losses due to real time prices settling significantly below the day ahead settlement price. The day ahead and subsequent real time prices are historically very similar. The event occurred within a 48 hour period. The remaining year-to-date comparable EBITDA variance of \$16 million is related to the fact that in 2018 we fulfilled more of our contracted volumes with lower priced power purchases. In 2019, lower priced power to service our contracted volumes was not available until later in the year, requiring additional higher cost production from the plant to support our contracts. In addition, the precipitator derate repair resulted in higher OM&A costs in the second quarter of 2019.

Sustaining and productivity capital expenditures for the three and six months ended June 30, 2019 decreased \$3 million and \$8 million, respectively, compared to the same periods in 2018, as there was less planned outage work performed in 2019.

US Coal's cash flow for the second quarter of 2019 was consistent with 2018. Year-to-date cash flow declined by \$32 million compared to the same period in 2018, due mainly to lower Comparable EBITDA, slightly offset by lower capital expenditures.

## Canadian Gas

	3 months ended June 30,		6 months ended June 30,	
	2019	2018	2019	2018
Availability (%)	89.2	84.5	94.3	91.6
Contract production (GWh)	423	326	860	741
Merchant production (GWh) <sup>(1)</sup>	(59)	33	100	71
Total production (GWh)	364	359	960	812
Gross installed capacity (MW)	945	953	945	953
Revenues <sup>(2)</sup>	55	92	127	196
Fuel and purchased power	12	19	43	48
<b>Comparable gross margin</b>	<b>43</b>	<b>73</b>	<b>84</b>	<b>148</b>
Operations, maintenance, and administration	11	12	22	25
Taxes, other than income taxes	1	—	1	1
<b>Comparable EBITDA<sup>(2)</sup></b>	<b>31</b>	<b>61</b>	<b>61</b>	<b>122</b>
<b>Deduct:</b>				
<b>Sustaining capital:</b>				
Routine capital	3	1	8	2
Planned major maintenance	4	6	5	7
<b>Total sustaining capital expenditures</b>	<b>7</b>	<b>7</b>	<b>13</b>	<b>9</b>
Productivity capital	—	—	—	1
<b>Total sustaining and productivity capital expenditures</b>	<b>7</b>	<b>7</b>	<b>13</b>	<b>10</b>
Provisions and other	—	—	—	(2)
<b>Canadian Gas cash flow</b>	<b>24</b>	<b>54</b>	<b>48</b>	<b>114</b>

(1) Includes purchased power, which is used for dispatch optimization, when economical.

(2) During the first quarter of 2019, we revised comparable EBITDA to remove the unrealized mark-to-market gains (losses). 2018 results have been revised to reflect this change.

Availability for the three and six months ended June 30, 2019 increased compared to the same periods in 2018, primarily due to lower planned outages at Fort Saskatchewan in the second quarter and Sarnia during the first quarter.

Production for the three months ended June 30, 2019 was in line with the same period in 2018, as higher production at Fort Saskatchewan was offset by lower production at Sarnia due to lower market demand. Production for the six months ended June 30, 2019 increased 148 GWh compared to the same period in 2018, mainly due to higher production at the Sarnia facility during the first quarter of 2019 due to lower planned outages and higher market demand.

Comparable EBITDA for the three and six months ended June 30, 2019 decreased by \$30 million and \$61 million, respectively, compared to the same periods in 2018, mainly due to the Mississauga contract ending Dec. 31, 2018 and lower scheduled payments from the Poplar Creek finance lease. In the three and six months ended June 30, 2018, comparable EBITDA included \$32 million and \$70 million of EBITDA, respectively, from the Mississauga and Poplar Creek contracts.

Sustaining and productivity capital in the second quarter was consistent year over year. Sustaining and productivity capital for the six months ended June 30, 2019 increased \$3 million compared to the same period in 2018, due to the timing of capital spares purchases for Sarnia.

Cash flow at Canadian Gas decreased by \$30 million and \$66 million in the second quarter and year-to-date periods of 2019, respectively, compared to 2018, due to lower comparable EBITDA.

## Australian Gas

	3 months ended June 30,		6 months ended June 30,	
	2019	2018	2019	2018
Availability (%)	90.6	93.9	86.0	92.8
Contract production (GWh)	453	473	919	913
Gross installed capacity (MW)	450	450	450	450
Revenues	40	41	81	82
Fuel and purchased power	1	1	2	2
<b>Comparable gross margin</b>	<b>39</b>	<b>40</b>	<b>79</b>	<b>80</b>
Operations, maintenance, and administration	8	9	18	18
<b>Comparable EBITDA</b>	<b>31</b>	<b>31</b>	<b>61</b>	<b>62</b>
<b>Deduct:</b>				
<b>Sustaining capital:</b>				
Planned major maintenance	2	—	2	—
<b>Total sustaining and productivity capital expenditures</b>	<b>2</b>	<b>—</b>	<b>2</b>	<b>—</b>
<b>Australian Gas cash flow</b>	<b>29</b>	<b>31</b>	<b>59</b>	<b>62</b>

Availability for the three and six months ended June 30, 2019 decreased compared to the same periods in 2018, primarily due to unplanned outages.

Production for the three months ended June 30, 2019 decreased 20 GWh compared to the same period in 2018, mainly due to decreased customer demand. Production for the six months ended June 30, 2019 was consistent with the same period in 2018. Our contracts in Australia are capacity contracts, and our results are not directly impacted by changes in electricity generation.

Comparable EBITDA for the three and six months ended June 30, 2019 was consistent with the same periods in 2018, which was expected due to the nature of our contracts.

Sustaining capital for the three and six months ended June 30, 2019 increased by \$2 million compared with the same periods in 2018, due to planned major maintenance at our Southern Cross facility in June 2019.

## Wind and Solar

	3 months ended June 30,		6 months ended June 30,	
	2019	2018	2019	2018
Availability (%)	95.2	96.2	95.1	95.3
Contract production (GWh)	518	529	1,275	1,278
Merchant production (GWh)	190	222	404	502
Total production (GWh)	708	751	1,679	1,780
Gross installed capacity (MW)	1,382	1,363	1,382	1,363
Revenues <sup>(1)</sup>	61	66	148	155
Fuel and purchased power	3	4	7	10
<b>Comparable gross margin</b>	<b>58</b>	<b>62</b>	<b>141</b>	<b>145</b>
Operations, maintenance, and administration	13	11	25	24
Taxes, other than income taxes	2	2	4	4
Net other operating income	(4)	—	(4)	—
<b>Comparable EBITDA<sup>(1)</sup></b>	<b>47</b>	<b>49</b>	<b>116</b>	<b>117</b>
<b>Deduct:</b>				
<b>Sustaining capital:</b>				
Planned major maintenance	3	1	5	4
<b>Total sustaining and productivity capital expenditures</b>	<b>3</b>	<b>1</b>	<b>5</b>	<b>4</b>
Payments on lease obligations <sup>(2)</sup>	1	—	1	—
Decommissioning and restoration costs settled	—	—	1	—
Other (insurance proceeds)	4	—	4	—
<b>Wind and Solar cash flow</b>	<b>39</b>	<b>48</b>	<b>105</b>	<b>113</b>

(1) During the first quarter of 2019, we revised comparable EBITDA to remove the unrealized mark-to-market gains (losses). 2018 results have been revised to reflect this change.

(2) On implementation of IFRS 16 in 2019, we included principal payments on lease obligations as a separate line.

Availability for the three months ended June 30, 2019 was lower than the same period in 2018, due to higher unplanned outages. Availability for the six months ended June 30, 2019 was consistent with 2018.

Production for the three and six months ended June 30, 2019 decreased by 43 GWh and 101 GWh, respectively, compared to the same periods in 2018, mainly due to lower wind resources in Western Canada and the United States, partially offset by higher wind resources in Eastern Canada.

Comparable EBITDA for the three and six months ended June 30, 2019 was consistent with the same periods in 2018, as lower overall production was mostly offset by insurance proceeds from a tower fire at Summerview. OM&A costs were up slightly due to increased contractor costs.

Wind and Solar's cash flow decreased by \$9 million and \$8 million in the three and six months ended June 30, 2019, respectively, compared to the same periods in 2018, due to lower production, higher capital expenditures and payments on lease obligations.

## Hydro

	3 months ended June 30,		6 months ended June 30,	
	2019	2018	2019	2018
<b>Production</b>				
Energy contracted				
Alberta hydro PPA assets (GWh) <sup>(1)</sup>	417	448	735	730
Other hydro energy (GWh) <sup>(1)</sup>	133	133	160	169
Energy merchant				
Other hydro energy (GWh)	25	28	28	33
<b>Total energy production (GWh)</b>	<b>575</b>	<b>609</b>	<b>923</b>	<b>932</b>
Ancillary services volumes (GWh) <sup>(2)</sup>	788	876	1,569	1,822
Gross installed capacity (MW)	926	926	926	926
<b>Revenues</b>				
Alberta hydro PPA assets energy	27	31	56	41
Alberta hydro PPA assets ancillary services	28	45	57	60
Capacity payments received under Alberta hydro PPA <sup>(3)</sup>	14	14	28	28
Other revenue <sup>(4)</sup>	18	17	23	23
<b>Total gross revenues</b>	<b>87</b>	<b>107</b>	<b>164</b>	<b>152</b>
Net payment relating to Alberta hydro PPA	(38)	(44)	(78)	(62)
<b>Revenues</b>	<b>49</b>	<b>63</b>	<b>86</b>	<b>90</b>
Fuel and purchased power	2	2	3	3
<b>Comparable gross margin</b>	<b>47</b>	<b>61</b>	<b>83</b>	<b>87</b>
Operations, maintenance, and administration	10	11	18	19
Taxes, other than income taxes	—	1	1	2
<b>Comparable EBITDA<sup>(5)</sup></b>	<b>37</b>	<b>49</b>	<b>64</b>	<b>66</b>
<b>Deduct:</b>				
<b>Sustaining capital:</b>				
Routine capital	1	1	2	1
Planned major maintenance	3	1	5	2
<b>Total sustaining and productivity capital expenditures</b>	<b>4</b>	<b>2</b>	<b>7</b>	<b>3</b>
Decommissioning and restoration costs settled	1	—	1	—
<b>Hydro cash flow</b>	<b>32</b>	<b>47</b>	<b>56</b>	<b>63</b>

(1) Alberta hydro PPA assets include 13 hydro facilities on the Bow and North Saskatchewan river systems included under the PPA legislation. Other hydro facilities include our hydro facilities in BC, Ontario and the hydro facilities in Alberta not included in the legislated PPAs.

(2) Ancillary services as described in the AESO Consolidated Authoritative Document Glossary.

(3) Capacity payments include the annual capacity charge as described in the Power Purchase Arrangements Determination Regulation AR 175/2000, available from Alberta Queen's Printer.

(4) Other revenue includes revenues from our non-PPA hydro facilities, our transmission business and other contractual arrangements, including the flood mitigation agreement with the Alberta government and black start services.

(5) During the first quarter of 2019, we revised comparable EBITDA to remove the unrealized mark-to-market gains (losses). 2018 results have been revised to reflect this change. However, there was no impact to Hydro's comparable EBITDA.

Production for the three and six months ended June 30, 2019 decreased by 34 GWh and 9 GWh, respectively, compared to the same periods in 2018. Lower production for the three months ended June 30, 2019 was mainly due to high water resources during the second quarter of 2018. Year-to-date production was in line with 2018 due to favourable market conditions and strong water resources in Alberta during the first quarter of 2019, partially offset by lower water resources in British Columbia.

Total gross revenues decreased by \$20 million for the second quarter of 2019 compared to 2018, due to lower ancillary services sales. For the year-to-date period, total gross revenues increased by \$12 million compared to 2018, due to favourable power and ancillary services pricing in the first quarter of 2019, which partially offset the decrease in the second quarter. After net payments relating to the Alberta hydro PPA, comparable EBITDA for the three and six months ended June 30, 2019 decreased by \$12 million and \$2 million, respectively, compared to the same periods in 2018.

Sustaining and productivity capital expenditures increased \$2 million and \$4 million for the second quarter and year-to-date period compared to the same periods in 2018, respectively, due to an overhaul at our Rundle and Three Sisters facilities.

Hydro's cash flow decreased by \$15 million and \$7 million for the three and six months ended June 30, 2019, respectively, compared to the same periods in 2018, due mainly to lower Comparable EBITDA and higher planned major maintenance.

## Energy Marketing

	3 months ended June 30,		6 months ended June 30,	
	2019	2018	2019	2018
Revenues and gross margin <sup>(1)</sup>	21	11	49	9
Operations, maintenance, and administration	8	5	17	13
<b>Comparable EBITDA<sup>(1)</sup></b>	<b>13</b>	<b>6</b>	<b>32</b>	<b>(4)</b>
<b>Deduct:</b>				
Provisions and other	(7)	(3)	(12)	5
<b>Energy Marketing cash flow</b>	<b>20</b>	<b>9</b>	<b>44</b>	<b>(9)</b>

(1) During the first quarter of 2019, we revised comparable EBITDA to remove the unrealized mark-to-market gains (losses). 2018 results have been revised to reflect this change.

For the three and six months ended June 30, 2019, comparable EBITDA was higher by \$7 million and \$36 million, respectively, compared to the same periods in 2018 due to strong results across all markets with particularly strong performance from US Western markets.

Energy Marketing's cash flow improved by \$11 million and \$53 million in the three and six months ended June 30, 2019, respectively, compared to the same periods in 2018, due to higher comparable EBITDA and other cash settlements.

In addition, for the three and six months ended June 30, 2019, Energy Marketing generated \$4 million and \$22 million, respectively, in unrealized mark-to-market gains (2018 - \$2 million and \$21 million gains, respectively), which were not included in comparable EBITDA or cash flow above. The cash flow from the 2019 unrealized value is expected to be realized in future periods.

## Corporate

	3 months ended June 30,		6 months ended June 30,	
	2019	2018	2019	2018
Operations, maintenance, and administration	(27)	(20)	(34)	(40)
Net other operating income (loss)	(2)	—	(2)	—
<b>Comparable EBITDA</b>	<b>(29)</b>	<b>(20)</b>	<b>(36)</b>	<b>(40)</b>
<b>Deduct:</b>				
<b>Sustaining capital:</b>				
Routine capital	2	3	5	6
<b>Total sustaining capital expenditures</b>	<b>2</b>	<b>3</b>	<b>5</b>	<b>6</b>
Productivity capital	—	—	—	2
<b>Total sustaining and productivity capital expenditures</b>	<b>2</b>	<b>3</b>	<b>5</b>	<b>8</b>
Payments on lease obligations <sup>(1)</sup>	1	—	2	—
Other	(2)	—	(2)	—
<b>Corporate cash flow</b>	<b>(30)</b>	<b>(23)</b>	<b>(41)</b>	<b>(48)</b>

(1) On implementation of IFRS 16 in 2019, we have included interest and principal payments on lease obligations as a separate line.

For the six months ended June 30, 2019, OM&A costs decreased by \$6 million, primarily due to the year-to-date realized net gain of \$9 million from the total return swap on our share-based payment plans, partially offset by increased legal fees. A portion of the settlement cost of our share-based payment plans is fixed by entering into total return swaps, which are cash settled every quarter. During the three months ended June 30, 2019, OM&A costs increased by \$7 million, due to realized losses from the total return swap on our share-based payment plan and higher legal fees. The loss on the total return swap realized during the second quarter of 2019 partially offset the gain realized in the first quarter of 2019.

## Key Financial Ratios

The methodologies and ratios used by rating agencies to assess our credit ratings 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 under IFRS, and may not be comparable to those used by other entities or by rating agencies. We are focused on strengthening our financial position and flexibility and aim to meet all our target ranges.

### FFO Before Interest to Adjusted Interest Coverage

For the twelve months ended	June 30, 2019	Dec. 31, 2018
FFO	745	927
Less: Early termination payment received on Sundance B and C PPAs	—	(157)
Add: Interest on debt, exchangeable securities and lease obligations, net of interest income and capitalized interest	163	174
<b>FFO before interest</b>	<b>908</b>	<b>944</b>
Interest on debt, exchangeable securities and lease obligations, net of interest income	167	176
Add: 50 per cent of dividends paid on preferred shares <sup>(1)</sup>	20	20
<b>Adjusted interest</b>	<b>187</b>	<b>196</b>
<b>FFO before interest to adjusted interest coverage (times)</b>	<b>4.9</b>	<b>4.8</b>

(1) Dividends paid on preferred shares for the three months ended June 30, 2018 and 2019 have been adjusted to include the dividends payable in the second quarter.

Our target for FFO before interest to adjusted interest coverage is four to five times. While both periods are within our target range, the ratio improved at June 30, 2019 compared to Dec. 31, 2018, mainly due to lower adjusted interest.

### Adjusted FFO to Adjusted Net Debt

As at	June 30, 2019	Dec. 31, 2018
FFO <sup>(1)</sup>	745	927
Less: Early termination payment received on Sundance B and C PPAs <sup>(1)</sup>	—	(157)
Less: 50 per cent of dividends paid on preferred shares <sup>(1, 2)</sup>	(20)	(20)
<b>Adjusted FFO</b>	<b>725</b>	<b>750</b>
Period-end long-term debt <sup>(3)</sup>	3,047	3,267
Exchangeable securities	324	—
Less: Cash and cash equivalents	(208)	(89)
Less: Principal portion of TransAlta OCP restricted cash	—	(27)
Add: 50 per cent of issued preferred shares	471	471
Fair value asset of hedging instruments on debt <sup>(4)</sup>	(6)	(10)
<b>Adjusted net debt</b>	<b>3,628</b>	<b>3,612</b>
<b>Adjusted FFO to adjusted net debt (%)</b>	<b>20.0</b>	<b>20.8</b>

(1) Last 12 months.

(2) Dividends paid on preferred shares for the three months ended June 30, 2018 and 2019 have been adjusted to include the dividends payable in the second quarter.

(3) Includes lease obligations and tax equity financing.

(4) Included in risk management assets and/or liabilities on the condensed consolidated financial statements as at June 30, 2019 and Dec. 31, 2018.

Our target range for adjusted FFO to adjusted net debt is 20 to 25 per cent. Our adjusted FFO to adjusted net debt declined due to lower adjusted FFO compared with 2018.

## Adjusted Net Debt to Comparable EBITDA

As at	June 30, 2019	Dec. 31, 2018
Period-end long-term debt <sup>(1)</sup>	3,047	3,267
Exchangeable securities	324	—
Less: Cash and cash equivalents	(208)	(89)
Less: Principal portion of TransAlta OCP restricted cash	—	(27)
Add: 50 per cent of issued preferred shares	471	471
Fair value asset of hedging instruments on debt <sup>(2)</sup>	(6)	(10)
<b>Adjusted net debt</b>	<b>3,628</b>	<b>3,612</b>
Comparable EBITDA <sup>(3,4)</sup>	947	1,152
Less: Early termination payment received on Sundance B and C PPAs	—	(157)
<b>Adjusted comparable EBITDA<sup>(3,4)</sup></b>	<b>947</b>	<b>995</b>
<b>Adjusted net debt to comparable EBITDA<sup>(3,4)</sup> (times)</b>	<b>3.8</b>	<b>3.6</b>

(1) Includes lease obligations and tax equity financing.

(2) Included in risk management assets and/or liabilities on the condensed consolidated financial statements as at June 30, 2019 and Dec. 31, 2018.

(3) Last 12 months.

(4) During the first quarter of 2019, we revised comparable EBITDA to remove the unrealized mark-to-market gains (losses). 2018 results have been revised to reflect this change.

Our target for adjusted net debt to comparable EBITDA is 3.0 to 3.5 times. Our adjusted net debt to comparable EBITDA ratio increased compared to 2018, mainly due to lower comparable EBITDA.

## Strategic Growth and Corporate Transformation

### Coal-to-Gas Conversions and Repowering of Sundance and Keephills

We are planning the coal-to-gas conversion and repowering of some or all of the units at Sundance and Keephills to gas-fired generation in the 2020 to 2023 time frame. During the first quarter of 2019, we issued Limited Notice to Proceed ("LNTP") for the coal-to-gas conversion on Sundance Unit 6 and on July 4, 2019, we issued Full Notice to Proceed ("FNTP") for this unit. We are targeting to complete the conversion of Sundance Unit 6 by the second half of 2020. We expect to issue LNTP and FNTP for a number of the other Sundance and Keephills units later in 2019 and in early 2020 and expect to complete the conversion of these units in 2021 and 2022. The cost to convert each unit is expected to be approximately \$30 to \$35 million per unit. In 2019, we expect to incur costs of approximately \$24 million to maximize our ability to co-fire gas more consistently at up to 30% of rated capacity and for advancing our coal-to-gas conversions.

In addition, we continue to evaluate the potential to repower one or more of the steam turbines at Sundance and Keephills by installing one or more combustion turbines and heat recovery steam generators, thereby creating highly efficient combined cycle units. We expect to make the decision to proceed with these investments in 2020. Repowering is expected to cost 40% lower than a new combined cycle facility while achieving a similar heat rate.

### Pioneer Gas Pipeline Partnership

On Dec. 17, 2018, the Corporation exercised its option to acquire 50 per cent ownership in the Pioneer Pipeline. During the second quarter of 2019, the Pioneer Pipeline transported first gas four months ahead of schedule to TransAlta's generating units at Sundance and Keephills. The Pioneer Pipeline is currently flowing approximately 50 MMcf/day of natural gas during this start-up phase where initial flows may fluctuate depending on market conditions. Firm throughput of approximately 130 MMcf/day of natural gas will commence flowing through the Pioneer Pipeline on Nov. 1, 2019. Tidewater and TransAlta each own a 50 per cent interest in the Pioneer Pipeline which is backstopped by a 15-year take-or-pay agreement from TransAlta at market rate tolls. The investment for TransAlta, including associated infrastructure, will be approximately \$100 million.

### US Wind Projects

On Feb. 20, 2018, TransAlta Renewables announced that it had entered into an arrangement to acquire two construction-ready wind projects in the United States. Construction of the projects are underway. The wind development projects consist of: i) a 90 MW project located in Pennsylvania that has a 15-year PPA with Microsoft Corp. ("Big Level") and ii) a 29 MW project located in New Hampshire with two 20-year PPAs ("Antrim") (collectively, the "US Wind Projects"), with counterparties that have Standard & Poor's credit ratings of A+ or better.

On March 28, 2019, the closing conditions related to the acquisition of Antrim were finalized and the Corporation acquired the development project. Cost estimates for the US Wind Projects have been re-forecasted to US\$259 million, primarily due to construction and weather related delays as well as higher interconnection costs. TransAlta Renewables will fund these costs either by acquiring additional preferred shares issued by a subsidiary of TransAlta or by subscribing for interest-bearing notes issued by the project entity. The proceeds from the issuance of such preferred shares or notes will be used exclusively in connection with the acquisition and construction of the US Wind Projects. TransAlta Renewables expects to fund these acquisition and construction costs



using its existing liquidity and tax equity financing. Foundations are complete and turbine erection is progressing at both projects. Both Big Level and Antrim are expected to be fully operational during the second half of 2019. See the Significant and Subsequent Events section of this MD&A for further details.

### **Windrise Wind Project**

On Dec. 17, 2018, TransAlta's 207 MW Windrise wind project was selected by the AESO as one of the three selected projects in the third round of the Renewable Electricity Program. TransAlta and the AESO executed a Renewable Electricity Support Agreement with a 20-year term. The Windrise project is situated on 11,000 acres of land located in the county of Willow Creek, Alberta and is expected to cost approximately \$270 million. The project development work is on schedule as it is progressing through the permitting process and is on track to reach commercial operation during the second quarter of 2021.

### **WindCharger Project**

During the first quarter of 2019, TransAlta approved the WindCharger project, an innovative 10 MW / 20 MWh energy storage project. WindCharger is located in southern Alberta in the Municipal District of Pincher Creek next to TransAlta's existing Summerview Wind Farm Substation. WindCharger will store energy produced by the nearby Summerview II Wind Farm and discharge into the Alberta Electricity Grid at times of high-peak demand. This project is expected to be the first utility-scale battery storage facility in Alberta and will be receiving co-funding support from Emissions Reduction Alberta. Regulatory applications, including a facilities application to the Alberta Utilities Commission, have been submitted with approvals expected during the third quarter of 2019. TransAlta is in the process of completing detailed design and engineering and procuring long-lead equipment. Construction is on-track to begin in March 2020 with a commercial operation date of June 2020. The total expected cost of the project to TransAlta is \$7 million.

### **Project Greenlight**

Project Greenlight is a multi-year program to transform our business and the delivery of the Corporation's strategy. Business units are focusing both on cash flow improvements and the way the Corporation is delivering sustainable value. Through this program we delivered on projects that improved performance by improving generation efficiency, improving heat rates, lowering fuel costs, reducing GHG emissions, reducing operating and maintenance costs, optimizing our capital spend, avoiding new costs, reducing overhead costs and financing costs, improving working capital, monetizing assets, streamlining processes and achieving efficiencies.

The success of this project has enabled financial flexibility for new investments and as we proceed with plans to embed the transformation process into the business, we expect to continue to realize new value through innovation and process improvements.

## **Significant and Subsequent Events**

### **TransAlta and Capital Power Swap Non-Operating Interests in Keephills 3 and Genesee 3**

On Aug. 2, 2019, the Corporation announced that it entered into an agreement with Capital Power Corporation ("Capital Power") to swap TransAlta's 50 per cent ownership interest in the Genesee 3 facility for Capital Power's 50 per cent ownership interest in the Keephills 3 facility. As a result, TransAlta will own 100 per cent of the Keephills 3 facility and Capital Power will own 100 per cent of the Genesee 3 facility. The purchase prices for each non-operating interest will largely offset each other, resulting in a net payment of approximately \$10 million from Capital Power to TransAlta, subject to working capital adjustments and other terms and conditions. The closing of the transaction is subject to certain closing conditions, including the receipt of all necessary governmental and regulatory approvals. The Corporation anticipates that the transaction will be neutral to both comparable EBITDA and FFO. We expect to recognize a net pre-tax loss in the range of \$155 million to \$205 million, mainly resulting from the write-down to fair value of TransAlta's existing 50 per cent of Keephills 3.

The Keephills 3 facility is a 463 MW coal-fired generating facility located approximately 70 kilometers west of Edmonton, Alberta, adjacent to TransAlta's existing Keephills Unit 1 and Unit 2 power plants. TransAlta and Capital Power are currently equal partners in the ownership of the Keephills 3 facility and TransAlta is responsible for its operations. The Keephills 3 facility achieved commercial operation in 2011, and has been identified as a candidate for TransAlta's intended coal-to-gas conversions.

The Genesee 3 facility is a 466 MW coal-fired generating facility located approximately 50 kilometers southwest of Edmonton, adjacent to Capital Power's Genesee generating station. TransAlta and Capital Power are also equal partners in the ownership of the Genesee 3 facility and Capital Power is responsible for its operations.

### **Normal Course Issuer Bid**

On May 27, 2019 the Corporation announced that the Toronto Stock Exchange ("TSX") accepted the notice filed by the Corporation to implement a NCIB for a portion of its common shares. Pursuant to the NCIB, the Corporation may repurchase up to a maximum of 14,000,000 common shares, representing approximately 4.92 per cent of issued and outstanding common shares as at May 27, 2019. Purchases under the NCIB may be made through open market transactions on the TSX and any alternative Canadian trading platforms on which the common shares are traded, based on the prevailing market price. Any common shares purchased under the NCIB will be cancelled.

The period during which TransAlta is authorized to make purchases under the NCIB commenced on May 29, 2019, and ends on May 28, 2020, or such earlier date on which the maximum number of common shares are purchased under the NCIB or the NCIB is terminated at the Corporation's election.

Under TSX rules, not more than 176,447 common shares (being 25 per cent of the average daily trading volume on the TSX of 705,788 common shares for the six months ended April 30, 2019) can be purchased on the TSX on any single trading day under the NCIB, with the exception that one block purchase in excess of the daily maximum is permitted per calendar week.

During the six months ended June 30, 2019, the Corporation purchased and cancelled 2,398,200 common shares at an average price of \$8.57 per common share, for a total cost of \$21 million. See Note 15 of the unaudited interim condensed consolidated financial statements as at and for the three and six months ended June 30, 2019 for further details.

### Management Changes

On Aug. 8, 2019, the Board of Directors appointed John Kousinioris to Chief Operating Officer of TransAlta Corporation. Mr. Kousinioris held previously the roles of Chief Legal Officer and most recently Chief Growth Officer at TransAlta. Prior to this promotion, he was responsible for overseeing the areas of business development, gas and renewables operations, commercial, and energy marketing.

On May 17, 2019, the Corporation announced the promotion of Todd Stack to CFO. Mr. Stack, who has served as Managing Director and Corporate Controller of the Corporation since February 2017, has been responsible for providing leadership and direction over TransAlta's financial activities, corporate accounting, reporting, tax, and planning.

Since joining TransAlta in 1990, Mr. Stack has acted as the Corporation's Treasurer, Corporate Controller, as well as a member of the corporate development team reviewing greenfield and acquisition opportunities. Prior to joining the finance team at TransAlta, Mr. Stack held a number of roles in the engineering team, including design, operations and project management. Mr. Stack replaces Christophe Dehout, who left the Corporation to pursue new opportunities.

### Strategic Investment by Brookfield

On March 25, 2019, the Corporation announced it had entered into an investment agreement whereby Brookfield will invest \$750 million in the Corporation. This investment provides the financial flexibility to drive TransAlta's transition to 100% clean energy by 2025, recognizes the anticipated future value of TransAlta's Alberta Hydro Assets, and accelerates the Corporation's plan to return capital to its shareholders.

Under the terms of the agreement, Brookfield agreed to invest \$750 million in TransAlta through the purchase of exchangeable securities, which are exchangeable by Brookfield into an equity ownership interest in TransAlta's Alberta Hydro Assets in the future at a value based on a multiple of the Hydro Assets' future EBITDA.

On May 1, 2019, Brookfield invested the initial tranche of \$350 million in exchange for 7% unsecured subordinated debentures due May 1, 2039. The remaining \$400 million will be invested in October 2020 in exchange for a new series of redeemable, retractable first preferred shares, subject to the satisfaction of certain conditions precedent.

In addition, subject to the exceptions in the investment agreement, Brookfield has committed to purchase TransAlta common shares on the open market to increase its share ownership in TransAlta to not less than 9% at the conclusion of the prescribed share purchase period, provided that Brookfield is not obligated to purchase any common shares at a price per share in excess of \$10 per share. TransAlta shareholders elected two experienced Brookfield directors, Harry Goldgut and Richard Legault, to our Board of Directors at the 2019 Annual and Special Meeting of shareholders. TransAlta and Brookfield intend to work together to complete TransAlta's transition to clean energy, maximize the value of the Hydro Assets, and create long-term shareholder value.

TransAlta has indicated that it intends to return up to \$250 million of capital to shareholders through share repurchases within the next three years.

Upon entering into the investment agreement and as required in the terms of the agreement, the Corporation paid to Brookfield a \$7.5 million structuring fee. A commitment fee of \$15 million was paid upon completion of the initial funding. These transaction costs have been recognized as part of the carrying value of the debentures.

### Skookumchuck Wind Energy Facility

On April 12, 2019, TransAlta signed an agreement to purchase a 49 per cent interest in the Skookumchuck Wind Energy Facility, a 136.8 MW wind facility currently under construction and located in Lewis and Thurston counties near Centralia in Washington state. The project has a 20-year power purchase agreement with an investment grade counterparty. TransAlta will make its investment decision when the facility reaches its commercial operation date, which is expected to be in December 2019. Total consideration for the investment will represent 49 per cent of the total construction cost, less capital contributions from tax equity investors.

## Mothballing of Sundance Units

On March 8, 2019, the Corporation announced that the AESO granted an extension to the mothballing of Sundance Units 3 and 5, which will remain mothballed until Nov. 1, 2021, extended from April 1, 2020.

The extensions were requested by TransAlta based on TransAlta's assessment of market prices and market conditions. TransAlta has the ability to return either of the units back to full operation by providing three months' notice to the AESO.

## Acquisition of Two US Wind Projects

During the first half of 2019, TransAlta Renewables funded \$64 million (US\$49 million) of construction costs for the US Wind Projects.

On March 28, 2019, the closing conditions related to the acquisition of Antrim were finalized and the Corporation acquired the development project for total cash consideration of \$24 million and the settlement of the balance of the outstanding loan receivable of \$41 million. As a result, we recognized \$50 million for assets under construction in property, plant and equipment and \$15 million in intangibles. The Corporation also paid the final holdback for the Big Level development project of \$7 million (US\$5 million) due on the closing of Antrim. Upon the closing of the purchase of Antrim, TransAlta Renewables funded an additional \$70 million (US\$52 million) by subscribing for an interest-bearing promissory note issued by the project entity.

Please refer to the Strategic Growth and Corporate Transformation section of this MD&A for updates on ongoing projects. Please refer to Note 4 of the audited annual 2018 consolidated financial statements within our 2018 Annual Integrated Report and Note 3 of our unaudited interim condensed consolidated financial statements as at and for the three and six months ended June 30, 2019 for significant events impacting both prior and current year results.

## Regulatory Updates

Refer to the Regional Regulation and Compliance discussion in our 2018 annual MD&A for further details that supplement the recent developments as discussed below:

### Canadian Federal Government

#### *Large Greenhouse Gas Emitter Regulations*

On June 21, 2018, the *Greenhouse Gas Pollution Pricing Act (GGPPA)* was passed. Under this Act, the Canadian federal government implemented a national price on GHG emissions. The price began at \$20 per tonne of carbon dioxide equivalent (CO<sub>2</sub>e) emitted in 2019 and will rise by \$10 per year until reaching \$50 per tonne in 2022.

#### *Carbon Tax*

On Jan. 1, 2019, the GGPPA's "backstop" mechanisms came into effect for large emitters in jurisdictions that did not implement an independent carbon pricing program or where the existing program was not deemed equivalent to the federal system - Ontario, Manitoba, New Brunswick, Saskatchewan, Prince Edward Island, Yukon and Nunavut.

The backstop mechanism has two components: a carbon levy for small emitters and regulation for large emitters called the Output Based Pricing Standard (OBPS). The carbon levy sets a carbon price per tonne of greenhouse gas emissions related to transportation fuels, heating fuels and other, small emission sources. The OBPS is an intensity-based standard where large emitters must meet an industry specific emission intensity performance standard per unit of production. If the facility's emission intensity is below or above the performance standard, the facility will generate carbon credits or carbon obligations equal to the difference between the industry's emission intensity performance standard and the regulated facility's emission intensity.

The final regulations for the OBPS were released on June 28, 2019. TransAlta currently operates under this system in Ontario.

#### *Clean Fuel Standard*

In 2016, the Canadian federal government announced plans to consult on the development of a Clean Fuel Standard ("CFS") to reduce Canada's greenhouse gas emissions through the increased use of lower carbon fuels, energy sources and technologies. The objective of the regulation is to achieve 30 million metric tonnes of annual reductions in GHG emissions by 2030. The CFS will establish lifecycle carbon intensity requirements separately for liquid, gaseous and solid fuels that are used in transportation, industry and buildings. Under the proposed policy, coal combusted at facilities that are covered by coal-fired electricity regulations will be exempt from the regulation. Natural gas used for electricity production is currently expected to be included under the gaseous stream.

Consultation on the gaseous stream, commenced in 2019 and will continue into 2020. Publication of the draft regulations for the gaseous stream will occur in late 2020 with final regulations expected in 2021. The gaseous stream is currently expected to come into force by 2023. TransAlta continues to be engaged in the consultation process.

### Alberta

#### *Large Greenhouse Gas Emitter Regulations*

On Jan. 1, 2018, the Alberta government transitioned from the *Specified Gas Emitters Regulation* to the *Carbon Competitiveness Incentive Regulation* ("CCIR"). Under the CCIR, the regulatory compliance moved from a facility-specific compliance standard to a product or sectoral performance compliance standard.

On April 16, 2019, the United Conservative Party ("UCP") won the Alberta provincial election with a majority government. The UCP have committed to moving away from the CCIR to a new regulation called the Technology Innovative Emissions Reduction ("TIER") regime, expected to take effect on Jan. 1, 2020.

Under the proposed TIER regulations, large emitters that emit over 100,000 tCO<sub>2</sub>e per year will be covered with an opt-in provision from 100,000 to 10,000 tCO<sub>2</sub>e per year. For the electricity sector, like CCIR, TIER is an intensity-based carbon standard where emission obligations are assessed on a tonnes of carbon per MWh. Electricity sector covered entities will have to meet a "good-as-best-gas" sector intensity standard that is proposed to be the same as CCIR at 370 tCO<sub>2</sub>e/GWh. All other larger emitters will need to reduce emission by 10% from their 2016-18 average facility emission factor.

Facilities with emissions above the set reduction requirements will need to comply with TIER by: 1) paying the Carbon Fund price, 2) making reductions at their facility, 3) remitting emission performance credits from other facilities, or 4) remitting emission offset credits.

To get stakeholder feedback on TIER, the Alberta government held consultation meetings throughout July ending with final written submissions due on Aug. 2, 2019. The Alberta government intends to draft and pass the new TIER regulation during the Fall session with TIER replacing CCIR on Jan. 1, 2020.

Upon finalization of the program, the TIER system will be submitted for review by the federal government. The federal government conducts an annual review of provincial carbon pricing systems to confirm alignment with the guidance requirements. The 2019 review process is expected to be completed in the fourth quarter of 2019.

#### *Carbon Tax*

The Albertan UCP government passed *Bill 1: An Act to Repeal the Carbon Tax* that removed the carbon tax as of May 30, 2019 on fossil fuel sources such as gasoline, natural gas, etc. The federal government has committed to replace the provincial carbon tax with an equivalent federal carbon tax as of January 1, 2020. TransAlta will not pay the carbon tax on the relevant fuels from June 1, 2019 to December 31, 2019.

#### *Electricity Market Review*

On July 24, 2019, the UCP cancelled the capacity market after completing their 90 day review process. The Alberta government has indicated they will continue with the energy-only market structure. This market structure will be supportive of TransAlta's current and future strategies.

### **Ontario**

#### *Large Greenhouse Gas Emitter Regulations*

Ontario large emitters are currently subject to the federal backstop OBPS regulation and are expected to remain under this regulation until at least the next federal review in 2022.

On July 4, 2019, the Government of Ontario released the final regulations for the provincial Greenhouse Gas Emissions performance Standards (EPS). The EPS establishes greenhouse gas emission limits on covered facilities. Large emitters generating over 50,000 tonnes CO<sub>2</sub>e or more per year will be covered with an opt-in provision for those emitters between 10,000 and 50,000 tCO<sub>2</sub>e annually. The carbon emissions limit for electricity is set at 420 tCO<sub>2</sub>e/GWh. The program also provides a method that accounts for the carbon efficiency of cogeneration units.

Facilities with emissions above the set reduction requirements can comply by: 1) buying excess emission units from the regulator, 2) making reductions at their facility, or 3) using emission performance units generated by facilities emitting below their emission intensity limit.

The first compliance period under the Regulation will begin on Jan. 1 in the year in which Ontario is removed from the list of provinces to which the federal OBPS applies. We currently anticipate this to occur on January 1, 2023.

#### *Carbon Tax*

The Federal carbon tax was implemented in Ontario as of April 1, 2019. It is expected to remain in place until the next Federal review in 2022.

#### *Electricity Market Review*

Ontario is implementing a transitional capacity market that will allow demand response and existing, uncontracted generators to participate. The first auction will be held in December 2019 for the 2020 obligation period. TransAlta assets are contracted and will not participate. This capacity market will evolve and allow participation by imports and uncontracted capacity at contracted facilities. TransAlta may be able to participate in the 2022 or later auctions.

Ontario is planning to implement major changes to its energy market, including the adoption of nodal pricing (transmission congestion pricing) and a day-ahead market. These changes are expected to have small impacts on prices in Southern Ontario where most of TransAlta's assets are located.

## Capital Structure and Liquidity

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

As at	June 30, 2019		Dec. 31, 2018	
	\$	%	\$	%
<b>TransAlta Corporation</b>				
Recourse debt - CAD debentures	647	9	647	9
Recourse debt - US senior notes	907	13	943	13
Exchangeable securities	324	5	—	—
Credit facilities	—	—	174	2
US tax equity financing	25	1	28	—
Other	10	—	11	—
Less: Cash and cash equivalents	(189)	(3)	(16)	—
Less: Principal portion of TransAlta OCP restricted cash	—	—	(27)	—
Less: fair value asset of economic hedging instruments on debt	(6)	—	(10)	—
Net recourse debt	1,718	25	1,750	24
Non-recourse debt	441	6	469	6
Lease obligations	60	1	63	1
<b>Total net debt - TransAlta Corporation</b>	<b>2,219</b>	<b>32</b>	<b>2,282</b>	<b>31</b>
<b>TransAlta Renewables</b>				
Credit facility	200	3	165	2
Less: cash and cash equivalents	(19)	—	(73)	(1)
Net recourse debt	181	3	92	1
Non-recourse debt	742	10	767	11
Lease obligations	15	—	—	—
<b>Total net debt - TransAlta Renewables</b>	<b>938</b>	<b>13</b>	<b>859</b>	<b>12</b>
<b>Total consolidated net debt</b>	<b>3,157</b>	<b>45</b>	<b>3,141</b>	<b>43</b>
Non-controlling interests	1,095	15	1,137	16
Equity attributable to shareholders				
Common shares	3,034	43	3,059	42
Preferred shares	942	13	942	13
Contributed surplus, deficit, and accumulated other comprehensive income	(1,117)	(16)	(1,004)	(14)
<b>Total capital</b>	<b>7,111</b>	<b>100</b>	<b>7,275</b>	<b>100</b>

Overall, our total consolidated net debt increased by \$16 million during the first six months of 2019 mainly due to the issuance of the exchangeable securities offset by lower drawings on the credit facilities and increased cash and cash equivalents. Between 2019 and 2021, we have approximately \$619 million of debt maturing. We will receive the proceeds from the issuance to Brookfield of the second tranche of exchangeable securities of \$400 million in the fourth quarter of 2020. See the Significant and Subsequent Events section for further details.

Our credit facilities provide us with significant liquidity. We have a total of \$2.2 billion (Dec. 31, 2018 - \$2.0 billion) of committed credit facilities, comprised of our \$1.25 billion (Dec. 31, 2018 - \$1.25 billion) committed syndicated bank credit facility, TransAlta Renewables' committed syndicated bank credit facility of \$0.7 billion (Dec. 31, 2018 - \$0.5 billion) and our \$0.2 billion (Dec. 31, 2018 - \$0.2 billion) committed bilateral facilities. These facilities were renewed, and TransAlta Renewables' facility was increased by \$200 million, during the second quarter of 2019 and expire in 2023, 2023, and 2021 respectively. The \$1.95 billion (Dec. 31, 2018 - \$1.75 billion) committed syndicated bank facilities are the primary source for short-term liquidity after the cash flow generated from the Corporation's business. In total, \$1.3 billion (Dec. 31, 2018 - \$0.9 billion) is not drawn. At June 30, 2019, the \$0.9 billion (Dec. 31, 2018 - \$1.1 billion) of credit utilized under these facilities was comprised of actual drawings of \$200 million (Dec. 31, 2018 - \$339 million) and letters of credit of \$654 million (Dec. 31, 2018 - \$720 million). The Corporation is in compliance with the terms of the credit facilities and all undrawn amounts are fully available. In addition to the \$1.3 billion available under the credit facilities, the Corporation also has \$208 million of available cash and cash equivalents.

The Corporation's subsidiaries have issued non-recourse bonds of \$1,182 million (Dec. 31, 2018 - \$1,235 million) that are subject to customary financing conditions and covenants that may restrict our ability to access funds generated by the facilities' operations. Upon meeting certain distribution tests, typically performed once per quarter, the funds are able to be distributed by the subsidiary entities to their respective parent entity. These conditions include meeting a debt service coverage ratio prior to distribution, which was met by these entities in the second quarter. However, funds in these entities that have accumulated since the second quarter test will remain there until the next debt service coverage ratio can be calculated in the third quarter of 2019. At June 30, 2019, \$23 million (Dec. 31, 2018 - \$33 million) of cash was subject to these financial restrictions.

We have \$31 million (Dec. 31, 2018 - \$31 million) of restricted cash related to the Kent Hills project financing that is being held in a construction reserve account, which was returned in July 2019. Additionally, certain non-recourse bonds require that certain reserve accounts be established and funded through cash held on deposit and/or by providing letters of credit. We have elected to use letters of credit as at June 30, 2019.

The weakening of the US dollar has decreased our long-term debt balances by \$38 million in 2019. Almost all our US-denominated debt is hedged either through financial contracts or net investments in our US operations. During the period, these changes in our US-denominated debt were offset as follows:

	June 30, 2019
Effects of foreign exchange on carrying amounts of US operations (net investment hedge)	(19)
Foreign currency economic cash flow hedges on debt	(5)
Economic hedges on US operations	(11)
Unhedged	(3)
<b>Total</b>	<b>(38)</b>

#### Share Capital

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

As at	August 8, 2019	June 30, 2019	Dec 31, 2018
	Number of shares (millions)		
<b>Common shares issued and outstanding, end of period</b>	<b>282.3</b>	<b>282.3</b>	<b>284.6</b>
Preferred shares			
Series A	10.2	10.2	10.2
Series B	1.8	1.8	1.8
Series C	11.0	11.0	11.0
Series E	9.0	9.0	9.0
Series G	6.6	6.6	6.6
<b>Preferred shares issued and outstanding, end of period</b>	<b>38.6</b>	<b>38.6</b>	<b>38.6</b>

#### Non-Controlling Interests

As of June 30, 2019, we own 60.6 per cent (June 30, 2018 - 61.1 per cent) of TransAlta Renewables. Our ownership percent decreased due to common shares issued under TransAlta Renewables Dividend Reinvestment Plan. We do not participate in this plan.

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

Reported earnings attributable to non-controlling interests for the year-to-date and second quarter 2019 decreased to \$51 million and \$16 million, respectively, from \$56 million and \$28 million, respectively, in the same periods of 2018. Earnings in both periods were down at TransAlta Renewables in 2019, primarily as a result of a decrease in finance and interest income related to subsidiaries of TransAlta, higher foreign exchange losses, partially offset by an increase in the change in fair value of investments in subsidiaries of TransAlta. Earnings from TA Cogen increased in both the quarter and the year-to-date 2019 periods, mainly due to strong Alberta pricing and lower costs of fuel at the coal-fired generating facility.

## Returns to Providers of Capital

### Net Interest Expense

The components of net interest expense are shown below:

	3 months ended June 30		6 months ended June 30	
	2019	2018	2019	2018
Interest on debt	42	45	83	98
Interest on exchangeable securities	5	—	5	—
Interest income	(3)	(3)	(5)	(6)
Capitalized interest	(1)	—	(2)	—
Loss on early redemption of US Senior Notes and Debentures	—	—	—	5
Interest on lease obligations	1	1	2	2
Credit facility and bank charges	4	3	7	6
Other interest	2	7	4	10
Accretion of provisions	6	6	12	12
<b>Net interest expense</b>	<b>56</b>	<b>59</b>	<b>106</b>	<b>127</b>

Interest expense decreased during the three and six months ended June 30, 2019 due to lower debt levels, the \$5 million pre-payment premium incurred in the first quarter of 2018 relating to the early redemption of the US\$500 million Senior Notes and the \$5 million of costs expensed in 2018 in connection with project level financing that was no longer practicable. Interest on the exchangeable securities was largely offset by lower interest on debt.

### Dividends to Shareholders

The following are the common and preferred shares dividends declared from Jan. 1, 2019 up to Aug 8, 2019:

Declaration date	Payable date		Common dividends per share	Preferred Series dividends per share				
	Common Shares	Preferred Shares		A	B	C	E	G
July 16, 2019	Oct. 1, 2019	Sept. 30, 2019	0.04	0.16931	0.23422	0.25169	0.32463	0.33125
April 15, 2019	July 1, 2019	June 30, 2019	0.04	0.16931	0.23136	0.25169	0.32463	0.33125

## Financial Position

The following table outlines significant changes in the Condensed Consolidated Statements of Financial Position as at June 30, 2019, compared to Dec. 31, 2018:

<b>Assets</b>	<b>Increase/ (decrease)</b>	<b>Primary factors explaining change</b>
Cash and cash equivalents	119	Timing of receipts and payments and cash received from the issuance of the exchangeable securities
Trade and other receivables	(252)	Timing of customer receipts and seasonality of revenues
Prepaid expenses	26	Annual property tax and insurance payments (\$22 million)
Inventory	26	Increased coal inventory at US Coal operations (\$30 million), partially offset by reduced coal inventory at Canadian Coal operations (\$9 million)
Restricted cash	(35)	Restricted cash related to the OCP bonds was used as part of the debt repayment
Property, plant, and equipment, net	(126)	Depreciation for the period (\$304 million), adjustments on implementing IFRS 16 (\$62 million), unfavourable change in foreign exchange rates (\$51 million) and retirement of assets and disposals (\$27 million), partially offset by additions (\$247 million), acquisition relating to Antrim (\$50 million) and revisions to decommissioning and restoration costs (\$21 million)
Right of use assets, net	79	Transfers from property, plant and equipment, intangible assets and other assets (\$38 million) and new right of use assets recognized under IFRS 16 (\$47 million) (see Accounting Changes section for further details), partially offset by depreciation (\$9 million)
Intangible assets	(12)	Amortization (\$25 million), partially offset by the acquisition relating to Antrim (\$14 million)
Risk management assets (current and long term)	(19)	Contract settlements and unfavourable foreign exchange rates, partially offset by favourable market prices
Other assets	(17)	Note receivable for the project development costs related to the Pioneer Pipeline moved to PP&E additions
Others	(18)	
<b>Total decrease in assets</b>	<b>(229)</b>	

<b>Liabilities and equity</b>	<b>Increase/ (decrease)</b>	<b>Primary factors explaining change</b>
Accounts payable and accrued liabilities	(132)	Timing of payments and accruals
Dividends payable	(11)	Timing of the declaration of common share dividends
Credit facilities, long term debt, and lease obligations (including current portion)	(220)	Repayments on the credit facilities (\$139 million), repayments of long-term debt (\$54 million) and favourable changes in foreign exchange (\$38 million) were partially offset by an increase in lease obligations on implementation of IFRS 16, net of repayments (\$12 million)
Exchangeable securities	324	Issuance of the exchangeable securities (see Significant and Subsequent Events section for further details)
Contract liabilities (current and long term)	17	Contract liabilities moved from defined benefit obligation and other long term liabilities as they are no longer considered leases on the adoption of IFRS 16 (see the Accounting Changes section for further details)
Defined benefit obligation and other long term liabilities	29	Actuarial losses (\$37 million) partially offset by liabilities moved to contract liabilities (\$17 million)
Deferred income tax liabilities	(68)	Decrease in taxable temporary differences mainly due to the Alberta tax rate reduction (see the Other Consolidated Analysis section for further details)
Equity attributable to shareholders	(138)	Net loss (\$55 million), other comprehensive loss (\$48 million), shares purchased under the NCIB (\$21 million) and common and preferred share dividends declared (\$21 million)
Non-controlling interests	(42)	Distributions paid and payable (\$70 million) and intercompany FVOCI investments (\$35 million), partially offset by net earnings (\$51 million) and changes in non-controlling interests in TransAlta Renewables from dividend reinvestment plan (\$12 million)
Others	12	
<b>Total decrease in liabilities and equity</b>	<b>(229)</b>	



## Cash Flows

The following tables outline significant changes in the Condensed Consolidated Statements of Cash Flows for the three and six months ended June 30, 2019, compared to the three and six months ended June 30, 2018:

3 months ended June 30,	2019	2018	Increase/ (decrease)	Primary factors explaining change
Cash and cash equivalents, beginning of period	109	329	(220)	
Provided by (used in):				
Operating activities	258	104	154	Favourable changes in non-cash working capital (\$179 million) were partially offset by lower cash flow from operations before changes in working capital (\$25 million)
Investing activities	(177)	(106)	(71)	Higher additions to PP&E (\$50 million), investment in the Pioneer Pipeline (\$33 million), and lower receipts from finance leases (\$8 million) were partially offset by the favourable change in non-cash investing working capital balances (\$10 million) and cash proceeds received from an insurance claim for the fire at Summerview (\$4 million)
Financing activities	19	(205)	224	Issuance of the exchangeable securities (\$350 million), lower repayments of long-term debt (\$40 million), lower repayment on the credit facilities (\$12 million) and lower distributions paid to subsidiaries' non-controlling interests (\$16 million), partially offset by lower proceeds on issuance of TransAlta Renewables common shares (\$144 million), higher financing fees paid (\$26 million), higher preferred share dividends paid (\$10 million) and higher share buybacks under NCIB (\$15 million)
Translation of foreign currency cash	(1)	1	(2)	
Cash and cash equivalents, end of period	208	123	85	

6 months ended June 30,	2019	2018	Increase/ (decrease)	Primary factors explaining change
Cash and cash equivalents, beginning of period	89	314	(225)	
Provided by (used in):				
Operating activities	340	529	(189)	Lower cash flow from operations before changes in working capital (\$165 million) mainly due to the 2018 one time receipt of \$157 million for the termination of the Sundance Units B and C PPAs. There was also an unfavourable change in non-cash working capital (\$24 million)
Investing activities	(230)	(159)	(71)	Investment in the Pioneer Pipeline (\$83 million), higher additions to PP&E (\$61 million) and lower receipts from finance leases (\$17 million), partially offset by the decrease in restricted cash related to the OCP debt (\$35 million) and a favourable change in non-cash investing working capital balances (\$44 million) and cash proceeds received from an insurance claim for the fire at Summerview (\$4 million)
Financing activities	10	(562)	572	Lower repayments of long-term debt (\$671 million), issuance of the exchangeable securities (\$350 million) and lower distributions paid to subsidiaries' non-controlling interests (\$25 million), partially offset by higher net repayments under credit facilities (\$243 million), lower proceeds on issuance of TransAlta Renewables common shares (\$144 million), lower realized gains on financial instruments (\$48 million), higher financing fees paid (\$21 million) and higher share buybacks under NCIB (\$14 million)
Translation of foreign currency cash	(1)	1	(2)	
Cash and cash equivalents, end of period	208	123	85	

## Other Consolidated Analysis

### Unconsolidated Structured Entities or Arrangements

Disclosure is required of all unconsolidated structured entities or arrangements such as transactions, agreements, or contractual arrangements with unconsolidated entities, structured finance entities, special purpose entities, or variable interest entities that are reasonably likely to materially affect liquidity or the availability of, or requirements for, capital resources. We currently have no such unconsolidated structured entities or arrangements.

## Guarantee Contracts

We have obligations to issue letters of credit and cash collateral to secure potential liabilities to certain parties, including those related to potential environmental obligations, commodity risk management and hedging activities, construction projects, and purchase obligations. At June 30, 2019, we provided letters of credit totaling \$654 million (Dec. 31, 2018 - \$720 million) and cash collateral of \$70 million (Dec. 31, 2018 - \$105 million). These letters of credit and cash collateral secure certain amounts included on our Condensed Consolidated Statements of Financial Position under risk management liabilities and decommissioning and other provisions.

## Income Taxes

In the second quarter of 2019, the Corporation recognized a deferred income tax recovery of \$40 million related to a decrease in the Alberta corporate tax rate from 12 per cent to 8 per cent. The lower tax rates will be phased in as follows: 11 per cent effective July 1, 2019; 10 per cent effective Jan. 1, 2020; 9 per cent effective Jan. 1, 2021; and 8 per cent effective Jan. 1, 2022.

## Commitments

During the second quarter of 2019, the Corporation entered into new contractual commitments for new assets beginning in the third quarter of 2019, with total payments of \$65 million. Annual payments will be: 2019 - \$9 million; 2020 - \$17 million; 2023 to 2038 - \$2-3 million per year.

In addition, beginning on Nov. 1, 2019, TransAlta has a commitment to transport the initial daily contract quantity of 139,000 gj/day of natural gas on a firm basis on the Pioneer Pipeline.

## Contingencies

### I. Line Loss Rule Proceeding

The Corporation has been participating in a 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 Alberta Electric System Operator to, among other things, perform such retroactive calculations. A recent decision by the AUC determined the methodology to be used retroactively and it is now possible to estimate the total potential retroactive exposure faced by the Corporation for its non-PPA MWs. Because of the complexity of the new methodology, the final calculations from the AESO will not be available for some time, and there will be no payments until 2021. The Applications for permission to appeal various AUC decisions were denied. There is some potential for further appeals, but the probability of success on such appeals is low. The current estimate of exposure based on known data is \$15 million and therefore the Corporation has recorded a provision of \$15 million as at June 30, 2019 and Dec. 31, 2018.

### II. FMG Disputes

The Corporation is currently engaged in two disputes with Fortescue Metals Group Ltd. ("FMG"). The first arose as a result of FMG's purported termination of the South Hedland PPA. TransAlta has sued FMG, seeking payment of amounts invoiced and not paid under the South Hedland PPA, as well as a declaration that the PPA is valid and in force. FMG, on the other hand, seeks a declaration that the PPA was lawfully terminated.

The second matter involves FMG's claims against TransAlta related to the transfer of the Solomon Power Station to FMG. FMG claims certain amounts related to the condition of the facility while TransAlta claims certain outstanding costs that should be reimbursed.

### III. Balancing Pool Dispute

Pursuant to a written agreement, the Balancing Pool paid the Corporation approximately \$157 million on March 29, 2018 as part of the net book value payment required on termination of the Sundance B and C PPAs. The Balancing Pool, however, excluded certain mining and corporate assets that the Corporation believes should be included in the net book value calculation, which amounts to an additional \$56 million. The dispute is currently proceeding through arbitration.

### IV. Mangrove

On April 23, 2019, Mangrove Partners 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 Partners is seeking various remedies but primarily to set aside the Brookfield transaction. TransAlta believes the claim is wholly lacking in merit and is taking all steps to defend against the allegations.

## Financial Instruments

Refer to Note 14 of the notes to the audited annual consolidated financial statements within our 2018 Annual Integrated Report and Note 9 and 14 of our unaudited interim condensed consolidated financial statements as at and for the six months ended June 30, 2019 for details on Financial Instruments. Refer to the Governance and Risk Management section of our 2018 Annual Integrated Report and Note 10 of our unaudited interim condensed consolidated financial statements for further details on our risks and how we manage them. Our risk management profile and practices have not changed materially from Dec. 31, 2018.

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

As at June 30, 2019, total Level III financial instruments had a net asset carrying value of \$656 million (Dec. 31, 2018 - \$695 million net asset). The decrease during the period is primarily due to the settlement of contracts and changes in foreign exchange rates, partially offset by favourable market price changes for contracts designated as cash flow hedges for which changes in fair value are recognized in other comprehensive income.

## 2019 Financial Outlook

The following table outlines our expectation on key financial targets for 2019:

Measure	Target
Comparable EBITDA	\$875 million to \$975 million
FCF	\$270 million to \$330 million
Dividend	\$0.16 per share annualized, 14 to 17 per cent payout of FCF

### Range of Key Assumptions

Market	Power Prices (\$/MWh)
Alberta Spot	\$50 to \$60
Alberta Contracted	\$50 to \$55
Mid-C Spot (US\$)	\$20 to \$25
Mid-C Contracted (US\$)	\$47 to \$53

### Other assumptions relevant to 2019 financial outlook

Sustaining capital	\$140 million to \$165 million (revised) <sup>(1)</sup>
Productivity capital	\$10 million to \$15 million
Sundance coal capacity factor	30%
Hydro/ Wind resource	Long term average

*(1) The original 2019 outlook for sustaining capital spend included an additional \$20 million to \$25 million in expected spend on finance leases. On implementation of IFRS 16, we reclassified payments on finance leases out of sustaining capital and now show this spend as a separate line to calculate FCF and segmented cash flow. See the Accounting Changes section of this MD&A for further details.*

## Operations

### Availability

Availability of our Canadian coal fleet is expected to be in the range of 87 to 89 per cent in 2019. Availability of our other generating assets (gas, renewables) is expected to be in the range of 90 to 96 per cent in 2019. We will be accelerating our transition to gas and renewables generation, and continue on our coal-to-gas conversion strategy as set out in the Strategic Growth and Corporate Transformation section of this MD&A.

### Market Pricing and Hedging Strategy

For 2019, power prices in Alberta are expected to be slightly higher than 2018 due to a full year with improved supply demand balances and strong settled prices year-to-date. Pacific Northwest power prices for 2019 are expected to be higher than 2018 as prices for the first half of the year are stronger relative to 2018. Prices in the third quarter of 2019 will be dependent on weather, however, we don't anticipate a repeat of the natural gas supply issues that impacted regional power prices in November and December. Ontario power prices are expected to be comparable to 2018 given weaker prices during the second quarter due to strong hydro generation.

The objective of our portfolio management strategy is to deliver a high confidence for annual FCF which also provides for positive exposure to price volatility in Alberta. Given our cash operating costs, we can be more or less hedged in a given period, and we expect to realize our annual FCF targets through a combination of forward hedging and selling generation into the spot market.

### Fuel Costs

In Alberta, we expect our cash fuel costs per tonne of coal to remain consistent with 2018 costs, even though we expect to mine approximately 2 - 3 million tonnes less in 2019. Total fuel costs on a dollar per MWh basis are expected to remain consistent with 2018 while total fuel costs are expected to be slightly lower due to increased co-firing with natural gas among the merchant units.

In the Pacific Northwest, our US Coal mine, adjacent to our power plant, is in the reclamation stage. Fuel at US Coal has been purchased primarily from external suppliers in the Powder River Basin and delivered by rail. The delivered fuel cost for the remainder of 2019 is expected to decrease by approximately 6 per cent compared to costs incurred in 2018 mainly due to lower natural gas prices.

Aside from the gas used for co-firing at the Canadian Coal plants, most of our other generation from gas is sold under contracts with pass-through provisions for fuel. For gas generation with no pass-through provision, we purchase natural gas from outside companies coincident with production, thereby minimizing our risk to changes in prices.

We closely monitor the risks associated with changes in electricity and input fuel prices on our future operations and, where we consider it appropriate, use various physical and financial instruments to hedge our assets and operations from such price risks.

### 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 2019 objective for Energy Marketing is for the segment to contribute between \$80 million to \$100 million in gross margin for the year.

### Exposure to Fluctuations in Foreign Currencies

Our strategy is to minimize the impact of fluctuations in the Canadian dollar against the US dollar and Australian dollar by offsetting foreign-denominated assets with foreign-denominated liabilities and by entering into foreign exchange contracts. We also have foreign-denominated expenses, including interest charges, which largely offset our net foreign-denominated revenues.

### Net Interest Expense

Net interest expense for 2019 is expected to be lower than in 2018 largely due to lower interest rates, even after including the new exchangeable securities. However, changes in interest rates and in the value of the Canadian dollar relative to the US dollar can affect the amount of net interest expense incurred. In addition, interest expense will increase as a result of implementing IFRS 16. See the Accounting Changes section of this MD&A for further details.

### Liquidity and Capital Resources

We expect to maintain adequate available liquidity under our committed credit facilities. We currently have access to approximately \$1.3 billion under our committed facilities and \$208 million in cash and cash equivalents. Our continued focus will be toward repositioning our capital structure and we expect to be well positioned to address the upcoming debt maturities in 2020 and 2022 with cash flow from operations, the proceeds received from the exchangeable securities and our existing credit facilities.

### Growth and Coal-to-Gas Conversion Expenditures

Our growth projects are focused on sustaining our current operations and supporting our growth strategy in our renewables platform. A summary of the significant growth and major projects that are in progress is outlined below:

Project	Total project		Remaining estimated spend in 2019	Target completion date	Details
	Estimated spend	Spent to date <sup>(1)</sup>			
Big Level wind development project <sup>(2)</sup>	231	124	107	Q4 2019	90 MW wind project with a 15-year PPA
Antrim wind development project <sup>(3)</sup>	105	85	20	Q3 2019	29 MW wind project with two 20-year PPAs
Pioneer gas pipeline partnership	100	98	2	Q4 2019	50 per cent ownership in the 120 km natural gas pipeline to supply gas to Sundance and Keephills
Windrise wind development project	270	18	33	Q2 2021	207 MW wind project with a 20-year Renewable Electricity Support Agreement with AESO
Coal-to-gas conversions <sup>(4)</sup>	185	8	24	2020 to 2022	Coal-to-gas conversions at Canadian Coal
<b>Total</b>	<b>891</b>	<b>333</b>	<b>186</b>		

(1) Represents amounts spent as of June 30, 2019.

(2) The numbers reflected above are in CAD but the actual cash spend on this project is in US funds and therefore these amounts will fluctuate with changes in foreign exchange rates. The estimated total spend is US\$178 million, spent to date is US\$93 million and estimated remaining spend in 2019 is US\$85 million. TransAlta Renewables will fund the construction costs using its existing liquidity and tax equity.

(3) The numbers reflected above are in CAD but the actual cash spend on this project is in US funds and therefore these amounts will fluctuate with changes in foreign exchange rates. The estimated total spend is US\$81 million, spent to date is US\$64 million and estimated remaining spend in 2019 is US\$17 million. TransAlta Renewables will fund the acquisition and construction costs using its existing liquidity and tax equity.

(4) Does not include repowering opportunities.

## Sustaining and Productivity Capital Expenditures

A significant portion of our sustaining and productivity capital is planned major maintenance, which includes inspection, repair and maintenance of existing components, and the replacement of existing components. Planned major maintenance costs are capitalized as part of PP&E and are amortized on a straight-line basis over the term until the next major maintenance event. It excludes amounts for day-to-day routine maintenance, unplanned maintenance activities, and minor inspections and overhauls, which are expensed as incurred.

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

Category	Description	Spent to date <sup>(1)</sup>	Expected spend in 2019
Routine capital	Capital required to maintain our existing generating capacity	23	50 – 60
Planned major maintenance	Regularly scheduled major maintenance	53	70 – 80
Mine capital	Capital related to mining equipment and land purchases	10	20 – 25
<b>Total sustaining capital<sup>(2)</sup></b>		<b>86</b>	<b>140 – 165</b>
Productivity capital	Projects to improve power production efficiency and corporate improvement initiatives	3	10 – 15
<b>Total sustaining and productivity capital</b>		<b>89</b>	<b>150 – 180</b>

(1) As at June 30, 2019.

(2) The original 2019 outlook for sustaining capital spend included an additional \$20 million to \$25 million in expected spend on finance leases. On implementation of IFRS 16, we reclassified payments on finance leases out of sustaining capital and now show this spend as a separate line to calculate FCF and segmented cash flow. See the Accounting Changes section of this MD&A for further details.

Significant planned major outages at TransAlta's operated units for the remainder of 2019 include the following:

- distributed planned maintenance expenditures across the entire Hydro fleet; and
- distributed expenditures across our Wind fleet, focusing on planned component replacements.

Lost production as a result of planned major maintenance, excluding planned major maintenance for US Coal, which is scheduled during a period of dispatch optimization, is estimated as follows for 2019:

	Canadian Coal	Gas and Renewables	Total	Lost to date <sup>(1)</sup>
GWh lost	600 - 625	350 - 375	950 - 1,000	780

(1) As at June 30, 2019.

## Funding of Capital Expenditures

Funding for these planned capital expenditures is expected to be provided by cash flow from operating activities, the proceeds received from the exchangeable securities and existing liquidity. We have access to approximately \$1.5 billion in liquidity. The funds required for committed growth, sustaining capital, and productivity projects are not expected to be significantly impacted by the current economic environment.

## Accounting Changes

### Current Accounting Changes

#### I. IFRS 16 Leases

The Corporation has adopted IFRS 16 Leases ("IFRS 16") with an initial adoption date of Jan. 1, 2019. IFRS 16 sets out the principles for the recognition, measurement, presentation and disclosure of leases. The standard provides a single lessee accounting model, requiring lessees to recognize a right of use asset and liabilities for all in-scope leases. Previously, the Corporation determined at contract inception whether an arrangement is or contains a lease under IAS 17 Leases (IAS 17) or International Financial Reporting Interpretations Committee Interpretation 4 *Determining whether an arrangement contains a lease*. As a result of the IFRS 16 adoption, the Corporation has changed its accounting policy for leases, which is outlined in Note 2 of the Corporation's unaudited interim condensed consolidated financial statements.

The Corporation has elected to adopt IFRS 16 using the modified retrospective approach on transition. Comparative information has not been restated and is reported under IAS 17. Refer to the Corporation's most recent annual consolidated financial statements for information on its prior accounting policy.

The Corporation recognized the cumulative impact of the initial application of the standard of \$3 million in Deficit as at Jan. 1, 2019. In applying IFRS 16 for the first time, the Corporation has used the following practical expedients permitted by the standard:

- Exemption to not recognize right of use assets and lease liabilities for short-term leases that have a remaining lease term of less than 12 months as at Jan. 1, 2019 and for low value leases;
- Excluding initial direct costs for the measurement of the right of use asset at the date of initial application;
- Using hindsight in determining the lease term where the contract contains options to extend or terminate the lease;

- Adjusting the right of use assets by the amount of IAS 37 onerous contract provision immediately before the date of initial application; and
- Measuring the right of use asset at an amount equal to the lease liability, adjusted by the amount of any prepaid or accrued lease payments relating to that lease recognized in the statement of financial position immediately before the date of initial application.

## Impact on the financial statements

### Lessee

The Corporation recognized the cumulative impact of the initial application of the standard recording a right of use asset based on the corresponding lease liability measured at the present value of the remaining lease payments discounted using the Corporation's incremental borrowing rate (or the rate implicit in the lease) applied to the lease liabilities at Jan. 1, 2019. We recognized lease liabilities of \$83 million as at Jan. 1, 2019, including \$63 million that was previously included as finance lease liabilities.

The associated right of use assets were measured at an amount equal to the lease liability, adjusted by the amount of any prepaid or accrued lease payments, onerous contract provisions and lease inducements. On Jan. 1, 2019, the Corporation recognized right of use assets of \$85 million, including \$38 million that was previously included in property, plant and equipment, intangible assets and other assets.

Applying the IFRS 16 definition of a lease to a contractual arrangement that was accounted for as a finance lease under IAS 17 but is no longer considered a lease under IFRS 16, resulted in the derecognition of a finance lease asset of \$29 million and a finance lease liability of \$32 million with the net impact of \$3 million recorded in Deficit.

### Lessor

Several of the Corporation's long term contracts at certain wind, hydro and solar facilities are no longer considered to be operating leases under IFRS 16. Revenues earned on these are now accounted for applying IFRS 15 *Revenue from Contracts with Customers*. No significant change in the pattern of revenue recognition arose. The Corporation continues to account for its subleases as operating leases.

Refer to Note 2 of the Corporation's unaudited interim condensed consolidated financial statements for a more detailed discussion of the Corporation's adoption of IFRS 16.

## II. Change in Estimates - Useful Lives

During the quarter, the Corporation has adjusted the useful life of its Sheerness assets to align with the dual fuel conversion plans. As a result, depreciation expense for the six months ended June 30, 2019 decreased by approximately \$2 million and the full year depreciation expense is expected to decrease by approximately \$11 million. The useful lives may be revised or extended in compliance with the Corporation's accounting policies, dependent upon future operating decisions and events.

## Selected Quarterly Information

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

	Q3 2018	Q4 2018	Q1 2019	Q2 2019
Revenues	593	622	648	497
Comparable EBITDA <sup>(1)</sup>	250	261	221	215
FFO	204	217	169	155
Net earnings (loss) attributable to common shareholders	(86)	(122)	(65)	—
Net earnings (loss) per share attributable to common shareholders, basic and diluted <sup>(2)</sup>	(0.30)	(0.43)	(0.23)	—
	Q3 2017	Q4 2017	Q1 2018	Q2 2018
Revenues	588	638	588	446
Comparable EBITDA <sup>(1)</sup>	233	275	393	248
FFO	196	219	318	188
Net earnings (loss) attributable to common shareholders	(27)	(145)	65	(105)
Net earnings (loss) per share attributable to common shareholders, basic and diluted <sup>(2)</sup>	(0.09)	(0.50)	0.23	(0.36)

(1) During the first quarter of 2019, we revised our approach to reporting adjustments to arrive at comparable EBITDA, mainly to be more comparable with other companies in the industry. Comparable EBITDA is now adjusted to exclude the impact of unrealized mark-to-market gains or losses. Both the current and prior period amounts have been adjusted to reflect this change.

(2) Basic and diluted earnings per share attributable to common shares are calculated each period using the weighted average number of 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 winter cold in the markets in which we operate and lower planned outages.

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

- change in income tax rates in the US in the fourth quarter of 2017 and in Alberta in the second quarter of 2019;
- effects of impairment charges during the second, third and fourth quarters of 2018;
- recognition of the \$157 million early termination payment received regarding Sundance B and C PPAs during the first quarter of 2018;
- a writedown of deferred tax assets in the first quarter of 2019;
- effects of changes in useful lives of certain Canadian Coal assets during the second and third quarters of 2017; and
- effects of an impairment of \$137 million in the fourth quarter of 2017 on intercompany financial instruments that is attributable only to the non-controlling interests.

## 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”). There have been no material changes in our ICFR or DC&P during the three and six months ended June 30, 2019, that have 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 are recorded, processed, summarized and reported within the time frame specified in 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 securities legislation is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding our required disclosure.

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

Management has evaluated, with the participation of our Chief Executive Officer and Chief Financial Officer, the effectiveness of our ICFR and DC&P as of the end of the period covered by this report. Based on the foregoing evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as at June 30, 2019, the end of the period covered by this report, our ICFR and DC&P were effective.

## Condensed Consolidated Statements of Earnings (Loss)

(in millions of Canadian dollars except per share amounts)

<i>Unaudited</i>	3 months ended June 30		6 months ended June 30	
	2019	2018	2019	2018
Revenues (Note 4)	497	446	1,145	1,034
Fuel, carbon costs, and purchased power	177	179	543	456
<b>Gross margin</b>	<b>320</b>	<b>267</b>	<b>602</b>	<b>578</b>
Operations, maintenance, and administration	130	123	234	256
Depreciation and amortization	143	146	288	276
Asset impairment charge (Note 3H)	—	12	—	12
Taxes, other than income taxes	8	8	15	16
Termination of Sundance B and C PPAs (Note 5)	—	—	—	(157)
Net other operating income	(12)	(10)	(22)	(21)
<b>Operating income (loss)</b>	<b>51</b>	<b>(12)</b>	<b>87</b>	<b>196</b>
Finance lease income	1	3	3	5
Net interest expense (Note 6)	(56)	(59)	(106)	(127)
Foreign exchange loss	(8)	(5)	(9)	(7)
Other gains (losses)	(12)	—	(12)	—
<b>Earnings (loss) before income taxes</b>	<b>(24)</b>	<b>(73)</b>	<b>(37)</b>	<b>67</b>
Income tax expense (recovery) (Note 7)	(50)	(6)	(33)	31
<b>Net earnings (loss)</b>	<b>26</b>	<b>(67)</b>	<b>(4)</b>	<b>36</b>
<b>Net earnings (loss) attributable to:</b>				
TransAlta shareholders	10	(95)	(55)	(20)
Non-controlling interests (Note 8)	16	28	51	56
	26	(67)	(4)	36
Net earnings (loss) attributable to TransAlta shareholders	10	(95)	(55)	(20)
Preferred share dividends (Note 16)	10	10	10	20
<b>Net earnings (loss) attributable to common shareholders</b>	<b>—</b>	<b>(105)</b>	<b>(65)</b>	<b>(40)</b>
<b>Weighted average number of common shares outstanding in the period (millions)</b>	<b>284</b>	<b>288</b>	<b>284</b>	<b>288</b>
<b>Net earnings (loss) per share attributable to common shareholders, basic and diluted (Note 15)</b>	<b>—</b>	<b>(0.36)</b>	<b>(0.23)</b>	<b>(0.14)</b>

See accompanying notes.



## Condensed Consolidated Statements of Comprehensive Income (Loss)

(in millions of Canadian dollars)

<i>Unaudited</i>	3 months ended June 30		6 months ended June 30	
	2019	2018	2019	2018
<b>Net earnings (loss)</b>	<b>26</b>	<b>(67)</b>	<b>(4)</b>	<b>36</b>
<b>Other comprehensive income (loss)</b>				
Net actuarial gains (losses) on defined benefit plans, net of tax <sup>(1)</sup>	(17)	15	(36)	18
Gains (losses) on derivatives designated as cash flow hedges, net of tax <sup>(2)</sup>	(3)	(1)	—	—
<b>Total items that will not be reclassified subsequently to net earnings</b>	<b>(20)</b>	<b>14</b>	<b>(36)</b>	<b>18</b>
Gains (losses) on translating net assets of foreign operations, net of tax	(33)	27	(54)	60
Gains (losses) on financial instruments designated as hedges of foreign operations, net of tax <sup>(3)</sup>	12	(12)	20	(24)
Gains (losses) on derivatives designated as cash flow hedges, net of tax <sup>(4)</sup>	46	22	(5)	28
Reclassification of gains on derivatives designated as cash flow hedges to net earnings, net of tax <sup>(5)</sup>	(29)	(31)	(8)	(54)
<b>Total items that will be reclassified subsequently to net earnings</b>	<b>(4)</b>	<b>6</b>	<b>(47)</b>	<b>10</b>
<b>Other comprehensive income (loss)</b>	<b>(24)</b>	<b>20</b>	<b>(83)</b>	<b>28</b>
<b>Total comprehensive income (loss)</b>	<b>2</b>	<b>(47)</b>	<b>(87)</b>	<b>64</b>
<b>Total comprehensive income (loss) attributable to:</b>				
TransAlta shareholders	22	(75)	(103)	7
Non-controlling interests (Note 8)	(20)	28	16	57
	<b>2</b>	<b>(47)</b>	<b>(87)</b>	<b>64</b>

(1) Net of income tax recovery of \$1 million and \$8 million for the three and six months ended June 30, 2019 (2018 - \$5 million and \$6 million expense).

(2) Net of income tax expense of \$1 million and \$1 million for the three and six months ended June 30, 2019 (2018 - nil and nil).

(3) Net of income tax expense of nil and nil for the three and six months ended June 30, 2019 (2018 - \$1 million and \$2 million recovery).

(4) Net of income tax expense of \$13 million and recovery of \$1 million for the three and six months ended June 30, 2019 (2018 - \$6 million and \$7 million expense).

(5) Net of reclassification of income tax recovery of \$8 million and \$2 million for the three and six months ended June 30, 2019 (2018 - \$8 million and \$15 million expense).

See accompanying notes.

## Condensed Consolidated Statements of Financial Position

(in millions of Canadian dollars)

<i>Unaudited</i>	June 30, 2019	Dec. 31, 2018
Cash and cash equivalents	208	89
Restricted cash (Note 13)	31	66
Trade and other receivables	504	756
Prepaid expenses	39	13
Risk management assets (Notes 9 and 10)	165	146
Inventory	268	242
	<b>1,215</b>	<b>1,312</b>
Long-term portion of finance lease receivables	183	191
Risk management assets (Notes 9 and 10)	624	662
Property, plant, and equipment (Note 11)		
Cost	13,184	13,202
Accumulated depreciation	(7,146)	(7,038)
	<b>6,038</b>	<b>6,164</b>
Right of use assets (Note 12)	79	—
Intangible assets	361	373
Goodwill	464	464
Deferred income tax assets	18	28
Other assets (Note 3)	217	234
<b>Total assets</b>	<b>9,199</b>	<b>9,428</b>
Accounts payable and accrued liabilities	364	496
Current portion of decommissioning and other provisions	60	70
Risk management liabilities (Notes 9 and 10)	103	90
Current portion of contract liabilities	10	8
Income taxes payable	9	10
Dividends payable (Note 15 and 16)	47	58
Current portion of long-term debt and lease obligations (Note 13)	105	148
	<b>698</b>	<b>880</b>
Credit facilities, long-term debt, and lease obligations (Note 13)	2,942	3,119
Exchangeable securities (Note 14)	324	—
Decommissioning and other provisions	404	386
Deferred income tax liabilities	433	501
Risk management liabilities (Notes 9 and 10)	33	41
Contract liabilities	95	80
Defined benefit obligation and other long-term liabilities	316	287
Equity		
Common shares (Note 15)	3,034	3,059
Preferred shares (Note 16)	942	942
Contributed surplus	12	11
Deficit	(1,562)	(1,496)
Accumulated other comprehensive income	433	481
<b>Equity attributable to shareholders</b>	<b>2,859</b>	<b>2,997</b>
Non-controlling interests (Note 8)	1,095	1,137
<b>Total equity</b>	<b>3,954</b>	<b>4,134</b>
<b>Total liabilities and equity</b>	<b>9,199</b>	<b>9,428</b>
Commitments and contingencies (Note 17)		
Subsequent events (Note 3)		

See accompanying notes.

# Condensed Consolidated Statements of Changes in Equity

(in millions of Canadian dollars)

Unaudited								
	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income	Attributable to shareholders	Attributable to non-controlling interests	Total
<i>6 months ended June 30, 2019</i>								
Balance, Dec 31, 2018	3,059	942	11	(1,496)	481	2,997	1,137	4,134
Impact of changes in accounting policy (Note 2)	—	—	—	3	—	3	—	3
Adjusted balance as at Jan. 1, 2019	3,059	942	11	(1,493)	481	3,000	1,137	4,137
Net earnings (loss)	—	—	—	(55)	—	(55)	51	(4)
Other comprehensive income (loss):								
Net losses on translating net assets of foreign operations, net of hedges and tax	—	—	—	—	(34)	(34)	—	(34)
Net losses on derivatives designated as cash flow hedges, net of tax	—	—	—	—	(13)	(13)	—	(13)
Net actuarial losses on defined benefits plans, net of tax	—	—	—	—	(36)	(36)	—	(36)
Intercompany fair value through OCI investments	—	—	—	—	35	35	(35)	—
Total comprehensive income (loss)	—	—	—	(55)	(48)	(103)	16	(87)
Common share dividends	—	—	—	(11)	—	(11)	—	(11)
Preferred share dividends	—	—	—	(10)	—	(10)	—	(10)
Shares purchased under NCIB (Note 15)	(26)	—	—	5	—	(21)	—	(21)
Changes in non-controlling interests in TransAlta Renewables (Note 8)	—	—	—	2	—	2	12	14
Effect of share-based payment plans (Note 15)	1	—	1	—	—	2	—	2
Distributions paid, and payable, to non-controlling interests (Note 8)	—	—	—	—	—	—	(70)	(70)
<b>Balance, Jun 30, 2019</b>	<b>3,034</b>	<b>942</b>	<b>12</b>	<b>(1,562)</b>	<b>433</b>	<b>2,859</b>	<b>1,095</b>	<b>3,954</b>
<i>6 months ended June 30, 2018</i>								
Balance, Dec 31, 2017	3,094	942	10	(1,209)	489	3,326	1,059	4,385
Impact of changes in accounting policy	—	—	—	(14)	—	(14)	1	(13)
Adjusted balance as at Jan. 1, 2018	3,094	942	10	(1,223)	489	3,312	1,060	4,372
Net earnings	—	—	—	(20)	—	(20)	56	36
Other comprehensive income (loss):								
Net gains on translating net assets of foreign operations, net of hedges and tax	—	—	—	—	36	36	—	36
Net losses on derivatives designated as cash flow hedges, net of tax	—	—	—	—	(26)	(26)	—	(26)
Net actuarial gains on defined benefits plans, net of tax	—	—	—	—	18	18	—	18
Intercompany fair value through OCI investments	—	—	—	—	(1)	(1)	1	—
Total comprehensive income	—	—	—	(20)	27	7	57	64
Common share dividends	—	—	—	(23)	—	(23)	—	(23)
Preferred share dividends	—	—	—	(20)	—	(20)	—	(20)
Shares purchased under NCIB (Note 15)	(6)	—	—	2	—	(4)	—	(4)
Changes in non-controlling interests in TransAlta Renewables (Note 3 and 8)	—	—	—	19	4	23	122	145
Effect of share-based payment plans	—	—	1	—	—	1	—	1
Distributions paid, and payable, to non-controlling interests (Note 8)	—	—	—	—	—	—	(83)	(83)
<b>Balance, June 30, 2018</b>	<b>3,088</b>	<b>942</b>	<b>11</b>	<b>(1,265)</b>	<b>520</b>	<b>3,296</b>	<b>1,156</b>	<b>4,452</b>

See accompanying notes.

# Condensed Consolidated Statements of Cash Flows

(in millions of Canadian dollars)

<i>Unaudited</i>	3 months ended June 30		6 months ended June 30	
	2019	2018	2019	2018
<b>Operating activities</b>				
Net earnings (loss)	26	(67)	(4)	36
Depreciation and amortization (Note 18)	173	182	347	343
Loss on sale of assets (Note 11)	17	—	17	—
Accretion of provisions (Note 6)	6	6	12	12
Decommissioning and restoration costs settled	(8)	(6)	(15)	(13)
Deferred income tax expense (recovery) (Note 7)	(57)	(16)	(47)	12
Unrealized (gain) loss from risk management activities	(18)	21	(16)	—
Unrealized foreign exchange losses	6	7	5	17
Provisions	2	—	4	5
Asset impairment charges (Note 3)	—	12	—	12
Other non-cash items	1	34	7	51
Cash flow from operations before changes in working capital	148	173	310	475
Change in non-cash operating working capital balances	110	(69)	30	54
<b>Cash flow from operating activities</b>	<b>258</b>	<b>104</b>	<b>340</b>	<b>529</b>
<b>Investing activities</b>				
Additions to property, plant, and equipment (Note 11)	(110)	(60)	(144)	(83)
Additions to intangibles	(3)	(5)	(6)	(10)
Restricted cash (Note 13)	—	—	35	—
Acquisition of renewable energy development projects (Note 3)	—	—	(32)	(30)
Investment in the Pioneer Pipeline (Note 3)	(33)	—	(83)	—
Proceeds on sale of property, plant, and equipment	1	—	2	1
Realized gains on financial instruments	—	—	3	—
Decrease in finance lease receivable	6	14	12	29
Increase in loan receivable	(4)	—	(4)	—
Other	11	—	10	1
Change in non-cash investing working capital balances	(45)	(55)	(23)	(67)
<b>Cash flow from (used in) investing activities</b>	<b>(177)</b>	<b>(106)</b>	<b>(230)</b>	<b>(159)</b>
<b>Financing activities</b>				
Net increase (repayment) in borrowings under credit facilities (Note 13)	(210)	(222)	(139)	104
Repayment of long-term debt (Note 13)	(25)	(65)	(54)	(725)
Issuance of exchangeable securities (Note 14)	350	—	350	—
Dividends paid on common shares (Note 15)	(12)	(11)	(23)	(23)
Dividends paid on preferred shares (Note 16)	(10)	—	(10)	(10)
Net proceeds on sale of non-controlling interest in subsidiary (Note 3)	—	144	—	144
Repurchase of common shares under NCIB (Note 15)	(18)	(3)	(18)	(4)
Realized gains (losses) on financial instruments	—	(2)	—	48
Distributions paid to subsidiaries' non-controlling interests (Note 8)	(24)	(40)	(56)	(81)
Decrease in lease obligations (Note 13)	(6)	(4)	(11)	(8)
Change in non-cash financing working capital balances	2	—	(1)	—
Financing fees	(28)	(2)	(28)	(7)
<b>Cash flow used in financing activities</b>	<b>19</b>	<b>(205)</b>	<b>10</b>	<b>(562)</b>
<b>Cash flow from operating, investing, and financing activities</b>	<b>100</b>	<b>(207)</b>	<b>120</b>	<b>(192)</b>
Effect of translation on foreign currency cash	(1)	1	(1)	1
<b>Increase in cash and cash equivalents</b>	<b>99</b>	<b>(206)</b>	<b>119</b>	<b>(191)</b>
<b>Cash and cash equivalents, beginning of period</b>	<b>109</b>	<b>329</b>	<b>89</b>	<b>314</b>
<b>Cash and cash equivalents, end of period</b>	<b>208</b>	<b>123</b>	<b>208</b>	<b>123</b>
Cash income taxes paid	7	63	15	75
Cash interest paid	53	67	85	104

See accompanying notes.

# Notes to Condensed Consolidated Financial Statements

*(Unaudited)*

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

## 1. Accounting Policies

### A. Basis of Preparation

These unaudited interim condensed consolidated financial statements have been prepared in accordance with International Accounting Standard (“IAS”) 34 *Interim Financial Reporting* using the same accounting policies as those used in TransAlta Corporation’s (“TransAlta” or the “Corporation”) most recent annual consolidated financial statements, except as outlined in *Note 2(A)*. These unaudited interim condensed consolidated financial statements do not include all of the disclosures included in the Corporation’s annual consolidated financial statements. Accordingly, they should be read in conjunction with the Corporation’s most recent annual consolidated financial statements which are available on SEDAR at [www.sedar.com](http://www.sedar.com) and on EDGAR at [www.sec.gov](http://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 Aug. 8, 2019.

### 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. 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. Refer to *Note 2(Z)* of the Corporation’s most recent annual consolidated financial statements.

## 2. Significant Accounting Policies

### A. Current Accounting Changes

#### I. IFRS 16 Leases

The Corporation has adopted IFRS 16 *Leases* ("IFRS 16") with an initial adoption date of Jan. 1, 2019. IFRS 16 sets out the principles for the recognition, measurement, presentation and disclosure of leases. The standard provides a single lessee accounting model, requiring lessees to recognize a right of use asset and liabilities for all in-scope leases. Previously, the Corporation determined at contract inception whether an arrangement is or contains a lease under IAS 17 *Leases* (IAS 17) or International Financial Reporting Interpretations Committee Interpretation 4 *Determining whether an arrangement contains a lease*. As a result of the IFRS 16 adoption, the Corporation has changed its accounting policy for leases, which is outlined below.

The Corporation has elected to adopt IFRS 16 using the modified retrospective approach on transition. Comparative information has not been restated and is reported under IAS 17. Refer to the Corporation's most recent annual consolidated financial statements for information on its prior accounting policy.

The Corporation recognized the cumulative impact of the initial application of the standard of \$3 million in Deficit as at Jan. 1, 2019. In applying IFRS 16 for the first time, the Corporation has used the following practical expedients permitted by the standard:

- Exemption to not recognize right of use assets and lease liabilities for short-term leases that have a remaining lease term of less than 12 months as at Jan. 1, 2019 and for low value leases;
- Excluding initial direct costs for the measurement of the right of use asset at the date of initial application;
- Using hindsight in determining the lease term where the contract contains options to extend or terminate the lease;
- Adjusting the right of use assets by the amount of IAS 37 onerous contract provision immediately before the date of initial application; and
- Measuring the right of use asset at an amount equal to the lease liability, adjusted by the amount of any prepaid or accrued lease payments relating to that lease recognized in the statement of financial position immediately before the date of initial application.

#### Impact on the financial statements

##### Lessee

The Corporation recognized the cumulative impact of the initial application of the standard recording a right of use asset based on the corresponding lease liability measured at the present value of the remaining lease payments discounted using the Corporation's incremental borrowing rate (or the rate implicit in the lease) applied to the lease liabilities at Jan. 1, 2019. The weighted average incremental borrowing rate applied to the lease liabilities on Jan. 1, 2019 was 5.71%.

The following table reconciles the Corporation's operating lease commitments at Dec. 31, 2018, as previously disclosed in the Corporation's annual consolidated financial statements, to the lease obligations recognized on initial application of IFRS 16 at Jan. 1, 2019 and included in credit facilities, long-term debt and lease obligations on the statement of financial position.

Non-cancellable operating lease commitments disclosed at Dec. 31, 2018	80
Less: Exemption for low value leases	(1)
Add: Extension and termination options reasonably certain to be exercised	4
	83
Discounted using the incremental borrowing rate at Jan. 1, 2019	(31)
<b>New lease liabilities recognized as at Jan. 1, 2019</b>	<b>52</b>
Add: 2018 finance lease obligations	63
Less: 2018 finance lease obligations that do not meet the IFRS 16 definition of a lease	(32)
<b>Lease liabilities as at Jan. 1, 2019</b>	<b>83</b>

The associated right of use assets were measured at an amount equal to the lease liability, adjusted by the amount of any prepaid or accrued lease payments, onerous contract provisions and lease inducements. On Jan. 1, 2019, the Corporation

recognized right of use assets of \$85 million, including \$38 million that was previously included in property, plant and equipment (PP&E), intangible assets and other assets.

Applying the IFRS 16 definition of a lease to a contractual arrangement that was accounted for as a finance lease under IAS 17 but is no longer considered a lease under IFRS 16, resulted in the derecognition of a finance lease asset of \$29 million and a finance lease liability of \$32 million with the net impact of \$3 million recorded in Deficit.

Refer to the discussion below, and to Note 12 for a breakdown of the Corporation's leases.

#### *Lessor*

Several of the Corporation's long term contracts at certain wind, hydro and solar facilities are no longer considered to be operating leases under IFRS 16. Revenues earned on these are now accounted for applying IFRS 15 *Revenue from Contracts with Customers*. No significant change in the pattern of revenue recognition arose. The Corporation continues to account for its subleases as operating leases.

#### **Impact of the new definition of a lease**

The change in the definition of a lease mainly relates to the concept of control. Under IFRS 16, a contract contains a lease when the customer obtains the right to control the use of an identified asset for a period of time in exchange for consideration.

The Corporation applied the definition of a lease and related guidance set out in IFRS 16 to all lease contracts in existence at Dec. 31, 2018. In preparation for the first time application of IFRS 16, all relevant contractual arrangements were reviewed to assess if the contract meets the new definition of a lease.

#### **Impact on lessee accounting**

For all contracts that meet the definition of a lease under IFRS 16 in which TransAlta is the lessee, and do not meet the exemption for short term or low value leases, the Corporation:

- Recognizes right of use assets and lease liabilities in the consolidated statement of financial positions, initially measured at the present value of the remaining lease payments discounted using the Corporation's incremental borrowing rate or rate implicit in the lease;
- Recognizes depreciation of the right of use assets and interest expense on lease obligations in the consolidated statement of earnings (loss);
- Recognizes the principal repayments on lease obligations as financing activities and interest payments on lease obligations as operating activities in the consolidated statement of cash flow.

For short term and low value leases, the Corporation recognizes the lease payments as an operating expense. Variable lease payments that do not depend on an index or a rate are not included in the measurement of the lease liability and the right of use asset and are recognized as an expense in the period in which the event or condition that triggers the payments occurs.

For new leases beginning after Jan. 1, 2019, the right of use asset is initially measured at an amount equal to the lease liability and is adjusted for any payments made at or before the commencement date, plus any initial direct cost incurred and an estimate of costs to dismantle and remove the underlying asset, or to restore the underlying asset or the site on which it is located, less any lease incentives received.

For new leases beginning after Jan. 1, 2019, the lease liability is initially measured at the present value of the lease payments that are not paid at commencement and discounted using the Corporation's incremental borrowing rate or the rate implicit in the lease. The lease liability is re-measured when there is a change in future lease payments arising from a change in an index or rate, or if there is a change in the Corporation's estimate or assessment of whether it will exercise an extension, termination, or purchase option. A corresponding adjustment is made to the carrying amount of the right of use asset, or is recorded in profit or loss if the carrying amount of the right of use asset has been reduced to zero.

The lease term includes periods covered by an option to extend if the Corporation is reasonably certain to exercise that option and periods covered by an option to terminate if the Corporation is reasonably certain not to exercise that option.

Right of use assets are depreciated over the shorter period of either the lease term or the useful life of the underlying asset. If a lease transfers ownership of the underlying asset or the cost of the right of use asset reflects that the Corporation expects to exercise the purchase option, the related right of use asset is depreciated over the useful life of the underlying asset.

### **Impact on lessor accounting**

IFRS 16 does not substantially change lessor accounting. Under IFRS 16, a lessor continues to classify leases as either finance leases or operating leases and accounts for those two types of leases differently.

Leases for which the Corporation is lessor are classified as finance or operating leases. Whenever the terms of the lease transfers substantially all the risk and rewards of ownership to the lessee, the contract is classified as a finance lease. All other leases are classified as an operating lease.

When the Corporation has subleased all or a portion of an asset it is leasing and for which it remains the primary obligor under the lease, it accounts for the head lease and the sublease as two separate contracts. The sublease is classified as a finance lease by reference to the right of use asset arising from the head lease.

### **II. Change in Estimates - Useful Lives**

During the quarter, the Corporation has adjusted the useful life of its Sheerness assets to align with the dual fuel conversion plans. As a result, depreciation expense for the six months ended June 30, 2019 decreased by approximately \$2 million and the full year depreciation expense is expected to decrease by approximately \$11 million. The useful lives may be revised or extended in compliance with the Corporation's accounting policies, dependent upon future operating decisions and events.

### **B. Comparative Figures**

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

## **3. Significant and Subsequent Events**

### **A. TransAlta and Capital Power Swap Non-Operating Interests in Keephills 3 and Genesee 3**

On Aug. 2, 2019, the Corporation announced that it entered into an agreement with Capital Power Corporation ("Capital Power") to swap TransAlta's 50 per cent ownership interest in the Genesee 3 facility for Capital Power's 50 per cent ownership interest in the Keephills 3 facility. As a result, TransAlta will own 100 per cent of the Keephills 3 facility and Capital Power will own 100 per cent of the Genesee 3 facility. The purchase prices for each non-operating interest will largely offset each other, resulting in a net payment of approximately \$10 million from Capital Power to TransAlta, subject to working capital adjustments and other terms and conditions. The closing of the transaction is subject to certain closing conditions, including the receipt of all necessary governmental and regulatory approvals. We expect to recognize a net pre-tax loss in the range of \$155 million to \$205 million, mainly resulting from the write-down to fair value of TransAlta's existing 50 per cent of Keephills 3.

The Keephills 3 facility is a 463 MW coal-fired generating facility located approximately 70 kilometers west of Edmonton, Alberta, adjacent to TransAlta's existing Keephills Unit 1 and Unit 2 power plants. TransAlta and Capital Power are currently equal partners in the ownership of the Keephills 3 facility and TransAlta is responsible for its operations. The Keephills 3 facility achieved commercial operation in 2011, and has been identified as a candidate for TransAlta's intended coal-to-gas conversions.

The Genesee 3 facility is a 466 MW coal-fired generating facility located approximately 50 kilometers southwest of Edmonton, adjacent to Capital Power's Genesee generating station. TransAlta and Capital Power are also equal partners in the ownership of the Genesee 3 facility and Capital Power is responsible for its operations.

### **B. Normal Course Issuer Bid**

On May 27, 2019 the Corporation announced that the Toronto Stock Exchange ("TSX") accepted the notice filed by the Corporation to implement a normal course issuer bid ("NCIB") for a portion of its common shares. Pursuant to the NCIB, the Corporation may repurchase up to a maximum of 14,000,000 common shares, representing approximately 4.92 per cent of issued and outstanding common shares as at May 27, 2019. Purchases under the NCIB may be made through open market transactions on the TSX and any alternative Canadian trading platforms on which the common shares are traded, based on the prevailing market price. Any common shares purchased under the NCIB will be cancelled.

The period during which TransAlta is authorized to make purchases under the NCIB commenced on May 29, 2019, and ends on May 28, 2020, or such earlier date on which the maximum number of common shares are purchased under the NCIB or the NCIB is terminated at the Corporation's election.



Under TSX rules, not more than 176,447 common shares (being 25 per cent of the average daily trading volume on the TSX of 705,788 common shares for the six months ended April 30, 2019) can be purchased on the TSX on any single trading day under the NCIB, with the exception that one block purchase in excess of the daily maximum is permitted per calendar week.

During the six months ended June 30, 2019, the Corporation purchased and cancelled 2,398,200 common shares at an average price of \$8.57 per common share, for a total cost of \$21 million. See Note 15 for further details.

### C. Strategic Investment by Brookfield

On March 25, 2019, the Corporation announced that it had entered into an investment agreement whereby Brookfield Renewable Partners or its affiliates (collectively "Brookfield") agreed to invest \$750 million in TransAlta through the purchase of exchangeable securities, which are exchangeable into an equity ownership interest in TransAlta's Alberta Hydro Assets in the future at a value based on a multiple of the Hydro Assets' future EBITDA.

On May 1, 2019, Brookfield invested the initial tranche of \$350 million in exchange for 7% unsecured subordinated debentures due May 1, 2039. The remaining \$400 million will be invested in October 2020 in exchange for a new series of redeemable, retractable first preferred shares, subject to the satisfaction of certain conditions precedent. The investment provides the financial flexibility to drive TransAlta's transition to 100% clean energy by 2025, recognizes the anticipated future value of TransAlta's Alberta Hydro Assets, and also accelerates the Corporation's plan to return capital to its shareholders. In addition, subject to the exceptions in the investment agreement, Brookfield has committed to purchase TransAlta common shares on the open market to increase its share ownership in TransAlta to not less than 9% at the conclusion of the prescribed share purchase period, provided that Brookfield is not obligated to purchase any common shares at a price per share in excess of \$10 per share.

TransAlta has indicated that it intends to return up to \$250 million of capital to shareholders through share repurchases within the next three years.

Upon entering into the investment agreement and as required in the terms of the agreement, the Corporation paid to Brookfield a \$7.5 million structuring fee. A commitment fee of \$15 million was paid upon completion of the initial funding. These transaction costs, representing three per cent of the total investment of \$750 million, have been recognized as part of the carrying value of the unsecured subordinated debentures.

### D. Skookumchuck Wind Energy Facility

On April 12, 2019, TransAlta signed an agreement to purchase a 49 per cent interest in the Skookumchuck Wind Energy Facility, a 136.8 MW wind facility currently under construction and located in Lewis and Thurston counties near Centralia in Washington state. The project has a 20-year power purchase agreement with an investment grade counterparty. TransAlta will make its investment decision when the facility reaches its commercial operation date, which is expected to be in December 2019. Total consideration for the investment will represent 49 per cent of the total construction cost, less capital contributions from tax equity investors.

### E. Pioneer Pipeline

On Dec. 17, 2018, the Corporation exercised its option to acquire 50 percent ownership in the Pioneer gas pipeline ("Pioneer Pipeline"). During the second quarter of 2019, the Pioneer Pipeline transported first gas four months ahead of schedule to TransAlta's generating units at Sundance and Keephills. The Pioneer Pipeline is currently flowing approximately 50 MMcf/day of natural gas during this start-up phase where initial flows may fluctuate depending on market conditions. Throughput of approximately 130 MMcf/day of natural gas will commence flowing through the Pioneer Pipeline on November 1, 2019. Tidewater and TransAlta each own a 50 per cent interest in the Pioneer Pipeline, which is backstopped by a 15-year take-or-pay agreement from TransAlta at market rate tolls. The investment for TransAlta, including associated infrastructure, will be approximately \$100 million.

During the six months ended June 30, 2019, TransAlta invested \$83 million in the Pioneer Pipeline and \$98 million life-to-date. The Pioneer Pipeline is held in a separate entity that is a joint operation with Tidewater, due to the fact that TransAlta is currently the only customer and both parties are providing the only cash flows to fund the operations. If these facts and circumstances change, the classification of the joint arrangement may change. The Corporation reports its interests in joint operations in its consolidated financial statements using the proportionate consolidation method by recognizing its share of the assets, liabilities, revenues and expenses in respect of its interest in the joint operation.

## F. Mothballing of Sundance Units

On March 8, 2019, the Corporation announced that the Alberta Electric System Operator ("AESO") granted an extension to the mothballing of Sundance Units 3 and 5, which will remain mothballed until Nov. 1, 2021, extended from April 1, 2020.

The extensions were requested by TransAlta based on TransAlta's assessment of market prices and market conditions. TransAlta has the ability to return either of the units back to full operation by providing three months' notice to the AESO.

## G. Acquisition of Two US Wind Projects

On Feb. 20, 2018, TransAlta Renewables announced it had entered into an arrangement to acquire two construction-ready projects in the Northeastern United States. The wind development projects consist of: i) a 90 MW project located in Pennsylvania that has a 15-year Power Purchase Arrangement ("PPA") with Microsoft Corp. ("Big Level"), and ii) a 29 MW project located in New Hampshire with two 20-year PPAs ("Antrim") (collectively, the "US Wind Projects"), with counterparties that have Standard & Poor's credit ratings of A+ or better. The commercial operation date for both projects is expected during the second half of 2019. A subsidiary of TransAlta acquired Big Level on Feb. 20, 2018.

On April 20, 2018, TransAlta Renewables completed the acquisition of an economic interest in the US Wind Projects from a subsidiary of TransAlta ("TA Power"). Pursuant to the arrangement, a TransAlta subsidiary owns the US Wind Projects directly and TA Power issued to TransAlta Renewables tracking preferred shares that pay quarterly dividends based on the pre-tax net earnings of the US Wind Projects. The tracking preferred shares have preference over the common shares of TA Power held by TransAlta, in respect of dividends and the distribution of assets in the event of the liquidation, dissolution or winding-up of TA Power. The construction and acquisition costs of the two US Wind Projects are expected to be funded by TransAlta Renewables using its existing liquidity and tax equity and are estimated to be approximately US \$259 million. TransAlta Renewables will fund these costs either by acquiring additional preferred shares issued by TA Power or by subscribing for interest-bearing notes issued by the project entity. The proceeds from the issuance of such preferred shares or notes will be used exclusively in connection with the acquisition and construction of the US Wind Projects.

During the first half of 2019, TransAlta Renewables funded \$64 million (US\$49 million) of construction costs.

On March 28, 2019, the closing conditions related to the acquisition of Antrim were finalized and the Corporation acquired the development project for total cash consideration of \$24 million and the settlement of the balance of the outstanding loan receivable of \$41 million. As a result, the Corporation recognized \$50 million for assets under construction in property, plant and equipment and \$15 million in intangibles. The Corporation also paid the final holdback for the Big Level development project of \$7 million (US\$5 million) due on the closing of Antrim. Upon the closing of the purchase of Antrim, TransAlta Renewables funded an additional \$70 million (US\$52 million) by subscribing for an interest-bearing promissory note issued by the project entity.

## H. TransAlta Renewables Acquires Three Renewable Assets from the Corporation

On May 31, 2018, TransAlta Renewables acquired from the Corporation an economic interest in the 50 MW Lakeswind wind farm in Minnesota and 21 MW of solar projects located in Massachusetts ("Mass Solar") through the subscription of tracking preferred shares of a subsidiary of the Corporation. In addition, TransAlta Renewables acquired from the Corporation ownership of the 20 MW Kent Breeze wind farm located in Ontario. The total purchase price for the three assets, was approximately \$166 million, including the assumption of \$62 million of tax equity obligations and project debt, for net cash consideration of \$104 million in equity value. The Corporation continues to operate these assets on behalf of TransAlta Renewables.

The acquisition of Kent Breeze was accounted for by TransAlta Renewables as a business combination under common control, requiring the application of the pooling of interests method of accounting, whereby the assets and liabilities acquired were recognized at the book values previously recognized by TransAlta at May 31, 2018, and not at their fair values. As a result, the Corporation recognized a transfer of equity from the non-controlling interests in the amount of \$1 million in 2018.

On June 28, 2018, TransAlta Renewables subscribed for an additional \$33 million of tracking preferred shares of a subsidiary of the Corporation related to Mass Solar, in order to fund the repayment of Mass Solar's project debt.

In connection with these acquisitions, the Corporation recorded a \$12 million impairment charge in the second quarter of 2018, of which \$11 million was recorded against PP&E, and \$1 million against intangibles.

### I. TransAlta Renewables Closes \$150 Million Offering of Common Shares

On June 22, 2018, TransAlta Renewables closed a bought deal offering of 11,860,000 common shares through a syndicate of underwriters (the "Offering"). The common shares were issued at a price of \$12.65 per common share for gross proceeds of approximately \$150 million (\$144 million net proceeds).

The net proceeds were used to partially repay drawn amounts under TransAlta Renewables' credit facility, which were drawn in order to fund recent acquisitions. The additional liquidity under the credit facility will be used for general corporate purposes, including ongoing construction costs associated with the US wind development, described above.

The Corporation did not purchase any additional common shares under the Offering and, following the closing, owned 161 million common shares, representing, approximately 61 per cent of the outstanding common shares of TransAlta Renewables. See Note 8 for further details of TransAlta's ownership of TransAlta Renewables.

### J. Early Redemption of Senior Notes

On March 15, 2018, the Corporation early redeemed all of its outstanding 6.650 per cent US\$500 million senior notes due May 15, 2018, for approximately \$617 million (US\$516 million). A \$5 million early redemption premium was recognized in net interest expense.

### K. Balancing Pool Provides Notice to Terminate the Alberta Sundance Power Purchase Arrangements

On Sept 18, 2017, the Corporation received formal notice from the Balancing Pool for the termination of the Sundance B and C PPAs effective March 31, 2018.

This announcement was expected and the Corporation took steps to re-take dispatch control for the units effective March 31, 2018. Pursuant to a written agreement, the Balancing Pool paid the Corporation approximately \$157 million on March 29, 2018. The Corporation is disputing the termination payment it received. The Balancing Pool excluded certain mining assets that the Corporation believes should be included in the net book value calculation for an additional termination payment of \$56 million. The dispute is currently proceeding through the PPA arbitration process.

## 4. Revenue

### Disaggregation of Revenue

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

3 months ended June 30, 2019	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues from contracts with customers	89	2	50	22	57	42	—	—	262
Revenue from leases	16	—	—	17	—	—	—	—	33
Revenue from derivatives <sup>(1)</sup>	(19)	73	(3)	—	11	—	26	2	90
Government incentives	—	—	—	—	2	—	—	—	2
Revenue from other <sup>(2)</sup>	89	11	—	1	2	7	—	—	110
<b>Total Revenue</b>	<b>175</b>	<b>86</b>	<b>47</b>	<b>40</b>	<b>72</b>	<b>49</b>	<b>26</b>	<b>2</b>	<b>497</b>

#### Revenues from contracts with customers

##### Timing of revenue recognition

At a point in time	15	2	—	—	9	—	—	—	26
Over time	74	—	50	22	48	42	—	—	236
<b>Total Revenue from contracts with customers</b>	<b>89</b>	<b>2</b>	<b>50</b>	<b>22</b>	<b>57</b>	<b>42</b>	<b>—</b>	<b>—</b>	<b>262</b>

(1) US Coal includes an end contract with a customer that is accounted for as a derivative.

(2) Includes merchant revenue and other miscellaneous.

3 months ended June 30, 2018	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues from contracts with customers	97	2	52	22	45	52	—	—	270
Revenue from leases	17	—	—	18	5	2	—	—	42
Revenue from derivatives <sup>(1)</sup>	(16)	48	(1)	—	(16)	—	13	—	28
Government incentives	—	—	—	—	5	—	—	—	5
Revenue from other <sup>(2)</sup>	81	1	—	1	12	9	—	(3)	101
<b>Total Revenue</b>	<b>179</b>	<b>51</b>	<b>51</b>	<b>41</b>	<b>51</b>	<b>63</b>	<b>13</b>	<b>(3)</b>	<b>446</b>

#### Revenues from contracts with customers

##### Timing of revenue recognition

At a point in time	11	2	—	—	2	—	—	—	15
Over time	86	—	52	22	43	52	—	—	255
<b>Total Revenue from contracts with customers</b>	<b>97</b>	<b>2</b>	<b>52</b>	<b>22</b>	<b>45</b>	<b>52</b>	<b>—</b>	<b>—</b>	<b>270</b>

(1) US Coal includes an end contract with a customer that is accounted for as a derivative.

(2) Includes merchant revenue and other miscellaneous.

6 months ended June 30, 2019	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues from contracts with customers	196	4	109	44	132	77	—	—	562
Revenue from leases	32	—	—	34	—	—	—	—	66
Revenue from derivatives <sup>(1)</sup>	(52)	35	2	—	13	—	72	2	72
Government incentives	—	—	—	—	4	—	—	—	4
Revenue from other <sup>(2)</sup>	224	193	1	3	12	9	—	(1)	441
<b>Total Revenue</b>	<b>400</b>	<b>232</b>	<b>112</b>	<b>81</b>	<b>161</b>	<b>86</b>	<b>72</b>	<b>1</b>	<b>1,145</b>

Revenues from contracts with customers

Timing of revenue recognition

At a point in time	23	4	—	—	15	—	—	—	42
Over time	173	—	109	44	117	77	—	—	520
<b>Total Revenue from contracts with customers</b>	<b>196</b>	<b>4</b>	<b>109</b>	<b>44</b>	<b>132</b>	<b>77</b>	<b>—</b>	<b>—</b>	<b>562</b>

(1) US Coal includes an end contract with a customer that is accounted for as a derivative.

(2) Includes merchant revenue and other miscellaneous.

6 months ended June 30, 2018	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues from contracts with customers	301	4	108	45	110	76	—	—	644
Revenue from leases	34	—	—	35	13	3	—	—	85
Revenue from derivatives <sup>(1)</sup>	(5)	112	5	—	(19)	—	30	—	123
Government incentives	—	—	—	—	10	—	—	—	10
Revenue from other <sup>(2)</sup>	118	22	—	2	23	11	—	(4)	172
<b>Total Revenue</b>	<b>448</b>	<b>138</b>	<b>113</b>	<b>82</b>	<b>137</b>	<b>90</b>	<b>30</b>	<b>(4)</b>	<b>1,034</b>

Revenues from contracts with customers

Timing of revenue recognition

At a point in time	21	4	—	—	6	—	—	—	31
Over time	280	—	108	45	104	76	—	—	613
<b>Total Revenue from contracts with customers</b>	<b>301</b>	<b>4</b>	<b>108</b>	<b>45</b>	<b>110</b>	<b>76</b>	<b>—</b>	<b>—</b>	<b>644</b>

(1) US Coal includes an end contract with a customer that is accounted for as a derivative.

(2) Includes merchant revenue and other miscellaneous.

## 5. Termination of Sundance B and C PPAs

On Sept. 18, 2017, the Corporation received formal notice from the Balancing Pool of the termination of the Sundance B and C PPAs effective March 31, 2018, and received a termination payment of \$157 million during the first quarter of 2018. See Note 3 for further details.

## 6. Net Interest Expense

The components of net interest expense are as follows:

	3 months ended June 30		6 months ended June 30	
	2019	2018	2019	2018
Interest on debt	42	45	83	98
Interest on exchangeable securities (Note 14)	5	—	5	—
Interest income	(3)	(3)	(5)	(6)
Capitalized interest	(1)	—	(2)	—
Loss on early redemption on US Senior Notes (Note 13)	—	—	—	5
Interest on lease obligations	1	1	2	2
Credit facility fees and bank charges	4	3	7	6
Other interest and fees <sup>(1)</sup>	2	7	4	10
Accretion of provisions	6	6	12	12
<b>Net interest expense</b>	<b>56</b>	<b>59</b>	<b>106</b>	<b>127</b>

(1) During the three and six months ended June 30, 2018, approximately \$5 million of costs were expensed due to project level financing that is no longer practicable.

## 7. Income Taxes

The components of income tax expense are as follows:

	3 months ended June 30		6 months ended June 30	
	2019	2018	2019	2018
Current income tax expense	7	10	14	19
Deferred income tax recovery related to the origination and reversal of temporary differences	(10)	(26)	(19)	(2)
Deferred income tax recovery resulting from changes in tax rates or laws <sup>(1)</sup>	(40)	—	(40)	—
Deferred income tax expense arising from the writedown (recovery) of deferred income tax assets <sup>(2)</sup>	(7)	10	12	14
<b>Income tax expense</b>	<b>(50)</b>	<b>(6)</b>	<b>(33)</b>	<b>31</b>

	3 months ended June 30		6 months ended June 30	
	2019	2018	2019	2018
Current income tax expense	7	10	14	19
Deferred income tax expense	(57)	(16)	(47)	12
<b>Income tax expense</b>	<b>(50)</b>	<b>(6)</b>	<b>(33)</b>	<b>31</b>

(1) In the second quarter of 2019, the Corporation recognized a deferred income tax recovery of \$40 million related to a decrease in the substantively enacted Alberta corporate tax rate from 12 per cent to 8 per cent. The lower tax rates will be phased in as follows: 11 per cent effective July 1, 2019; 10 per cent effective Jan. 1, 2020; 9 per cent effective Jan. 1, 2021, and 8 per cent effective Jan. 1, 2022. A deferred tax recovery of \$40 million was recorded in the statement of earnings and a deferred tax expense of \$4 million was recorded in the statement of other comprehensive income.

(2) During the three and six months ended June 30, 2019, the Corporation reversed a previous writedown of deferred tax assets of \$7 million and recorded a writedown of deferred income tax assets of \$12 million, respectively (June 30, 2018 - \$10 million and \$14 million writedown). 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 no longer considered probable that sufficient future taxable income will be available from the Corporation's directly owned U.S. operations to utilize the underlying tax losses. During the three months ended June 30, 2019, the Alberta corporate tax rate decreased to 11 per cent effective July 1, 2019.

## 8. Non-Controlling Interests

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

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

Period	Percentage
Aug. 1, 2017 to June 21, 2018	64.0
June 22, 2018 to July 30, 2018 <sup>(1)</sup>	61.1
July 31, 2018 to Nov. 29, 2018 <sup>(2)</sup>	61.0
Nov. 30, 2018 to Dec. 31, 2018 <sup>(2)</sup>	60.9
Jan. 1, 2019 to March 31, 2019 <sup>(2)</sup>	60.8
Apr. 1, 2019 to June 30, 2019 <sup>(2)</sup>	60.6

(1) Reduction due to TransAlta Renewables common shares issuance that occurred during the second quarter of 2018. The Corporation did not participate in this common share issuance. See Note 3 for further details.

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

Amounts attributable to non-controlling interests are as follows:

	3 months ended June 30		6 months ended June 30	
	2019	2018	2019	2018
<b>Net earnings</b>				
TransAlta Cogeneration L.P.	5	3	9	6
TransAlta Renewables	11	25	42	50
	<b>16</b>	<b>28</b>	<b>51</b>	<b>56</b>
<b>Total comprehensive income</b>				
TransAlta Cogeneration L.P.	5	3	9	6
TransAlta Renewables	(25)	25	7	51
	<b>(20)</b>	<b>28</b>	<b>16</b>	<b>57</b>
<b>Cash Distributions paid to non-controlling interests</b>				
TransAlta Cogeneration L.P.	6	19	21	39
TransAlta Renewables	18	21	35	42
	<b>24</b>	<b>40</b>	<b>56</b>	<b>81</b>
<b>As at</b>			<b>June 30, 2019</b>	<b>Dec. 31, 2018</b>
Equity attributable to non-controlling interests				
TransAlta Cogeneration L.P.			163	176
TransAlta Renewables			932	961
			<b>1,095</b>	<b>1,137</b>
Non-controlling interests per share (per cent)				
TransAlta Cogeneration L.P.			49.99	49.99
TransAlta Renewables			39.4	39.1

## 9. Financial Instruments

### A. Financial Assets and Liabilities – Measurement

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

### B. Fair Value of Financial Instruments

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

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

##### a. Level I

Fair values are determined using inputs that are quoted prices (unadjusted) in active markets for identical assets or liabilities that the Corporation has the ability to access at the measurement date. In determining Level I fair values, the Corporation uses quoted prices for identically traded commodities obtained from active exchanges such as the New York Mercantile Exchange.

##### b. Level II

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

Fair values falling within the Level II category are determined through the use of quoted prices in active markets, which in some cases are adjusted for factors specific to the asset or liability, such as basis, credit valuation, and location differentials.

The Corporation's commodity risk management Level II financial instruments include over-the-counter derivatives with values based on observable commodity futures curves and derivatives with inputs validated by broker quotes or other publicly available market data providers. Level II fair values are also determined using valuation techniques, such as option pricing models and regression or extrapolation formulas, where the inputs are readily observable, including commodity prices for similar assets or liabilities in active markets, and implied volatilities for options.

In determining Level II fair values of other risk management assets, the Corporation uses observable inputs other than unadjusted quoted prices that are observable for the asset or liability, such as interest rate yield curves and currency rates. For certain financial instruments where insufficient trading volume or lack of recent trades exists, the Corporation relies on similar interest or currency rate inputs and other third-party information such as credit spreads.

##### c. Level III

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

The Corporation may enter into commodity transactions for which market-observable data is not available. In these cases, Level III fair values are determined using valuation techniques such as the Black-Scholes, mark-to-forecast, and historical bootstrap models with inputs that are based on historical data such as unit availability, transmission congestion, demand profiles for individual non-standard deals and structured products, and/or volatilities and correlations between products derived from historical prices.

The Corporation also has various commodity contracts with terms that extend beyond a liquid trading period. As forward market prices are not available for the full period of these contracts, the value of these contracts is derived by reference to a forecast that is based on a combination of external and internal fundamental modelling, including discounting. As a result, these contracts are classified in Level III.

The Corporation has a Commodity Exposure Management Policy, which governs both the commodity transactions undertaken in its proprietary trading business and those undertaken to manage commodity price exposures in its generation business. This Policy defines and specifies the controls and management responsibilities associated with commodity trading activities, as well as the nature and frequency of required reporting of such activities.

Methodologies and procedures regarding commodity risk management Level III fair value measurements are determined by the Corporation's risk management department. Level III fair values are calculated within the Corporation's energy



trading risk management system based on underlying contractual data as well as observable and non-observable inputs. Development of non-observable inputs requires the use of judgment. To ensure reasonability, system-generated Level III fair value measurements are reviewed and validated by the risk management and finance departments. Review occurs formally on a quarterly basis or more frequently if daily review and monitoring procedures identify unexpected changes to fair value or changes to key parameters.

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

As at Description	June 30, 2019		December 31, 2018	
	Base fair value	Sensitivity	Base fair value	Sensitivity
Long-term power sale - US	718	+105 -192	801	+116 -116
Unit contingent power purchases	–	+2 -2	18	+4 -4
Structured products - Eastern US	15	+2 -2	6	+5 -5
Long-term wind energy sale - Eastern US	(26)	+20 -20	(39)	+21 -21
Others	6	+6 -5	9	+3 -3

*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.

For periods over two years out, market forward power prices are not readily observable. For these periods, fundamental-based forecasts and market indications have been used to determine proxies for base, high, and low power price scenarios. The base price forecast has been developed by using a fundamental-based forecast (the provider is an independent and widely accepted industry expert for scenario and planning views). Forward power price ranges per MWh used in determining the Level III base fair value at June 30, 2019 are US\$24 - US\$32 (Dec. 31, 2018 - US\$20 - US\$35). The sensitivity analysis has been prepared using the Corporation's assessment that a US\$6 - US\$11 (Dec. 31, 2018 - US\$6) price decrease or increase, respectively, in the forward power prices as a reasonably possible change.

*ii. Unit Contingent Power Purchases*

Under the unit contingent power purchase agreements, the Corporation has agreed to purchase power contingent upon the actual generation of specific units owned and operated by third parties. Under these types of agreements, the purchaser pays the supplier an agreed upon fixed price per MWh of output multiplied by the pro rata share of actual unit production (nil if a plant outage occurs). The contracts are accounted for as at fair value through profit and loss.

The key unobservable inputs used in the valuations are delivered volume expectations and hourly shapes of production. Hourly shaping of the production will result in realized prices that may be at a discount (or premium) relative to the average settled power price. Reasonably possible alternative inputs were used to determine sensitivity on the fair value measurements.

This analysis is based on historical production data of the generation units for available history. Price and volumetric discount ranges per MWh used in the Level III base fair value measurement at June 30, 2019, are nil (Dec. 31, 2018 - nil) and 2.2 per cent to 2.8 per cent (Dec. 31, 2018 - 2.2 per cent to 16.9 per cent), respectively. The sensitivity analysis has been prepared using the Corporation's assessment of a reasonably possible change in price discount ranges of approximately 1.1 per cent to 1.9 per cent (Dec. 31, 2018 - 1.1 per cent to 1.9 per cent) and a change in volumetric discount rates of approximately 8.6 per cent to 10.7 per cent (Dec. 31, 2018 - 8.6 per cent to 27.3 per cent), which approximate one standard deviation for each input.

### *iii. Structured Products - Eastern US*

The Corporation has fixed priced power and heat rate contracts in the eastern United States. Under the fixed priced power contracts, the Corporation has agreed to buy or sell power at non-liquid locations, or during non-standard hours. The Corporation has also bought and sold heat rate contracts at both liquid and non-liquid locations. Under a heat rate contract, the buyer has the right to purchase power at times when the market heat rate is higher than the contractual heat rate.

The key unobservable inputs in the valuation of the fixed priced power contracts are market forward spreads and non-standard shape factors. A historical regression analysis has been performed to model the spreads between non-liquid and liquid hubs. The non-standard shape factors have been determined using the historical data. Basis relationship and non-standard shape factors used in the Level III base fair value measurement at June 30, 2019, are 92 per cent to 104 per cent and 64 per cent to 107 per cent (Dec. 31, 2018 - 75 per cent to 109 per cent and 63 per cent to 104 per cent), respectively. The sensitivity analysis has been prepared using the Corporation's assessment of a reasonably possible change in market forward spreads of approximately 3 per cent to 7 per cent (Dec. 31, 2018 - 4 per cent to 7 per cent) and a change in non-standard shape factors of approximately 2 per cent to 9 per cent (Dec. 31, 2018 - 4 per cent to 9 per cent), which approximate one standard deviation for each input.

The key unobservable inputs in the valuation of the heat rate contracts are implied volatilities and correlations. Implied volatilities and correlations used in the Level III base fair value measurement at June 30, 2019, are 29 per cent to 35 per cent and 70 per cent (Dec. 31, 2018 - 25 per cent to 84 per cent and 70 per cent), respectively. The sensitivity analysis has been prepared using the Corporation's assessment of a reasonably possible change in implied volatilities ranges and correlations of approximately 30 per cent to 32 per cent and 30 per cent, respectively (Dec. 31, 2018 - 37 per cent to 49 per cent and 30 per cent).

### *iv. Long-Term Wind Energy Sale - Eastern US*

In relation to the acquisition of Big Level (See Note 3), 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 is expected to occur in the second half of 2019, with the contract commencing on July 1, 2019 and extending for 15 years from the commercial operation date. The contract is accounted for at fair value through profit or loss.

The key unobservable inputs used in the valuation of the contract are expected proxy generation volumes and forward prices for power and RECs beyond 2024 and 2022, respectively. Forward power and REC price ranges per MWh used in determining the Level III base fair value at June 30, 2019 are US\$41-US\$64 and US\$7 (Dec. 31, 2018 - US\$42-US\$68 and US\$7-US\$8), respectively. The sensitivity analysis has been prepared using the Corporation's assessment that a change in expected proxy generation volumes of 10 per cent, a change in energy prices of US\$6, and a change in REC prices of US\$1 as reasonably possible changes.

## **II. Commodity Risk Management Assets and Liabilities**

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

Commodity risk management assets and liabilities classified by fair value levels as at June 30, 2019, are as follows: Level I - \$1 million net liability (Dec. 31, 2018 - \$3 million net asset), Level II - \$12 million net liability (Dec. 31, 2018 - \$19 million net liability), Level III - \$656 million net asset (Dec. 31, 2018 - \$695 million net asset).

Significant changes in commodity net risk management assets (liabilities) during the six months ended June 30, 2019 are primarily attributable to contract settlements and unfavourable foreign exchange rates, partially offset by favourable market prices during the period.

The following tables summarize the key factors impacting the fair value of the Level III commodity risk management assets and liabilities during the six months ended June 30, 2019 and 2018, respectively:

	6 months ended June 30, 2019			6 months ended June 30, 2018		
	Hedge	Non-hedge	Total	Hedge	Non-hedge	Total
Opening balance	689	6	695	719	52	771
Changes attributable to:						
Market price changes on existing contracts	17	—	17	6	(7)	(1)
Market price changes on new contracts	—	10	10	—	(9)	(9)
Contracts settled	(27)	(7)	(34)	(40)	(28)	(68)
Change in foreign exchange rates	(31)	(1)	(32)	40	1	41
Transfers into (out of) Level III	—	—	—	—	(4)	(4)
<b>Net risk management assets at end of period</b>	<b>648</b>	<b>8</b>	<b>656</b>	<b>725</b>	<b>5</b>	<b>730</b>
<b>Additional Level III information:</b>						
Gains (losses) recognized in other comprehensive income	(14)	—	(14)	46	—	46
Total gains (losses) included in earnings before income taxes	(27)	9	(18)	40	(15)	25
Unrealized gains (losses) included in earnings before income taxes relating to net assets held at period end	—	2	2	—	(43)	(43)

### 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 \$10 million as at June 30, 2019 (Dec. 31, 2018 - \$2 million net liability) are classified as Level II fair value measurements. The changes in other net risk management assets during the six months ended June 30, 2019 are primarily attributable to market changes and contract settlements.

### 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 <sup>(1)</sup>				Total carrying value
	Level I	Level II	Level III	Total	
Exchangeable securities - June 30, 2019	—	348	—	348	324
Long-term debt - June 30, 2019	—	3,050	—	3,050	2,972
Long-term debt - Dec. 31, 2018	—	3,181	—	3,181	3,204

(1) Includes current portion.

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

The carrying amount of other short-term financial assets and liabilities (cash and cash equivalents, trade accounts receivable, collateral paid, accounts payable and accrued liabilities, collateral received, and dividends payable) approximates fair value due to the liquid nature of the asset or liability. The fair values of the Corporation's loan receivable, the finance lease receivables and lease liabilities approximate the carrying amounts.

## C. Inception Gains and Losses

The majority of derivatives traded by the Corporation are based on adjusted quoted prices on an active exchange or extend beyond the time period for which exchange-based quotes are available. The fair values of these derivatives are determined using inputs that are not readily observable. Refer to section B of this note 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:

	6 months ended June 30	
	2019	2018
Unamortized net gain at beginning of period	49	105
New inception gain (loss)	—	(14)
Change in foreign exchange rates	—	4
Amortization recorded in net earnings during the period	(32)	(34)
<b>Unamortized net gain at end of period</b>	<b>17</b>	<b>61</b>

## 10. Risk Management Activities

### A. Risk Management Strategy

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. In certain cases, the Corporation seeks to minimize the effects of these risks by using derivatives to hedge its risk exposures. The Corporation’s risk management strategy, policies and controls are designed to ensure that the risks it assumes comply with the Corporation’s internal objectives and its risk tolerance.

The Corporation has two primary streams of risk management activities: (i) financial exposure management and (ii) commodity exposure management. Within these activities, risks identified for management include commodity risk, interest rate risk, liquidity risk, equity price risk, and foreign currency risk.

The Corporation seeks to minimize the effects of commodity risk, interest rate risk and foreign currency risk by using derivative financial instruments to hedge risk exposures. Of these derivatives, the Corporation may apply hedge accounting to those hedging commodity price risk and foreign currency risk.

The use of financial derivatives is governed by the Corporation’s policies approved by the Board, which provide written principles on commodity risk, interest rate risk, liquidity risk, equity price risk and foreign currency risk, as well as the use of financial derivatives and non-derivative financial instruments.

Liquidity risk, credit risk and equity price risk are managed through means other than derivatives or hedge accounting.

The Corporation enters into various derivative transactions as well as other contracting activities that do not qualify for hedge accounting or where a choice was made not to apply hedge accounting. As a result, the related assets and liabilities are classified as derivatives at fair value through profit and loss. The net realized and unrealized gains or losses from changes in the fair value of these derivatives are reported in net earnings in the period the change occurs.

The Corporation designates certain derivatives as hedging instruments to hedge commodity price risk, foreign currency exchange risk in cash flow hedges and hedges of net investments in a foreign operations. Hedges of foreign exchange risk on firm commitments are accounted for as cash flow hedges.

At the inception of the hedge relationship, the Corporation documents the relationship between the hedging instrument and the hedged item, along with its risk management objectives and its strategy for undertaking various hedge transactions. At the inception of the hedge and on an ongoing basis, the Corporation also documents whether the hedging instrument

is effective in offsetting changes in fair values or cash flows of the hedged item attributable to the hedged risk, which is when the hedging relationships meet all of the following hedge effectiveness requirements:

- There is an economic relationship between the hedged item and the hedging instrument;
- The effect of credit risk does not dominate the value changes that result from that economic relationship; and
- The hedge ratio of the hedging relationship is the same as that resulting from the quantity of the hedged item that the Corporation actually hedges and the quantity of the hedging instrument that the entity actually uses to hedge that quantity of hedged item.

If a hedging relationship ceases to meet the hedge effectiveness requirement relating to the hedge ratio, but the risk management objective for that designated hedging relationship remains the same, the Corporation adjusts the hedge ratio of the hedging relationship so that it continues to meet the qualifying criteria.

## B. Net Risk Management Assets and Liabilities

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

As at June 30, 2019

	Cash flow hedges	Not designated as a hedge	Total
<b>Commodity risk management</b>			
Current	59	1	60
Long-term	583	—	583
<b>Net commodity risk management assets (liabilities)</b>	<b>642</b>	<b>1</b>	<b>643</b>
<b>Other</b>			
Current	1	1	2
Long-term	1	7	8
<b>Net other risk management assets (liabilities)</b>	<b>2</b>	<b>8</b>	<b>10</b>
<b>Total net risk management assets (liabilities)</b>	<b>644</b>	<b>9</b>	<b>653</b>

As at Dec. 31, 2018

	Cash flow hedges	Not designated as a hedge	Total
<b>Commodity risk management</b>			
Current	59	—	59
Long-term	628	(8)	620
<b>Net commodity risk management assets (liabilities)</b>	<b>687</b>	<b>(8)</b>	<b>679</b>
<b>Other</b>			
Current	—	(3)	(3)
Long-term	—	1	1
<b>Net other risk management assets (liabilities)</b>	<b>—</b>	<b>(2)</b>	<b>(2)</b>
<b>Total net risk management assets (liabilities)</b>	<b>687</b>	<b>(10)</b>	<b>677</b>

On May 31, 2019, the Corporation de-designated \$30 million of US denominated debt, leaving a total of USD \$370 million, designated as a part of the hedge of TransAlta's net investment in foreign operations.

## C. Nature and Extent of Risks Arising from Financial Instruments

The following discussion is limited to the nature and extent of certain risks arising from financial instruments, which are also more fully discussed in Note 15 of the Corporation's most recent annual consolidated financial statements.

### I. Market Risk

#### a. Commodity Price Risk

The Corporation has exposure to movements in certain commodity prices in both its electricity generation and proprietary trading businesses, including the market price of electricity and fuels used to produce electricity. Most of the Corporation's electricity generation and related fuel supply contracts are considered to be contracts for delivery or receipt of a non-financial item in accordance with the Corporation's expected own use requirements and are not considered to be financial instruments. As such, the discussion related to commodity price risk is limited to the Corporation's proprietary trading business and commodity derivatives used in hedging relationships associated with the Corporation's electricity generating activities.

#### i. Commodity Price Risk – 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.

In compliance with the Commodity Exposure Management Policy, proprietary trading activities are subject to limits and controls, including Value at Risk ("VaR") limits. The Board approves the limit for total VaR from proprietary trading activities. VaR is the most commonly used metric employed to track and manage the market risk associated with trading positions. A VaR measure gives, for a specific confidence level, an estimated maximum pre-tax loss that could be incurred over a specified period of time. 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. VaR is estimated using the historical variance/covariance approach. VaR is a measure that has certain inherent limitations. The use of historical information in the estimate assumes that price movements in the past will be indicative of future market risk. As such, it may only be meaningful under normal market conditions. Extreme market events are not addressed by this risk measure. In addition, the use of a three-day measurement period implies that positions can be unwound or hedged within three days, although this may not be possible if the market becomes illiquid.

Changes in market prices associated with proprietary trading activities affect net earnings in the period that the price changes occur. VaR at June 30, 2019, associated with the Corporation's proprietary trading activities was \$3 million (Dec. 31, 2018 - \$2 million).

#### ii. Commodity Price Risk - Generation

The generation segments utilize various commodity contracts to manage the commodity price risk associated with electricity generation, fuel purchases, emissions, and byproducts, as considered appropriate. A Commodity Exposure Management Policy is prepared and approved annually, which outlines the intended hedging strategies associated with the Corporation's generation assets and related commodity price risks. Controls also include restrictions on authorized instruments, management reviews on individual portfolios, and approval of asset transactions that could add potential volatility to the Corporation's reported net earnings.

TransAlta has entered into various contracts with other parties whereby the other parties have agreed to pay a fixed price for electricity to TransAlta. While not all of the contracts create an obligation for the physical delivery of electricity to other parties, the Corporation has the intention and believes it has sufficient electrical generation available to satisfy these contracts and, where able, has designated these as cash flow hedges for accounting purposes. As a result, changes in market prices associated with these cash flow hedges do not affect net earnings in the period in which the price change occurs. Instead, changes in fair value are deferred in AOCI until settlement, at which time the net gain or loss resulting from the combination of the hedging instrument and hedged item affects net earnings.

VaR at June 30, 2019, associated with the Corporation's commodity derivative instruments used in generation hedging activities was \$18 million (Dec. 31, 2018 - \$18 million). For positions and economic hedges that do not meet hedge accounting requirements or for short-term optimization transactions such as buybacks entered into to offset existing hedge positions, these transactions are marked to the market value with changes in market prices associated with these transactions affecting net earnings in the period in which the price change occurs. VaR at June 30, 2019, associated with these transactions was \$11 million (Dec. 31, 2018 - \$13 million).

### b. Currency Rate Risk

The Corporation has exposure to various currencies, such as the US dollar and the Australian dollar (“AUD”), as a result of investments and operations in foreign jurisdictions, the net earnings from those operations and the acquisition of equipment and services from foreign suppliers. Further discussion on Currency Rate Risk can be found in Note 15(C)(I)(c) of the Corporation's most recent annual consolidated financial statements.

## II. Credit Risk

Credit risk is the risk that customers or counterparties will cause a financial loss for the Corporation by failing to discharge their obligations, and the risk to the Corporation associated with changes in creditworthiness of entities with which commercial exposures exist. The Corporation actively manages its exposure to credit risk by assessing the ability of counterparties to fulfil their obligations under the related contracts prior to entering into such contracts. The Corporation makes detailed assessments of the credit quality of all counterparties and, where appropriate, obtains corporate guarantees, cash collateral, third-party credit insurance, and/or letters of credit to support the ultimate collection of these receivables. For commodity trading and origination, the Corporation sets strict credit limits for each counterparty and monitors exposures on a daily basis. TransAlta uses standard agreements that allow for the netting of exposures and often include margining provisions. If credit limits are exceeded, TransAlta will request collateral from the counterparty or halt trading activities with the counterparty.

The Corporation uses external credit ratings, as well as internal ratings in circumstances where external ratings are not available, to establish credit limits for customers and counterparties. The following table outlines the Corporation's maximum exposure to credit risk without taking into account collateral held, including the distribution of credit ratings, as at June 30, 2019:

	Investment grade (Per cent)	Non-investment grade (Per cent)	Total (Per cent)	Total amount
Trade and other receivables <sup>(1)</sup>	91	9	100	504
Long-term finance lease receivables	100	—	100	183
Risk management assets <sup>(1)</sup>	98	2	100	789
Loan and notes receivable <sup>(2)</sup>	—	100	100	37
<b>Total</b>				<b>1,513</b>

(1) Letters of credit and cash and cash equivalents are generally the primary types of collateral held as security related to some of these amounts.

(2) The loan receivable of \$37 million due from the Corporation's partner at Kent Hills wind farm. The counterparty has no external credit ratings.

The maximum credit exposure to any one customer for commodity trading operations and hedging, including the fair value of open trades, net of any collateral held, at June 30, 2019, was \$10 million (Dec. 31, 2018 - \$13 million).

## III. Liquidity Risk

Liquidity risk relates to the Corporation's ability to access capital to be used for proprietary trading activities, commodity hedging, capital projects, debt refinancing, and general corporate purposes. As at June 30, 2019, TransAlta maintains investment grade ratings from two credit rating agencies and below investment grade ratings from two credit rating agencies. Between 2019 and 2021, we have approximately \$619 million of debt maturing. We will receive the proceeds from the issuance to Brookfield of the second tranche of exchangeable securities of \$400 million in the fourth quarter of 2020. See Note 14 for further details.

A maturity analysis of the Corporation's financial liabilities is as follows:

	2019	2020	2021	2022	2023	2024 and thereafter	Total
Accounts payable and accrued liabilities	364	—	—	—	—	—	364
Long-term debt <sup>(1)</sup>	44	486	89	618	341	1,422	3,000
Exchangeable securities <sup>(2)</sup>	—	—	—	—	—	350	350
Commodity risk management (assets) liabilities	(24)	(80)	(105)	(125)	(119)	(190)	(643)
Other risk management (assets) liabilities	(1)	(4)	—	(5)	—	—	(10)
Lease obligations	10	17	12	7	3	26	75
Interest on long-term debt and lease obligations <sup>(3)</sup>	90	147	124	117	87	702	1,267
Interest on exchangeable securities <sup>(2, 3)</sup>	12	25	25	25	25	25	137
Dividends payable	47	—	—	—	—	—	47
<b>Total</b>	<b>542</b>	<b>591</b>	<b>145</b>	<b>637</b>	<b>337</b>	<b>2,335</b>	<b>4,587</b>

(1) Excludes impact of hedge accounting.

(2) Assumes the debentures will be exchanged on Jan. 1, 2025. See Note 14 for further details.

(3) Not recognized as a financial liability on the Condensed Consolidated Statements of Financial Position.

## D. Collateral and Contingent Features in Derivative Instruments

Collateral is posted based on negotiated terms with counterparties, which can include 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. If a material adverse event resulted in the Corporation's senior unsecured debt falling below investment grade, the counterparties to such derivative instruments could request ongoing full collateralization.

As at June 30, 2019, the Corporation had posted collateral of \$105 million (Dec. 31, 2018 - \$120 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 could result in the Corporation having to post an additional \$32 million (Dec. 31, 2018 - \$120 million) of collateral to its counterparties.

## 11. Property, Plant, and Equipment

A reconciliation of the changes in the carrying amount of PP&E is as follows:

	Land	Coal generation	Gas generation	Renewable generation	Mining property and equipment	Assets under construction	Capital spares and other <sup>(1)</sup>	Total
As at As at Dec. 31, 2018	94	2,172	836	2,125	508	200	229	6,164
Adjustments on implementation of IFRS 16 (Note 2) <sup>(2)</sup>	—	—	—	(4)	(58)	—	—	(62)
Additions <sup>(3)</sup>	—	—	—	—	—	137	110	247
Acquisitions (Note 3)	—	—	—	—	—	50	—	50
Depreciation	—	(148)	(39)	(62)	(47)	—	(8)	(304)
Revisions and additions to decommissioning and restoration costs	—	10	3	3	5	—	—	21
Retirement of assets and disposals <sup>(4)</sup>	(2)	1	(2)	(4)	(3)	—	(17)	(27)
Change in foreign exchange rates	(1)	(9)	(22)	(9)	(1)	(5)	(4)	(51)
Transfers	—	60	22	8	26	(116)	—	—
<b>As at June 30, 2019</b>	<b>91</b>	<b>2,086</b>	<b>798</b>	<b>2,057</b>	<b>430</b>	<b>266</b>	<b>310</b>	<b>6,038</b>

(1) Includes major spare parts and stand-by equipment available, but not in service, and spare parts used for routine, preventive, or planned maintenance.

(2) Includes \$33 million transferred to right of use assets and \$29 million of finance lease assets that were derecognized on implementation of IFRS 16 (see Note 2 for further details).

(3) Includes cash additions of \$144 million and \$103 million relating to the Pioneer Pipeline.

(4) During the second quarter, Centralia sold boiler parts included in Capital spares and other for a net loss of \$17 million, which was recognized in other gains (losses) on the statement of earnings (loss).



## 12. Right of Use Assets

The Corporation leases various properties and types of equipment. Lease contracts are typically made for fixed periods. Leases are negotiated on an individual basis and contain a wide range of different terms and conditions. The lease agreements do not impose covenants, but leased assets may not be used as security for borrowing purposes.

A reconciliation of the changes in the carrying amount of the right of use assets is as follows:

	Land	Buildings	Vehicles	Equipment	Total
New leases recognized Jan. 1, 2019	29	22	1	—	52
Adjustments on recognition <sup>(1)</sup>	(1)	(4)	—	—	(5)
Transfers from PP&E, intangibles and other assets	—	—	3	35	38
As at Jan. 1, 2019	28	18	4	35	85
Additions	—	2	—	1	3
Depreciation	(1)	(2)	(1)	(5)	(9)
<b>As at June 30, 2019</b>	<b>27</b>	<b>18</b>	<b>3</b>	<b>31</b>	<b>79</b>

(1) Adjusted by the amount of any prepaid or accrued lease payments, onerous contract provisions and lease inducements.

For the three and six months ended June 30, 2019, TransAlta paid \$7 million and \$13 million, respectively, related to the above leases, consisting of \$1 million and \$2 million in interest, respectively, and \$6 million and \$11 million in principal repayments, respectively.

Some of the Corporation's land leases that met the definition of a lease were not recognized as they require variable payments based on production or revenue. For the three and six months ended June 30, 2019, the Corporation expensed \$1 million and \$2 million, respectively, in variable land lease payments for these leases.

For further information regarding leases please refer to Notes 4, 6, 10, 13 and 17.

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

### A. Amounts Outstanding

The amounts outstanding are as follows:

As at	June 30, 2019			Dec. 31, 2018		
	Carrying value	Face value	Interest <sup>(1)</sup>	Carrying value	Face value	Interest <sup>(1)</sup>
Credit facilities <sup>(2)</sup>	200	200	3.4%	339	339	3.8%
Debtentures	647	651	5.8%	647	651	5.8%
Senior notes <sup>(3)</sup>	907	917	5.4%	943	955	5.4%
Non-recourse <sup>(4)</sup>	1,183	1,197	4.3%	1,236	1,250	4.4%
Other <sup>(5)</sup>	35	35	9.2%	39	39	9.2%
	<b>2,972</b>	<b>3,000</b>		<b>3,204</b>	<b>3,234</b>	
Lease obligations	75			63		
	<b>3,047</b>			<b>3,267</b>		
Less: current portion of long-term debt	(86)			(130)		
Less: current portion of lease obligations	(19)			(18)		
Total current long-term debt and lease obligations	<b>(105)</b>			<b>(148)</b>		
<b>Total credit facilities, long-term debt, and lease obligations</b>	<b>2,942</b>			<b>3,119</b>		

(1) Interest is an average rate weighted by principal amounts outstanding before the effect of hedging.

(2) Composed of bankers' acceptances and other commercial borrowings under long-term committed credit facilities.

(3) US face value at June 30, 2019 - US\$0.7 billion (Dec. 31, 2018 - US\$0.7 billion).

(4) Includes US\$1 million at June 30, 2019 (Dec. 31, 2018 - US\$1 million).

(5) Includes US\$19 million at June 30, 2019 (Dec. 31, 2018 - US\$21 million) of tax equity financing.

The Corporation has a total of \$2.2 billion (Dec. 31, 2018 - \$2.0 billion) of committed credit facilities, comprised of the Corporation's \$1.25 billion (Dec. 31, 2018 - \$1.25 billion) committed syndicated bank credit facility, TransAlta Renewables' committed syndicated bank credit facility of \$0.7 billion (Dec. 31, 2018 - \$0.5 billion), and the Corporation's \$0.2 billion (Dec. 31, 2018 - \$0.2 billion) committed bilateral facilities. These facilities were renewed, and TransAlta Renewables' facility was increased by \$200 million, during the second quarter of 2019 and expire in 2023, 2023, and 2021 respectively. The \$1.95 billion (Dec. 31, 2018 - \$1.75 billion) committed syndicated bank facilities are the primary source for short-term liquidity after the cash flow generated from the Corporation's business.

In total, \$1.3 billion (Dec. 31, 2018 - \$0.9 billion) is not drawn. At June 30, 2019, the \$0.9 billion (Dec. 31, 2018 - \$1.1 billion) of credit utilized under these facilities was comprised of actual drawings of \$200 million (Dec. 31, 2018 - \$339 million) and letters of credit of \$654 million (Dec. 31, 2018 - \$720 million). The Corporation is in compliance with the terms of the credit facilities and all undrawn amounts are fully available. In addition to the \$1.3 billion available under the credit facilities, the Corporation also has \$208 million of available cash and cash equivalents.

The Corporation's total outstanding letters of credit as at June 30, 2019 were \$654 million (Dec. 31, 2018 - \$720 million), including TransAlta Renewables outstanding letters of credit of \$92 million (Dec. 31, 2018 - \$77 million) with no (Dec. 31, 2018 - nil) amounts exercised by third parties under these arrangements. The Corporation has two uncommitted \$100 million demand letter of credit facilities and TransAlta Renewables has an uncommitted \$100 million demand letter of credit facility.

TransAlta's debt has terms and conditions, including financial covenants, that are considered normal and customary. As at June 30, 2019, the Corporation was in compliance with all debt covenants.

## B. Restrictions on Non-Recourse Debt

The Corporation's subsidiaries have issued non-recourse bonds of \$1,182 million (Dec. 31, 2018 - \$1,235 million) that are subject to customary financing conditions and covenants that may restrict the Corporation's ability to access funds generated by the facilities' operations. Upon meeting certain distribution tests, typically performed once per quarter, the funds are able to be distributed by the subsidiary entities to their respective parent entity. These conditions include meeting a debt service coverage ratio prior to distribution, which was met by these entities in the second quarter. However, funds in these entities that have accumulated since the second quarter test will remain there until the next debt service coverage ratio can be calculated in the third quarter of 2019. At June 30, 2019, \$23 million (Dec. 31, 2018 - \$33 million) of cash was subject to these financial restrictions.

Additionally, certain non-recourse bonds require that certain reserve accounts be established and funded through cash held on deposit and/or by providing letters of credit. The Corporation has elected to use letters of credit as at June 30, 2019.

## C. Security

Non-recourse debts of \$742 million in total (Dec. 31, 2018 - \$766 million) are each secured by a first ranking charge over all of the respective assets of each of the Corporation's subsidiaries that issued the bonds, which includes certain renewable generation facilities with total carrying amounts of \$996 million at June 30, 2019 (Dec. 31, 2018 - \$1,021 million). At June 30, 2019, a non-recourse bond of approximately \$125 million (Dec. 31, 2018 - \$127 million) is secured by a first ranking charge over the equity interests of the issuer that issued the non-recourse bond.

The TransAlta OCP bonds with a carrying value of \$315 million at June 30, 2019 (Dec. 31, 2018 - \$342 million) are secured by the assets of TransAlta OCP, including the right to annual capital contributions and OCA payments from the Government of Alberta. Under the OCA, the Corporation receives annual cash payments on or before July 31 of approximately \$40 million (approximately \$37 million, net to the Corporation), commencing Jan. 1, 2017, and terminating at the end of 2030.

## D. Restricted Cash

The Corporation has \$31 million (Dec. 31, 2018 - \$31 million) of restricted cash related to the Kent Hills project financing that is being held in a construction reserve account, which was returned in July 2019. The Corporation also has nil (Dec. 31, 2018 - \$35 million) of restricted cash related to the TransAlta OCP bonds.

## 14. Exchangeable Securities

On March 25, 2019, the Corporation announced that it had entered into an investment agreement whereby Brookfield agreed to invest \$750 million in TransAlta through the purchase of exchangeable securities, which are exchangeable into an equity ownership interest in TransAlta's Alberta Hydro Assets in the future at a value based on a multiple of the Hydro Assets' future EBITDA ("Option to Exchange"). The Exchangeable Securities will consist of the \$350 million debentures and \$400 million preferred shares which will be issued in October of 2020.

### A. \$350 Million Unsecured Subordinated Debentures

As at	June 30, 2019		
	Carrying value	Face value	Interest
Exchangeable debentures - due May 1, 2039	324	350	7.0%

### B. Option to Exchange

As at	June 30, 2019	
	Base fair value	Sensitivity
Option to Exchange - embedded derivative	—	+37 -28

The investment agreement allows Brookfield the Option to Exchange all of the outstanding Exchangeable Securities into an equity ownership interest in 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 and therefore it is 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 is 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 discount rate of 1 per cent is a reasonably possible change.

### C. Management Fee

Under the terms of the investment agreement, TransAlta has agreed to form a Hydro Assets Operating Committee consisting of two representatives from Brookfield and two representatives from TransAlta to provide advice to management on the operation of the Alberta Hydro Assets. In connection with this, the Corporation has committed to pay Brookfield an annual Management Fee of \$1.5 million for six years beginning May 1, 2019, which is recognized in the operations, maintenance and administration expense on the statement of earnings (loss).

## 15. Common Shares

### A. Issued and Outstanding

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

	6 months ended June 30			
	2019		2018	
	Common shares (millions)	Amount	Common shares (millions)	Amount
Issued and outstanding, beginning of period	284.6	3,059	287.9	3,095
Shares purchased and retired under NCIB <sup>(1)</sup>	(2.4)	(26)	(0.6)	(6)
Stock options exercised	0.1	1	—	—
	282.3	3,034	287.3	3,089
Amounts receivable under Employee Share Purchase Plan	—	—	—	(1)
<b>Issued and outstanding, end of period</b>	<b>282.3</b>	<b>3,034</b>	<b>287.3</b>	<b>3,088</b>

(1) 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 retained earnings.

### B. NCIB Program

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

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

	June 30, 2019	June 30, 2018
Total shares purchased	2,398,200	587,300
Average purchase price per share	\$ 8.57	\$ 6.77
<b>Total cost</b>	<b>21</b>	<b>4</b>
Weighted average book value of shares cancelled	26	6
Increase to retained earnings	5	2

### C. Earnings per Share

	3 months ended June 30		6 months ended June 30	
	2019	2018	2019	2018
Net earnings (loss) attributable to common shareholders	—	(105)	(65)	(40)
Basic and diluted weighted average number of common shareholders outstanding (millions)	284	288	284	288
<b>Net earnings (loss) per share attributable to common shareholders, basic and diluted</b>	<b>—</b>	<b>(0.36)</b>	<b>(0.23)</b>	<b>(0.14)</b>

### D. Dividends

On July 16, 2019, the Corporation declared a quarterly dividend of \$0.04 per common share, payable on Oct. 1, 2019.

On April 15, 2019, the Corporation declared a quarterly dividend of \$0.04 per common share, payable on July 1, 2019.

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

## E. Stock Options

The stock options granted to executive officers of the Corporation during the six months ended June 30, 2019 and 2018 are as follows:

Grant month	Number of stock options granted (millions)	Exercise price	Vesting period (years)	Expiration length (years)
January 2019 <sup>(1)</sup>	1.2	\$ 5.59	3	7
January 2018	0.7	\$ 7.45	3	7

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

## 16. Preferred Shares

### A. Issued and Outstanding

All preferred shares issued and outstanding are non-voting cumulative redeemable fixed rate first preferred shares, other than the Series B preferred shares which are non-voting cumulative redeemable floating rate first preferred shares.

As at June 30, 2019 and Dec. 31, 2018, the Corporation had 10.2 million Series A, 1.8 million Series B, 11.0 million Series C, 9.0 million Series E, 6.6 million Series G shares issued and outstanding.

### B. Dividends

The following summarizes the preferred share dividends declared within the three and six months ended June 30:

Series	Quarterly amounts per share	3 months ended June 30		6 months ended June 30	
		2019	2018	2019 <sup>(1)</sup>	2018
A	0.16931	2	1	2	3
B	0.23136 <sup>(2)</sup>	—	1	—	1
C	0.25169	3	3	3	6
E	0.32463	3	3	3	6
G	0.33125	2	2	2	4
<b>Total for period</b>		<b>10</b>	<b>10</b>	<b>10</b>	<b>20</b>

(1) No dividends were declared in the first quarter of 2019 as the quarterly dividend related to the period covering the first quarter of 2019 was declared in December 2018.

(2) Series B Preferred Shares pay quarterly dividends at a floating rate based on the 90-day Government of Canada Treasury Bill rate, plus 2.03 per cent. Approximately \$400 thousand dividends were declared in the three months ended June 30, 2019.

On July 16, 2019 the Corporation declared a quarterly dividend of \$0.16931 per share on the Series A preferred shares, \$0.23422 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 \$0.33125 per share on the Series G preferred shares, all payable on Sept. 30, 2019.

On April 15, 2019 the Corporation declared a quarterly dividend of \$0.16931 per share on the Series A preferred shares, \$0.23136 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 \$0.33125 per share on the Series G preferred shares, all payable on June 30, 2019 and paid on July 2, 2019.

## 17. Commitments and Contingencies

### A. Commitments

During the second quarter of 2019, the Corporation entered into new contractual commitments for new assets beginning in the third quarter of 2019, with total payments of \$65 million. Annual payments will be: 2019 - \$9 million; 2020 - \$17 million; 2023 to 2038 - \$2-3 million per year.

In addition, beginning on Nov. 1, 2019, TransAlta has a commitment to transport the initial daily contract quantity of 139,000 gj/day of natural gas on a firm basis on the Pioneer Pipeline.

### 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. Inquiries from regulatory bodies may also arise in the normal course of business, to which the Corporation responds as required. 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.

#### I. Line Loss Rule Proceeding

The Corporation has been participating in a 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 Alberta Electric System Operator to, among other things, perform such retroactive calculations. A recent decision by the AUC determined the methodology to be used retroactively and it is now possible to estimate the total potential retroactive exposure faced by the Corporation for its non-PPA MWs. Because of the complexity of the new methodology, the final calculations from the AESO will not be available for some time, and there will be no payments until 2021. The Applications for permission to appeal various AUC decisions were denied. There is some potential for further appeals, but the probability of success on such appeals is low. The current estimate of exposure based on known data is \$15 million and therefore the Corporation has recorded a provision of \$15 million as at June 30, 2019 and Dec. 31, 2018.

#### II. FMG Disputes

The Corporation is currently engaged in two disputes with Fortescue Metals Group Ltd. ("FMG"). The first arose as a result of FMG's purported termination of the South Hedland PPA. TransAlta has sued FMG, seeking payment of amounts invoiced and not paid under the South Hedland PPA, as well as a declaration that the PPA is valid and in force. FMG, on the other hand, seeks a declaration that the PPA was lawfully terminated.

The second matter involves FMG's claims against TransAlta related to the transfer of the Solomon Power Station to FMG. FMG claims certain amounts related to the condition of the facility while TransAlta claims certain outstanding costs that should be reimbursed.

#### III. Balancing Pool Dispute

Pursuant to a written agreement, the Balancing Pool paid the Corporation approximately \$157 million on March 29, 2018 as part of the net book value payment required on termination of the Sundance B and C PPAs. The Balancing Pool, however, excluded certain mining and corporate assets that the Corporation believes should be included in the net book value calculation, which amounts to an additional \$56 million. The dispute is currently proceeding through arbitration.

#### IV. Mangrove

On April 23, 2019, Mangrove Partners 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 Partners is seeking various remedies but primarily to set aside the Brookfield transaction. TransAlta believes the claim is wholly lacking in merit and is taking all steps to defend against the allegations.

## 18. Segment Disclosures

### A. Reported Segment Earnings (Loss)

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

(1) Corporate segment revenues and fuel and purchased power relates to intercompany elimination of profit in inventory on purchased emission credits

3 months ended June 30, 2018	Canadian Coal	U.S. Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues	179	51	51	41	51	63	13	(3)	446
Fuel and purchased power	136	20	18	2	4	2	—	(3)	179
Gross margin	43	31	33	39	47	61	13	—	267
Operations, maintenance, and administration	43	12	12	9	11	11	5	20	123
Depreciation and amortization	64	16	10	12	29	7	1	7	146
Asset impairment	—	—	—	—	12	—	—	—	12
Restructuring provision	—	—	—	—	—	—	—	—	—
Taxes, other than income taxes	4	1	—	—	2	1	—	—	8
Net other operating income	(10)	—	—	—	—	—	—	—	(10)
Operating income (loss)	(58)	2	11	18	(7)	42	7	(27)	(12)
Finance lease income	—	—	3	—	—	—	—	—	3
Net interest expense									(59)
Foreign exchange loss									(5)
Loss before income taxes									(73)

(1) Corporate segment revenues and fuel and purchased power relates to intercompany elimination of profit in inventory on purchased emission credits

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

(1) Corporate segment revenues and fuel and purchased power relates to intercompany elimination of profit in inventory on purchased emission credits

6 months ended June 30, 2018	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues	448	138	113	82	137	90	30	(4)	1,034
Fuel, carbon, and purchased power	332	64	47	4	10	3	—	(4)	456
Gross margin <sup>(1)</sup>	116	74	66	78	127	87	30	—	578
Operations, maintenance, and administration	90	27	25	18	24	19	13	40	256
Depreciation and amortization	114	32	21	24	56	15	1	13	276
Asset impairment	—	—	—	—	12	—	—	—	12
Taxes, other than income taxes	7	2	1	—	4	2	—	—	16
Termination of Sundance B and C PPAs	(157)	—	—	—	—	—	—	—	(157)
Net other operating income	(21)	—	—	—	—	—	—	—	(21)
Operating income (loss)	83	13	19	36	31	51	16	(53)	196
Finance lease income	—	—	5	—	—	—	—	—	5
Net interest expense									(127)
Foreign exchange gain									(7)
Earnings before income taxes									67

(1) Corporate segment revenues and fuel and purchased power relates to intercompany elimination of profit in inventory on purchased emission credits

## 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 June 30		6 months ended June 30	
	2019	2018	2019	2018
Depreciation and amortization expense on the Condensed Consolidated Statements of Earnings	143	146	288	276
Depreciation included in fuel and purchased power	30	36	59	67
<b>Depreciation and amortization on the Condensed Consolidated Statements of Cash Flows</b>	<b>173</b>	<b>182</b>	<b>347</b>	<b>343</b>



## Exhibit 1

(Unaudited)

The information set out below is referred to as “unaudited” as a means of clarifying that it is not covered by the audit opinion of the independent registered public accounting firm that has audited and reported on the Annual Audited Consolidated Financial Statements.

### To the Financial Statements of TransAlta Corporation

#### EARNINGS COVERAGE RATIO

The following selected financial ratio is calculated for the period ended June 30, 2019:

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

(0.40) times

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

## Supplemental Information

		June 30, 2019	Dec 31, 2018
Closing market price (TSX) (\$)		8.52	5.59
Price range for the last 12 months (TSX) (\$)	High	10.14	7.90
	Low	5.44	5.44
FFO before interest to adjusted interest coverage <sup>(2)</sup> (times)		4.9	4.8
Adjusted FFO to adjusted net debt <sup>(2)</sup> (%)		20.0	20.8
Adjusted net debt to comparable EBITDA <sup>(1,2)</sup> (times)		3.8	3.7
Adjusted net debt to invested capital <sup>(1)</sup> (%)		51.0	49.7
Return on equity attributable to common shareholders <sup>(2)</sup> (%)		(18.4)	(15.8)
Return on capital employed <sup>(2)</sup> (%)		(1.2)	0.7
Earnings coverage <sup>(2)</sup> (times)		(0.4)	0.2
Dividend payout ratio based on FFO <sup>(1,2)</sup> (%)		6.2	7.6
Dividend coverage <sup>(2)</sup> (times)		13.8	18.3
Dividend yield <sup>(2)</sup> (%)		1.9	2.9

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

(2) Last 12 months. During the first quarter of 2019, we revised comparable EBITDA to remove the unrealized mark-to-market gains (losses). 2018 results have been revised to reflect this change.

### Ratio Formulas

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

**Adjusted FFO to adjusted net debt** = FFO - 50 per cent dividends paid on preferred shares / period end long-term debt and lease obligations including fair value (asset) liability of hedging instruments on debt + 50 per cent issued preferred shares - cash and cash equivalents

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

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

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

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

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

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

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

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

## Glossary of Key Terms

**Availability** - A measure of the 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.

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

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

**Gigawatt** - 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)** - Gases having potential to retain heat in the atmosphere, including water vapour, carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, and perfluorocarbons.

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

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

**Power Purchase Arrangement (PPA)** - A long-term arrangement established by regulation for the sale of electric energy from formerly regulated generating units to buyers.

**Unplanned Outage** - The shut-down of a generating unit due to an unanticipated breakdown.

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